The Liability of Carbon Dioxide Storage

by

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Abstract

This research examines the liability of storing CO_2 in geological formations. There is a potential tortious and contractual liability exposure if stored CO_2 is not fully contained by the geological formation. Using a combination of case study and survey methods, this research examines the risks confronted by CO_2 storage, the legal and regulatory regimes governing these risks, and liability arrangements in other sectors where analogous risks have been confronted. Currently identifiable sources of liability include induced seismicity, groundwater contamination, harm to human health and the environment, property interests, and permanence. The risks of CO_2 storage are analyzed in the context of several case studies: acid gas injection, natural gas storage, secondary oil recovery, and enhanced oil recovery. Methods for containing liability are considered in the context of regulatory analogs.

This research finds that the current public and private mechanisms that would govern CO_2 storage liability do not adequately address the issue. The analysis reveals six lessons learned: (1) the successful resolution of the CO_2 liability issue will require combining our understanding of physical and regulatory analogs; (2) the prospect of CO_2 storage liability will affect the implementation of predictive models and incentives to monitor leakage; (3) jurisdictional differences in liability exposure could affect where storage projects are eventually sited; (4) the development of liability rules is a function of an industry's emergence, but an industry's emergence, in turn, may affect the content of the liability rules; (5) regulatory compliance is not always a safe harbor for liability; and (6) statutes of limitation and repose mean that private liability is not necessarily "forever". A new liability arrangement is advocated where the current permitting regime is amended, long-term liability is managed by a governmental CO_2 Storage Corporation with backing from an industry-financed CO_2 Storage Fund, compensation for tortious liability occurs through an Office of Special Masters for CO_2 Storage in the U.S. Federal Court of Claims, and the permanence issue is addressed on an annual *ex post* basis during the injection phase of CO_2 storage operations and on an *ex ante* basis when sites are transferred to the CO_2 Storage Corporation.

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Table of Contents

Tables

Figures

Glossary

AAU	Assigned amount unit
AGS	Alliance for Global Sustainability
ANPR	Advance notice of proposed rulemaking
BLM	U.S. Bureau of Land Management
CAA	Clean Air Act
CCS	Carbon dioxide capture and storage
CDM	Clean development mechanism
CDOC	California Department of Conservation
CER	Certified emission reduction
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
C.F.R.	U.S. Code of Federal Regulations
CO_2	Carbon dioxide
COP	Conference of the parties
CSLF	Carbon Sequestration Leadership Forum
CWA	Clean Water Act
DOE	U.S. Department of Energy
DOI	U.S. Department of Interior
EA	Environmental assessment
EEZ	Exclusive economic zone
EGR	Enhanced gas recovery
EIA	U.S. Energy Information Administration
EIS	Environmental impact statement
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act of 2005
ERU	Emission reduction unit
EUB	Alberta Energy & Utilities Board
FERC	U.S. Federal Energy Regulatory Commission
FLPMA	Federal Land Policy and Management Act of 1976
FONSI	Finding of no significant impact
FWQA	Federal Water Quality Administration
GAO	U.S. Government Accountability Office, formerly U.S. General Accounting Office
GHG	Greenhouse gas
GIS	Geographic information system
H_2CO_3	Carbonic acid
H_2S	Hydrogen sulfide
HHS	U.S. Department of Health & Human Services
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
IPCC Inventory Guidelines	IPCC Guidelines for National Greenhouse Gas Inventories
IPCC Special Report	IPCC Special Report on Carbon Dioxide Capture and Storage
JI	Joint implementation
KDHE	Kansas Department of Health and Environment
lCER	Long-term certified emission reduction
LLR	Licensee liability rating
LNG	Liquefied natural gas
London Convention	Convention on the Prevention of Marine Pollution by Dumping of Wastes and other Matter
London Protocol	Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and other Matter
LULUCF	Land use, land-use change and forestry
MAOP	Maximum allowable operating pressure
MIT	Massachusetts Institute of Technology
MLA	Mineral Leasing Act of 1920
MMP	Minimum miscibility pressure
MMS	U.S. Minerals Management Service
MMV	Measurement, monitoring, and verification
MOP	Meeting of the parties
NEPA	National Environmental Policy Act of 1969
NGO	Non-governmental organization
NIOSH	National Institute of Occupational Safety and Health
NRC	U.S. Nuclear Regulatory Commission
OSPAR Convention	Convention for the Protection of the Marine Environment of the North-East Atlantic
OSHA	U.S. Occupational Safety and Health Administration
OTA	U.S. Office of Technology Assessment

RCRA	Resource Conservation and Recovery Act
RMU	Removal unit
RRC	Railroad Commission of Texas
SACS	Saline Aquifer CO_2 Storage project (Sleipner)
SBSTA	Subsidiary Body for Scientific and Technological Advice
SDWA	Safe Drinking Water Act of 1974
SDWAA	Solid Waste Disposal Act Amendments of 1980
tCER	Temporary certified emission reduction
UIC	Underground Injection Control
UN	United Nations
UNCLOS	United Nations Convention on the Law of the Sea
UNFCCC	United Nations Framework Convention on Climate Change
USDW	Underground source of drinking water
USGS	U.S. Geological Survey
U.S.C.	U.S. Code
WAG	Water-alternating-gas
WHO	World Health Organization

1. Overview of Thesis

This thesis examines the liability of storing carbon dioxide ("CO_2") in geological formations. CO_2 storage is an option among the portfolio of mitigation actions for stabilizing atmospheric CO_2 concentrations. The technology involves the long-term isolation of CO_2 that is separated from industrial and energy-related sources. Liability concerns are raised if the stored CO_2 is not fully contained by the geological formation into which the CO_2 was injected.

There is an unfolding body of technical literature on the risks of CO_2 storage which is framed by prior knowledge from analogous subsurface injection activities. This technical literature is situated within an uncertain and developing body of law. The issue of CO_2 storage liability has begun to be examined on the federal and state level, but the discussion has centered on attempts to externalize liability rather than addressing how liability will be managed in the long-term.[1] The analysis in this thesis uses the United States legal regime as a basis for precedent.

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[1] The discussion in the United States has been motivated by the FutureGen project, discussed *infra* in note 309 and the associated text. *See* FUTUREGEN INDUSTRIAL ALLIANCE, FINAL REQUEST FOR PROPOSALS 44 (March 7, 2006) ("The offeror agrees to take title to the injected CO_2 and indemnify the FutureGen Industrial Alliance and its members from any potential liability associated with the CO_2"); Tex. H.B. 149 (2006) (Texas Railroad Commission "shall acquire title to CO_2 captured" by a FutureGen project); failed Costello Amendment to H.R. 5656 (2006) (U.S. Department of Energy indemnifies FutureGen consortium and companies for "any legal liability arising out of, or resulting from, the storage, or unintentional release, of sequestered emissions," up to $500 million per incident); Illinois House Bill 5825 (first reading November 1, 2006) ("If a civil proceeding is commenced against an operator arising from the escape or migration of injected carbon dioxide, then the Attorney General shall, upon timely and appropriate notice by the operator, appear on behalf of the operator and defend the action. … [U]nless the court or jury finds that the action was intentional, willful, or wanton misconduct, the State shall indemnify the operator for any damages awarded and court costs and attorneys' fees assessed as part of any final and unreversed judgment or shall pay the judgment.").

1.1. Objectives of Thesis

This thesis has three objectives. They are to:

- Analyze the effectiveness of current public and private liability mechanisms for CO_2 storage risks
- Assess the treatment of liability in contexts analogous to CO_2 storage
- Develop a liability framework governing CO_2 storage risks

1.2. Approach

This thesis uses a combination of case study and survey methods for analyzing the CO_2 storage liability issue. Case studies in the liability context have an added importance compared to other studies of social inquiry because of their use as precedent. The approach of the thesis is shown graphically in Figure 1.1. Liability rules are formed on the basis of preceding decisions on similar questions of fact and law. For CO_2 storage, the relevant precedent will be activities facing analogous subsurface injection risks and/or contractual obligations. Thus, the liability of CO_2 storage is impacted by the characteristics of the technology itself and the law underlying tortious and contractual liability, which in turn is informed by prior historical cases.

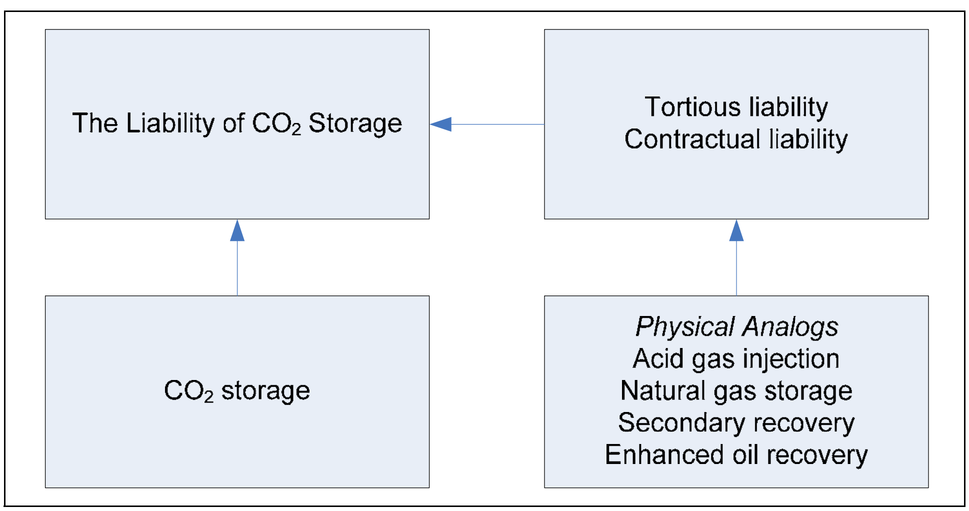

Figure 1.1 Approach of Thesis

The thesis begins with introductory background material on the research topic. The first half of Chapter 2 is geared towards readers unfamiliar with CO_2 storage technology. It begins with a discussion of the prerequisites to CO_2 storage, the types of geological formations into which CO_2 would be injected, the behavior of the injected CO_2 after it has been injected into the formation, storage integrity of the formation, and the effectiveness of tools for monitoring the CO_2 storage site. The second half of the chapter is geared towards readers unfamiliar with the topic of liability. It discusses the mechanisms by which liability may be incurred, strategies that have been used by the public and private sectors for containing liability, and exemplary schemes for managing large-scale long-term liabilities of the sort that might be expected for CO_2 storage.

Chapter 3 analyzes the regulation of CO_2 storage under the current regime. Because the law in this area is only partly developed, the analysis is both historical and prognostic. The analysis is divided between onshore storage, which is governed largely by national laws and regulations, and offshore storage, which is governed largely by international agreements as implemented by countries.

Because CO_2 storage has not yet reached commercialization, the analysis of the risks of large-scale CO_2 storage is limited and necessarily speculative. A web-based survey was distributed to CO_2 storage experts from industry and non-governmental organizations, with the purpose of garnering their opinions of the risks facing CO_2 storage. Their survey responses were followed up through optional interviews to allow respondents to expand on their views expressed in the survey. The design and results of the survey are discussed in Chapter 4.

Based on the perceived risks identified by the expert survey, Chapters 5 and 6 examine, where applicable, the technical bases for the risk and present case studies which show how liability for these risks has been treated historically. In particular, Chapter 5 analyzes those risks where CO_2 storage operators may have a legal duty to take reasonable precautions to contain the risk (liability for tortious damages) and Chapter 6 investigates the effect of CO_2 leakage on carbon-constraining policies and the breach of contracts for storing CO_2.

Chapter 7 provides an in-depth analysis of three case studies of subsurface injection liability: acid gas injection, natural gas storage, and secondary recovery/enhanced oil recovery. These "physical analogs" were chosen because of their technical similarities to CO_2 storage. In fact, acid gas injection and enhanced oil recovery projects already inject large amounts of CO_2 into the subsurface, albeit for different purposes than climate change mitigation and smaller scales than what might be expected if CO_2 storage is to have a meaningful impact for stabilizing atmospheric CO_2 concentrations.

Finally, Chapter 8 provides an integrated discussion of CO_2 storage risks and liability frameworks. The implication of the analysis in this thesis is that the current private and public frameworks that would govern CO_2 storage do not adequately address liability. In the first half of the chapter, six lessons learned are described from the historical treatment of analogous risks and liability in other sectors. In the second half of the chapter, a proposal is put forward for addressing the CO_2 storage liability issue.

2. Background

2.1. Introduction

This chapter is intended to provide background on the CO_2 storage liability issues explored in this thesis. The first half of the chapter reviews the fundamentals of the geological storage of CO_2, including the prerequisites to CO_2 storage (such as the possible sources of CO_2, methods of CO_2 capture, and forms of CO_2 transport), likely geological storage formations, subsurface behavior of CO_2, potential pathways of leakage, and measurement, monitoring and verification. The second half of the chapter reviews the fundamentals of liability, specifically tortious and contractual liability, as well as public and private mechanisms that have been used to manage liability historically.

2.2. Geological Storage of CO_2

As a result of concern that human activities are increasing atmospheric concentrations of CO_2 and that those increasing concentrations are at least partially attributable to the warming of the Earth's climate,[2] global climate change is rapidly becoming an integral part of the international environmental agenda.[3] The issue is complicated by uncertainty as to the magnitude and timing of climate change, the effect of climate change on natural systems, and the

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[2] The Intergovernmental Panel on Climate Change ("IPCC"), an international scientific body established by the World Meteorological Organization and United Nations Environment Programme, estimates that atmospheric concentrations of carbon dioxide have increased from 280 parts per million in pre-industrial times to 368 parts per million in the year 2000. Climate models comparing the Earth's temperature variations with and without results from anthropogenic influences conclude that global temperature rise is attributable to both natural and human-induced forcing. INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CLIMATE CHANGE 2001: SYNTHESIS REPORT, SUMMARY FOR POLICY MAKERS 5, 7 (2001).

[3] *See, e.g.*, United Nations Framework Convention on Climate Change, *opened for signature* June 4, 1992, S. Treaty Doc. No. 102-38 (1992), 31 I.L.M. 849 (1992) (*entered into force* Mar. 21, 1994) [hereinafter UNFCCC]. *See also* David M. Reiner, *Whither Kyoto? Ten Years of Climate Change Policymaking*, 4 GEO. J. INT'L AFF. 127, 132-33 (2003); David G. Victor et al, *A Madisonian Approach to Climate Policy*, 309 SCI. 1820, 1820 (2005).

potential to adapt to a changing climate.[4] Climate change can be mitigated by stabilization of atmospheric CO_2 concentrations,[5] but stabilization will require a sustained reduction of CO_2 emissions to substantially below current levels.[6]

Fossil fuels, the leading source of CO_2 emissions,[7] are expected to remain the dominant source of energy supply well into the twenty-first century.[8] In the absence of any government policy to manage greenhouse gas ("GHG") emissions, global primary energy production is expected to be dominated by petroleum, natural gas, and coal.[9] Because energy efficiency and renewable energy resources are not expected to be deployed at a pace fast enough to constrain cumulative CO_2 emissions to prudent levels, even with assumptions of technological success for non-carbon-emitting technologies, additional technology options will be necessary in order to constrain CO_2 emissions.[10] One option being considered among the portfolio of mitigation actions is carbon dioxide capture and storage ("CCS").

The Intergovernmental Panel on Climate Change ("IPCC") defines CCS as "a process consisting of the separation of CO_2 from industrial and energy-related sources, transport to a

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[4] Eugene Skolnikoff, *The Role of Science in Policy: The Climate Change Debate in the United States*, 41 ENV'T 16 (1999).

[5] N.W. Arnell et al, *The Consequences of CO_2 Stabilisation for the Impacts of Climate Change*, 53 CLIMATIC CHANGE 413, 441 (2002); K. Hasselmann et al, *The Challenge of Long-Term Climate Change*, 302 SCI. 1923, 1924 (2003). Because of technical and economic constraints, probably the most that can be done is to stabilize atmospheric carbon dioxide concentrations at twice pre-industrial levels, or 560 parts per million. S. Julio Friedmann & Thomas Homer-Dixon, *Out of the Energy Box*, 83 FOREIGN AFF. 72, 82 (2004). The increase in atmospheric concentrations of carbon dioxide is due to the imbalance of anthropogenic emissions and carbon sinks. Jae Edmonds, *Atmospheric Stabilization: Technology Needs, Opportunities, and Timing*, *in* U.S. POL'Y ON CLIMATE CHANGE: WHAT NEXT? 49 (Aspen Inst., 2002).

[6] T.M.L. Wigley, R. Richels & J.A. Edmonds, *Economic and Environmental Choices in the Stabilization of Atmospheric CO_2 Concentrations,* 379 NATURE 240, 241 (1996).

[7] U.S. ENVTL. PROTECTION AGENCY, DRAFT INVENTORY OF GREENHOUSE GAS EMISSIONS AND SINKS: 1990-2004 53 (2006) (finding that carbon dioxide emissions from fossil fuel combustion constituted 5,656.6 teragrams of carbon dioxide equivalents out of total emissions of 5,835.3 teragrams of carbon dioxide equivalents, or about 97% of total carbon dioxide emissions).

[8] *See, e.g.*, U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 65 (2006).

[9] *Id.* at 6.

[10] Edmonds, *supra* note 5, at 52; The Nation's Energy Future: The Role of Renewable Energy and Energy Efficiency Hearing Before the H. Comm. on Sci. (2001) (testimony of Ken Humphreys, Pacific Northwest Nat'l Lab.). *See also* David G. Hawkins, *No Exit: Thinking about Leakage from Geologic Carbon Storage Sites* 29 ENERGY 1571, 1575 (2004); Donald Kennedy, *The Hydrogen Solution*, 305 SCI. 917 (2004).

storage location and long-term isolation from the atmosphere".[11] At least twenty-one countries have been exploring the development of improved cost-effective technologies for separating and capturing CO_2 for its transport and long-term safe storage.[12] The IPCC has modeled CCS deployment under six emission scenarios and finds that the average global cumulative storage ranges from 380 billion tonnes of CO_2 ($GtCO_2$) for stabilizing atmospheric CO_2 concentrations at 750 ppmv to 2,160 $GtCO_2$ for stabilization at 450 ppmv.[13] This thesis focuses on the storage of CO_2 in geological formations. Although there is potential for CO_2 to be stored directly in the ocean[14] or in the form of mineral carbonates,[15] the injection of CO_2 into geological formations is widely considered to have the greatest near-term potential.[16]

2.2.1. Prerequisites to CO_2 Storage

2.2.1.1. Sources of CO_2

CCS requires a relatively pure, high pressure stream of CO_2 for reasons of technical and economic efficiency.[17] Three types of sources are most amenable for CO_2 capture (see Figure 2.1). One option is to capture CO_2 from fossil fuel power plants. The U.S. Environmental Protection Agency ("EPA") estimates that fossil fuel power plants are responsible for over 40%

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[11] INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, IPCC SPECIAL REPORT ON CARBON DIOXIDE CAPTURE AND STORAGE 3 (2005) [hereinafter IPCC Special Report].

[12] The Carbon Sequestration Leadership Forum ("CSLF") is an international collaboration to address the technical and policy issues associated with carbon capture and sequestration. Its members are: Australia, Brazil, Canada, China, Colombia, Denmark, European Community, France, Germany, India, Italy, Japan, Korea, Mexico, Netherlands, Norway, Russia, Saudi Arabia, South Africa, the United Kingdom, and the United States. Carbon Sequestration Leadership Forum, About the CSLF, *at* http://www.cslforum.org/about.htm (last visited Dec. 1, 2005).

[13] IPCC Special Report, *supra* note 11, at 354.

[14] IPCC Special Report, *supra* note 11, at 277-317; MARK DE FIGUEIREDO, THE HAWAII CARBON DIOXIDE OCEAN SEQUESTRATION FIELD EXPERIMENT: A CASE STUDY IN PUBLIC PERCEPTIONS AND INSTITUTIONAL EFFECTIVENESS (S.M. thesis, MIT, 2003).

[15] Klaus Lackner et al, Carbon Dioxide Disposal in Carbonate Minerals, 20 ENERGY 1153 (1995); HOWARD HERZOG, CARBON SEQUESTRATION VIA MINERAL CARBONATION: OVERVIEW AND ASSESSMENT (MIT Laboratory for Energy & the Environment, Mar. 14, 2002); IPCC Special Report, *supra* note 11, at 319-337.

[16] IPCC Special Report, *supra* note 11, at 21.

[17] HOWARD HERZOG, AN INTRODUCTION TO CO_2 SEPARATION AND CAPTURE TECHNOLOGIES (MIT Energy Lab. Working Paper, 1999).

of U.S. CO_2 emissions from fossil fuel combustion.[18] A second option is to capture CO_2 from industrial processes which transform materials chemically, physically, or biologically.[19] Examples include petrochemical processes, cement production, and the removal of CO_2 from natural gas to improve its heating value or meet industry specifications.[20] A third option is to capture CO_2 from the production of hydrogen fuels from carbon-rich feedstocks.[21] Hydrogen fuels can be used in many applications, including gas turbines and fuel cells, but the development of centralized generation of hydrogen has been limited by infrastructure barriers, such as the transportation of hydrogen over long distances.[22]

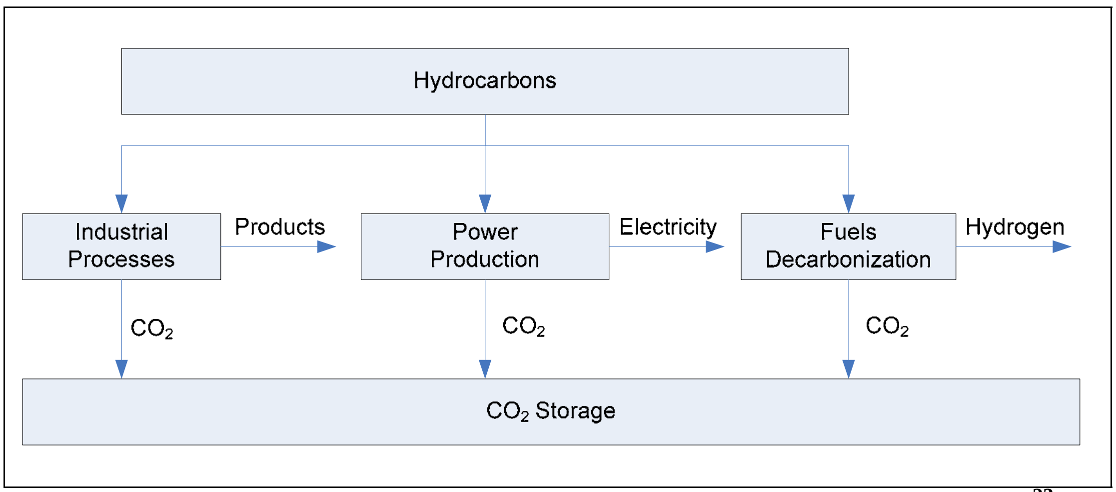

Figure 2.1 Potential CCS Pathways (Adapted from Herzog & Golomb)[23]

An important consideration in determining the potential for CCS is the geographical relationship between CO_2 sources and geological storage formations (the so-called source-sink matching issue). Where large stationary emission sources and geological storage sites are

[18] U.S. ENVTL. PROTECTION AGENCY, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990-2003 ES-7 (EPA 430-R-05-003, 2005).
[19] IPCC Special Report, *supra* note 11, at 78.
[20] *Id.*
[21] HERZOG, *supra* note 17.
[22] *See generally* NAT'L ACADEMY OF ENGINEERING, THE HYDROGEN ECONOMY: OPPORTUNITIES, COSTS, BARRIERS, AND R&D NEEDS (2004).
[23] Howard Herzog & Dan Golomb, *Carbon Capture and Storage from Fossil Fuel Use, in* ENCYCLOPEDIA OF ENERGY 277 (C.J. Cleveland *et al.* eds., 2004).

located in close proximity to one another, the potential for the emissions to be reduced using CCS is greater than in cases where sources and sinks are located far apart. This is because CCS costs are affected by the length and size of the transmission infrastructure required.[24] As shown in Figure 2.2, the IPCC found that North America had the largest number of stationary sources of CO_2 (37%), followed by Asia (24%), and OECD[25] Europe (14%).[26] In the next fifty years, it is expected that the distribution of emission sources will shift from the OECD countries to developing countries, especially China, South Asia, and Latin America.[27]

Figure 2.2 Global Distribution of Large Stationary Sources of CO_2 (IPCC)[28]

2.2.1.2. CO_2 Capture

The purpose of the capture component of CCS is to produce a relatively pure stream of CO_2 that may be readily transported to a storage site.[29] CO_2 capture can take one of three approaches. One method of capture is post-combustion separation, which normally uses a liquid solvent, such

[24] IPCC Special Report, *supra* note 11, at 78.
[25] *See* Organization for Economic Cooperation and Development, About OECD, *at* http://www.oecd.org/about/0,2337,en_2649_201185_1_1_1_1_1,00.html (last visited July 21, 2006).
[26] *Id.* at 83.
[27] *Id.* at 85-88.
[28] *Id.* at 84. Reprinted with the permission of Cambridge University Press.
[29] *Id.* at 28.

as monoethanolamine ("MEA"), to preferentially capture the small fraction (~ 15% by volume) of CO_2 in a flue gas stream.[30] A second method of capture is oxyfuel combustion, where fossil fuels are burned in the presence of oxygen instead of air, which results in a flue gas that is mainly water vapor and CO_2.[31] The CO_2 in the stream has a higher CO_2 concentration (greater than 80% by volume) than the classic post-combustion scenario.[32] A third method of capture is pre-combustion separation, which, for example, would be employed in an integrated gasification combined cycle ("IGCC") power plant. In an IGCC plant, coal is processed in a reactor with steam and oxygen to produce a synthesis gas composed mainly of carbon monoxide and hydrogen.[33] The carbon monoxide is then reacted with steam in a shift reaction to produce CO_2 and additional hydrogen.[34] The resulting mixture of CO_2 and hydrogen can be separated, with CO_2 being stored in a geological formation and hydrogen being used for electricity production.[35] Schematics of post-combustion separation, oxyfuel combustion, and pre-combustion separation are shown in Figure 2.3, Figure 2.4, and Figure 2.5 respectively.

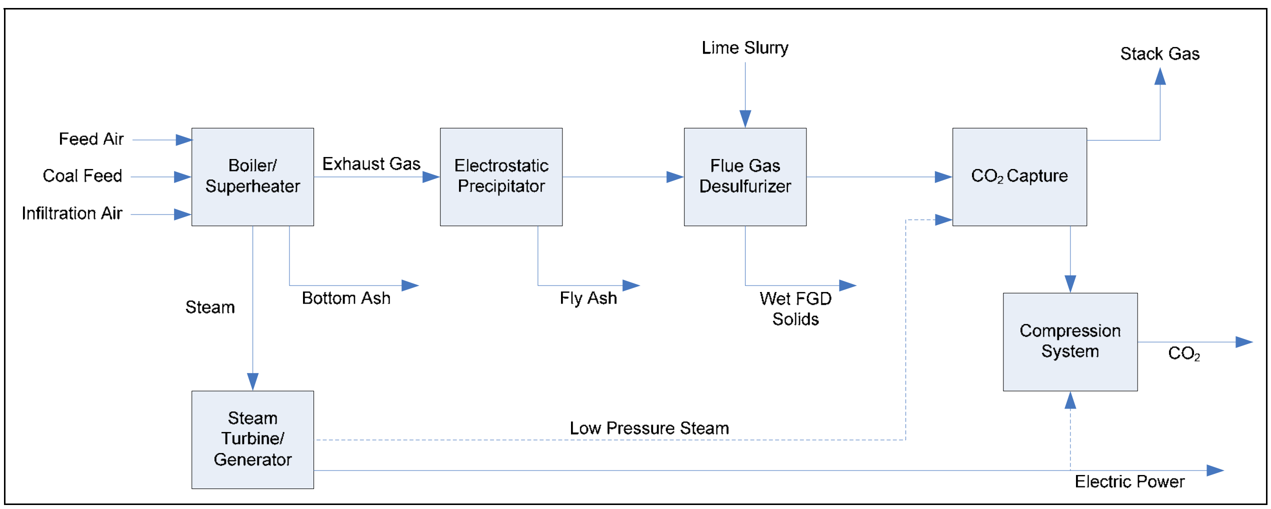

Figure 2.3 Post-Combustion Separation

[30] *Id.* at 25.
[31] *Id.*
[32] *Id.*
[33] *Id.*
[34] *Id.*
[35] *Id.*

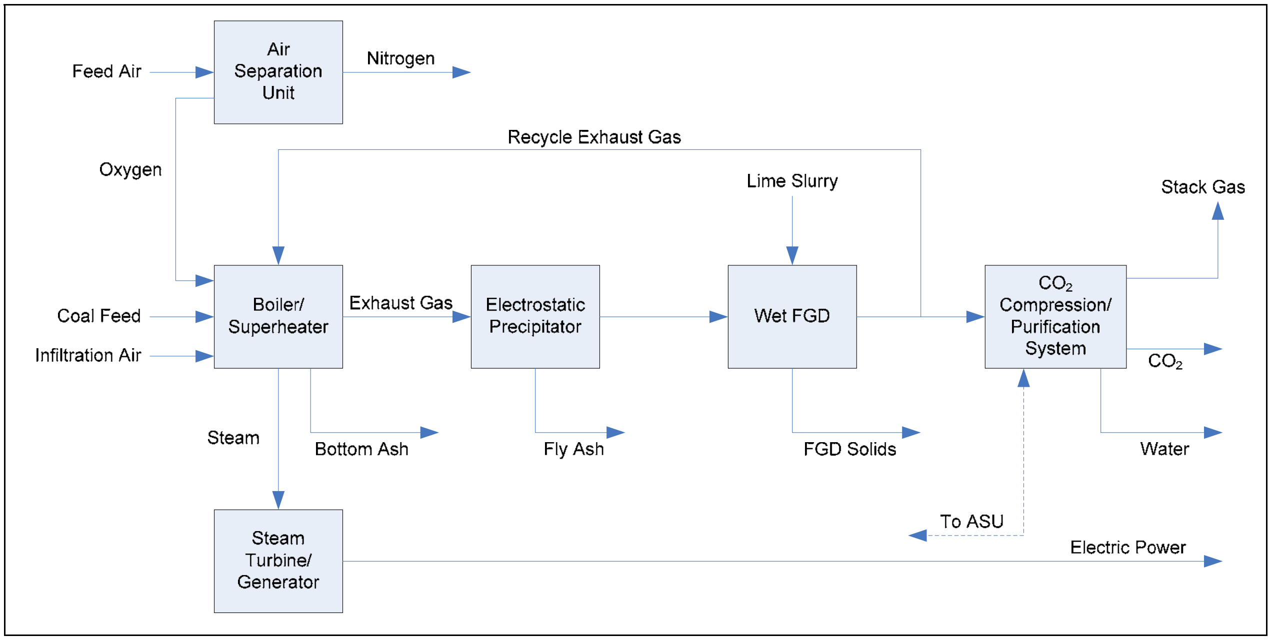

Figure 2.4 Oxyfuel Combustion

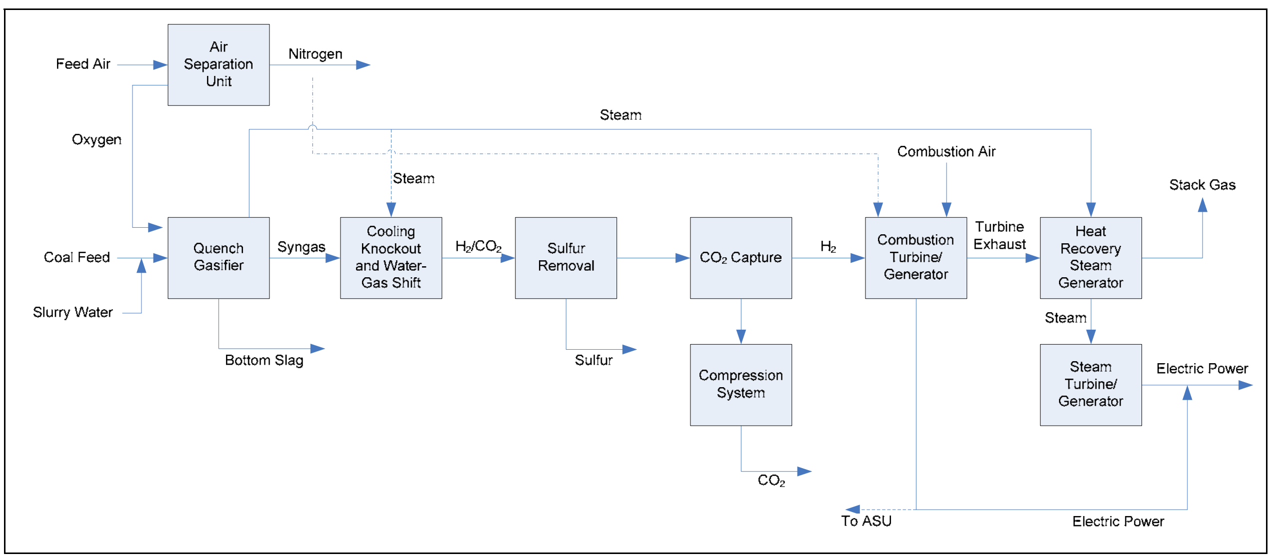

Figure 2.5 Pre-Combustion Separation

2.2.1.3. CO_2 Transport

After the CO_2 has been captured, it must be compressed and transported to the storage site. Pipelines are the preferred method of transporting large amounts of CO_2. There is already an extensive CO_2 pipeline infrastructure in the U.S. (see Table 2.1), with a capacity of over 110 million standard cubic meters per day (scm/day) (over 216,000 tonnes per day).[36] Much of the pipeline infrastructure is used for enhanced oil recovery ("EOR"), the process of injecting CO_2 into oil reservoirs to increase the amount of oil that can be produced. In the United States, CO_2 pipelines are regulated by the U.S. Department of Transportation.[37] A study by the International Energy Agency ("IEA") found that in the period from 1990-2002, there were no injuries and no fatalities related to leakage from U.S. CO_2 pipelines.[38]

[36] GEMMA HEDDLE ET AL, THE ECONOMICS OF CO_2 STORAGE 15 (MIT Laboratory for Energy & the Environment Report No. MIT LFEE 2003-003 RP, 2003).
[37] 49 C.F.R. § 195 (2006). In this thesis, all references to the Code of Federal Regulations ("C.F.R.") are are for the year 2006, unless otherwise specified.
[38] J. Gale & J. Davison, *Transmission of CO_2: Safety and Economic Considerations*, *in* PROC. SIXTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. (J. Gale & Y. Kaya eds. 2000).

Table 2.1 CO_2 Pipelines in the United States (Heddle et al)[39]

PIPELINE	OPERATOR	ROUTE	CO_2 CAPACITY (10^6 scm/day)	LENGTH (km)
Cortez	Kinder Morgan	McElmo Dome to Denver City CO_2 Hub	28	311
Central Basin	Kinder Morgan	Denver City CO_2 Hub to McCamey, TX	17	Unknown
Sheep Mountain II	BP	Rosebud connection to Denver City CO_2 Hub and onward to Seminole San Andres Unit (TX)	14	139
Bravo	BP	Bravo Dome to Denver City CO_2 Hub	11	135
Sheep Mountain I	BP	Sheep Mountain Field to Rosebud connection with Bravo Dome	9	114
Canyon Reef Carriers	Kinder Morgan	McCamey, TX to SACROC Field	7	87
Este	ExxonMobil	Denver City CO_2 Hub to Salt Creek, TX	7	Unknown
Choctaw	Denbury Resources	Jackson Dome to Bayou Choctaw Field, LA	6	115
Slaughter	ExxonMobil	Denver City CO_2 Hub to Hockley County, TX	5	Unknown
Val Verde	Petrosource	Connects Mitchell, Gray Ranch, Pucket and Terrell gas processing facilities to Canyon Reef Carriers main line	4	51
West Texas	Trinity Pipeline	Denver City CO_2 Hub to Reeves County, TX	3	Unknown
Llano Lateral	Trinity Pipeline	Runs off Cortez main line to Llano, NM	3	33
Weyburn	Dakota Gasification	Great Plains Synfuels plant (Beulah, ND) to Weyburn field (Saskatchewan, Canada)	3	330
McElmo Creek	ExxonMobil	McElmo Dome to McElmo Creek Unit (UT)	2	25

2.2.2. Geological Formations and Subsurface Behavior of CO_2

The goal of geological CO_2 storage is to return CO_2 to the place from which it came: the underground.[40] The geological storage of carbon has been a natural process in the Earth's upper crust for hundreds of millions of years, and the source of coals, oil, natural gas, and carbonate rocks.[41] Thus although CO_2 storage for climate change mitigation is a novel idea, it is grounded in natural geological processes.

The storage process involves injection of CO_2 into porous and permeable spaces of sedimentary rock and trapped by less permeable rock layers that would impede the subsurface

[39] HEDDLE ET AL, *supra* note 36, at 16.
[40] Friedmann & Homer-Dixon, *supra* note 5, at 79.
[41] IPCC Special Report, *supra* note 11, at 199.

migration of CO_2.[42] The injection pressure must be greater than the *in situ* pressure of the receiving formation so that CO_2 can enter the geological formation.[43] However, if the injection pressure exceeds the pressure on the overlying caprock, the formation is vulnerable to fracturing.[44] Storage capacity is maximized when CO_2 is injected in its supercritical phase.[45] See Figure 2.6. A supercritical fluid has the properties of both a liquid and a gas. In its supercritical phase, injected CO_2 will tend to migrate upwards and laterally because the density of the supercritical CO_2 would be less than the density of the brine in the geological formation.[46]

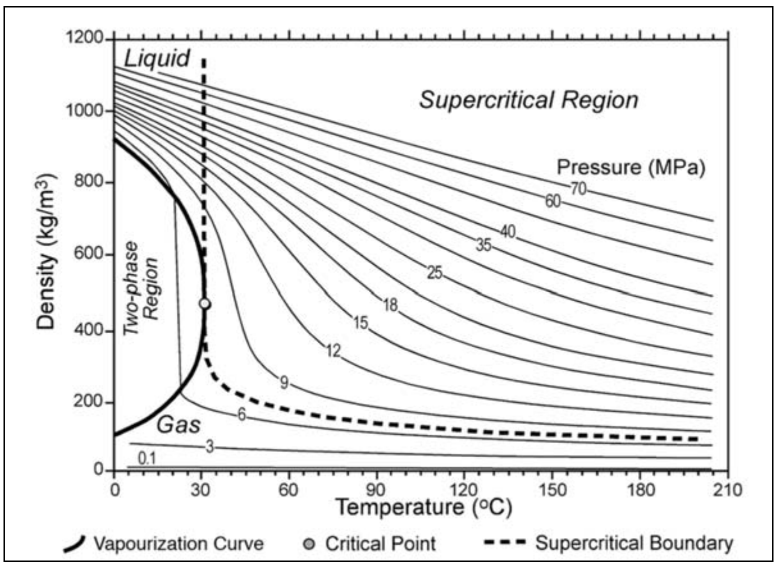

Figure 2.6 CO_2 Density as a Function of Temperature and Pressure (IPCC)[47]

Not all subsurface geological formations are appropriate for CO_2 storage and the subsurface formations that are appropriate are not always located near large point sources of CO_2. The suitability of a geological formation for CO_2 storage will depend on several

[42] Elizabeth J. Wilson & Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law*, 36 ENVTL. L. REP. 10114, 10115 (2006).
[43] *Id.*
[44] *Id.*
[45] This is generally achieved by injecting carbon dioxide below depths of 800 meters, using the hydrostatic pressure gradient rule of thumb of 10.5 megapascals per kilometer (MPa/km). *Id.*
[46] *Id.*
[47] IPCC Special Report, *supra* note 11, at 387. Reprinted with the permission of Cambridge University Press.

characteristics. First, the storage formation must have adequate injectivity and capacity.[48] Injectivity is the rate at which CO_2 may be injected in a well. By definition, injectivity is the mass flow rate of CO_2 that can be injected per unit of reservoir thickness and per unit of downhole pressure difference.[49] Injectivity can be determined from the mobility of the CO_2, which is the ratio of the absolute permeability of the reservoir and injectate viscosity.[50] The capacity of a geological reservoir defines the amount of CO_2 that can be stored in a formation. Second, the storage formation must have an overlying low permeability caprock that impedes CO_2 migration.[51] The trapping of CO_2 beneath a caprock is known as structural trapping. This is known as a "structural trapping" mechanism. Structural traps are characteristic of sedimentary basins. Sedimentary basins are primarily occupied by saline water, oil, and gas.[52] Third, the storage formation should be situated in a stable geological environment so that the structural integrity of the formation is not compromised.[53]

This thesis concentrates on the storage of CO_2 in deep saline formations[54] and oil and gas fields, which are considered to be the most likely near-term geological storage options. Deep saline formations and oil and gas fields are believed to offer the largest capacity for geological storage and in many cases are in close proximity to large sources of CO_2. Deep saline formations and oil and gas fields share some commonalities.[55] For example, fluid flow in both is constrained by upper and lower less permeable layers of rock, generally shale.[56] However, deep

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[48] *Id.* at 213.
[49] HEDDLE ET AL, *supra* note 36, at 5.
[50] Law and Bachu find a linear relationship between carbon dioxide injectivity and mobility: CO_2 injectivity = $0.0208 \times CO_2$ mobility. D. Law & S. Bachu, *Hydrogeological and Numerical Analysis of CO_2 Disposal in Deep Aquifers in the Alberta Sedimentary Basin*, 37 ENERGY CONVERSION MGMT. 1167 (1996).
[51] IPCC Special Report, *supra* note 11, at 208, 213.
[52] *Id.* at 208.
[53] *Id.* at 213.
[54] The terms "deep saline formations" and "saline aquifers" are used interchangeably in this thesis.
[55] U.S. DEP'T OF ENERGY, TERRESTRIAL SEQUESTRATION OF CO_2: AN ASSESSMENT OF RESEARCH NEEDS 6 (1998).
[56] *Id.*

saline formations are generally found over larger surface areas than oil and gas fields.[57] There are a number of other CO_2 storage options that are not considered in this thesis, such as the adsorption of CO_2 on to coal, the reaction of CO_2 with metal oxides to produce mineral carbonates, the use of salt caverns to store CO_2, and the direct injection of CO_2 into deep ocean waters. These other options will require greater scientific inquiry and validation to gain acceptance in the scientific community.

Table 2.2 Global Capacity Estimates of CO_2 Storage Reservoirs

STORAGE OPTION	GLOBAL CAPACITY ESTIMATES		
	HERZOG & GOLOMB[58]	GALE[59]	PARSON & KEITH[60]
Ocean	1,000 – 10,000+ GtC	-	-
Deep saline formations	100 – 10,000 GtC	109 – 2,725 GtC	100 – 1,000 GtC
Depleted oil and gas reservoirs	100 – 1,000 GtC	251 GtC	200-500 GtC
Coal seams	10 – 1,000 GtC	5.4 GtC	100-300 GtC
Terrestrial	10 – 100 GtC	-	-
Utilization	Currently <0.1 GtC/yr	-	-

As discussed in Section 2.2.1.1, the feasibility of CCS as a climate change mitigation option depends on CO_2 sources being in close geographical proximity to storage opportunities ("sinks"). Bradshaw and Dance have conducted a qualitative assessment of the likelihood that a suitable CO_2 storage formation will be present in a given area, which they call prospectivity.[61] They divide the world into three categories: highly prospective, prospective, and non-prospective.[62] Highly prospective areas have significant storage potential. An example of a

[57] *Id.*
[58] Herzog & Golomb, *supra* note 23.
[59] John Gale, *Geological Storage of CO_2: What's Known, Where are the Gaps and What More Needs to Be Done*, *in* PROC. SIXTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. (J. Gale & Y. Kaya eds. 2000).
[60] E.A. Parson & D.W. Keith, *Fossil Fuels Without CO_2 Emissions*, 282 SCI. 1053 (1998).
[61] IPCC Special Report, *supra* note 11, at 94.
[62] John Bradshaw & Tess Dance, *Mapping Geological Storage Prospectivity of CO_2 for the World's Sedimentary Basins and Regional Source to Sink Matching*, *in* PROC. SEVENTH INT'L CONF. GREENHOUSE GAS CONTROL TECHNOLOGIES (E.S. Rubin et al eds. 2004).

highly prospective formation would be one that currently produces substantial volumes of hydrocarbons.[63] Prospective areas are smaller hydrocarbon formations or formations with minor tectonic deformation.[64] Non-prospective formations are not suitable for CO_2 storage.[65]

The results of the prospectivity analysis are shown in Figure 2.7. The United States was found to have a large number of CO_2 sources as well as a large number of highly prospective or prospective sinks, which is a positive outcome for CCS.[66] South America is similarly positive for CCS, with a low number of CO_2 sources, but a large number of highly prospective or prospective sinks.[67] On the other hand, India was found to have a large number of CO_2 sources, but few highly prospective or prospective sinks.[68]

The Bradshaw and Dance analysis was done on a global basis, and thus its applicability to national CO_2 storage policy is limited. Regional source-sink matching assessments are currently being undertaken in Australia, Canada, and the United States using geographic information systems ("GIS") models.[69] Initially, these studies are analyzing CCS feasibility using purely technical criteria such as storage capacity, injectivity, and long-term containment.[70] Once suitable storage sites have been identified, site selection will be further constrained by economic, environmental, and safety criteria.[71]

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[63] *Id.*
[64] *Id.*
[65] *Id.*
[66] *Id.*
[67] *Id.*
[68] *Id.*
[69] IPCC Special Report, *supra* note 11, at 224. *See also* DAVID CHENG, INTEGRATION OF DISTRIBUTED AND HETEROGENEOUS INFORMATION FOR PUBLIC-PRIVATE POLICY ANALYSES 56-61 (S.M. thesis, MIT, 2004).
[70] IPCC Special Report, *supra* note 11, at 224.
[71] *Id.* at 225.

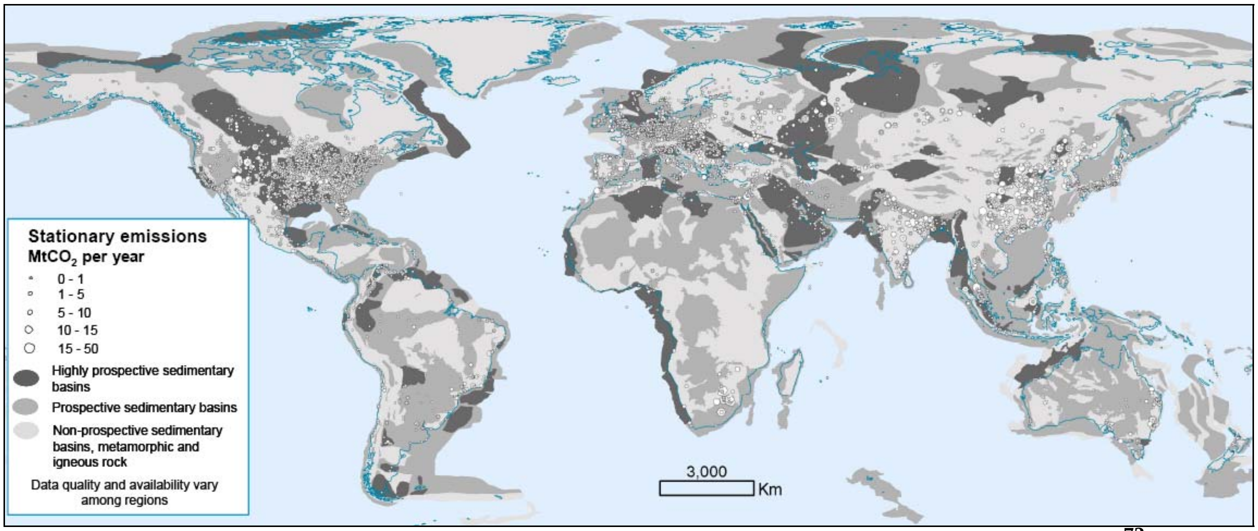

Figure 2.7 Matching Sources and Prospective Storage Formations (IPCC)[72]

2.2.2.1. Deep Saline Formations

Deep saline formations are made up of sedimentary rock saturated with water containing high concentrations of dissolved salts.[73] They offer the largest potential storage volume among potential geological reservoirs and their location is not limited to areas where oil and gas are found. The water contained in saline formations is not suitable for industrial and agricultural use or for human consumption.[74] Saline formations have remained largely unexploited, except for some limited use in underground natural gas storage in the midwestern United States.[75] Thus, there is less overall knowledge about specific saline storage formations than oil and gas fields.

Saline formations come in two types: closed formations and open formations. Closed formations have defined boundaries caused by folded rocks or faults, which reduce the possibility of CO_2 migrating into potable aquifers or leaking to the surface.[76] Open formations

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[72] Bradshaw & Dance, *supra* note 62, *in* IPCC Special Report, *supra* note 11, at 95. Reprinted with the permission of Cambridge University Press.
[73] IPCC Special Report, *supra* note 11, at 217.
[74] Stefan Bachu, *Sequestration of CO_2 in Geological Media: Criteria and Approach for Site Selection in Response to Climate Change*, 41 ENERGY CONVERSION & MGMT. 953, 960 (2000).
[75] *See infra* Part 7.3.1.
[76] INT'L MARITIME ORG., INVITATION TO CONSIDER THE LEGAL QUESTIONS ASSOCIATED WITH CO_2 SEQUESTRATION IN GEOLOGICAL FORMATIONS UNDER THE LONDON CONVENTION AND PROTOCOL ANNEX 2 3 (LC.2/Circ. 439, 2005).

are flat or gently sloping formations. In an open formation, it would be possible for CO_2 to migrate laterally in the subsurface, but movement would likely be slow.[77]

The effectiveness of a deep saline formation for containing stored CO_2 will depend on whether the CO_2 is effectively "trapped" in the formation. Orr describes geophysical and geochemical trapping in a saline formation:

> [I]njected CO_2 will flow more easily through high permeability paths, but the flow will not be dominated by the pressure gradients imposed by injection and production wells. Gravity segregation caused by the density difference between the injected CO_2 and brine will cause preferential flow at the top of the aquifer, though injection of the CO_2 well below the top of the aquifer can mitigate this gravity segregation to some extent. Aquifers with large volume, reasonable permeability and thickness, and good pressure communication over large distances will be most attractive such that large volumes could be injected without raising aquifer pressure significantly. The injected CO_2 will dissolve in the brine, and the resulting brine/CO_2 mixture will be slightly more dense than the brine alone. Slow vertical flow of the denser brine will cause further dissolution, as fresh brine is brought in contact with the CO_2 phase. Trapping of a separate CO_2 phase by brine can also act to immobile CO_2 as a residual phase. Estimates of the time scales for dissolution and the resulting vertical convection suggest that hundreds to thousands of years will be required to dissolve all the CO_2, but by that time, much of the CO_2 will exist in a trapped residual phase. Relatively slow chemical reactions, depending on the chemical composition of the brine and minerals present in the aquifer, may then store some of the CO_2 as minerals.[78]

Deep saline formations offer several potential trapping mechanisms. One type of trapping mechanism is "physical trapping". One type of physical trapping mechanism is structural trapping, where CO_2 is trapped beneath a low-permeability caprock which acts as a seal.[79] For example, structural traps cause hydrocarbons to be contained in hydrocarbon fields. Another type of physical trapping mechanism is stratigraphic trapping, where CO_2 is trapped due

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[77] *Id*.
[78] Franklin Orr, *Distinguished Author Series: Storage of Carbon Dioxide in Geologic Formations*, J. PETROLEUM TECH., Sept. 2004, at 94.
[79] INT'L MARITIME ORG., *supra* note 76, at 2.

to variations in the lithology of the geological formation.[80] Physical trapping can also occur hydrodynamically, which occurs where the flow of *in situ* formation water and CO_2 occurs over long distances and is very slow.[81] A second type of trapping mechanism is "residual trapping" (also known as "capillary trapping"). This occurs when CO_2 migrates through the rock matrix and some of the CO_2 is retained in the pore space of the rock by capillary forces.[82] The more rock that the CO_2 passes through, the more residual trapping that will occur.[83] Residual trapping has been extensively studied in the oil industry because capillary forces can cause residual oil to be trapped in pore spaces.[84] A third type of trapping occurs where CO_2 dissolves in the waters of the saline formation.[85] This is known as "solubility trapping". The IPCC notes that up to 30% of the injected CO_2 will dissolve in the formation water over tens of years.[86] Finally, the injected CO_2 may be subject to "mineral trapping", where a portion of the injected CO_2 is converted to carbonate minerals. Mineral trapping is the most permanent form of CO_2 storage, but also the slowest of the trapping mechanisms (occurring over hundreds to thousands of years).[87]

The difficulty of estimating deep saline formation storage capacity is non-trivial because of the variety of parameters that affect the efficiency of CO_2 storage. For example, estimations of capacity will depend on the permeability and porosity of the reservoir, the depth of storage, size of the pore volume, and the presence of existing resources in the formation.[88] Capacity will also depend on the pressure and stress regimes of the formation, i.e. the amount of CO_2 that can

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80 IPCC Special Report, *supra* note 11, at 208.
81 *Id.*
82 *Id.* at 206.
83 Carbon Sequestration Leadership Forum, Draft Discussion Paper from the Task Force for Reviewing and identifying Standards with Regards to CO_2 Storage Capacity Management 13 (CSLF-T-2005-9, Aug. 15, 2005).
84 Lynn Orr, *Predicting Flow Behavior of Geologic Storage of CO_2*, presented at Stanford Univ. Global Climate & Energy Project Int'l Workshop, Beijing (Aug. 23, 2005), *at* http://gcep.stanford.edu/pdfs/wR5MezrJ2SJ6NfFl5sb5Jg/18_china_orr.pdf.
85 IPCC Special Report, *supra* note 11, at 206.
86 *Id.*
87 *Id.*
88 Carbon Sequestration Leadership Forum, *supra* note 83, at 6.

be injected before the fracture point of the formation is reached. The IPCC estimates that saline aquifer storage capacity for CO_2 is at least 1,000 $GtCO_2$ and reports studies indicating capacity an order of magnitude higher.[89] There is significant variability in capacity estimates due to differences in underlying assumptions and methods.[90]

2.2.2.2. Oil and Gas Fields

Although oil and gas fields offer less overall CO_2 storage capacity in aggregate than their deep saline formation counterparts (see Table 2.2), oil and gas fields will likely be the first CO_2 storage options in the United States. The geophysical properties of oil and gas fields have been studied extensively and there is already an infrastructure in place for subsurface injection. Oil and gas fields are appealing because the injected CO_2 would occupy the space where, in a sense, the CO_2 originally came from, and because oil and gas fields have proven to be effective hydrocarbon storage reservoirs for millions of years.[91] If oil and gas production has not damaged the seal that trapped the hydrocarbons, the reservoir should be able to contain the injected CO_2.[92] In addition, CO_2 storage in oil and gas fields would be subject to many of the same geophysical and geochemical trapping mechanisms noted in the case of deep saline formations.

One potential target would be to store CO_2 in conjunction with EOR operations. EOR is the practice of injecting CO_2 to increase the production of oil from a reservoir, and constitutes about 5% of total oil production in the United States.[93] The concept of injecting CO_2 into subsurface geological formations, in fact, began with EOR. CO_2 injection for climate change

[89] IPCC Special Report, *supra* note 11, at 223.
[90] Carbon Sequestration Leadership Forum, *supra* note 83, at 3.
[91] Friedmann & Homer-Dixon, *supra* note 5, at 79.
[92] Orr, *supra* note 78, at 92.
[93] HERZOG, *supra* note 17, at 1.

mitigation is an extension of EOR. The implications of EOR for CO_2 storage are described in detail in Section 7.4 of this thesis.

Enhanced gas recovery ("EGR") provides a second target for CO_2 storage. The CO_2 would be injected into a depleted gas reservoir to re-pressurize the reservoir and increase the recovery of natural gas.[94] EGR has been discussed in the technical literature, but has not been demonstrated on the commercial scale.[95] Natural gas reservoirs are good candidates for CO_2 storage because of their proven integrity for containing gas indefinitely, but Orr suggests that EGR is not economically viable without incentives for CO_2 storage.[96]

A third target would be to store CO_2 in depleted oil and gas fields which are not in production. The CO_2 would not be injected for the enhanced recovery of hydrocarbons and the field would probably already have been abandoned. Natural gas has been stored in depleted underground gas reservoirs for years, which has provided technical experience and significant regulatory precedent for subsurface injection into depleted reservoirs. Because injection would likely occur in abandoned fields, the storage operator would need to verify that there were no inadequately plugged injection wells in the area that could serve as high permeability conduits for CO_2 leakage to the surface.[97]

2.2.3. Pathways of Leakage

In the United States, the EPA has developed minimum requirements for injection well design, construction, monitoring, and abandonment. The EPA has not yet decided how it will apply these criteria to commercial CO_2 storage. The regulatory scheme that would control the underground injection of CO_2 is discussed in Section 3.2 of this thesis.

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[94] IPCC Special Report, *supra* note 11, at 216.
[95] *Id.*
[96] Orr, *supra* note 78, at 93.
[97] *See infra* Section 2.2.3.

To prevent the subsurface migration of injected fluids from the well, EPA underground injection regulations require the use of a packer, injection tubing, and long string casing (see Figure 2.8). A packer is a mechanical device set immediately above the injection zone that seals the outside of the tubing to the inside of the long string casing of the injection well.[98] The injection tubing is the innermost layer of the injection well, and conducts injected fluids from the surface to the injection zone; it is generally constructed of corrosion-resistant material because of its continuous contact with fluids.[99] The long string casing extends from the surface to or through the injection zone and terminates where the injected fluids enter the geological formation.[100]

The EPA also requires that injection well operators follow certain well closure and abandonment procedures once their injection operations are complete. For example, wells injecting non-hazardous fluids must be flushed with a non-reactive fluid, plugged with a cement meeting certain specifications, and each cement plug must be tagged and tested.[101] Operators submit plugging and abandonment reports to the EPA and/or applicable state agency indicating that their pre-determined plugging and abandonment plan was satisfied.[102] The U.S. Government Accountability Office ("GAO", formerly U.S. General Accounting Office) reports that most leakage from injection wells occurs through leaks in the injection well casing, excessive injection pressure, the presence of improperly abandoned wells, leaking packer

[98] U.S. ENVTL. PROTECTION AGENCY, CLASS I UNDERGROUND INJECTION CONTROL PROGRAM: STUDY OF THE RISKS ASSOCIATED WITH CLASS I UNDERGROUND INJECTION WELLS 10 (EPA 816-R-01-007, 2001).
[99] *Id.*
[100] *Id.*
[101] *Id.* at 28.
[102] *Id.* at 27.

assemblies, corrosion of the casing or tubing, and injection directly through the casing without packer and tubing.[103]

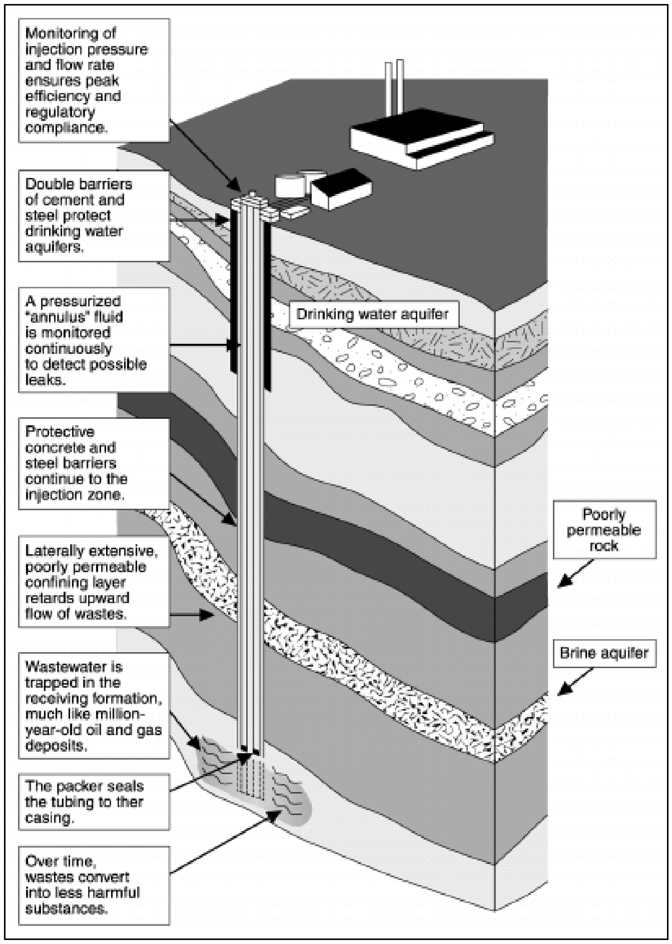

Figure 2.8 Typical Injection Well Configuration (GAO)[104]

As discussed in Section 2.2.2.2, because of existing infrastructure and geological knowledge, the first CO_2 storage projects in the United States will likely take place at oil and gas fields. These sites may possess numerous wells, including abandoned and orphaned wells. An abandoned well is a well that has been properly plugged according to state records, while an

[103] *Id.* at 31-32. *See also* U.S. GENERAL ACCOUNTING OFFICE, HAZARDOUS WASTE – CONTROLS OVER INJECTION WELL DISPOSAL OPERATIONS (GAO/RCED 87-170, 1987). *Id.* at 10. A typical well configuration is shown in Figure 2.8.
[104] U.S. GENERAL ACCOUNTING OFFICE, DEEP INJECTION WELLS: EPA NEEDS TO INVOLVE COMMUNITIES EARLIER AND ENSURE THAT FINANCIAL ASSURANCE REQUIREMENTS ARE ADEQUATE 7 (GAP-03-761, 2003).

orphaned well is an inactive well, possibly unplugged, that does not have a known owner. If a well is properly plugged, it will likely contain CO_2 effectively. However, there is always a possibility that abandoned or orphaned wells in close proximity to the storage formation have not been adequately plugged, completed, or cemented.[105] Unplugged wells pose a threat of subsurface migration and leakage to the surface. The threat remains until the well is properly plugged.[106]

Ide et al suggest that even "properly plugged" injection wells are not immune from leakage because when CO_2 is injected into a subsurface formation containing brine, the mixture of brine and CO_2 forms carbonic acid:[107] The carbonic acid can degrade the cement plug of the injection well.[108] Thus injection wells that are plugged consistent with regulatory requirements may not be immune to leakage. In addition, particularly for wells plugged prior to the 1930s, there may be wells that have not been plugged with cement at all, but instead were plugged with tree stumps, logs, animal carcasses, and mud.[109] In other cases, wells might have been plugged with cement, but the cement was contaminated with surrounding mud during the hardening process, leading to an ineffective seal. See Figure 2.9. There is little empirical data on the likelihood of an abandoned or orphaned well existing on a specific site suitable for CO_2 storage, the probability of CO_2 escaping from an abandoned or orphaned well, or the magnitude of the consequences that may result due to the leakage.[110]

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[105] MASSACHUSETTS INSTITUTE OF TECHNOLOGY, THE FUTURE OF COAL (J. Deutch & E. Moniz eds., 2006).
[106] RAILROAD COMM'N OF TEXAS, WELL PLUGGING PRIMER 2 (2000).
[107] S. Taku Ide et al, *CO_2 Leakage Through Existing Wells: Current Technology and Regulations, in* PROC. EIGHTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. (2006).
[108] *Id. See also* Andrew Dugid et al, *The Effect of Carbonated Brine on the Interface between Well Cement and Geologic Formations under Diffusion-Controlled Conditions*, *in* PROC. EIGHTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. (2006).
[109] Ide et al, *supra* note 107.
[110] *Id.*

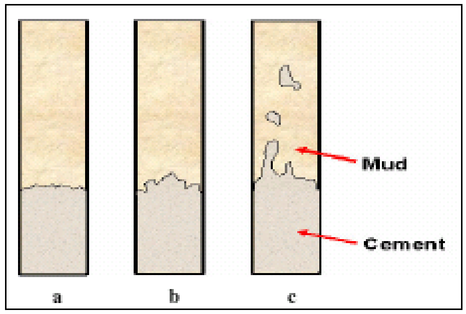

Figure 2.9 Cement Plug Contaminated with Mud during Hardening (Ide et al)[111]
(Increasing temporal progression from Time a to b to c)

Celia and Bachu have modeled the potential for leakage from injection wells.[112] They note that any significant leakage would occur through or along the cement zones, such as through well plugs within the casing or through the cement used for sealing the casing to the formation.[113] Although cements exist that are sufficient to contain the stored CO_2, Celia and Bachu find that permeability could be affected by incomplete sealing along the boundaries, generation of cracks within the cement, generation of a microannulus along the outside of the well casing, and degradation of the cement with time.[114]

The Energy Policy Act of 2005 ("EPAct") creates a federal program to remediate, reclaim and close abandoned and orphaned oil and gas wells located on land administered by the U.S. Department of the Interior and U.S. Department of Agriculture.[115] The program will prioritize the wells for closure based on public health and safety, potential environmental harm,

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[111] *Id.* Reprinted with the permission of the author.
[112] Michael A. Celia and Stefan Bachu, *Geological Sequestration of CO_2: Is Leakage Unavoidable and Acceptable?, in* PROC. SIXTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. 477 (J. Gale & Y. Kaya eds. 2000).
[113] *Id.*
[114] *Id.*
[115] Energy Policy Act of 2005, Pub. L. No. 109-58, sec. 349, § 15907, 119 Stat. 594, 709-711 (2005), codified at 42 U.S.C. § 15907 (2006) [hereinafter EPAct]. In this thesis, all references to the United States Code ("U.S.C.") are for the year 2006, unless otherwise specified.

and land use priorities.[116] Costs will be recovered from entities holding a state or federally mandated bond on the well, as well as their sureties or guarantors.[117]

EPAct creates a reclamation pilot program for new oil and gas leases on federal lands, where lessees may be required to remediate, reclaim and close all orphaned wells on the land leased, with the lessee to be reimbursed by a royalty credit against the federal share of royalties owed for the actual costs of remediating, reclaiming, and closing the orphaned wells.[118] Under the pilot program, the lessee may also be allowed to reclaim an orphaned well on unleased federally owned land or an orphaned well located on an existing lease on federally owned land (for which the lessee is not legally responsible to reclaim).[119] Reimbursement is provided for the full costs of remediating, reclaiming, and closing the orphaned wells through credits against the federal share of royalties.[120]

The EPAct also creates a program of technical and financial assistance to remedy the problem of orphaned and abandoned wells located on state or private lands.[121] The program will assist in identifying persons providing a bond for an orphaned or abandoned well, provide criteria for ranking wells, provide information and training programs, and fund state mitigation efforts on a cost-shared basis.[122] Some states, such as Texas, already have programs for remediating abandoned and orphaned wells, with funds derived from a fee paid by existing operators.[123]

Although abandoned and orphaned wells are the primary source of concern, there is also the potential for leakage due to the local geological characteristics of the storage formation or

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[116] *Id.* § 349(b)(1).
[117] *Id.* § 349(b)(2)-(3).
[118] *Id.* § 349(f)(1)(A).
[119] *Id.* § 349(f)(2)(A).
[120] *Id.* § 349(f)(1)(B).
[121] *Id.* § 349(g)(1).
[122] *Id.* § 349(g)(3).
[123] Tex. Nat. Res. Code § 91.111(b) (2006).

inadequate site characterization. With respect to local geology, a transmissive fault could have a significant impact on the migration of CO_2 from the geological reservoir.[124] For example, CO_2 could migrate up the fault and into an adjacent drinking water aquifer.[125] Another example would be the injected CO_2 displacing saline water in a deep saline formation and the displaced saline water migrating into the drinking water aquifer via the fault.[126] The activation of faults by the subsurface injection of fluids is also known to be a cause of induced seismic events.[127]

2.2.4. Measurement, Monitoring, and Verification

The assignment of liability to a CO_2 storage operator will likely involve the use of measurement, monitoring, and verification ("MMV") technologies. MMV technologies are important for monitoring the condition of the storage operation, verifying the amount of CO_2 that has been stored in the formation, demonstrating that the stored CO_2 is contained in the geological formation, and detecting leakage of CO_2 if it occurs. There are two categories of MMV technologies that have relevance to the liability context: technologies that monitor of the subsurface movement of CO_2, and technologies that monitor environmental impacts due to leakage of CO_2 from the geological formation.[128] Any CO_2 storage site will also use MMV technologies for site characterization to ensure the storage integrity of the geological formation. Table 2.3 summarizes the available MMV technologies for CO_2 storage. These technologies will be explored in this section.

[124] Chin-Fu Tsang et al, *Scientific Considerations Related to Regulation Development for CO_2 Sequestration in Brine Formations*, FIRST NAT'L CONF. CARBON SEQUESTRATION (2001).
[125] *See infra* Chapter 5.1.
[126] Jason Anderson, *Monitoring and Verification of Geological and Ocean Carbon Dioxide Disposal*, VERIFICATION YEARBOOK 198 (2003).
[127] B. ORLIC, MODELING MAN-INDUCED GEOLOGICAL HAZARDS CAUSED BY GAS EXTRACTION AND INJECTION (2003).
[128] This follows the formulation by Anderson, *supra* note 126, at 198.

Table 2.3 MMV Technologies for CO_2 Storage (adapted from IPCC)[129]

MEASUREMENT TECHNIQUE	APPLICATIONS
Introduced and natural tracers	Tracing movement of CO_2 in the storage formation Quantifying solubility trapping Tracing leakage
Vertical seismic profiling and cross-well seismic imaging	Detecting detailed distribution of CO_2 in the storage formation Detecting leakage through faults and fractures
Time-lapse 3-D seismic imaging	Tracking CO_2 movement in and above storage formation
Passive seismic monitoring	Development of microfractures in formation and caprock CO_2 migration pathways
Electrical and electromagnetic techniques	Tracking movement of CO_2 in and above the storage formation Detecting migration of brine into shallow aquifers
Subsurface pressure	Control of formation pressure below fracture gradient Wellbore and injection tubing condition Leakage out of the storage formation
Well logs	Tracing CO_2 movement in and above storage formation Tracking migration of brine into shallow aquifers Calibrating seismic velocities for 3D seismic surveys
Water composition	Quantifying solubility and mineral trapping Quantifying CO_2-water-rock interactions Detecting leakage into shallow groundwater aquifers
Soil gas sampling	Detect elevated levels of CO_2 Identify source of elevated soil gas CO_2 Evaluate ecosystem impacts
CO_2 land-surface flux monitoring by flux chambers or eddy-covariance	Detect, locate and quantify CO_2 releases
Visible and infrared imaging from satellite or planes	Detect vegetative stress

2.2.4.1. Subsurface Monitoring

Subsurface monitoring of CO_2 movement can be done by direct or indirect methods.[130] The most common approach for direct monitoring is to use a tracer that is injected with the CO_2, such as a noble gas or carbon isotope not present in the reservoir.[131] The first EOR project with long-term CO_2 storage, located at the Weyburn oil field in Canada, uses carbon with a different

[129] Adapted from IPCC Special Report, *supra* note 11, at 236.
[130] *See generally* IPCC Special Report, *supra* note 11, at 235-242.
[131] Gregory J. Nimz & G. Bryant Hudson, *The Use of Noble Gas Isotopes for Monitoring Leakage of Geologically Stored CO_2*, *in* 2 CO_2 CAPTURE PROJECT SUMMARY (S. Benson ed., 2004).

isotopic composition, ^{13}C ("carbon-13"), than the *in situ* carbon of the reservoir, ^{12}C ("carbon-12").[132] Regardless of whether a noble gas or carbon isotope is used, the path of the tracer will indicate the movement of the stored CO_2. Figure 2.10 shows the carbon-13 composition of fluid samples from the Weyburn storage formation before injection, 12 months after injection, and 31 months after injection. The carbon-13 composition is expressed in terms of δ-units, which is the ratio of carbon-13 to carbon-12, or more generally the ratio of the rare isotope to the more abundant isotope.[133] The altered isotopic composition is the result of solubility trapping of CO_2 in the waters of the formation (CO_2 mixing with water to form carbonic acid), and thus the change in isotopic composition is measured in $\delta^{13}C_{HCO3}$.

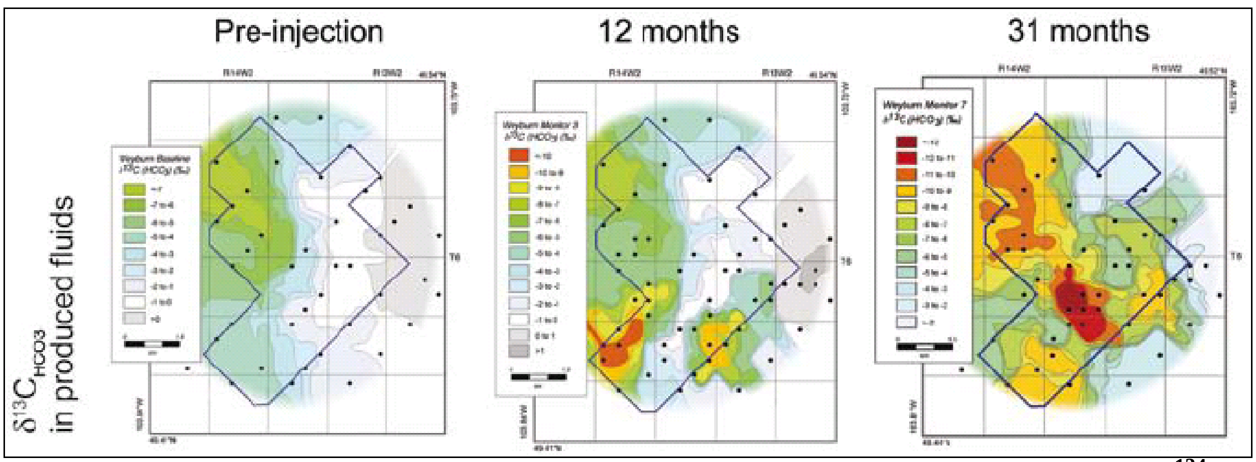

Figure 2.10 Path of Carbon Tracer within *in situ* Fluid at Weyburn (IPCC/PTRC)[134]
(Black dots indicate sample wells)

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[132] Mark Raistrick et al, *Using Carbon Isotope Ratios and Chemical Data to Trace the Fate of Injected CO_2 in a Hydrocarbon Reservoir at the IEA Weyburn Greenhouse Gas Monitoring and Storage Project, Saskatchewan, Canada, in* PROC. EIGHTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. (2006).

[133] *See generally* PATRICK J. SHULER & YONGCHUN TANG, ATMOSPHERIC CO_2 MONITORING SYSTEMS: A CRITICAL REVIEW OF AVAILABLE TECHNIQUES AND TECHNOLOGY GAPS A-1 (Report for SMV Group, CO_2 Capture Project, Feb. 2002).

[134] D.J. White et al, Theme 2: Prediction, Monitoring and Verification of CO_2 Movements, *in* IEA GHG WEYBURN CO_2 MONITORING & STORAGE PROJECT SUMMARY REPORT 2000-2004 (M. Wilson & M. Monea eds. 2004), at 120 [hereinafter Weyburn Phase I Report], *reprinted in* IPCC Special Report, *supra* note 11, at 238. *See also* E. Perkins et al, *Long Term Predictions of CO_2 Storage by Mineral and Solubility Trapping in the Weyburn Midale Reservoir*, *in* PROC. SEVENTH INT'L CONF. GREENHOUSE GAS CONTROL TECHNOLOGIES (E.S. Rubin et al eds. 2004). Reprinted with permission of PTRC and Cambridge University Press.

The most common indirect monitoring approach is to use seismic monitoring. Sound waves are directed at the subsurface location and devices are used to record the sound wave reflections.[135] There are a number of different ways to conduct seismic monitoring. Examples include generating sound waves and maintaining sensors at the surface ("conventional seismic"), generating sound waves at the surface but maintaining sensors in wells in the subsurface ("vertical seismic"), generating sound waves in the subsurface and maintaining sensors in wells in the subsurface ("cross-well seismic"), or conducting cross-well seismic monitoring with a third well to create a three-dimensional profile of the subsurface ("3D seismic").[136]

Figure 2.11 shows an example of seismic monitoring of Statoil's Sleipner CO_2 storage project in the North Sea. As discussed in Section 3.3.5.1 of this thesis, Statoil strips CO_2 from natural gas recovered from the Sleipner field and injects the CO_2 into the Utsira saline formation beneath the seafloor. CO_2 storage began at Sleipner in 1996 and a long-term CO_2 storage monitoring project was initiated in conjunction with the Sleipner project. The top row ("a") of Figure 2.11 shows the seismic monitoring of a vertical cross section of the subsurface over time. The clear vertical line in the center of the images (indicated by the letter "c") shows the point of CO_2 injection. The vertical seismic cross-section shows the upward and lateral movement of the CO_2 within the Utsira formation. The images also show that CO_2 is physically trapped by the overlying caprock. The bottom row ("b") of Figure 2.11 shows the seismic monitoring of a horizontal cross section of the subsurface over time. The point of injection is indicated by the letter "c". The images show the lateral migration of the CO_2 plume over time. The IPCC reports that the lateral extent of the plume is presently about 5 square kilometers.[137]

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[135] Anderson, *supra* note 126, at 197.
[136] *Id. See also* IPCC Special Report, *supra* note 11, at 237.
[137] IPCC Special Report, *supra* note 11, at 218.

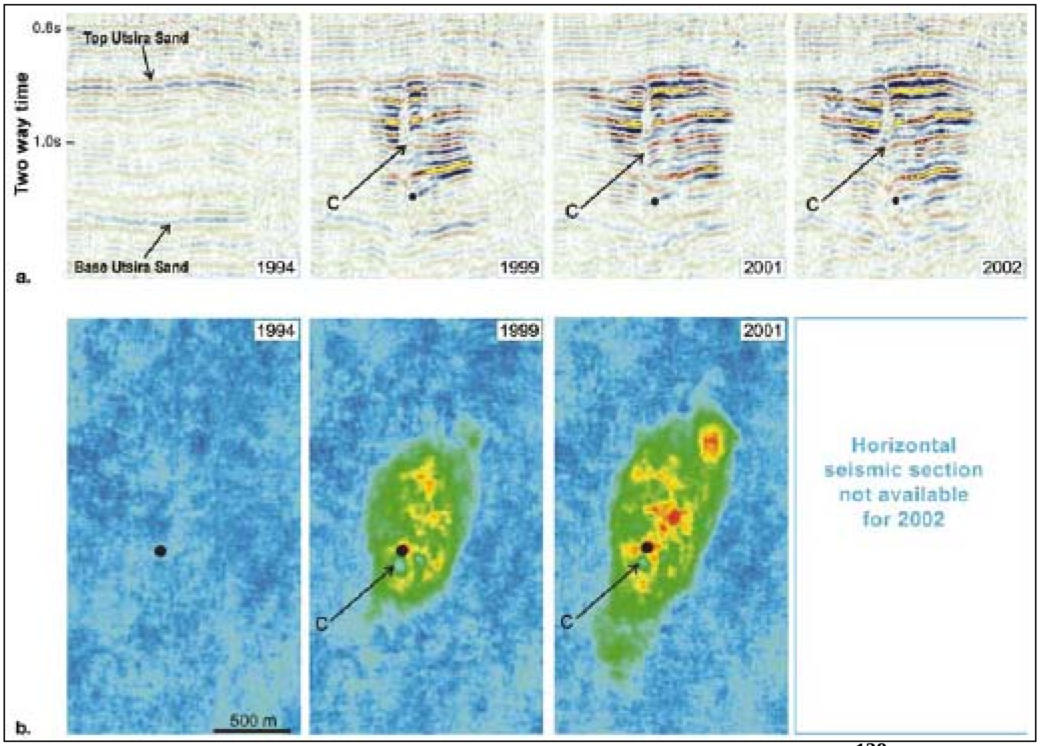

Figure 2.11 Seismic Monitoring at Sleipner (IPCC)[138]
Top row ("a") shows vertical cross section of CO_2 plume over time
Bottom row ("b") shows horizontal cross section of CO_2 plume over time

The detection of microseismic events ("passive seismic") is another way of monitoring the state of the geological formation and migration of the CO_2.[139] Microseismic events can be produced in response to CO_2 interacting with pre-existing or new fractures, as well as pressure changes in the reservoir.[140] Sensors are generally deployed in the injection well.[141] Passive seismic has historically been used to determine the integrity of an injection well, mapping faults, and tracking the movement of injected fluids.[142] Passive seismic techniques have also been used

[138] *Id*. Reprinted with the permission of Cambridge University Press.
[139] IPCC Special Report, *supra* note 11, at 237.
[140] S.C. Maxwell & T.I. Urbancic, *The Potential Role of Passive Seismic Monitoring for Real-Time 4D Reservoir Characterization*, SPE RESERVOIR EVALUATION & ENGINEERING, Feb. 2005, at 70.
[141] *Id.*
[142] *Id.* at 72-73.

in conjunction with hydraulic fracturing, where fractures are induced in a hydrocarbon formation to increase the formation's permeability.[143]

Indirect monitoring can also take the form of electrical and electromagnetic monitoring technologies which measure natural or induced electrical or magnetic fields.[144] The electrical or magnetic fields are measured in a pre-injection survey prior to the commencement of CO_2 storage operations.[145] The pre-injection findings are compared with electrical or magnetic fields measured after injection to determine the presence of CO_2.[146] CO_2 injection changes the characteristics of these electrical and magnetic fields.[147] For example, the dissolution of minerals in a geological formation will decrease the electrical current's resistance, while the displacement of saline waters with CO_2 will increase resistance.[148]

A final type of indirect monitoring is to take measurements of physical characteristics in the wellbore.[149] Examples include measuring temperature and pressure in the subsurface using well logs.[150] Monitoring could also take the form of measuring physical or chemical changes in the cement, including assessing the cement bond and the continuity of cement around the well casing.[151] Measurement of cement integrity is typically conducted with cement bond logs combined with variable density logs, which send an acoustic wave of 20 kHz through the injection well casing and measure the transit time and attenuation.[152] The amplitude of the

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[143] *Id.* at 71.
[144] IPCC Special Report, *supra* note 11, at 237.
[145] *Id.*
[146] *Id.*
[147] CARBON SEQUESTRATION LEADERSHIP FORUM, DISCUSSION PAPER FROM THE TASK FORCE FOR IDENTIFYING GAPS IN CO_2 MONITORING AND VERIFICATION OF STORAGE 9 (CSLF-T-2005-10, 2005).
[148] *Id.*
[149] *See, e.g.,* Kamel Bennaceur, *CO_2 Sub-Surface Risk Management & Mitigation*, *at* IEA/CSLF WORKSHOP ON LEGAL ASPECTS OF STORING CARBON DIOXIDE (2004).
[150] *See, e.g.,* Sally M. Benson et al, *Monitoring Protocols and Life-Cycle Costs for Geologic Storage of Carbon Dioxide*, *in* PROC. SEVENTH INT'L CONF. GREENHOUSE GAS CONTROL TECHNOLOGIES (E.S. Rubin et al eds. 2004).
[151] IPCC Special Report, *supra* note 11, at 239.
[152] Dat Vu-Hoang, *Assessing the Integrity of Downhole CO_2 Storage using In-Situ Sonic, Advanced Ultrasonic, and Electromagnetic Measurements*, *in* PROC. EIGHTH INT'L CONF. GREENHOUSE GAS CONTROL TECHNOLOGIES (2006).

acoustic wave is a function of the amount of cement around the casing: low amplitude indicates the presence of cement, while high amplitude indicates no cement.[153]

2.2.4.2. Monitoring Environmental Impacts

One source of CO_2 storage liability is environmental degradation, such as the carbonation of drinking water aquifers or damage to ecosystems from high concentration exposures of CO_2.[154] In addition, if it could be proven that environmental degradation was caused by CO_2 leakage from a geological formation, it could provide circumstantial evidence for other sources of liability, such as human toxicological effects or contributions of leaked CO_2 to climate change.

The seismic methods described in Section 2.2.4.1 can be used to identify subsurface migration before CO_2 reaches a drinking water aquifer.[155] Groundwater contamination can also be determined by taking water samples from drinking water aquifers of concern. The water samples can be analyzed for selected ions (such as sodium, potassium, and calcium), gases (such as CO_2), and acidity (pH). If noble gas or carbon isotope tracers are used in the injectate, groundwater could be monitored for the presence of the tracer.[156] Ideally, water samples would have been taken prior to CO_2 injection operations to provide a basis for comparison.

A number of monitoring technologies are available for monitoring high concentration exposures of CO_2 to ecosystems. Leakage of CO_2 into the subsurface area directly above the water table (known as the "vadose zone") can be determined by monitoring of CO_2 concentrations in soil air, flux from soils, and monitoring at the surface for increased levels of

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[153] *Id.*
[154] *See infra* Sections 5.3 and 5.4.
[155] IPCC Special Report, *supra* note 11, at 239.
[156] *Id.*

CO_2.[157] Commercial sensors on the market can be used to continuously monitor CO_2 in the air; these are generally used in occupational settings prone to high exposures of CO_2.[158] As in the case of groundwater contamination, if the CO_2 is injected with a tracer, an analysis for the noble gas or isotope can be conducted in the case of damage to ecosystems.[159]

A limitation with surface monitoring is the difficulty of differentiating between natural ecological fluxes of CO_2 and CO_2 leakage from the geological reservoir, particularly where the leakage is very small.[160] The small leakage could be hidden within the larger CO_2 flux. Current research is focused on developing a methodology for enhancing the data properties associated with CO_2 leakage, while reducing the background noise from the natural CO_2 fluxes.[161] The health of terrestrial ecosystems can also be determined by measuring the productivity and biodiversity of flora and fauna. In areas where vegetation is sparse, such as deserts, direct observation may not be possible.[162]

Portable sensors for detecting CO_2 are useful for measurements at a single point, but have a limited range.[163] A large number of portable sensors would be required to cover a wide area. Satellite-based remote sensing can be used to determine CO_2 levels over large areas.[164] These sensors tend to be inaccurate because of variability of atmospheric CO_2 and the long path length

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157 CARBON SEQUESTRATION LEADERSHIP FORUM, *supra* note 147, at 10. *See also* YINGQI ZHANG ET AL, VADOSE ZONE REMEDIATION OF CO_2 LEAKAGE FROM GEOLOGIC CO_2 STORAGE SITES (LBNL-54680, 2004).
158 IPCC Special Report, *supra* note 11, at 240.
159 CARBON SEQUESTRATION LEADERSHIP FORUM, *supra* note 147, at 10.
160 *Id.*
161 *See, e.g.*, Jennifer L. Lewicki et al, *An Improved Strategy to Detect CO_2 Leakage for Verification of Geologic Carbon Sequestration*, 32 GEOPHYS. RES. LETT. L19403 (2005).
162 IPCC Special Report, *supra* note 11, at 240.
163 Anderson, *supra* note 126, at 199.
164 *Id.*

over which the CO_2 is measured.[165] Therefore satellite monitoring might be more suitable as a warning system to prompt further investigation.[166]

2.3. Liability

Liability is the legal responsibility that one has to another or to society, enforceable by civil remedy or criminal punishment.[167] There are two kinds of liability that are especially relevant to CO_2 storage: tortious liability and liability for breach of contract. Tortious liability is liability that arises from the breach of a duty that is fixed primarily by law and owed to persons generally.[168] Breach of contract occurs when a party fails to perform one's own promise, repudiates the promise, or both.[169] This section examines the general application of tortious liability and breach of contract causes of action, as well as the associated remedies if liability is found. It then discusses private and public mechanisms that have been used to contain liability, with an emphasis on the management of large-scale long-term liabilities of the type that might be expected for CO_2 storage.

2.3.1. Tortious Liability

One potential source of liability for a CO_2 storage operator would be through a tortious liability cause of action. The plaintiff bringing the suit would claim that the operator had breached a duty owed to the plaintiff and therefore should be held liable for the associated damages. A threshold issue for activities such as CO_2 storage, where harm may occur far into the future, is whether the cause of action would be time-barred – referred to later in this thesis as the cause of action being subject to a statute of limitations and/or a statute of repose. If the

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[165] IPCC Special Report, *supra* note 11, at 240.
[166] Anderson, *supra* note 126, at 199.
[167] *See*, *e.g.*, BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "liability").
[168] *Id.* (s.v. "tortious liability")
[169] *Id.* (s.v. "breach of contract")

plaintiff is not time barred, there are four potential tortious causes of action that could be brought in connection with CO_2 storage, depending on the facts at issue: trespass, nuisance, negligence, and strict liability.

2.3.1.1. Statutes of Limitations and Repose

Every state has some version of a statute placing temporal limits on a plaintiff's cause of action.[170] States will generally have a statute of limitations for liability and sometimes will have a statute of repose. Statutes of limitations and repose are similar in that they both prescribe a time period in which a cause of action must be brought.[171] The primary difference is that a statute of limitations begins to run after the plaintiff's injury has manifested itself, while a statute of repose begins to run at the conclusion of the defendant's activities which gave rise to the injury.[172] Thus a plaintiff's cause of action could potentially be time-barred by a statute of repose before the injury has even been suffered.[173] Although a statute of repose generally has a longer time limit than a statute of limitations, statutes of repose are frequently shorter than the average latency period for cancer and other diseases.[174] The reach of a statute of repose is limited because statutes of repose tend to be specific to a given activity, such as the liability of an architect who designs a building intended to have an indefinite life span.[175] A few states have enacted statutes of repose that have general applicability.[176]

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[170] Note, *Developments in the Law: Statutes of Limitations*, 63 HARV. L. REV. 1177, 1179 (1950).
[171] Josephine Herring Hicks, Note, *The Constitutionality of Statutes of Repose: Federalism Reigns*, 38 VAND. L. REV. 627, 629 (1985) (noting that statutes of limitations "limit the time in which a plaintiff may bring suit after the cause of accrues" while statutes of repose "potentially bar the plaintiff's suit before the cause of action arises").
[172] *Id.*
[173] Robert A. Van Kirk, Note, *The Evolution of Useful Life Statutes in the Products Liability Reform Effort*, 1989 DUKE L.J. 1689, 1704 (1989).
[174] Note, *Developments in the Law: Toxic Waste Litigation*, 99 HARV. L. REV. 1458, 1609 (1986).
[175] *See, e.g.*, The Amer. Inst. of Architects, Issue Brief: Statute of Repose (Dec. 2005).
[176] Note, *supra* note 174, at 1609.

Statutes of limitations and repose are a legislative determination that not all injuries should be compensated. A choice is made that temporally barring the plaintiff's claims outweighs the interests of allowing the action to go forward.[177] Statutes of limitations and repose are generally justified on the grounds of fairness to the defendant.[178] For example, defendants may have difficulties in meeting an evidentiary burden for activities that occurred far in the past.[179] Statutes of limitations and repose are also justified on the grounds that juries might expect the defendant to follow safety standards based upon current technology, rather than technologies which existed at the time of the defendant's activities.[180] In addition, the insurance industry has argued that time-barring statutes allow them to "predict potential losses with greater certainty".[181]

On the other hand, statutes of repose have been criticized as being overly harsh to environmental liability plaintiffs.[182] Injuries resulting from activities of environmental contamination often have long latency periods.[183] In addition, because of evolving scientific knowledge, the plaintiff's injury might be known, but the causal connection between the injury and the activities that gave rise to the injury might not be known until after the cause of action is time-barred.[184] Thus a "one size fits all" time limitation on bringing a cause of action might not strike the appropriate balance between providing future certainty to the defendant concerning the

[177] Eli J. Richardson, *Eliminating the Limitations of Limitations Law*, 29 ARIZ. ST. L.J. 1015, 1020 (1997).
[178] Note, *supra* note 170, at 1185.
[179] *Id.*
[180] Andrew A. Ferrer, Note, *Excuses, Excuses: The Application of Statutes of Repose to Environmentally-Related Injuries*, 33 B.C. ENVTL. AFF. L. REV. 345, 355 (2006).
[181] Van Kirk, *supra* note 173, at 1706.
[182] *See, e.g.*, Ferrer, *supra* note 180, at 373 (noting some courts refusal to apply statutes of repose because they may be contrary to principles of fairness).
[183] Peter S. Menell, *The Limitations of Legal Institutions for Addressing Environmental Risks*, 5 J. ECON. PERSP. 93, 95 (1991).
[184] Ferrer, *supra* note 180, at 372.

liability of his/her activities and compensating the injured plaintiff.[185] As applied to CO_2 storage, although there is reason to believe that trapping mechanisms would lead to CO_2 leakage being more likely in the near-term than decades into the future, there is always the potential that the risks associated with leakage might not manifest themselves until after the requisite statute of repose. Thus potential plaintiffs could be left with uncompensated injuries.

One might argue that the application of statutes of limitations and repose to CO_2 storage is less compelling than in other areas where these statutes have been applied historically. For example, in the case of a defective product, a statute of repose might specify that a cause of action must be brought within ten years from the date of purchase.[186] The purchaser is put on notice that the manufacturer is potentially liable for any injuries from the product occurring over its first ten years of use. After ten years, the purchaser can no longer justifiably expect that the manufacturer will be liable, and can either discard the product or continue using it at his/her own risk.[187] Presumably, the "limited" liability would also be reflected in the price of the product. *Ceteris paribus*, a product which has a longer time over which a liability cause of action may be brought will be more expensive. With CO_2 storage, the potential victims could be innocent third parties not involved in the CO_2 storage transaction. Unlike the defective product example, the risks of CO_2 storage might not be voluntarily assumed by the injured parties. Where an injury is the result of externalities or imperfect consent, as in the case of CO_2 storage, the absence of temporal limitations on the plaintiff's cause of action might be justified.[188] On the other hand, this assumes that consumers have knowledge that the products they purchase are associated with statutes of repose. In addition, statutes of limitations and repose have been applied to toxic torts,

[185] Van Kirk, *supra* note 173, at 1723, 1725.
[186] Hicks, *supra* note 171, at 629.
[187] *See, e.g.*, Van Kirk, *supra* note 173, at 1724.
[188] Note, *The Fairness and Constitutionality of Statutes of Limitations for Toxic Tort Suits*, 96 HARV. L. REV. 1683 (1983).

where as in the case of CO_2 storage, the injured parties did not voluntarily assume the risks, yet are potentially time-barred from bringing their claims.[189]

2.3.1.2. Tortious Liability Causes of Action

Much of the case law on subsurface injection has focused on the subsurface trespass issue.[190] When CO_2 is injected into the subsurface, the CO_2 will migrate upwards and laterally in the formation. If the CO_2 storage operator[191] has not characterized the geological formation properly, the CO_2 could potentially migrate into adjoining areas of the subsurface where property rights have not been acquired.[192] This could lead to a subsurface trespass cause of action, where the plaintiff would need to show the intentional and unauthorized entry of the defendant's CO_2, and that he/she was harmed[193] (such as by lost use of the subsurface space). Courts have generally been "cautious in finding liability for injected fluid subsurface entries".[194] A trespass cause of action could also take the form of a surface trespass, where stored CO_2 migrates to the surface and causes environmental harm. The remedies in a trespass suit have typically included diminution in value and costs of restoration.[195] A diminution in value remedy is compensation for the reduced market value of the property.[196]

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[189] A toxic tort is a civil wrong arising from exposure to a toxic substance, such as asbestos or hazardous waste. BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "tort").

[190] *See, e.g.*, Lone Star Gas Co. v. Murchison, 353 S.W.2d 870 (Tex.Civ.App. 1962); White v. N.Y. State Nat. Gas Corp., 190 F.Supp. 342 (W.D. Pa. 1960); Tate v. United Fuel Gas Co., 71 S.E.2d 65 (W.Va. 1952); Central Ky. Natural Gas Co. v. Smallwood, 252 S.W.2d 866 (Ky. 1952). *See also* Owen L. Anderson, *Geophysical "Trespass" Revisited*, 5 TEX. WESLEYAN L. REV. 137 (1999). *See also infra* Section 5.5.

[191] In my discussion of tortious liability, I use a hypothetical CO_2 storage operator to demonstrate the various causes of action that one might expect. This is not meant to imply that a CO_2 storage operator is the only defendant in a tortious liability action, nor is it meant to imply that the CO_2 storage operator would even be the defendant in liability litigation. The defendants will obviously depend on the facts at issue in the case.

[192] Wilson & de Figueiredo, *supra* note 42, at 10121.

[193] Terry D. Ragsdale, *Hydraulic Fracturing: The Stealthy Subsurface Trespass*, 28 TULSA L.J. 311, 337 (1993).

[194] *Id.* at 335.

[195] Robert H. Cutting, *"One Man's Ceilin' Is Another Man's Floor": Property Rights as the Double Edged Sword*, 31 ENVTL. L. 819, 867 (2001).

[196] BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "diminution-in-value method").

A second potential private cause of action could be on the grounds of nuisance, where as in the case of a trespass, potential plaintiffs might include subsurface owners. Trespass and nuisance claims are virtually the same for statute of limitations purposes, and courts have sometimes misinterpreted the causes of action as being virtually identical.[197] The difference between a trespass claim and a nuisance claim is that a trespass claim involves actual intentional physical invasion of the plaintiff's property, while nuisance arises from the substantial interference of the use and enjoyment of the plaintiff's property.[198] Nuisance claims have been confronted in the subsurface injection context where salt water injected for secondary oil recovery contaminated a private drinking water well.[199] In the CO_2 storage context, the nuisance claim would be, for example, that the injected CO_2 migrated into a private groundwater supply and caused its carbonation. The carbonation would have interfered with the use and enjoyment of the groundwater. A nuisance is typically remedied through an injunction and/or payment of damages for the harmed property.[200] An injunction is a court order that commands or forbids a party from taking an action.[201] For CO_2 storage, this could be an order to halt subsurface injection operations.

A third potential cause of action would be a negligence cause of action, which comprises the bulk of tortious litigation. Like trespass and nuisance, a negligence claim could address harm to property and the environment. In addition, negligence could be used to provide recovery for the effects of CO_2 leakage on human health. It is black letter law that "[a]ctionable negligence involves a legal duty to use due care, a breach of such legal duty, and the breach as the proximate

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[197] G. Nelson Smith III, *Nuisance and Trespass Claims in Environmental Litigation: Legislative Inaction and Common Law Confusion*, 36 SANTA CLARA L. REV. 39, 54 (1995).
[198] *Id.*
[199] *See, e.g.*, Gulf Oil Corp v. Hughes, 371 P.2d 81, 82 (Okla. 1962). *See also infra* Section 7.4.4.
[200] Boomer v. Atlantic Cement Co., 257 N.E.2d 870 (N.Y. 1970).
[201] BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "injunction").

or legal cause of the resulting injury."[202] The standard of care is that of a reasonably prudent person, a hypothetical person who exercises the degree of judgment that society requires for protection of their own.[203]

To be successful in a negligence cause of action, the plaintiff would need to be successful on four prongs. First, the plaintiff would need to show that the defendant CO_2 storage operator had a duty of reasonable care over the CO_2 storage operation. An example would be the duty to conduct appropriate monitoring and verification of the site. Second, the plaintiff would need to show that the defendant CO_2 storage operator breached that duty by unreasonable conduct, for example by not remedying unsafe conditions or not conducting appropriate monitoring. Third, the plaintiff would need to show that there was harm caused to the plaintiff due to the defendant CO_2 storage operator's breach of duty. Examples of harm would be damage to the plaintiff's health, contamination of subsurface minerals, or harm to the surface property. Fourth, the plaintiff would need to show damages resulting from the harm caused by the defendant CO_2 storage operator. If successful on the negligence claim, the plaintiff's remedies for health claims could potentially include medical costs, compensation for the increased risk of future harm, future medical monitoring costs, and compensation for emotional injury.[204] With respect to property claims, the remedies would center on damage to the subsurface minerals or to property, such as the change in property value or the costs of restoration.[205]

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[202] Felburg v. Don Wilson Builders, 142 Cal.App.3d 383, 393 (Cal.Ct.App. 1983). *See also* Melanie R. Kay, Comment, *Environmental Negligence: A Proposal for a New Cause of Action for the Forgotten Innocent Owners of Contaminated Land*, 94 CALIF. L. REV. 149, 170 (2006).
[203] BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "reasonable person").
[204] Mark Geistfeld, *Analytics of Duty: Medical Monitoring and Related Forms of Economic Loss,* 88 VA. L. REV. 1921, 1939 (2002); John C.P. Goldberg & Benjamin C. Zipursky, *Unrealized Torts*, 88 VA. L. REV. 1625, 1630 (2002). *See infra* Section 5.4.2.
[205] James R. Cox, *Reforming the Law Applicable to the Award of Restoration Damages as a Remedy for Environmental Torts*, 20 PACE ENVTL. L. REV. 777, 781-93 (2003); Kenneth F. McCallion, *A Survey of Approaches to Assessing Damages to Contaminated Private Property*, 3 FORDHAM ENVTL. L. REP. 125, 126-30 (1992).

Finally, there is the potential that CO_2 storage could be subject to strict liability, a cause of action that is based on the absolute duty to make something safe.[206] Unlike negligence, a finding of strict liability does not depend on the amount of care taken by the defendant. The defendant could have taken all possible preventive measures and still be found liable. Strict liability governs abnormally dangerous activities, which by definition create a significant risk of serious harm even if reasonable care is used.[207] If CO_2 storage was deemed to be abnormally dangerous, either by a legislature or the judiciary, the plaintiff would only need to show that the plaintiff was harmed and that there was a causal connection between the CO_2 storage and the injury. If the plaintiff is able to prove that the plaintiff's injuries were caused by CO_2 leakage from the storage formation, the defendant CO_2 storage operator would be liable for harm. Although strict liability has been justified on the grounds of fairness and efficiency, it has been criticized for its failure to adequately discount the contributory responsibility of victims and its failure to achieve fairness among victims who garner similar injuries in other contexts.[208]

Even if a plaintiff is able to bring a private cause of action, the plaintiff may still confront problems in showing causation, which will be discussed in detail later in this thesis.[209] For right now, it is important to understand that the plaintiff would need to show that CO_2 leakage from a geological formation is capable of causing the harm in question. Even if it could be shown that CO_2 leakage from a geological formation is generally capable of causing the harm suffered by the plaintiff, the plaintiff would still need to show that leakage from a specific CO_2 storage operation caused the specific harm in question.

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[206] BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "liability").
[207] BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "abnormally dangerous activity").
[208] Robert L. Rabin, *Rethinking Tort and Environmental Liability Laws: Needs and Objectives of the Late 20th Century and Beyond*, 24 HOUS. L. REV. 27, 49 (1987).
[209] *See infra* Chapter 5.

2.3.2. Contractual Liability

The other potential source of liability for a CO_2 storage operation would be for a breach of contract. A contract is a promise or a set of promises, for the breach of which the law gives a remedy.[210] For the purposes of this thesis, I will be concerned with written express contracts, where the terms of the promises are explicitly set out in writing.[211] In particular, my interest is on the contract where an operator promises to inject another party's CO_2 in a geological formation. Generically, assuming a carbon-constrained regulatory regime, the transaction could be thought of as the CO_2 storage operator selling credits to a buyer at the carbon price in exchange for storing the CO_2.[212] The contractual liability issue for CO_2 storage is a function of several issues: whether a contract was actually formed, the terms of the contract, whether there has been a breach of the contract, and the remedies that are available to the plaintiff.

It is black letter law that the formation of a contract requires mutual assent by the parties and consideration. An enforceable obligation only attaches if one party has manifested an intent to enter into a bargain (known as an "offer") and the other party has manifested assent to the terms of the offer (known as "acceptance").[213] For a CO_2 storage contract, assent could occur by a party signing the contract. Consideration is equivalent to a bargain – something that is bargained for and received by a promisor from the promisee. For a CO_2 storage contract, consideration could be the promise to pay money in exchange for the promise to inject CO_2 into the subsurface. Consideration serves an evidentiary function in the case of liability because it goes to showing the existence of a contract.

[210] Rest. Contracts 2d § 1.
[211] Contracts need not be in a written; oral contracts are valid as well. And they need not be express; contracts can be implied from a set of facts or implied by law. *See* Rest. Contracts 2d § 4.
[212] *See infra* Section 6.3.
[213] Rest. Contracts 2d §§ 17, 24, 50.

The CO_2 storage contract will have a number of terms, some of which are standard and others which are specific to CO_2 storage. For our purposes, we will be concerned with the standards of performance that are associated with the CO_2 storage contract. The CO_2 storage operator will promise to store a certain amount of CO_2 in the storage formation. However, there is a possibility that not all of the CO_2 will remained stored over time. The CO_2 storage contract will specify under what conditions performance of the contract will be deemed satisfied, for example the proportion of CO_2 that must remain in the subsurface.

If the CO_2 storage operator does not comply with the promises set forth in the contract, for example less CO_2 is stored in the geological formation than what is set out in the contract, then the operator faces liability for breach of contract. In the event of breach, the non-breaching party will generally receive what is known as expectancy damages, which are based on the contract price and place the non-breaching party in the position she would have been in if the promise had been performed.[214] Thus expectancy damages could be thought of as a substitute for performing the contract: either the promisor must perform her promise or if the promise is breached, the promisor must put the promise in the same position she would have occupied had the promise been performed. There may also be damages caused by reliance on the contract.[215] In some cases, the breach of a contract can be efficient. This occurs where the breaching party retains a profit after compensating the non-breaching party for its expectancy damages.[216] Another possibility of damages is specific performance, where the breaching party is ordered to perform on penalty of contempt of court.[217] However, specific performance is generally only awarded where expectancy damages are not adequate, such as when damages cannot be proven

[214] Rest. Contracts 2d § 344(a).
[215] *Id.* at § 344(b).
[216] *See, e.g.*, Craig S. Warkol, *Resolving the Paradox Between Legal Theory and Legal Fact: The Judicial Rejection of the Theory of Efficient Breach*, 20 CARDOZO L. REV. 321, 324 (1998).
[217] Rest. Contracts 2d § 359(1).

with reasonable certainty, or if it is difficult to procure suitable substitute performance by means of money.[218] With a CO_2 storage contract, expectancy damages would likely be the preferred approach because of the fungibility of CO_2, especially if there is the presence of a carbon market. Expectancy damages would be limited to damages flowing from the breach (such as the cost of covering the contract) and reasonably foreseeable damages that occurred as a result of the breach (such as lost profits).[219]

2.3.3. Mechanisms for Managing Liability

Both the private sector and public sector have developed a number of tools for managing large-scale and/or long-term liabilities. These include insurance and private mechanisms; government as insurer and risk manager; immunity caps, floors, and exemptions; and compensation funds. These approaches are non-exclusive. Often times, one or more of these strategies is combined to address the liability issue, for example combining command-and-control regulations with insurance. I approach these mechanisms through the use of regulatory analogs. As Reiner & Herzog describe, regulatory analogs are distinct from physical analogs.[220] A physical analog is an activity that presents similar physical or engineering challenges to a given technology. Regulatory analogs, in contrast, may confront very different physical risks, but can offer lessons as a regulatory proxy.[221]

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[218] *Id.* at § 360.
[219] Hadley v. Baxendale, 9 Exch. 341, 156 Eng. Rep. 145 (1854).
[220] D.M. Reiner & H.J. Herzog, *Developing a Set of Regulatory Analogs for Carbon Sequestration*, 29 ENERGY 1561 (2004).
[221] *Id.*

2.3.3.1. Insurance and Private Mechanisms

One approach to liability management for CO_2 storage is to use insurance. Liability insurance, as described by Abraham, performs three functions.[222] First, liability insurance has a risk transferring function, by transferring risk from risk-averse parties to risk-preferring parties.[223] Second, liability insurance has a risk spreading function by combining individual risks into a pool.[224] Third, liability insurance has a risk-allocation function by charging premiums to reflect the level of risk posed by the insured.[225] Environmental liability presents unique challenges because the frequency and severity of risk is characterized by extreme uncertainty,[226] and CO_2 storage is no exception. Precise information about the frequency and severity of risk is necessary for providing an accurate estimate of the insurance premium, and for insurance companies to set aside sufficient resources in case of an accident.[227]

Under the traditional model of insurance, insurance is obtained from the private sector, but many environmental risks do not meet the conditions for private insurability.[228] Insurance of environmental risks raises problems because courts have interpreted environmental insurance policy language to cover losses that insurers never intended to cover.[229] In addition, many environmental risks are not well suited to actuarial modeling because there is a lack of historical information about how the risks manifest themselves.[230]

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[222] Kenneth S. Abraham, *Environmental Liability and the Limits of Insurance*, 88 COLUM. L. REV. 942, 945 (1988).
[223] *Id.* at 946.
[224] *Id.*
[225] *Id.*
[226] *Id.* at 948.
[227] MICHAEL G. FAURE & DAVID GRIMEAUD, FINANCIAL ASSURANCE ISSUES OF ENVIRONMENTAL LIABILITY, REPORT FOR THE EUROPEAN COMM'N 96 (2000).
[228] Paul K. Freeman & Howard Kunreuther, *The Roles of Insurance and Well-Specified Standards in Dealing with Environmental Risks*, 17 MANAGERIAL & DECISION ECON. 517, 519 (1996).
[229] *Id.* at 521; Abraham, *supra* note 222, at 960.
[230] *Id.*

As a result, private environmental liability insurance policies often differ from comprehensive general liability policies.[231] For example, environmental liability policies are generally issued on a claims-made basis rather than on an occurrence basis.[232] A claims-made policy insures against claims made during the policy period, while occurrence coverage insures against injuries which occurred during the policy period, regardless of when the claim was made.[233] In addition, environmental liability insurance generally only covers claims arising from past actions, while commercial general liability policies insure against injuries that may occur as a result of future activities.[234] Environmental liability insurance is specific to a particular site, and the insurer conducts a detailed site assessment before issuing a policy.[235] The major issue facing environmental liability insurance is not whether firms can obtain coverage at affordable prices, but rather whether insurance markets can predictably estimate the social costs of the risks imposed in setting environmental liability insurance premiums.[236]

Private contractual techniques can also be used to allocate risk among parties, such as representations, covenants, warranties, conditions and indemnities.[237] Representations are the presentations of fact which go to the heart of the contract.[238] For example, the owner of the storage site may make a representation about the condition of the site. Covenants are promises to do something. For example, parties may make an affirmative covenant to operate the site in a certain way. Warranties are a special type of covenant; they are express or implied promises

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[231] Martin T. Katzman, *Pollution Liability Insurance and Catastrophic Environmental Risk*, J. RISK & INSURANCE 75, 87 (1988).
[232] *Id.*
[233] Abraham, *supra* note 222, at 964.
[234] Katzman, *supra* note 231, at 88.
[235] *Id.* at 87.
[236] Jeffrey Kehne, *Encouraging Safety Through Insurance-Based Incentives: Financial Responsibility for Hazardous Wastes*, 96 YALE L.J. 403, 423 (1986).
[237] David E. Pierce, *Structuring Routine Oil and Gas Transactions to Minimize Environmental Liability*, 33 WASHBURN L.J. 76, 110 (1993).
[238] BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "representation").

guaranteed by one of the contracting parties to provide compensation if one of the representations is found to be invalid.[239] Finally, an indemnity is a contract where one party agrees to cover the liability of another party given a certain factual development.[240] Indemnification has been mentioned in several federal and state proposals for CO_2 storage projects.[241] An example of an indemnity would be Firm A agreeing to indemnify Firm B for injuries from tortious liability judgments associated with CO_2 leakage Firm B's CO_2 storage project. Note that the indemnity merely shifts the risk from Firm B to Firm A. Firm A still needs to determine how it will address this financial responsibility, whether by internalizing the cost or acquiring insurance. In the negotiation of an indemnification agreement, the parties should be most concerned with determining the "trigger" of indemnification and the scope of the indemnity.[242] The trigger is typically a claim or court judgment resulting in financial loss to the indemnified party.[243] The scope is the allocation of risks among the parties.[244]

2.3.3.2. Government as Insurer and Risk Manager

Recent research by Moss examines the role of government for managing risk and an alternative to the private insurance model.[245] Moss finds that private markets for managing risk often fail because of adverse selection problems, systematic biases in the perception of risk, problems in providing credible commitments to cover losses for systematic risks, and problems with risk externalization. Government can be in a better position than the private sector to manage risks because of its powers of coercion and taxation. For example, the government can

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[239] BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "warranty").
[240] Pierce, *supra* note 237, at 110.
[241] *See supra* note 1.
[242] Penny L. Parker & John Slavich, *Contractual Efforts to Allocate the Risk of Environmental Liability: Is There a Way to Make Indemnities Worth More than the Paper They Are Written On?*, 44 SW. L.J. 1349, 1365, 1369 (1991).
[243] Pierce, *supra* note 237, at 110.
[244] Parker & Slavich, *supra* note 242, at 1368-69.
[245] *See generally*, DAVID A. MOSS, WHEN ALL ELSE FAILS: GOVERNMENT AS THE ULTIMATE RISK MANAGER (2002).

compel parties to purchase insurance, or can use the tax regime to spread risk across generations.[246]

Government also has the ability to compel parties to take actions that have the effect of limiting liability. This is analogous to the current regulatory regime for underground injection (see *infra* Section 3.2), where a regulatory agency such as the EPA imposes design and operational requirements on all CO_2 storage operators. These standards are created with an eye towards limiting the risk of the underground injection activity, which in turn limits the liability of operators. For example, operators who inject non-hazardous waste beneath the lowermost underground source of drinking water must demonstrate the geophysical integrity of the geological formation to prove that the injectate will not migrate into a drinking water supply. Although the goal of the EPA's underground injection requirements is to protect underground sources of drinking water,[247] the notion of using regulations to limit the risks of an activity could apply to any risk as long as the administrative agency had appropriate authority to regulate the risk at issue.

2.3.3.3. Liability Caps, Floors, and Exemptions

Another option for addressing the liability issue would be to use an immunity cap or floor. Under an immunity cap, the operator would be financially responsible for all liability that has a dollar value under the cap, but would be not financially responsible for any payments over the cap. Potentially, government could step in and agree to make payments for liability over the cap. This may also depend on how the cap is set. The cap could be set on a per-incident basis or on a per-person-injured basis. There have been recent calls on both the state and federal level to place a cap on tortious liability for non-economic and punitive damages, which is often heralded

[246] *Id.* at 50-52.
[247] 42 U.S.C. §§ 300g(a)(1), 300h(a)(1).

as "tort reform".[248] Under a liability floor, which seems less applicable to CO_2 storage than a cap, the operator would not be liable for payments under the floor, but would be liable to any payments above the floor. A real-world example of this might be private health insurance, where individuals are responsible for their medical bills up to a certain deductible, above which the health insurance company will make payments for medical expenses.

A variation on the liability cap is the liability exemption, which would completely exempt a party from being liable for a given cause of action or injury. A liability exemption is a liability cap where the cap is set at zero. A *per se* liability exemption could mean that injured parties would be left without compensation. As applied to CO_2 storage, liability exemptions would not make sense unless government took on the liability that otherwise would be borne by the private sector. This could provide an incentive for CO_2 storage by removing the costs associated with potential liability. However, if liability is completely absolved, it could create incentives for a CO_2 storage operator to take fewer precautions than it would otherwise take – the problem of moral hazard. The moral hazard could also be mitigated by temporally limiting the liability exemption.

The immunity cap mechanism is used by the Price-Anderson Act, which governs liability for nuclear power plants in the United States.[249] Price-Anderson was enacted in 1957 with two purposes: to ensure that adequate funds would be available to satisfy liability in the case of a catastrophic nuclear accident, and to allow the private sector to participate in the nuclear industry by removing the threat of potentially enormous liability.[250] The Act has been amended several

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[248] *See* Am. Enterprise Inst. for Pub. Pol'y Res., AEI Liability Project, *at* http://www.aei.org/research/liability/projectID.23/default.asp (last visited Nov. 30, 2006).
[249] The Price-Anderson Act applies to nuclear power plants, other nuclear facilities, and U.S. Department of Energy contractors working on nuclear energy projects. I restrict my analysis to nuclear power plant operators.
[250] Price-Anderson Act Renewal and Nuclear Energy Production and Efficiency Incentives Hearing Before the S. Comm. on Energy & Nat. Res. (2001) (testimony of Joseph R. Gray, Associate General Counsel for Licensing and Regulation, Nuclear Regulatory Comm'n)

times since its initial enactment and was last amended by the EPAct, which reauthorized Price-Anderson through December 31, 2025.[251]

The Price-Anderson Act combines immunity cap and insurance approaches. Price-Anderson requires that each nuclear operator purchase primary insurance in the maximum amount available from private insurance sources, currently $300 million.[252] All nuclear operators purchase this insurance from American Nuclear Insurers, an insurance pool of about sixty investor-owned property and casualty insurance companies.[253] The average annual primary insurance premium for a nuclear power plant is $400,000.[254] In the event of harm exceeding the primary insurance amount, each facility would be required to acquire secondary insurance in the amount of $15 million per plant per year, up to $95.8 million per incident.[255] The secondary insurance, also purchased from American Nuclear Insurers, would be pooled among the 104 licensed power plants[256] to create a secondary pool of about $10 billion. In the approximately fifty years that Price-Anderson has been in force, nuclear liability has never exceeded the primary insurance amount.[257] The largest liability incident was an accident at the Three Mile Island Nuclear Station, which resulted in liability of $70 million.[258] If damages were to exceed both the primary and secondary insurance coverage, private operators would not be liable for any additional amount. The U.S. Nuclear Regulatory Commission ("NRC") would provide a report

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[251] EPAct, *supra* note 115, at § 2011.
[252] 10 C.F.R. § 140.11(a)(4).
[253] Amer. Nuclear Insurers, ANI History, *at* http://www.amnucins.com/html/history.html (last updated Aug. 17, 2004).
[254] U.S. GOV'T ACCOUNTABILITY OFFICE, NUCLEAR REGULATION: NRC'S LIABILITY INSURANCE REQUIREMENTS FOR NUCLEAR POWER PLANTS OWNED BY LIMITED LIABILITY COMPANIES 7 n.4 (GAO-04-654, May 2004).
[255] 10 C.F.R. § 140.11(a)(4).
[256] U.S. Energy Info. Admin., U.S. Nuclear Reactors, *at* http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/reactsum.html (last visited May 12, 2006).
[257] Memorandum from L. Joseph Callan, Executive Director for Operations, U.S. Nuclear Reg. Comm'n to The Commissioners regarding NRC's 1998 Report to Congress on the Price-Anderson Act (July 2, 1998) (noting that from 1957 to December 1997, 195 alleged incidents were filed under the Price-Anderson Act, with insured losses and expenses paid of $131 million, $70 million of which derived from the Three Mile Island Accident).
[258] Of the $70 million in total damages, $42 million was related to "indemnity" and $28 million was related to "expenses". *Id.*

to Congress setting forth the causes and extent of damage,[259] and Congress would "take whatever actions it deemed necessary … to provide full and prompt compensation to the public for all public liability claims".[260]

In addition to meeting the NRC's safety and operational requirements for nuclear facilities, operators must also demonstrate that they comply with Price-Anderson's liability insurance requirements. Every year, American Nuclear Insurers sends proof of insurance to the NRC after the operator has paid its annual primary insurance premium.[261] The operator must also submit an indemnity agreement to the NRC stating that it will maintain the required primary insurance.[262] In return, the nuclear operator is guaranteed reimbursement of liability claims through the liability insurance.[263] If a nuclear operator is found not to be in compliance with the insurance requirements, the NRC has authority to revoke or suspend the operator's license, but "no licensee has ever failed to pay its annual primary insurance premium and American Nuclear Insurers would notify the NRC if a licensee failed to pay".[264] With respect to the secondary insurance, all nuclear operators must provide a guarantee of their ability to pay the secondary insurance premiums.[265] Most nuclear operators meet this requirement by showing evidence of the secondary insurance bond that all nuclear operators maintain with American Nuclear Insurers.[266] A minority of operators provide financial statements to NRC showing that cash flow could be generated to pay for secondary insurance premiums within three months.[267]

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[259] 42 U.S.C. § 2210(i)(1).
[260] 42 U.S.C. § 2210(e)(2).
[261] U.S. GOV'T ACCOUNTABILITY OFFICE, *supra* note 254, at 7.
[262] *Id.*
[263] *Id.*
[264] *Id.*
[265] *Id. See also* 10 C.F.R. § 140.11(a)(4).
[266] *Id.* at 8.
[267] *Id.*

In 1966, Congress amended Price-Anderson to give federal district courts original jurisdiction over "any public liability action arising out of or resulting from an extraordinary nuclear occurrence … without regard to the citizenship of any party or the amount in controversy".[268] Congress again amended Price-Anderson in 1988, extending federal district court jurisdiction to liability arising out of or resulting from a "nuclear incident" rather than just an extraordinary nuclear occurrence.[269] The 1998 amendments also created a federal cause of action (termed a "public liability action") for any suit asserting public liability arising from a nuclear incident.[270] Congress provided that the substantive rules of decision would be the law of the state in which the nuclear incident occurred.[271] In addition, the 1998 amendments barred courts from awarding punitive damages arising from nuclear incidents. The constitutionality of these provisions was upheld by the Third Circuit in the Three Mile Island litigation.[272]

Many commentators consider the Price-Anderson liability limitation to have been a critical factor in the development of the United States private nuclear power industry.[273] Price-Anderson has been criticized as being a subsidy to the nuclear power industry because it eliminates the financial risk of loss above the liability cap and externalizes those losses onto the

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[268] Pub L. No. 89-645, sec. 3, 80 Stat. 891, 892 (1966), *codified at* 42 U.S.C. § 2210(n)(2). An extraordinary nuclear occurrence is defined as "any event causing a discharge or dispersal of source, special nuclear, or by product material from its intended place of confinement in amounts offsite, or causing radiation levels offsite, which the Commission determines to be substantial, and which the Commission determines has resulted or will probably result in substantial damages to persons offsite or property offsite". 80 Stat. 891, 891 (1966). *See also* Lujan v. Regents of Univ. of Calif., 69 F.3d 1511, 1515 (10th Cir. 1995).
[269] Pub. L. No. 100-408, sec. 11, 102 Stat. 1066 (1988), *codified at* 42 U.S.C. § 2210(n)(2).
[270] *Id.*
[271] *Id.*
[272] In re TMI Litigation Cases Consol. II., 940 F.2d 832 (3d Cir. 1991). *See also* O'Conner v. Commonwealth Edison Co., 13 F.3d 1090 (7th Cir. 1994).
[273] *See, e.g.*, Victor E. Schwartz et al., *Federalism and Federal Liability Reform: The United States Constitution Supports Reform*, HARV. J. ON LEGIS. 269, 290 (1999); Michael Trebilock & Ralph A. Winter, *The Economics of Nuclear Accident Law*, 17 Int'l Rev. L. & Econ. 215, 219, 228 (1997); Renewal of the Price Anderson Act Hearing Before the S. Comm. on Env't & Pub. Works, Subcomm. on Transp., Infrastr. & Nuclear Safety (2002) (testimony of Peter A. Bradford).

taxpayers and/or injured parties.[274] However, others argue that Price-Anderson creates an obligation for private operators to purchase liability insurance, which would not otherwise be the case.[275] Without the insurance obligation, firms might decide to purchase less liability insurance than the maximum privately available amount and seek bankruptcy protection in the event of a catastrophic nuclear incident, which would externalize a much larger loss on the public.[276]

2.3.3.4. Compensation Funds

The final mechanism for addressing liability examined here is the administrative compensation fund. Payments into a fund are made by those entities creating the kinds of injuries that would be compensable under the fund.[277] This fund pool is then used to compensate parties for their injuries. The types of injuries to be paid by the compensation fund are pre-determined by the authorizing legislation or regulation, and the ultimate compensation judgments are made during an administrative proceeding.

Abraham notes that there are three major issues that compensation fund schemes must confront: the events to be compensable by a fund, the method of financing the fund, and the measure of compensation awarded to eligible victims.[278] The compensable event is the event that triggers a claimant's right to receive compensation from a fund, such as suffering a particular kind of injury or being exposed to a particular substance.[279] Thus in the CO_2 storage context, the compensable event could be exposure to CO_2 or suffering damages that are specific

[274] Dan M. Berkovitz, *Price-Anderson Act: Model Compensation Legislation? The Sixty-Three Million Dollar Question*, 12 HARV. ENVTL. L. REV. 1, 21 n.96 (1989); David M. Rocchio, *The Price-Anderson Act: Allocation of the Extraordinary Risk of Nuclear Generated Electricity: A Model Punitive Damage Provision*, B.C. ENVTL. AFF. L. REV. 521, 530 (1987); Joseph P. Tomain, *Nuclear Futures*, 15 DUKE ENVTL. L. & POL'Y F. 221, 244 (2005). *See also* Michael Abramowicz, *Predictive Decisionmaking*, 92 VA. L. REV. 69, 109 (2006).
[275] JOHN DEUTCH ET AL., MIT STUDY ON THE FUTURE OF NUCLEAR POWER 82 (2003).
[276] *Id.*
[277] Kenneth Abraham, *Individual Action and Collective Responsibility: The Dilemma of Mass Tort* Reform, 73 VA. L. REV. 845, 886 (1987).
[278] *Id.*
[279] *Id.*

to CO_2 exposure.[280] Following Abraham's analysis, an advantage of the compensation fund mechanism is that the injured party would not have to trace their injuries to a particular operator's injected CO_2 stream. This solves a causation problem that arises when a CO_2 storage reservoir contains CO_2 streams from multiple parties. Instead, all operators make payments into the fund, and the injured party need only show that the injuries were due to CO_2 exposure. Of course, there is still the problem of showing that the injuries resulted from CO_2. Abraham has suggested that the causation problem could be solved by offering compensation only for a set of designated compensable events, or to offer compensation on a probabilistic basis.[281] With the probabilistic compensation arrangement, victims would only receive a percentage of their damages, equal to the percentage probability that, for example, CO_2 caused their injuries.

The second issue confronting compensation funds is calculating the level of payments that must be made into the fund. Abraham suggests that payments could be made on the basis of activity levels, or on the basis of quality-based assessments. As applied to CO_2 storage, this could mean, for example, making payments dependent on the quantity of CO_2 stored in the formation (the activity level of the operator), or on the basis of reservoir characteristics of the reservoir such as geophysical characteristics or proximity to population centers (the quality-based assessment). Abraham notes that the efficacy of the quality-based assessment depends on whether the risks posed are predictable;[282] most analyses of CO_2 storage suggest that the risks can be minimized through proper site characterization and underground injection protocols. The level of payments will also depend on the risk of insolvency.[283] The compensation fund would be required to compensate victims for their injuries regardless of whether the parties that caused

[280] *See* Chapter 5.
[281] Abraham, *supra* note 277, at 888.
[282] *Id.* at 890.
[283] *Id.* at 892.

the injuries became insolvent, and thus all parties share the risk of another party becoming insolvent.[284] Abraham argues that this is a more equitable result than the tortious liability concept of joint and several liability, where co-defendants would each be individually liable for the full damages from a party's injuries and bear the entire risk of another party's insolvency.[285] To address the insolvency issue, he suggests setting a premium that accounts for future insolvency, and that if insolvency is less than what is predicted, contributors to the fund could lower their payments.[286]

The final issue raised by Abraham is measuring how injured parties should be compensated.[287] For example, it may be difficult to determine the payment of pain and suffering damages, which could be imposed in a classical tortious liability case.[288] Abraham suggests that substitutes could be crafted in a compensation fund context, such as the payment of scheduled benefits depending on the injury incurred, allowing the compensation fund to seek punitive damages with payments made back to the fund (in order to retain the deterrent effect to parties of pain and suffering damages.).[289]

An example of a compensation fund is the Vaccine Injury Compensation Trust Fund, a no-fault compensation system for children that suffer injuries from one of seven mandatory childhood vaccines.[290] The fund was established by the National Childhood Vaccine Injury Act of 1986 after vaccine manufacturers began to exit the market for fear of liability and the federal government became concern of insufficient vaccine supply.[291] The fund operates as an

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[284] *Id.* at 892.
[285] *Id.*
[286] *Id.*
[287] *Id.* at 894.
[288] *Id.* at 895.
[289] *Id.* at 896.
[290] 26 U.S.C. § 9510.
[291] Elizabeth A. Breen, *A One Shot Deal: The National Childhood Vaccine Injury Act*, 41 WM. & MARY L. REV. 309, 316 (1999).

alternative to the tortious liability system. The source of fund income is a 75-cent excise taxes placed on each dose of covered vaccine.[292] As an alternative to the tortious liability system, injured parties seeking compensation from the fund file petitions with the U.S. Court of Federal Claims, which is reviewed by a special master.[293] Compensation is only provided if the party can prove that the vaccine caused the injury in question, or by meeting the requirements on a Vaccine Injury Table.[294] The Vaccine Injury Table lists the vaccines covered under the Act and the injuries that are associated with each vaccine.[295] The injuries listed on the Vaccine Injury Table are determined by an independent panel of scientific experts.[296] Injuries not listed in the table are compensable, but require additional evidence.[297] Deaths are compensable at a legislated $250,000 payment.[298] All compensation is provided on a no-fault basis, with no requirement to show that the vaccine manufacturer was negligent.[299] The Secretary of Health and Human Services may rebut the claim by showing that the injury was caused by factors unrelated to the administration of the vaccine.[300] If the rebuttal of the Secretary fails or if the Secretary decides not to challenge the claim, then the Special Master will determine the level of compensation to be provided.[301] Petitioners are required to first bring their claims before the special master, but petitioners who are dissatisfied with their judgments may decline the award and bring a private tortious action against the manufacturer of the vaccine.[302] However,

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[292] 26 U.S.C. § 4131.
[293] 42 U.S.C. § 300aa-12.
[294] 42 U.S.C. § 300aa-11(c).
[295] *See* U.S. Health Resources & Services Admin., National Vaccine Injury Compensation Program: Vaccine Injury Table, *available at* http://www.hrsa.gov/vaccinecompensation/table.htm (last visited Dec. 1, 2006).
[296] U.S. Centers for Disease Control & Prevention, Vaccine Safety Overview, *at* http://www.cdc.gov/od/science/iso/general_info/overview.htm (last modified Oct. 23, 2006).
[297] 42 U.S.C. § 300aa-11(c).
[298] U.S. GENERAL ACCOUNTING OFFICE, VACCINE INJURY COMPENSATION: PROGRAM CHALLENGED TO SETTLE CLAIMS QUICKLY AND EASILY 5 (GAO/HEHS-00-8, 1999).
[299] 42 U.S.C. § 300aa-11.
[300] 42 U.S.C. § 300aa-13(a)(1)(B).
[301] 42 U.S.C. § 300aa-13(a)(1).
[302] 42 U.S.C. § 300aa-22, 23.

manufacturers are not liable for unavoidable side effects caused by vaccines that are properly prepared and accompanied by adequate warnings.[303] In addition, petitioners are not permitted to recover punitive damages.[304] The GAO has noted that the revenues generated by the Fund exceed the payments out of the fund.[305] The excess amount has been loaned to the Treasury to pay for other federal programs and activities.[306]

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303 *Id.*
304 *Id.*
305 U.S. GENERAL ACCOUNTING OFFICE, *supra* note 298, at 16-19.
306 *Id.* at 16.

3. Regulation of CO_2 Storage

3.1. Introduction

This chapter examines the current regulatory framework for CO_2 storage. Geological storage of CO_2 may occur in onshore and offshore geological formations (see Table 3.1). Onshore storage has received significant attention in the United States and Canada, while offshore storage has been closely examined in Europe, especially in conjunction with oil and gas extraction. In addition, CO_2 could be injected into a geological formation which extends beneath both the onshore and offshore, which has been proposed in Australia.

Table 3.1 Selected Current and Prospective CCS Projects

PROJECT	SPONSOR	COUNTRY	START DATE	STORAGE METHOD	GEOLOGICAL TARGET	AVG INJECTION RATE (t/day)[307]
Sleipner	Statoil	Norway	1996	Offshore	Aquifer	3,000
Weyburn	EnCana	Canada	2000	Onshore	EOR	3-5,000
In Salah	BP	Algeria	2004	Onshore	Aquifer	3-4,000
Snøhvit	Statoil	Norway	2007	Offshore	Aquifer	2,000
Gorgon	Chevron	Australia	2009	Onshore[308]	Aquifer	10,000
DF1 (Peterhead)	BP	UK	2009	Offshore	EOR	Unknown
Draugen	Statoil and Shell	Norway	2011	Offshore	EOR	Unknown
Unknown	Eramet, Alcan, Norsk Hydro	Norway	2011	Offshore	EOR	Unknown
Carson	BP	USA	2011	Offshore	EOR	Unknown
FutureGen	DOE and FutureGen Industrial Alliance[309]	USA	2011	Onshore	Unknown	Unknown
Unknown	RWE	Germany	2014	Unknown	Aquifer/EOR	Unknown
Latrobe	Monash	Australia	2015	Offshore	EOR	Unknown
Tilbury	RWE	UK	2016	Unknown	Unknown	Unknown

[307] IPCC Special Report, *supra* note 11, at 201.
[308] Carbon dioxide injection operations will take place onshore, but the aquifer extends beneath both the land surface and the seabed.
[309] As of December 2006, the FutureGen Industrial Alliance member companies were American Electric Power, Anglo American LLC, BHP Billiton, China Huaneng Group, CONSOL Energy, E.ON U.S., Foundation Coal, Peabody Energy, PPL Corporation, Rio Tinto Energy America, Southern Company, and Xstrata Coal. *See* FutureGen, Alliance Members, *at* http://www.futuregenalliance.org/alliance/members.stm (last visited Jan. 12, 2007).

From a technical standpoint, whether CO_2 is injected into an onshore or offshore geological formation is inconsequential. The effectiveness of storage depends on the geological characteristics of the formation, not whether the formation is located onshore or offshore. However, there are considerations not related to the technical aspects of injection that could make onshore storage more favorable than offshore storage, or vice versa. For example, offshore storage would be more expensive than onshore storage in most cases because of higher drilling costs (offshore drilling costs are four times higher than onshore),[310] the cost of installing an offshore platform, and higher pipeline costs (offshore pipelines are 40-70% more costly than onshore).[311] Onshore storage appears to have a clearer regulatory framework since it relies on national law rather than international agreements, which are still being interpreted as to their legality with respect to CO_2 storage.

Offshore storage could be favorable where there is a lack of onshore geological capacity, where there is already offshore infrastructure that could easily be adapted for CO_2 storage, where enhanced recovery of hydrocarbons is already taking place, and/or where the goal of storage is to mitigate emissions from an offshore hydrocarbon recovery operation. In addition, offshore storage poses a decreased threat to human health than onshore storage because less people, if any, would be living near an offshore storage operation and because the most likely source of leakage risk, improperly plugged wells, is less likely to occur in the offshore context.

3.2. Regulation of Onshore Storage of CO_2

Although there is no federal or state scheme regulating CO_2 storage *per se*, the EPA does have a regulatory framework governing most types of underground injection, the Underground Injection Control ("UIC") Program. The UIC Program was created under the Safe Drinking

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[310] HEDDLE ET AL, *supra* note 36, at 83.
[311] IPCC Special Report, *supra* note 11, at 190.

Water Act of 1974 ("SDWA"), which requires the EPA to establish requirements to assure that any underground injection activities will not endanger drinking water sources.[312] Underground injection of fluids must be authorized by permit or rule, and certain types of injection are prohibited because they may present an imminent and substantial danger to public health.[313] The motivation for creation of the UIC Program was concern that the "proliferation" of underground injection of fluid wastes would lead to "substantial hazards and dangers associated with … injection of contaminates" and the "indiscriminate sweeping of our wastes underground".[314] The UIC Program was not developed with CO_2 storage in mind and the regulatory framework that eventually governs CO_2 storage will probably deviate from the current system.[315] However, small scale CO_2 storage projects are being permitted under the UIC Program,[316] and the current framework will certainly be relied upon heavily in the development of any future permitting system.[317]

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[312] 42 U.S.C. § 300h(b)(1). SDWA was enacted in 1974 and amended in 1977, 1980, 1986, 1988, and 1996. *See* Safe Drinking Water Act, Pub. L. No. 93-523, 88 Stat. 1660 (1974); Safe Drinking Water Act Amendments of 1977, Pub. L. No. 95-190, 91 Stat. 1393 (1977); Safe Drinking Water Act Amendments of 1980, Pub. L. No. 96-502, 94 Stat. 2737 (1980); Safe Drinking Water Act Amendments of 1986, Pub. L. 99-339, 100 Stat. 642 (1986); Lead Contamination Control Act of 1988, Pub. L. No. 100-572, 102 Stat. 2884 (1988); Safe Drinking Water Act Amendments of 1996, Pub. L. No. 104-182, 110 Stat. 1613 (1996). Funding for most programs authorized under SDWA expired in Fiscal Year 2003. EPA and the states are continuing to implement the 1996 Amendments and a broad reauthorization is not expected during the present Congressional session. Note that SDWA programs do not expire as long as they are appropriated funds by Congress. CONGRESSIONAL RESEARCH SERVICE, CRS ISSUE BRIEF FOR CONGRESS: SAFE DRINKING WATER ACT: IMPLEMENTATION AND ISSUES 3 (October 13, 2004).

[313] Underground Injection Control Program, 40 C.F.R. § 144.1.

[314] H.R. Rep. No. 97-9, A Legislative History of the Safe Drinking Water Act 561 (Feb. 1982). *See also* In Re Envtl. Disposal Systems, Inc., 2005 WL 2206804 (E.P.A. Envtl. App. Bd. 2005).

[315] ELIZABETH WILSON, MANAGING THE RISKS OF GEOLOGIC CARBON SEQUESTRATION: A REGULATORY AND LEGAL ANALYSIS 158 (unpublished Ph.D. thesis, Carnegie Mellon Univ., 2004) (on file with author).

[316] For example, a carbon sequestration experiment which took place two years ago in the Frio saline formation of West Texas received a UIC permit under its experimental well classification (Class V). About 3,750 tonnes of carbon dioxide were injected over a two-week period. SUSAN HAVORKA ET AL, REPORT TO THE TEXAS COMMISSION ON ENVIRONMENTAL QUALITY TO ACCOMPANY A CLASS V APPLICATION FOR AN EXPERIMENTAL TECHNOLOGY PILOT INJECTION WELL: FRIO PILOT IN CO_2 SEQUESTRATION IN BRINE-BEARING SANDSTONES 4 (2003). A number of other pilot experiments are being developed under the U.S. Department of Energy's Regional Carbon Sequestration Partnership program. *See* U.S. Dep't of Energy, Carbon Sequestration Regional Partnerships, *at* http://www.fe.doe.gov/programs/sequestration/partnerships/index.html (last visited May 11, 2006).

[317] Elizabeth J. Wilson et al, *Regulating the Ultimate Sink: Managing the Risks of Geologic CO_2 Storage*, 37 ENVTL. SCI. TECH. 3476 (2003) (noting that "experience with underground injection will shape the regulatory environment" for geological carbon sequestration).

3.2.1. Historical Precursors to Federal Underground Injection Regulation

Regulation of the underground injection of industrial wastes dates back to 1921, when the Kansas State Corporation Commission was given authorization to regulate brine injection in oil fields.[318] In 1961, Texas became the first state to regulate the injection of other types of wastes; the Texas Injection Well Act of 1961 gave the Railroad Commission of Texas ("RRC") authority over the underground injection of oil field wastes and the Texas Board of Water Engineers jurisdiction over the injection of all other wastes.[319] In the 1960s and early 1970s, a number of states established programs regulating underground injection, including Colorado, Michigan, New York, Ohio, and West Virginia.[320] State and/or EPA underground injection programs now exist in every state as a result of the federal UIC requirements.[321]

Federal policy for the control of underground injection was first adopted by the Federal Water Quality Administration ("FWQA") of the U.S. Department of the Interior in 1970.[322] FWQA opposed the storage or disposal of contaminants "without strict control and clear demonstration that such wastes will not interfere with present or potential use of subsurface water supplies, contaminate interconnected surface waters or otherwise damage the environment".[323] Congress ratified this policy four years later in the SDWA provisions related to underground injection.[324]

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318 *See e.g.*, State v. Lebow, 280 P. 773, 774 (Kan. 1929).

319 The Texas scheme of underground injection regulation dividing authority over hydrocarbon-related injection and non-hydrocarbon-related injection, is still found today. *See* Tex. Water Code Ann. §§ 27.011 (2006).

320 Wilson et al, *supra* note 317, at 3477.

321 *See infra* Figure 3.1.

322 FEDERAL WATER QUALITY ADMINISTRATION, POLICY ON DISPOSAL OF WASTE BY SUBSURFACE INJECTION (COM 5040.10, Oct. 15, 1970). FWQA was abolished in December 1970 and its functions were transferred to EPA. Reorganization Plan No. 3 of 1970, 84 Stat. 2083, 2087 (1970).

323 *Id.*

324 H.R. REP NO. 93-1185, *reprinted in* 1974 U.S.C.C.A.N. 6454, 6481.

Following the adoption of the Federal Water Pollution Control Act of 1972 ("Clean Water Act" or "CWA"), the EPA sought to regulate underground injection on the federal level.[325] The CWA directed the EPA to obtain information on the control of pollution from "the disposal of pollutants in wells".[326] According to its statutory text, the CWA prohibits the "discharge of pollutants into the navigable waters" from a point source without a permit, with navigable waters defined as "waters of the United States".[327] However, the CWA does not provide the EPA with authority to regulate underground injection. This was confirmed in a December 1973 legal opinion by the EPA Office of General Counsel:

> Under § 502(12) [of the CWA] the term "discharge of a pollutant" is defined so as to include only discharges into navigable waters (or the contiguous zone of the ocean). Discharges into ground waters are not included.[328]

Thus the opinion concluded that the EPA's authority to control for the discharge of a pollutant into navigable waters did not include underground injection of waste.

3.2.2. Safe Drinking Water Act

In 1974, Congress adopted the SDWA to assure that water supply systems serving the public meet minimum national standards for the protection of public health.[329] The SDWA directs the EPA Administrator to establish national drinking water supply standards to protect public health and minimum requirements for state programs to prevent underground injection that endangers drinking water sources.[330] At minimum, the SDWA requires the EPA to: (1) prohibit unauthorized underground injection effective three years after the enactment of the bill;

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[325] Wilson et al., *supra* note 317, at 3478.
[326] *Id.*
[327] 33 U.S.C. §§ 1251(a)(1), 1362.
[328] Opinion, Office of General Counsel, U.S. Envtl. Protection Agency (1973), *reprinted in Exxon Corp. v. Train*, 554 F.2d 1310, 1321 n.21 (5th Cir. 1977).
[329] 1974 U.S.C.C.A.N. at 6454.
[330] 42 U.S.C. §§ 300g(a)(1), 300h(a)(1).

(2) require applicants for underground injection permits bear the burden of proving to the state that its injection will not endanger drinking water sources; (3) refrain from adopting regulations which either on their face or as applied would authorize underground injection which endangers underground sources of water; (4) adopt inspection, monitoring, recordkeeping, and reporting requirements; and (5) apply their injection control programs to underground injections by federal agencies and by any other person whether or not occurring on federally-owned or leased property.[331]

With respect to the underground injection provisions of the SDWA, the EPA Administrator is to designate those states in which a state underground injection control program may be necessary to assure that underground injection will not endanger drinking water sources.[332] Because all fifty states have been so designated, all states are required to have a program for controlling underground injection. States are permitted to assume primary responsibility for the implementation and enforcement of their respective state underground injection control programs upon the timely showing that the state program meets the requirements of the federal (UIC) regulations promulgated by the EPA, known as "primacy".[333] In the absence of an approved program, the EPA is responsible for regulating underground injection in a state.[334] The EPA has discretion whether to require states to use a permit system, rulemaking, or a combination of both to control underground injection.[335] The EPA has granted primacy for all underground injection to thirty-three states, as shown in Figure 3.1. Of the remaining states, seven states operate under a joint federal/state underground injection control

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[331] 1974 U.S.C.C.A.N. at 6481.
[332] 42 U.S.C. § 300h-1(a)(1).
[333] *See, e.g.*, Memorandum from Alan Levin, Director, EPA State Programs Division, to Water Division Directors (Regions I-X), Water Supply Branch Chiefs, and UIC Representatives regarding Procedure for Review of State Primacy Application (UIC), Ground Water Program Guidance #15 (July 31, 1981).
[334] 42 U.S.C. § 300h-1(c).
[335] 42 U.S.C. § 300h(b)(1)(B).

program, and ten states have not received any kind of primacy. In states which have not received primacy, the EPA is responsible for permitting underground injection in that state. In states that have joint federal/state programs, the states have primacy to regulate underground injection wells related to hydrocarbon production, but have not received primacy for other types of underground injection wells. State underground injection programs are delegated primacy if they are proven to be at least as stringent as federal UIC standards and/or effective in protecting pollution of underground sources of drinking water.[336] As will be discussed in Section 3.2.3, the standard for granting primacy depends on whether the injection well is associated with hydrocarbon production. A summary of the primacy status of each state is shown in Table 3.2.

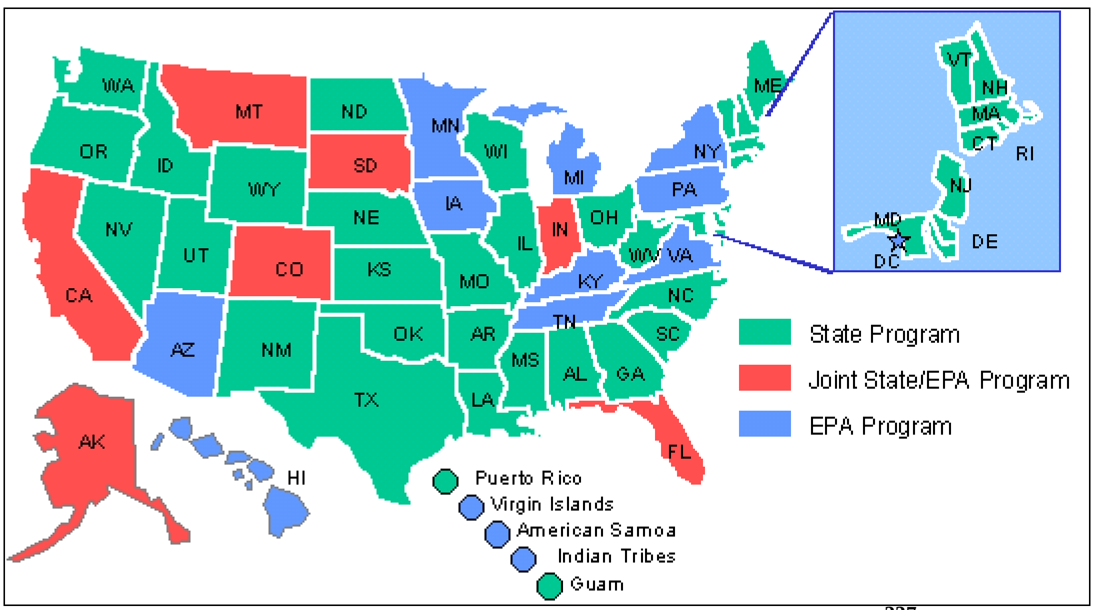

Figure 3.1 Map of UIC State Primacy Status (EPA)[337]

[336] 42 U.S.C. § 300h(b)(1).
[337] U.S. Envtl. Protection Agency, State UIC Programs, *at* http://www.epa.gov/safewater/uic/primacy.html (last modified Nov. 26, 2002).

Table 3.2 UIC Primacy Status of States (EPA)[338]

STATE	TYPE [339]	CLASSES	EFFECTIVE DATE	FEDERAL REGISTER REFERENCE
Alabama	1425	II	August 2, 1982	47 Fed Reg. 33268
Alabama*	1422	I, III, IV, V	August 25, 1983	47 Fed Reg. 38640
Alaska**	1425	II	May 6, 1986	51 Fed Reg. 16683
Arkansas	1422	I, III, IV, V	July 6, 1982	47 Fed Reg. 29236
Arkansas*	1425	II	March 26, 1984	49 Fed Reg. 11179
California**	1425	II	March 14, 1983	48 Fed Reg. 6336
Colorado**	1425	II	April 2, 1984	49 Fed Reg. 13040
Connecticut*	1422	I - V	March 26, 1984	49 Fed Reg. 11179
Delaware*	1422	I - V	April 5, 1984	49 Fed Reg. 13525
Florida**	1422	I, III, IV, V	February 7, 1983	48 Fed Reg. 5556
Georgia*	1422	I - V	April 19, 1984	49 Fed Reg. 15553
Idaho*	1422	I - V	June 7, 1985	50 Fed Reg. 23956
Illinois	1425	II	February 1, 1984	49 Fed Reg. 3990
Illinois*	1422	I, III, IV, V	February 1, 1984	49 Fed Reg. 3991
Indiana**	1425	II	August 19, 1991	56 Fed Reg. 41072
Kansas	1422	I, III, IV, V	December 2, 1983	48 Fed Reg. 54350
Kansas*	1425	II	February 9, 1984	49 Fed Reg. 4735
Louisiana*	1422/25	I - V	April 23, 1982	47 Fed Reg. 17487
Maine*	1422	I - V	August 25, 1983	48 Fed Reg. 38641
Maryland*	1422	I - V	April 19, 1984	49 Fed Reg. 15553
Massachusetts*	1422	I - V	November 23, 1982	47 Fed Reg. 52705
Mississippi	1425	II	September 28, 1983	54 Fed Reg. 8734
Mississippi**	1422	I, III, IV, V	August 25, 1983	48 Fed Reg. 38641
Missouri	1425	II	December 2, 1983	48 Fed Reg. 54349
Missouri*	1422	I, III, IV, V	July 17, 1985	50 Fed Reg. 28941
Montana	1425	II	November 19, 1996	61 Fed Reg. 58933
Nebraska	1425	II	February 3, 1984	48 Fed Reg. 4777
Nebraska*	1422	I, III, IV, V	June 12, 1984	49 Fed Reg. 24134

[338] U.S. Envtl. Protection Agency, *Responsibility for the UIC Program, at* http://www.epa.gov/safewater/uic/primacy2.html (last modified June 1, 2004). (* means the state has full primacy for UIC, ** means the state shares primacy with EPA)

[339] Refers to the SDWA provision under which EPA has delegated authority. States delegated under SDWA § 1422 (42 U.S.C. § 300h-1) have shown that the state UIC program is at least as stringent as standards in 40 C.F.R. § 144-148. States delegated under SDWA § 1425 (42 U.S.C. § 300h-4) have shown that the state program is effective in preventing pollution of underground sources of drinking water, as specified by 40 C.F.R. §144.3. SDWA § 1425 applies only to Class II wells. *Id.*

Table 3.2 UIC Primacy Status of States (EPA) (Cont'd)

STATE	TYPE	CLASSES	EFFECTIVE DATE	FEDERAL REGISTER REFERENCE
Nevada	1422	I - V	October 5, 1988	53 Fed Reg. 39089
New Hampshire*	1422	I - V	September 21, 1982	47 Fed Reg. 41561
New Jersey*	1422	I - V	July 15, 1983	48 Fed Reg. 32343
New Mexico	1425	II	February 5, 1982	47 Fed Reg. 5412
New Mexico*	1422	I, III, IV, V	July 11, 1983	48 Fed Reg. 31640
North Carolina*	1422	I - V	April 19, 1984	49 Fed Reg. 15553
North Dakota	1425	II	August 23, 1983	48 Fed Reg. 38237
North Dakota*	1422	I, III, IV, V	September 21, 1984	49 Fed Reg. 37065
Ohio	1425	II	August 23, 1983	48 Fed Reg. 38238
Ohio*	1422	I, III, IV, V	November 29, 1984	49 Fed Reg. 46896
Oklahoma	1425	II	December 2, 1981	46 Fed Reg. 58488
Oklahoma*	1422	I, III, IV, V	June 24, 1982	47 Fed Reg. 27273
Oregon*	1422/25	I - V	September 25, 1984	49 Fed Reg. 37593
Rhode Island*	1422	I - V	August 1, 1984	49 Fed Reg. 30698
South Carolina*	1422	I - V	July 10, 1984	49 Fed Reg. 28057
South Dakota**	1425	II	October 24, 1984	49 Fed Reg. 42728
Texas	1422	I, III, IV, V	January 6, 1982	47 Fed Reg. 618
Texas*	1425	II	April 23, 1982	47 Fed Reg. 17488
Utah	1425	II	October 8, 1982	47 Fed Reg. 44561
Utah*	1422	I, III, IV, V	January 19, 1983	48 Fed Reg. 2321
Vermont*	1422	I - V	June 22, 1984	49 Fed Reg. 25633
Washington*	1422	I - V	August 9, 1984	49 Fed Reg. 31875
West Virginia*	1422/25	I - V	December 9, 1983	48 Fed Reg. 55127
Wisconsin*	1422	I - V	September 30, 1983	48 Fed Reg. 44783
Wyoming	1425	II	November 22, 1982	47 Fed Reg. 52434
Wyoming*	1422	I, III, IV, V	July 15, 1983	48 Fed Reg. 32343

The 1980 reauthorization of the SDWA exempts the underground injection of fluids which are used in connection with natural gas storage operations.[340] Also, the SDWA authorizes any state to assume primary responsibility for controlling underground injection related to oil and gas recovery and production by demonstrating that its program meets the requirements of the SDWA and represents an "effective" program.[341] The Congressional intent of these provisions was for major oil and gas producing states, most of whom already had underground injection regulations in place, to be able to continue these programs unencumbered by additional federal requirements.[342] In addition, Congress was persuaded that natural gas storage does not pose a threat to drinking water quality and storage operators have an economic incentive to prevent natural gas leakage.[343]

3.2.3. EPA Underground Injection Control (UIC) Program

The EPA has implemented the SDWA requirements for the control of underground injection through the establishment of the UIC Program. Persons seeking to operate injection wells must obtain a permit under one of the five classifications of wells that have been established by the EPA.[344] The EPA has established five classes of injection wells, as shown in Table 3.3. A permit will not be granted if the underground injection results in the movement of fluid containing a contaminant into underground sources of drinking water, where the presence of that contaminant may cause a violation of any primary drinking water regulation or may adversely affect public health.[345] If a permit has been granted and if in the course of monitoring

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[340] "The term 'underground injection' means the subsurface emplacement of fluids by well injection. Such term does not include the underground injection of natural gas for purposes of storage." 42 U.S.C. § 300h(d)(1).
[341] *Id.* § 300h(b)(2).
[342] H.R. REP NO. 96-1348, *reprinted in* 1980 U.S.C.C.A.N. 6080, 6084.
[343] *Id.* at 6085.
[344] 40 C.F.R. § 144.6.
[345] *Id.* § 144.12(a). A contaminant means any physical, chemical, biological, or radiological substance or matter in water. *Id.* § 144.3.

it is found that there is movement of a contaminant into the underground source of drinking water ("USDW"), the permit may be modified or terminated.[346] Under the UIC program, a fluid is defined as "any material or substance which flows or moves whether in a semi-solid, liquid, sludge, gas, or any other form or state"[347] and a well is any "shaft" or "dug hole" that is "deeper than its largest surface dimension, where the principal factor of the hole is the emplacement of fluids".[348] An injection well is "any well into which fluids are being injected".[349] The legislative history of the SDWA indicates that Congress intended "underground injection" not to be limited to the injection of wastes or injection for disposal purposes.[350]

[346] *Id.*
[347] *Id.* § 144.3.
[348] *Id.*
[349] *Id.*
[350] 1974 U.S.C.C.A.N. at 6484.

Table 3.3 Classifications of Underground Injection Wells (40 C.F.R. § 144.6)

CLASS	DESCRIPTION
Class I	(1) Wells used by generators of hazardous waste or owners or operators of hazardous waste management facilities to inject hazardous waste beneath the lowermost formation containing, within one-quarter mile of the well bore, an underground source of drinking water.
	(2) Other industrial and municipal disposal wells which inject fluids beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.
	(3) Radioactive waste disposal wells which inject fluids below the lowermost formation containing an underground source of drinking water within one quarter mile of the well bore.
Class II	(1) Wells which inject fluids which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection.
	(2) Wells which inject fluids for enhanced recovery of oil or natural gas.
	(3) Wells which inject fluids for storage of hydrocarbons which are liquid at standard temperature and pressure.
Class III	Wells which inject for extraction of minerals including: (1) Mining of sulfur by the Frasch process; (2) *In situ* production of uranium or other metals; this category includes only in-situ production from ore bodies which have not been conventionally mined. Solution mining of conventional mines such as stopes leaching is included in Class V; (3) Solution mining of salts or potash.
Class IV	(1) Wells used by generators of hazardous waste or of radioactive waste, by owners or operators of hazardous waste management facilities, or by owners or operators of radioactive waste disposal sites to dispose of hazardous waste or radioactive waste into a formation which within one-quarter (1/4) mile of the well contains an underground source of drinking water.
	(2) Wells used by generators of hazardous waste or of radioactive waste, by owners or operators of hazardous waste management facilities, or by owners or operators of radioactive waste disposal sites to dispose of hazardous waste or radioactive waste above a formation which within one-quarter (1/4) mile of the well contains an underground source of drinking water.
	(3) Wells used by generators of hazardous waste or owners or operators of hazardous waste management facilities to dispose of hazardous waste, which cannot be classified under paragraph (a)(1) or (d) (1) and (2) of this section (e.g., wells used to dispose of hazardous waste into or above a formation which contains an aquifer which has been exempted pursuant to 40 C.F.R. § 146.04).
Class V	Wells not included in Class I, II, III, or IV.

Class I wells are used by operators to inject fluids beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.[351] The EPA recognizes three types of Class I wells: wells for the injection of hazardous waste;[352] wells for the injection of radioactive waste;[353] and wells for the injection of all other industrial and municipal waste fluids.[354] There are 529 active Class I injection wells located at 272 facilities in 19 states.[355] Of these 529 wells, 163 are classified as hazardous waste injection wells and 366 are non-hazardous.[356] As shown in Figure 3.2, the majority of the hazardous injection wells are located in Texas (78) and Louisiana (18); most of the non-hazardous wells are found in Florida (112) and Texas (110).[357] Florida is the only state with Class I municipal wells (104).[358]

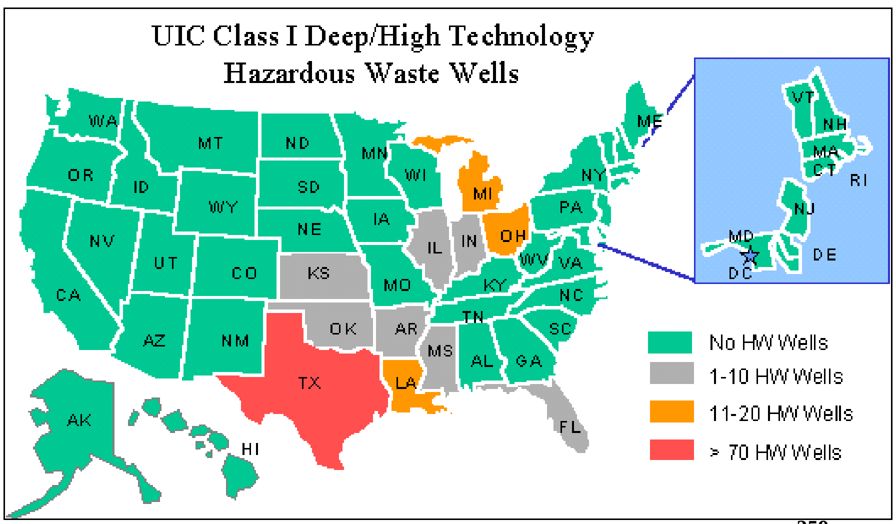

Figure 3.2 Map of UIC Class I Injection Wells (EPA)[359]

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[351] 40 C.F.R. § 144.6.
[352] The UIC regulations use the definition of hazardous waste defined by the EPA in 40 C.F.R. § 261.3, regulations promulgated under the Resource Conservation and Recovery Act (RCRA). *Id.* § 144.3.
[353] The UIC regulations define radioactive waste as any waste which contains radioactive material in concentrations which exceed those listed in 10 C.F.R. § 20. *Id.*
[354] *Id.* § 144.6.
[355] U.S. Envtl. Protection Agency, Deep Wells (Class I), *at* http://www.epa.gov/safewater/uic/classi.html (last modified Nov. 26, 2002).
[356] *Id.*
[357] *Id.*
[358] *Id.* Florida's Class I municipal wells inject non-hazardous, secondary-treated effluent from wastewater treatment plants. Florida Department of Environmental Protection, Underground Injection Control Program, *at* http://www.dep.state.fl.us/water/uic/ (last modified June 16, 2004). *See also* Wilson et al., *supra* note 317, at 3480.
[359] U.S. Envtl. Protection Agency, *supra* note 355.

Class I wells inject waste into brine-saturated formations or non-freshwater zones.[360] In the Great Lakes region, these depths range from 1,700 to 6,000 feet, while in the Gulf Coast region, these depths range from 2,200 to 12,000 feet.[361] Class I wells must be located in geologically stable areas that are free of transmissive fractures or faults through which injected fluids could travel to drinking water sources.[362] In addition, operators must demonstrate internal and external mechanical integrity of the well.[363] Class I wells must be cased and cemented to prevent the movement of fluids.[364] They are continuously monitored and must maintain a pressure that will not initiate new fractures or propagate existing fractures.[365] EPA regulations provide for an area of review of one-quarter mile for non-hazardous and municipal wells, and two miles for hazardous wells.[366]

Operators seeking to inject hazardous waste must demonstrate via a "no-migration petition" that hazardous constituents will not migrate out of the injection zone for 10,000 years.[367] They must also demonstrate that injection of hazardous waste will not induce earthquakes or increase the frequency of naturally occurring earthquakes.[368] Hazardous wells have more stringent construction requirements than non-hazardous wells, and the well design must be approved by the UIC program before construction.[369] Finally, hazardous wells have

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[360] U.S. ENVTL. PROTECTION AGENCY, CLASS I UNDERGROUND INJECTION CONTROL PROGRAM: STUDY OF THE RISKS ASSOCIATED WITH CLASS I UNDERGROUND INJECTION WELLS 12, (EPA-816-R-01-007, 2001).
[361] *Id.* at 12.
[362] *Id.* at 18.
[363] *Id.* at 13.
[364] *Id.* at 22.
[365] *Id.* at 23.
[366] *Id.* at 19. Note that states may specify a larger area of review for non-hazardous and municipal wells.
[367] *Id.* at 20.
[368] *Id.* at 18.
[369] *Id.* at 22.

additional monitoring requirements, including alarms and devices that must be installed in the event that certain parameters detailed in the UIC permit are not maintained.[370]

Operators of Class I injection wells must show that they have adequate financial resources to close and abandon their injection wells if they cease operation.[371] The amount of required financial assurance depends on the estimated cost of plugging and abandoning the injection well.[372] These costs can vary greatly. For example, the plugging and abandonment of one injection well in Michigan cost $25,000, while the cost in the case of a larger and deeper well in Ohio was $250,000.[373] Financial assurance can be demonstrated by the use of trust funds, surety bonds, letters of credit, or insurance.[374]

In 2003, the U.S. Government Accountability Office ("GAO", formerly General Accounting Office) conducted a study of the UIC financial assurance requirements for Class I injection wells (wells injecting at the greatest depth according to the EPA's classifications).[375] The GAO expressed concern that the UIC financial assurance requirements could be inadequate in cases of owner bankruptcy or other events that force well closure of Class I wells.[376] The study noted four cases where injection well owners had declared bankruptcy, and in two of the cases, the financial resources were inadequate for plugging and abandonment of the injection well.[377] The GAO concluded that "current financial assurance requirements may not ensure that

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[370] *Id.* at 23.
[371] 40 C.F.R. § 144.63.
[372] 40 C.F.R. § 144.62.
[373] U.S. GOV'T ACCOUNTABILITY OFFICE, DEEP INJECTION WELLS: EPA NEEDS TO INVOLVE COMMUNITIES EARLIER AND ENSURE THAT FINANCIAL ASSURANCE REQUIREMENTS ARE ADEQUATE 9 (GAO-03-761, June 2003).
[374] 40 C.F.R. § 144.63.
[375] U.S. GOV'T ACCOUNTABILITY OFFICE, *supra* note 373.
[376] *Id.* at 17.
[377] *Id.* at 18.

adequate resources are available to close a commercial deep injection well in the event of bankruptcy or ceased operations”.[378]

Class II wells inject fluids related to the production of hydrocarbons.[379] The EPA recognizes three types of Class II wells: wells which inject fluids which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production; wells which inject fluids for the enhanced recovery of oil or natural gas; and wells which inject fluids for the storage of hydrocarbons which are liquid at standard temperature and pressure.[380] As mentioned previously, injection wells associated with natural gas storage are exempted from SDWA and UIC requirements.

There are 167,000 Class II oil and gas wells, most of which are located in Texas (53,000), California (25,000), Oklahoma (22,000), and Kansas (15,000).[381] A summary of the Class II wells on a state-by-state basis is shown in Figure 3.3. Class II wells that inject fluids for the production of oil and gas are called enhanced recovery wells and are designated as Class II-R.[382] Wells that inject fluids for the purpose of disposal are called disposal wells and designated as Class II-D.[383] Wells used for the storage of liquid hydrocarbons or hydrocarbon products are designated Class II-H wells.[384] Of Class II wells, approximately 21% are Class II-D, 78% Class II-R, and 1% Class II-H.[385]

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[378] *Id.* at 4.
[379] 40 C.F.R. § 144.6.
[380] *Id.*
[381] *Id.*
[382] U.S. Envtl. Protection Agency, *Introduction to the Underground Injection Control Program* (Jan. 2003), *at* http://www.epa.gov/safewater/dwa/electronic/presentations/uic/uic.pdf.
[383] *Id.*
[384] *Id.*
[385] *Id.*

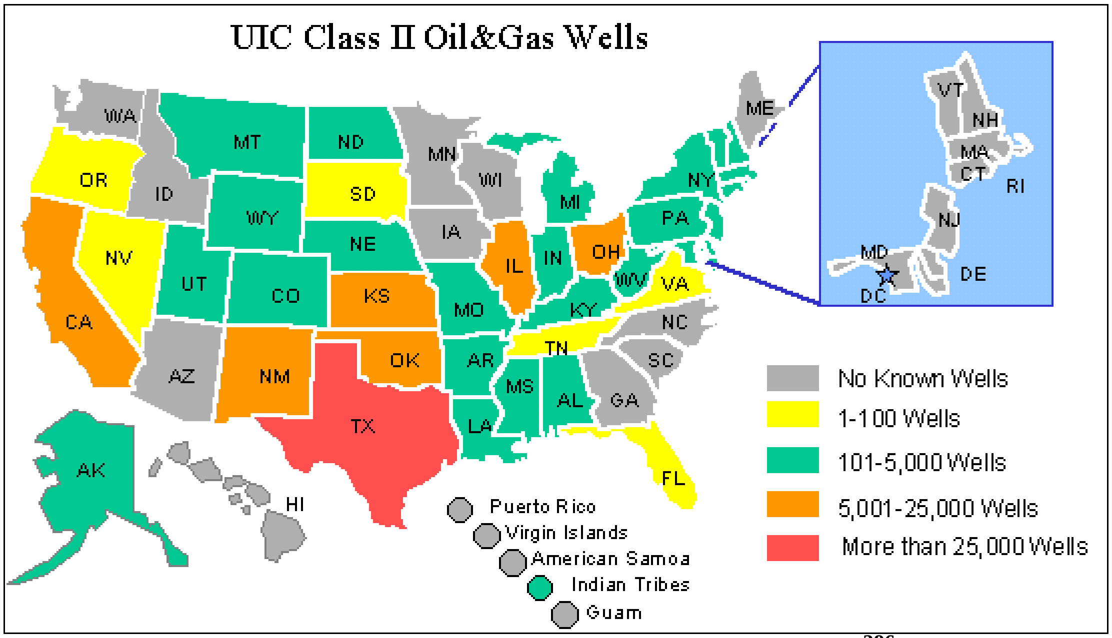

Figure 3.3 Map of UIC Class II Injection Wells (EPA)[386]

Requirements for Class II well construction are relaxed compared to the requirements for other UIC well classes. Under Section 1425 of the SDWA, a state program governing hydrocarbon production wells need only show it has "an effective program … to prevent underground injection which endangers drinking water sources".[387] In contrast, for all other classes of wells, states must demonstrate that their programs "contain minimum requirements for effective programs to prevent underground injection which endangers drinking water sources".[388] In other words, hydrocarbon wells need not meet minimum EPA requirements as long as the state underground injection program is deemed effective by the EPA, while all other types of wells must meet minimum EPA requirements. Hydrocarbon injection well permits are generally administered by a state oil and gas agency and permits for all other types of injection wells are

[386] U.S. Envtl. Protection Agency, Oil and Gas Injection Wells (Class II), *at* http://www.epa.gov/safewater/uic/classii.html (last modified Nov. 26, 2002).
[387] 42 U.S.C. § 300h-4(a).
[388] 42 U.S.C. § 300h(b)(1).

generally administered by a state's environmental protection agency.[389] These relaxed requirements were intended to assure that constraints on energy production activities would be kept limited in scope while assuring the safety of present and potential sources of drinking water.[390]

Class III injection wells are used for the extraction of minerals.[391] There are approximately 19,000 Class III wells.[392] Examples of uses for Class III wells include salt solution mining (pumping water into a salt formation to extract salt), in-situ leaching of uranium (injecting a fluid to leach out uranium salts, from which uranium is subsequently extracted), and sulfur production.[393] The construction requirements for a Class III well depend on the type of mineral being extracted.[394] Area of review ranges from 1/4 mile to 2-1/2 miles.[395]

Class IV wells are used for the injection of hazardous or radioactive waste where the waste is injected into a formation or above a formation which within one-quarter mile of the well contains an underground source of drinking water.[396] These wells are prohibited unless the wells are used to inject contaminated groundwater that has been treated and is being injected into the same formation from which it was drawn.[397] However, hazardous waste may be injected in the Class I context, where the fluid is injected beneath the lowermost underground source of drinking water; in the Class IV context, fluids are injected above the drinking water aquifer.

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[389] Wilson et al, *supra* note 317, at 3479. For example, in Wyoming, injection wells related to oil and gas production are the responsibility of the Wyoming Oil and Gas Conservation Commission, while all other injection wells are the responsibility of the Wyoming Department of Environmental Quality. Wyo. Dep't Envtl. Quality, Underground Injection Control, *at* http://deq.state.wy.us/wqd/groundwater/uicprogram/index.asp (last updated Sept. 27, 2004).
[390] 1980 U.S.C.C.A.N. at 6085.
[391] 40 C.F.R. § 144.6.
[392] U.S. Envtl. Protection Agency, *supra* note 382.
[393] U.S. Envtl. Protection Agency, Mining Wells (Class III), *at* http://www.epa.gov/safewater/uic/classiii.html (last modified Nov. 26, 2002).
[394] U.S. Envtl. Protection Agency, *supra* note 382.
[395] *Id.*
[396] 40 C.F.R. § 144.6.
[397] *Id.*

Class IV wells are generally used as part of a remediation program pursuant to the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") or the Resource Conservation and Recovery Act ("RCRA").[398]

Class V wells are, by definition, injection wells not included in Class I, II, III, or IV.[399] Class V wells are subject to the same statutory and regulatory requirements as other UIC classifications, i.e. the prohibition against endangerment of underground sources of drinking water.[400] They are typically shallow injection wells, such as for storm water drainage or septic systems, but they may be deep wells, such as for geothermal re-injection.[401] They are also used in the context of scientific experimentation. There are more than 650,000 Class V wells in the United States, and Class V wells are found in every state.[402]

3.2.4. Applicability of Underground Injection Control Regime to CO_2

At present, it is unclear how the injection and storage of CO_2 would be regulated in a UIC regime. The issue was considered by the Interstate Oil and Gas Compact Commission ("IOGCC") CO_2 Geological Sequestration Task Force, which recommended that states that have primacy under the UIC Program should continue to regulate EOR wells under Class II status.[403] For CO_2 storage not associated with EOR, the IOGCC recommended that because CO_2 is a commodity and an analog to natural gas storage, that CO_2 storage be regulated under state natural gas storage statutes and existing regulatory frameworks.[404] In the alternative, the IOGCC

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[398] 40 C.F.R. § 144.13.
[399] *Id.* § 144.6.
[400] U.S. Envtl. Protection Agency, Shallow Injection Wells (Class V), *at* http://www.epa.gov/safewater/uic/classv.html (last modified Nov. 26, 2002).
[401] *Id.*
[402] U.S. Envtl. Protection Agency, Final Determination Fact Sheet, *at* http://www.epa.gov/safewater/uic/fact6-7-02text.pdf (last viewed Jan. 11, 2005).
[403] INTERSTATE OIL & GAS COMPACT COMM'N, IOGCC CO_2 GEOLOGICAL SEQUESTRATION TASK FORCE FINAL REPORT 51 (2005).
[404] *Id.*

recommended that a new sub-classification for Class II wells or a completely new classification be established; it opposed the regulation of CO_2 storage as a Class I or Class V well.[405] The EPA has not yet decided how it will apply the UIC regulations to large-scale CO_2 storage, but has held meetings on the subject to obtain input from relevant stakeholders and regulators.[406]

The consequence of the IOGCC's recommendation that CO_2 be regulated like natural gas storage is that CO_2 storage would not be regulated under the UIC regime at all. This is because natural gas storage has received a statutory exemption from the SDWA. Although CO_2 is a "naturally occurring gas", it likely would not come under the UIC exemption for "natural gas" storage *per se*. In 1993, the U.S. Court of Appeals for the Tenth Circuit concluded that "neither the language of the SDWA, nor the relevant legislative history reveals a clear congressional intent to treat CO_2 as 'natural gas' within the meaning of the Act."[407] However, the Tenth Circuit's decision did not deal with CO_2 storage in the context of greenhouse gas mitigation. The facts of the case were that ARCO Oil and Gas Co. operated an injection well for wastes connected with the extraction of CO_2.[408] The EPA designated the disposal well a Class I well.[409] ARCO argued that the wastes were associated with a Class II well because they were brought to the surface in connection with natural gas production.[410] The EPA countered that the definition of natural gas for the purposes of UIC included only energy-related hydrocarbons, such as methane and butane, not CO_2.[411] In reviewing the legislative history, the Tenth Circuit found that Congress did not reveal whether it considered the production of CO_2 to be one of the

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405 *Id.* at 52.
406 *See e.g.*, ADAM SMITH, REGULATORY ISSUES CONTROLLING CARBON CAPTURE AND STORAGE 35 (S.M. thesis, MIT, 2004). *See also* Lawrence Berkeley Nat'l Lab., Int'l Symp. for Site Characterization of CO_2 Geological Storage, *at* http://esd.lbl.gov/CO2SC/ (Mar. 22, 2006).
407 ARCO Oil and Gas Co. v. EPA, 14 F.3d 1431, 1436 (10th Cir. 1993).
408 *Id.* at 1431.
409 *Id.*
410 *Id.*
411 *Id.* at 1433.

protected energy production activities.[412] The court deferred to the EPA's decision in excluding CO_2 from the definition of natural gas.[413] In a separate decision, the Tenth Circuit upheld defining CO_2 as "natural gas" for the purposes of issuing a right-of-way across federal land for a CO_2 pipeline.[414] Thus the Tenth Circuit's logic has been that CO_2 is not necessarily "natural gas" and one must look to Congressional intent to determine whether the storage of CO_2 is encompassed within natural gas storage legislation. The end result in the Tenth Circuit is that CO_2 is "natural gas" for the purposes of pipeline and transportation, but not "natural gas" for the purposes of underground injection.

There are two potential UIC frameworks for CO_2. One would be to allow states to regulate CO_2 injection and storage according to the injection well classifications that they see fit. The second would be for federal regulators to specify a UIC classification for CO_2 storage through rulemaking or guidance documents. Under the current regime, CO_2 storage injection wells could come under one of three potential classifications: Class I non-hazardous injection wells; Class II EOR wells; and Class V experimental wells.

Class I non-hazardous injection wells would likely encompass CO_2 injected into deep saline formations. CO_2 is not a hazardous waste for the purposes of the UIC Program because it is not a hazardous waste for the purposes of RCRA. The EPA excludes certain materials from its enforcement of RCRA under 40 C.F.R. § 261.4, but CO_2 is not among the materials that have been excluded from hazardous waste regulation. However, CO_2 has also not been explicitly listed as hazardous in the EPA's list of RCRA hazardous wastes at 40 C.F.R. § 261.3. Any

[412] *Id.* at 1435.
[413] *Id.* at 1436.
[414] Exxon Corp. v. Lujan, 970 F.2d 757, 763 (10th Cir. 1992) (affirming a decision of the U.S. Bureau of Land Management to issue a right-of-way for a carbon dioxide pipeline under the Mineral Leasing Act, rather than under the Federal Land Policy and Management Act).

regulatory filings would need to characterize CO_2 to show that it is not a hazardous waste.[415] A waste is a characteristic waste if it displays the properties of ignitability, corrosivity, reactivity, or toxicity as defined by 40 C.F.R. §§ 261.21-261.24.

Several commentators have argued that CO_2 storage should be regulated under a Class I regime.[416] One argument is that a Class I regime is appropriate because CO_2 might be stored for long time periods (thousands of years) and Class I hazardous injection wells are the only UIC wells required to demonstrate no migration for a long time period (10,000 years).[417] However, the no-migration petition is based on criteria for hazardous waste injection wells, and CO_2 would be regulated under a non-hazardous waste classification. Tsang et al. argue that Class I injection wells are the most relevant to CO_2 injection into brine formations.[418] They assume that CO_2 will likely be stored at depths greater than 800 meters to keep CO_2 in a supercritical state, and most drinking water aquifers are shallower than 800 meters.[419] Their argument is specific to brine formations. Class II injection wells, where CO_2 is injected for EOR, could also include depths greater than 800 meters.

A Class II regime would be appropriate where CO_2 is injected in conjunction with the production of oil or natural gas. CO_2 is already injected for EOR, and the injection wells are permitted under the Class II regime.[420] In the context of EOR, UIC classifications seem straight forward because the Class II injection well would be abandoned once the production activities cease. However, if the injection well has been depleted of hydrocarbons (i.e. hydrocarbon production is no longer possible) and CO_2 is to be stored in the depleted hydrocarbon formation,

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415 U.S. Envtl. Protection Agency, s*upra* note 360, at 1.
416 *See* Smith, *supra* note 406, at 36.
417 *Id.*
418 C.-F. Tsang et al, *Scientific Considerations Related to Regulation Development for CO_2 Sequestration in Brine Formations* 4, PROC. FIRST NAT'L CONF. CARBON SEQUESTRATION (2001), *available at* http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/p33.pdf.
419 Id.
420 U.S. Envtl. Protection Agency, *supra* note 381.

a Class II regime might not apply. Class II wells are defined to be used for fluids injected in connection with conventional oil and gas production, enhanced recovery of oil or natural gas, and the storage of hydrocarbons.[421] Injection unrelated to the recovery or storage of hydrocarbons is not encompassed under a Class II regime. This is complicated by the fact that although an oil and gas reservoir may be "depleted", there may still be hydrocarbons in the reservoir, albeit unrecoverable hydrocarbons. Thus the operator would need to show an intent to extract hydrocarbons in order for the Class II regime to apply.

A Class V well would be appropriate for the injection and storage of CO_2 for experimental purposes. Scientists affiliated with the Gulf Coast Carbon Center received a Class V permit from Texas regulators for an experiment injecting CO_2 into the Frio brine formation in Texas.[422] The group was advised that they would be ineligible for a Class II permit because the CO_2 was not intended for enhanced oil production or the disposal of pre-refinery oil field waste.[423]

3.2.5. Possibilities for an Exemption or New Classification/Sub-Classification

Some commentators have noted the UIC regime, in its current form, may not meet the needs of CO_2 injection and storage.[424] Wilson et al note that there are no federal requirements for monitoring actual fluid movement in an injection zone, or for monitoring leakage in

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[421] 40 C.F.R. § 144.6.

[422] HAVORKA ET AL, *supra* note 316, at 4. *See also* Smith, *supra* note 406, at 36. The Gulf Coast Carbon Center is a regional industry-academic partnership affiliated with University of Texas, and a member of the U.S. Department of Energy's Southeast Regional Partnership. U.S. Dep't of Energy, *Southeast Regional Carbon Sequestration Partnership, at* http://www.fe.doe.gov/programs/sequestration/partnerships/2003sel_southeast.html (last modified Aug. 2, 2004). U.S. Dep't of Energy, *Fossil Energy Techline: Frio Formation Test Well Injected with Carbon Dioxide* (Nov. 19, 2004), *at* http://www.fossil.energy.gov/news/techlines/2004/tl_frio_injection.html. A number of other pilot experiments are being developed under the U.S. Department of Energy's Regional Carbon Sequestration Partnership program. *See* U.S. Dep't of Energy, Carbon Sequestration Regional Partnerships, *at* http://www.fe.doe.gov/programs/sequestration/partnerships/index.html (last visited May 11, 2006).

[423] HAVORKA ET AL, *supra* note 316, at 4.

[424] *See* Smith, *supra* note 406, at 36.

overlying zones, with the exception of Class I hazardous wells.[425] Morgan argues that UIC regulations are procedurally-based rather than performance-based, and that a performance-based regulation, such as mandating a maximum leakage rate, would be more appropriate for CO_2 injection wells.[426] UIC regulations do not specify a containment time for injected waste, with the exception of Class I hazardous wells, which mandate no migration within the geological formation for at least 10,000 years.[427]

If CO_2 injection and storage is not regulated under the current UIC regime, there are two other possibilities. The first would be for Congress to exempt CO_2 from underground injection regulations, similar to what has been done for natural gas storage. The second would be to create a separate classification or a sub-category with a current injection well class, specifically for CO_2.

Exempting CO_2 from the current underground injection regime would require an act of Congress. In the 1980 reauthorization of the Safe Drinking Water Act, Congress exempted the underground storage of natural gas.[428] The House Committee on Interstate and Foreign Commerce noted that "sufficient evidence does not exist indicating that natural gas storage poses a threat to drinking water quality and that storage operators have an economic incentive to prevent gas leakages".[429]

One could envision a similar argument made for CO_2 storage. Note that the House Committee argument focused on the effect of natural gas *storage* on drinking water quality and not the effect of natural gas on drinking water. Following the House Committee's logic, there

[425] Wilson et al, *supra* note 317, at 3479.
[426] Smith, *supra* note 406, at 36 (summarizing personal communication with Dr. Granger Morgan, Carnegie Mellon University, regarding suitability of UIC program for geologic carbon storage).
[427] Wilson, *supra* note 317, at 3481.
[428] 42 U.S.C. § 300h(d)(1).
[429] 1980 U.S.C.C.A.N. at 6085.

are two issues that would need to be considered with respect to an exemption: (1) whether CO_2 storage poses a threat to drinking water quality; and (2) whether there is an economic incentive to prevent CO_2 leakage from a geological reservoir. The first issue would best be informed by an investigation of the differences in the threat to drinking water quality posed by CO_2 storage as compared with natural gas storage. With respect to the second issue, natural gas has economic value as a commodity. If a carbon tax or an equivalent "cap and trade" mechanism was instituted, CO_2 storage operators could have an incentive to prevent leakage. However, issues of federalism and legal consistency might arise from the use of state-by-state regulation of underground injection within a CO_2 market. Even if both prongs of the House Committee's argument were shown to be true for CO_2 storage, Congressional action would still be required to exempt CO_2 storage from the SDWA and UIC regulations.

Sub-categories are already used by the UIC program. The EPA defines sub-categories if operating and construction practices warrant such.[430] For example, as noted in the discussion of Class II well sub-categories, UIC distinguishes between disposal wells, wells used for EOR, and wells used for hydrocarbon storage. It would be a logical extension of current regulations to create a new sub-category under a Class I or Class V regime. Although the UIC program has created sub-categories of wells, the EPA has not created new classes of wells. However, there is nothing in the SDWA that says they cannot create a new UIC class of wells. Regardless of whether a sub-classification or new classification is used, guidance from the EPA specific to CO_2 injection would address some of the uncertainties and possible inconsistencies in the regulation

[430] *See, e.g.* U.S. ENVTL. PROTECTION AGENCY, STATEMENT OF BASIS AND PURPOSE: UNDERGROUND INJECTION CONTROL REGULATIONS 6 (National UIC Docket Control Number D01079, 1989) (responding to comments that Class III wells be sub-categorized), *available at* http://www.epa.gov/safewater/uic/pdfs/statement_of_basis_and_purpose_uic_1980.pdf.

of CO_2 injection wells, such as addressing regulatory discrepancies between storage in depleted oil and gas reservoirs versus storage following EOR.

3.2.6. Conclusion

Strict regulations on the design and operation of a CO_2 injection well can have the effect of minimizing the potential for CO_2 leakage, therefore minimizing liability. The strength of the UIC Program is that injection well operators must comply with detailed technical requirements for underground injection. For example, all UIC permit applicants must apply for a construction permit which specifies how the injection well will be constructed to prevent the injected fluids from migrating into underground sources of drinking water.[431] However, the requirements for the injection of hazardous fluids are significantly more rigorous than for the injection of non-hazardous fluids.[432] For example, hazardous waste injection well operators must demonstrate that the injected fluid will not migrate into an underground source of drinking water for 10,000 years (known as a "no migration petition").[433] Non-hazardous injection wells are not required to present a no migration petition. Hazardous injection wells also have post-injection monitoring requirements that are not mandated for non-hazardous injection wells.[434] UIC defines a hazardous fluid on the basis of it being listed as hazardous in the Resource Conservation and Recovery Act ("RCRA").[435] Because CO_2 has not been deemed hazardous by RCRA, not only is CO_2 storage not regulated by RCRA, but it also is not regulated as a hazardous fluid under the UIC Program.

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[431] U.S. GOV'T ACCOUNTABILITY OFFICE, *supra* note 373, at 1.
[432] Wilson et al, *supra* note 317, at 3481.
[433] 40 C.F.R. § 148.20(a)(1)(i).
[434] 40 C.F.R. § 146.68.
[435] 40 C.F.R. § 146.3 ("Hazardous waste means a hazardous waste as defined in 40 C.F.R § 261.3."). 40 C.F.R. § 146.3 is RCRA's definition of hazardous waste.

The EPA has begun discussions on whether the current UIC classification system is appropriate for CO_2 storage.[436] In March 2006, the Team Leader of the UIC Program argued that there were five key technical issues confronting the EPA's determination for treatment of CO_2 storage: site characterization for the CO_2 injection well, the area of review for determining locations of abandoned wells and leakage pathways, well construction and plugging and abandonment procedures, modeling and analytical tools for predicting the fate of CO_2, and monitoring and verification.[437] The EPA will continue to use its experimental well classification, Class V, for current CO_2 storage pilot projects,[438] but the regulatory approach is expected to change for long-term commercial projects which are expected to be operational by 2012.[439]

In summary, the regulatory issues surrounding CO_2 storage will need to be clarified to facilitate large-scale implementation. The UIC Program will likely form the basis for the regulation, and could very well become the regulatory regime for CO_2 injection and storage. It is unclear how the UIC Program will be interpreted with respect to CO_2. Under the current UIC regime, one could interpret the regulations to provide three classifications for carbon storage: a regime for experiments (Class V wells), a regime CO_2 injection and storage for EOR (Class II wells), and a regime for the injection of CO_2 into all other geological formations (Class I wells). In the alternative, there may be precedent for advancing legislation that would exempt CO_2 from

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[436] WORLD RESOURCES INST., WORKSHOP SUMMARY: WRI CARBON DIOXIDE CAPTURE AND STORAGE WORKSHOP 6 (Feb. 28, 2006).

[437] Bruce Kobelski, EPA Efforts: Carbon Capture and Storage, Address at the Int'l Symp. for Site Characterization of CO_2 Geological Storage (Mar. 22, 2006), *at* http://esd.lbl.gov/CO2SC/.

[438] *See* HAVORKA ET AL, *supra* note 316, at 4; U.S. Dep't of Energy, *supra* note 316.

[439] Kobelski, *supra* note 437. Two commercial-scale sequestration projects have been proposed in the United States. The first is FutureGen, a $1.2 billion public-private partnership to build a coal-fired power plant with carbon capture and sequestration that will produce hydrogen. Address before a Joint Session of the Congress on the State of the Union, 39 WEEKLY COMP. PRES. DOC. 109 (Jan. 28, 2003). More recently, BP has proposed a carbon capture and sequestration project in conjunction with BP's Carson oil refinery and the Edison Mission Group. Press Release, BP, BP and Edison Mission Group Plan Major Hydrogen Power Project for California (Feb. 10, 2006).

the current underground injection regime, or regulatory clarity could be provided by creating a separate classification regime for CO_2 injection wells.

3.3. Regulation of Offshore Storage of CO_2

Increasing attention is being paid to the use of sub-seabed geological formations, such as offshore oil and gas reservoirs and deep saline formations, to store CO_2. Sub-seabed storage is attractive because it decreases the environmental hazards that would ordinarily be faced by storage conducted onshore. Although some of the sources of CO_2 storage risk are found in both the onshore and offshore contexts (such as induced seismicity), several sources of the risk pose a greater likelihood of harm from onshore CO_2 storage because of the higher probability of humans living near the operations, such as the potential to be affected by groundwater contamination or hazards to human health.

Although CO_2 storage conducted onshore would generally be governed by national law,[440] CO_2 storage conducted offshore would be impacted by international law.[441] Because sub-seabed CO_2 storage has not been specifically addressed in any multilateral environmental agreements that are currently in force, its legality will depend on global and regional marine agreements that govern the general subject area. Sub-seabed CO_2 storage has been the subject of some legal and regulatory analysis,[442] however, the work has often not considered the operational context of CO_2 storage, or was written before recent developments with respect to CO_2 storage's application to pertinent marine agreements.

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[440] INT'L ENERGY AGENCY, LEGAL ASPECTS OF STORING CO_2 31 (2005).
[441] *Id.* at 21.
[442] *See, e.g.,* Karen N. Scott, *The Day After Tomorrow: Ocean CO_2 Sequestration and the Future of Climate Change*, 18 GEO. INT'L ENVTL. L. REV. 57, 66 (2005); RAY PURDY & RICHARD MACRORY, GEOLOGICAL CARBON SEQUESTRATION: CRITICAL LEGAL ISSUES (2004); DE FIGUEIREDO *supra* note 14; JASON HEINRICH, LEGAL IMPLICATIONS OF CO_2 OCEAN STORAGE (2002); W.J. Lenstra, Address at the IPCC Workshop on Carbon Dioxide Capture and Storage (Nov. 19, 2002).

This section addresses the issue of whether sub-seabed CO_2 storage is consistent with existing international law. I begin by examining CO_2 storage in the context of the 1982 United Nations Convention on the Law of the Sea ("UNCLOS"),[443] with particular attention paid to provisions related to state jurisdiction, protection of the marine environment, and dispute settlement. Next, I analyze regulation of CO_2 storage under the 1972 Convention on the Prevention of Marine Pollution by Dumping of Wastes and other Matter ("London Convention"),[444] which provides minimum rules and standards that all parties to UNCLOS must comply with to prevent, reduce and control pollution of the marine environment by dumping.[445] The next subsection focuses on how the legality of CO_2 storage under the London Convention may change with the 1996 Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and other Matter ("London Protocol"), which replaces the London Convention.[446] I then address CO_2 storage in the context of one regional agreement, the Convention for the Protection of the Marine Environment of the North-East Atlantic ("OSPAR Convention"),[447] which has received considerable attention because of current and prospective projects to store CO_2 beneath the North Sea. Finally, I analyze three of these projects to determine their compatibility with international law.

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[443] United Nations Convention on the Law of the Sea, *opened for signature* Dec. 10, 1982, U.N. Doc. A/CONF.62/122 (1982), *reprinted in* Official Text of the United Nations Convention on the Law of the Sea, U.N. Sales No. E.83.V.5 (1983) and 21 I.L.M. 1261 (1982) [hereinafter UNCLOS].
[444] Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter, *opened for signature* Dec. 29, 1972, 26 U.S.T. 2406, 1046 U.N.T.S. 120 [hereinafter London Convention].
[445] UNCLOS, *supra* note 443, art. 210, § 6 ("National laws, regulations and measures shall be no less effective in preventing, reducing and controlling such pollution than the global rules and standards.")
[446] 1996 Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter, 1972 and Resolutions Adopted by the Special Meeting, *opened for signature* Nov. 7, 1996, 36 I.L.M. 1 [hereinafter London Protocol].
[447] Convention for the Protection of the Marine Environment of the North-East Atlantic, *opened for signature* Sept. 22, 1992, 32 I.L.M. 1072 [hereinafter OSPAR Convention].

3.3.1. CO_2 Storage in the UNCLOS Regime

UNCLOS, which establishes a legal order for the seas and oceans, applies to the seabed, ocean floor, and subsoil.[448] As a result, UNCLOS has jurisdiction over sub-seabed CO_2 storage. UNCLOS entered into force on November 16, 1994, and has 149 parties to date.[449] Notably, the United States is not a party to UNCLOS, but rather is a party to the 1958 Geneva Conventions on the Law of the Sea, which preceded UNCLOS.[450] The main difference between the 1958 Geneva Conventions and UNCLOS is regulation of the deep sea bed, which has traditionally been opposed to by the United States.[451] However, the Bush administration is on record as supporting UNCLOS because of its potential economic benefits and implications for national security.[452] On February 25, 2004, the Senate Foreign Relations Committee unanimously recommended that the full Senate give its advice and consent to UNCLOS ratification, but the treaty was not taken up by the Senate.[453] Nonetheless, its accession to UNCLOS will likely not affect the CO_2 storage strategy of the United States, which has concentrated on onshore CO_2

[448] *See, e.g.*, UNCLOS Convention, *supra* note 443, art. 1, 2, 56, 76.
[449] U.N. Division of Ocean Affairs & the Law of the Sea, Chronological List of Ratifications of, Accessions and Successions to the Convention and the Related Agreements, *available at* http://www.un.org/Depts/los/reference_files/chronological_lists_of_ratifications.htm (last visited Nov. 24, 2005).
[450] The 1958 Geneva Conventions on the Law of the Sea are: Convention on the Territorial Sea and the Contiguous Zone, *opened for signature* Apr. 29, 1958, 15 U.S.T. 1606, 516 U.N.T.S. 205; Convention on the Continental Shelf, *opened for signature* Apr. 29, 1958, 15 U.S.T. 471, 499 U.N.T.S. 311; Convention on the High Seas, *opened for signature* Apr. 29, 1958, 13 U.S.T. 2312, 450 U.N.T.S. 82; Convention on Fishing and Conservation of the Living Resources of the High Seas, *opened for signature* Apr. 29, 1958, 17 U.S.T. 138, 559 U.N.T.S. 285.
[451] *See, e.g.*, President Ronald Reagan, Statement on United States Participation in the Third United Nations Conference on the Law of the Sea (Jan. 29, 1982) (noting "while most provisions of the draft convention are acceptable and consistent with United States interests, some major elements of the deep seabed mining regime are not acceptable").
[452] Condoleezza Rice, Questions for the Record from Senator Richard G. Lugar Nomination Hearing for Dr. Condoleezza Rice (Jan. 18-19, 2005), *available at* http://lugar.senate.gov/sfrc/rice_qfa.html ("The Administration supports early Senate action on the Convention. The Administration urges the Senate Foreign Relations Committee to again favorably report out the Convention and Implementing Agreement, with the Resolution of Advice and Consent to Ratification as reported by the Committee last March").
[453] CONGRESSIONAL RESEARCH SERVICE, CRS ISSUE BRIEF FOR CONGRESS: THE LAW OF THE SEA CONVENTION AND U.S. POLICY (Aug. 4, 2005).

storage rather than sub-seabed CO_2 storage for various reasons, including existing knowledge and infrastructure related to the enhanced recovery of oil by CO_2 injection.[454]

3.3.1.1. State Jurisdiction

UNCLOS sets forth boundaries within which states have certain sovereign rights. A coastal state has full sovereign rights over its "territorial sea", which extends 12 miles from the coast and includes the seabed and subsoil.[455] Although a state would not be prohibited from engaging in sub-seabed CO_2 storage within its territorial sea, it would still be subject to other provisions of UNCLOS, such as those related to pollution of the marine environment by dumping,[456] and thus the right is not one without constraint.

Beyond the territorial sea, UNCLOS has two sets of provisions governing the seabed and subsoil. In one set of provisions, UNCLOS defines a coastal state's "continental shelf" as comprising the seabed and subsoil extending from the boundary of the territorial sea to 200-miles from shore (or to the outer edge of the continental margin if it extends beyond that distance).[457] A state has "sovereign rights" for the purpose of "exploring and exploiting" the natural resources of its continental shelf, including the mineral and other non-living resources of the seabed.[458] In a second set of provisions, UNCLOS defines a coastal state's 200-mile "exclusive economic zone ("EEZ") beyond the territorial sea,[459] within which a state has "sovereign rights for the purpose of exploring and exploiting, conserving and managing" living and non-living natural resources of the seabed and its subsoil, as well as the super-adjacent waters.[460]

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[454] *See, e.g.*, Samuel Bodman, Address at the Clean Coal and Power Conference (Nov. 22, 2005); Samuel Bodman, Address at the National Coal Council (June 9, 2005).
[455] UNCLOS Convention, *supra* note 443, art. 3
[456] *Id.* art. 210.
[457] *Id.* art. 76.
[458] *Id.* art. 77.
[459] *Id.* art. 57.
[460] *Id.* art. 56.

Under both the EEZ and continental shelf definitions of sovereign rights, CO_2 injection associated with EOR would be permitted as a form of exploiting natural resources. The legality of other methods of CO_2 storage, such as the injection of CO_2 into a deep saline formation, is more uncertain and depends on whether a geological formation for CO_2 storage is considered a non-living natural resource. The issue here is not a state's right over resources contained in the formation, such as oil contained in a hydrocarbon formation, but rather a state's sovereign right over the pore space of the geological formation that would contain the stored CO_2. Although the question of whether pore space is a non-living natural resource was likely not considered by the drafters of UNCLOS, geological storage capacity is a natural resource from the perspective of a twenty-first century state, and there is considerable state practice demonstrating an entitlement to exploiting geological storage capacity.[461]

Beyond a coastal state's limits of national jurisdiction is an area known as the high seas, which is open to all states regardless of whether they are coastal or land-locked, and include the seabed and subsoil.[462] The development of resources in the area is overseen by the International Seabed Authority, with requirements that activities be carried out for the benefit of mankind as a whole and that financial benefits be shared.[463] As a result of the objections of several states with interests in deep seabed mining, provisions were renegotiated in a 1994 Agreement that came into force in 1996,[464] however, rules governing the financial terms are premised on the extraction of resources and do not contemplate injection into a geological formation in the area.[465] Thus

[461] Scott, *supra* note 442, at 66.
[462] UNCLOS Convention, *supra* note 443, art. 86.
[463] *Id.* art. 140.
[464] Agreement Relating to the Implementation of Part XI of the United Nations Convention on the Law of the Sea of 10 December 1982, *opened for signature* Jul. 28, 1994, U.N. GAOR, 48th Sess., 101st plen. mtg., Annex, U.N. Doc. A/RES/48/263/Annex (1994), *reprinted in* 33 I.L.M. 1309, Annex at 1313 (1994).
[465] *See, e.g.*, Agreement, § 8(b) ("The rates of payments under the system shall be within the range of those prevailing in respect of land-based mining…").

although sub-seabed CO_2 storage could be allowed upon the authorization of the International Seabed Authority, it is uncertain how royalty payments would be calculated.

3.3.1.2. Protection and Preservation of the Marine Environment

UNCLOS provides that states have an obligation to protect and preserve the marine environment, and are to take measures to prevent, reduce and control pollution of the marine environment.[466] There are two provisions which are of particular relevance to CO_2 storage. First, under Article 195 of UNCLOS, states are to act "so as not to transfer, directly or indirectly, damage or hazards from one area to another or transform one type of pollution into another". Under one reading of this provision, CO_2 storage could be seen as transforming pollution related to climate change into potential pollution of the marine environment (due to the risk of CO_2 being emitted from the geological formation into the waters), however this reading is problematic for two reasons. First, it neglects the fact that the ocean is a natural sink for CO_2, eventually increasing the acidity of the oceans due to CO_2 uptake.[467] In other words, CO_2 storage mitigates the pollution of oceans from CO_2. Second, although leakage to the surface is a major concern in the onshore CO_2 storage context, it does not appear to be particularly problematic in the case of offshore CO_2 storage. The most likely source of leakage is from high permeability conduits, in particular abandoned or orphaned wells which are poorly plugged,[468] which is a concern that is less likely to be faced by offshore CO_2 storage since there are less

[466] Under Article 1 of UNCLOS, "pollution of the marine environment" is defined as:

> [T]he introduction by man, directly or indirectly, of substances or energy into the marine environment, including estuaries, which results or is likely to result in such deleterious effects as harm to living resources and marine life, hazards to human health, hindrance to marine activities, including fishing and other legitimate uses of the sea, impairment of quality for use of sea water and reduction of amenities.

[467] Christopher L. Sabine et al., The Oceanic Sink for Anthropogenic CO_2, 305 SCIENCE 367 (2004).

[468] What Are the Administration Priorities for Climate Change Hearing Before the House Comm. on Science (2003) (testimony of Dr. Sally Benson, Lawrence Berkeley National Laboratory).

offshore wells that have been drilled,[469] and those that are drilled adhere to strict standards for drilling and completion.[470] The largest demonstration of sub-seabed CO_2 storage to date has not found any leakage of injected CO_2 from the geological formation.[471]

The second environmental provision of relevance to sub-seabed CO_2 storage is Article 210 of UNCLOS, which regulates pollution by dumping. States are to adopt laws and regulations to prevent, reduce and control pollution of the marine environment by dumping. Article 1 of UNCLOS defines dumping as "any deliberate disposal of wastes or other matter from vessels, aircraft, platforms or other man-made structures at sea" but notes that dumping does not include the "placement of matter for a purpose other than the mere disposal thereof". In addition, Article 1 specifies that dumping does not include the "disposal of wastes or other matter incidental to, or derived from the normal operations of vessels, aircraft, platforms or other man-made structures at sea and their equipment" except for "wastes or other matter transported by or to vessels, aircraft, platforms or other man-made structures at sea, operating for the purpose of disposal of such matter or derived from the treatment of such wastes or other matter on such vessels, aircraft, platforms or structures". This provision raises a number of questions. First is the injection of CO_2 into a sub-seabed geological formation considered "disposal"? Second, is CO_2 a "waste or other matter"? Third, what are the implications for CO_2 storage that dumping is only from "vessels, aircraft, platforms other man-made structures at sea"? Fourth, what, if any, forms of CO_2 storage would constitute "placement of matter for a purpose other than mere disposal", "disposal of waste or other matter incidental to, or derived from normal operations of

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[469] *See, e.g.*, MINERALS MGM'T SERVICE, NUMBER OF FEDERAL OFFSHORE AND ONSHORE WELLS, FISCAL YEARS 1990-2000, *at* http://www.mrm.mms.gov/Stats/pdfdocs/fed_well.pdf (last visited Nov. 24, 2005) (noting that in Fiscal Year 2000, there were 18,493 federal offshore wells and 94,641 federal onshore wells).
[470] *See, e.g.*, International Organization for Standardization, ISO/TC 67/SC 3 - Drilling and Completion Fluids and Well Cements, at http://www.standard.no/imaker.exe?id=5658 (last visited Dec. 4, 2005).
[471] *See, e.g.*, Rob Arts et al., *Recent Time-Lapse Seismic Data Show No Indication of Leakage at the Sleipner CO_2 Injection Site, in* PROC. SEVENTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. (E.W. Rubin et al., eds., 2004).

vessels, aircraft, platforms or other man-made structures at sea and their equipment", or "wastes or other matter transported by or to vessels, aircraft, platforms or other man-made structures at sea, operating for the purpose of disposal of such matter or derived from the treatment of such wastes or other matter on such vessels, aircraft, platforms or structures"? UNCLOS does not provide much guidance in answering these questions, other than a provision in Article 210 stating that national laws, regulations, and measures should be "no less effective" than international rules and standards for preventing, reducing and controlling pollution by dumping. These international rules and standards have been interpreted to be defined by the London Convention.[472] I delay considering the issues regarding dumping embodied in these questions until consideration of the London Convention in Section 3.3.2, where I will show that there are methods of sub-seabed CO_2 storage that would not constitute pollution by dumping.

3.3.1.3. Enforcement and Dispute Settlement

UNCLOS sets forth enforcement provisions related to pollution from seabed activities and pollution by dumping.[473] In both cases, rules for enforcement are to be established by competent international organizations or diplomatic conference, but a coastal state may enforce the pollution by dumping provisions within its territorial sea, EEZ, or onto its continental shelf. Although there are specific enforcement provisions related to pollution from "vessels",[474] UNCLOS is silent as to enforcement from sources of pollution that are not vessels.

The International Tribunal for the Law of the Sea was established by UNCLOS to adjudicate disputes in connection with UNCLOS,[475] with thirteen cases having been entered into

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[472] *See, e.g.*, Alan E. Boyle, Marine Pollution under the Law of the Sea Convention, 79 AMER. J. INT'L. L. 347, 354 (1985).
[473] UNCLOS Convention, *supra* note 443, art. 213-214.
[474] *Id.* art. 217-220.
[475] *Id.* annex VI

the Tribunal's list of cases since its inauguration in October 1996.[476] The cases before the Tribunal have fallen into two categories. The first has been the arrest of a shipping vessel by a coastal state and attempts by the vessel's Flag State to achieve its release.[477] The second has been related to provisional measures pending the constitution of an arbitral tribunal for settling disputes.[478] Although the Tribunal's jurisprudence does provide some precedent for the legality of CO_2 storage taking the form of direct injection into waters, its application to sub-seabed CO_2 storage is fairly limited since the Tribunal has not made clear pronouncements on substantial UNCLOS legal questions[479] and sub-seabed CO_2 storage operations would take the from of an offshore platform or pipeline to the injection point rather than a vessel injecting CO_2 beneath the seabed.

In addition to the International Tribunal for the Law of the Sea, there are three other mechanisms for dispute settlement under UNCLOS: the International Court of Justice, a five-member arbitral tribunal established in accordance with the Convention, and a special arbitral tribunal established in accordance with the Convention.[480] The special arbitral tribunal would be particularly relevant to disputes related to CO_2 storage because it is designed for specialized disputes requiring scientific expertise, such as "protection and preservation of the environment" and "pollution from vessels and by dumping".[481] Generally speaking, "states have not brought many new law of the sea cases to either the international courts or the arbitral tribunals", possibly because no one court has exclusive authority to interpret UNCLOS and thus different

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[476] International Tribunal for the Law of the Sea, Proceedings and Judgments – List of Cases, *at* http://www.itlos.org/cgi-bin/cases/list_of_cases.pl?language=en (last visited Nov. 24, 2005).
[477] Christoph Schwarte, Environmental Concerns in the Adjudication of the International Tribunal for the Law of the Sea, 16 GEO. INT'L ENVTL. L. REV. 421, 424
[478] *Id.*
[479] *Id.* at 439.
[480] UNCLOS Convention, *supra* note 443, art. 287.
[481] *Id.* annex VIII, art. 1.

tribunals could interpret a rule differently, leading to inconsistent jurisprudence,[482] however the risk is minimized where the various courts and tribunals decide few cases.[483] The implication for CO_2 storage of having these various dispute resolution mechanisms is unclear, simply because of the lack of precedent, but the need for specialized expertise could favor the use of the special arbitral tribunal or the International Tribunal for the Law of the Sea.

3.3.2. CO_2 Storage in the London Convention Regime

The 1972 London Convention establishes a legal regime for the dumping of wastes or other matter, providing a minimum set of global rules and standards for compliance under UNCLOS Article 210. The Convention went into force on August 30, 1975, and thus was a legal regime in place prior to the drafting of UNCLOS. The London Convention has 81 parties, and unlike UNCLOS, the United States is a party to the London Convention.[484] Generally speaking, each coastal state has a duty to enforce the Convention within its jurisdiction, while enforcement on the high seas lies with the flag state of the dumping vessel.[485] The London Convention has established a working group to consider specific issues related to CO_2 storage and to set forth the consistency of CO_2 storage with the London Convention.[486] The working group developed a list of legal issues associated with CO_2 storage under the London Convention and Protocol, and contracting parties have been asked to prepare their views on these legal questions.[487]

[482] John E. Noyes, Law of the Sea Dispute Settlement: Past, Present, and Future, 5 ILSA J. Int'l & Comp. L. 301, 303-305 (1999).
[483] John E. Noyes, The International Tribunal for the Law of the Sea, 32 Cornell Int'l L. J. 109, 181 (1998).
[484] International Marine Organization, *Parties to the London Convention*, *at* http://www.londonconvention.org/PartiesToLC.htm (last visited Nov. 24, 2005).
[485] London Convention, *supra* note 444, art. VII
[486] INTERNATIONAL MARINE ORGANIZATION, REPORT OF THE TWENTY-SIXTH CONSULTATIVE MEETING OF CONTRACTING PARTIES TO LONDON CONVENTION § 6.35 (2004).
[487] INTERNATIONAL MARINE ORGANIZATION, INVITATION TO CONSIDER THE LEGAL QUESTIONS ASSOCIATED WITH CO_2 SEQUESTRATION IN GEOLOGICAL FORMATIONS UNDER THE LONDON CONVENTION AND PROTOCOL LC.2/Circ. 439 (2005).

3.3.2.1. Pollution by Dumping

The London Convention prohibits the dumping of wastes or other matter (with some exceptions, discussed *infra*), and adopts the same definition of "dumping" as UNCLOS. Dumping is defined as "any deliberate disposal at sea of wastes or other matter from vessels, aircraft, platforms or other man-made structures at sea" and does not include "placement of matter for a purpose other than the mere disposal thereof" or "the disposal at sea of wastes or other matter incidental to, or derived from the normal operations of vessels, aircraft, platforms or other man-made structures at sea and their equipment" except for "wastes or other matter transported by or to vessels, aircraft, platforms or other man-made structures at sea, operating for the purpose of disposal of such matter or derived from the treatment of such wastes or other matter on such vessels, aircraft, platforms or structures".[488] In addition, the London Convention specifies that dumping does not include the "disposal of wastes or other matter directly arising from, or related to the exploration, exploitation and associated off-shore processing of sea-bed mineral resources".[489]

It is likely that sub-seabed CO_2 storage is not governed by the London Convention because dumping is defined as deliberate disposal *at sea*. The Convention defines "sea" to be "all marine waters other than the internal waters of States" and does not provide any mention of seabed or subsoil.[490] The ambiguity of whether the London Convention governs the seabed was faced about a decade ago when sub-seabed disposal was proposed as a method of disposing radioactive waste, where the debate was whether "deliberate disposal at sea" refers to the location of the dumping structure or whether it refers to the final resting place of the dumped

[488] London Convention, *supra* note 444, art. III, § 1.
[489] *Id.*
[490] *Id.* art. III, § 3.

material.[491] At the Thirteenth Consultative Meeting of the London Convention, the contracting parties approved a resolution that the disposal of radioactive wastes into sub-seabed repositories accessed from the sea would constitute disposal under the Convention and thus be prohibited.[492] The resolution was specific to radioactive waste and does not govern CO_2 storage nor any other type of sub-seabed injection. The Secretariat of the London Convention is on record that storage of CO_2 in geological structures under the seabed is not covered under the London Convention.[493] The counter-argument would be that the overriding emphasis of the London Convention is on the interconnected nature of the marine environment.[494] One could also argue that given the preamble to the London Convention, recalling Resolution 2740(XXV) of the United Nations General Assembly which declares the principles governing the seabed, ocean floor and subsoil beyond the limits of national jurisdiction, the London Convention's governance of pollution of the marine environment would be broad enough to cover sub-seabed CO_2 storage.[495] However, both of these arguments are contrary to the clear language of the Convention regarding dumping as deliberate disposal "at sea".

Nonetheless, even if sub-seabed CO_2 storage was deemed to be governed by the London Convention, CO_2 injection in conjunction with offshore oil or natural gas operations would not be governed by the Convention. CO_2 storage would also side-step the Convention if it was deemed to be placement of matter for a purpose other than mere disposal. The next section will clarify how the London Convention defines wastes or other matter, but there is also the issue of whether CO_2 storage is actually placement of CO_2, and whether the placement is for a purpose

[491] Robert A. Kaplan, Comment, *Into the Abyss: International Regulation of Subseabed Nuclear Waste Disposal*, 139 U. PA. L. REV. 769, 778-779 (1991).
[492] Resolution LDC.41(13), Disposal of Radioactive Wastes into Sub-Sea-Bed Repositories Accessed From the Sea (1990).
[493] René Coenen, Address at the International Energy Agency/Carbon Sequestration Leadership Forum Workshop on Legal Aspects of Storing CO_2 (Jul. 13, 2004).
[494] Kaplan, *supra* note 491, at 779.
[495] Scott, *supra* note 442, at 75.

other than mere disposal. CO_2 storage for the purpose of climate change mitigation would likely not qualify as "placement" because operations are not planned with the intent of recovering the stored CO_2; the purpose of CO_2 storage is to keep CO_2 in the ground. However, if CO_2 storage was done within the context of a climate regime and the operators retained ownership to the injected CO_2, one could make an argument that the CO_2 was not yet disposed of (the injected CO_2 being still the property of the operators who own the carbon permits) and therefore qualifies as placement of wastes or other matter not governed by the Convention. It is the view of the Secretariat to the London Convention that this would be "stretching" the interpretation of "placement" beyond its original meaning.[496] Finally, sub-seabed CO_2 storage that did not use "vessels, aircraft, platforms or other man-made structures at sea" would not constitute dumping. Thus if a land-based pipeline was used to transport CO_2 from shore to the sub-seabed injection point, this method of CO_2 storage would not constitute dumping under the London Convention, unless the pipeline infrastructure was deemed to be a type of "other man-made structure at sea".

3.3.2.2. Wastes or Other Matter

The London Convention divides "wastes or other matter" into three categories: wastes or other matter that are prohibited from being dumped, wastes or other matter that may be dumped under a prior special permit, and wastes or other matter that may be dumped under a prior general permit.[497] Wastes or other matter falling in the first category, those prohibited from being dumped, are listed in Annex I to the Convention. CO_2 is not included in the Annex I list and would appear not to be prohibited from being dumped, but the London Convention was amended in 1996 to also prohibit the dumping of industrial wastes, defined as those wastes

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[496] Coenen, *supra* note 493.
[497] London Convention, *supra* note 444, art. IV, § 1.

generated by manufacturing or processing operations.[498] The parties to the London Convention have not taken a position on whether CO_2 emissions from fossil fuel power plants would constitute wastes generated from manufacturing or processing operations. Wastes or other matter falling in the second category, those that require a prior special permit, are listed in Annex II to the Convention, and CO_2 is not included in that list. If CO_2 was not deemed to be an industrial waste, then it would fall under the category of wastes or other matter that may be dumped under a prior general permit. The permit would be issued by an appropriate authority designated by the contracting party.[499]

3.3.2.3. Precautionary Approach

Parties to the London Convention are to be "guided" by a precautionary approach whereby "appropriate preventive measures are taken when there is reason to believe that substances or energy introduced in the marine environment are likely to cause harm even when there is no conclusive evidence to prove a causal relation between inputs and their effects."[500] If sub-seabed CO_2 storage was deemed to fall within the dumping provisions of the London Convention and even if CO_2 was not deemed to be an industrial waste prohibited from being dumped, CO_2 storage could be prohibited under the precautionary approach if it is likely to cause harm when introduced to the marine environment. The issue here would be the likelihood of CO_2 emissions from the sub-seabed geological formation entering the waters, and would be guided by the same arguments discussed in Section 3.3.1 of this thesis. There is also an issue of whether the precautionary approach extends beyond pollution by dumping since the approach mentions "substances introduced in the marine environment" rather than the dumping of wastes

[498] *Id.* annex I, § 11.
[499] *Id.* art. VI, § 1.
[500] Resolution LDC.44(14), The Application of a Precautionary Approach in Environmental Protection within the Framework of the London Dumping Convention (1991).

or other matter. One could even construe induced seismic events or risks from subsurface migration as causes of harm governed by the precautionary approach, but this would depend on whether CO_2 injected into the seabed would constitute a substance being introduced in the marine environment and whether the harm would be "likely". Sub-seabed CO_2 storage is particularly attractive because its harm to the environment is seen to be unlikely, especially compared to the risks derived from onshore CO_2 storage.

3.3.2.4. Implementation and Enforcement

Implementation and enforcement of the London Convention provisions is largely a matter of national law. Each contracting party designates an appropriate authority which has the power over issuing permits, maintaining records, and monitoring that the Convention provisions are being adhered to.[501] The contracting party has authority to implement the convention to all vessels registered in its territory or flying its flag, vessels loading in its territory or territorial seas matter which is to be dumped, and vessels and fixed or floating platforms under its jurisdiction believed to be engaged in dumping.[502] Parties are to take appropriate measures to prevent and punish conduct in violation of the Convention if the conduct occurs in their territories,[503] but are to cooperate in developing enforcement procedures for violations of the London Convention on the high seas.[504] Thus the contracting party would have authority over CO_2 storage operations within its jurisdiction, which read together with UNCLOS would include its territorial sea, EEZ, and continental shelf. CO_2 storage operations on the high seas would be governed by the International Seabed Authority and UNCLOS provisions related to the high seas, as virtually all of the contracting parties to the London Convention are also parties to UNCLOS.

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[501] London Convention, *supra* note 444, art. VI, § 1.
[502] *Id.* art. VII, § 1.
[503] *Id.* art. VII, § 2.
[504] *Id.* art. VII, § 3.

3.3.3. CO_2 Storage in the London Protocol Regime

The 1996 London Protocol superseded the London Convention when it entered into force on March 24, 2006.[505] The Protocol has been ratified by 30 parties to date.[506] The United States, although a party to the London Convention, is not a party to the London Protocol, and is not be bound to the Protocol's provisions because the Protocol is a successive treaty relating to the same subject matter as the London Convention; the provisions of the Protocol would be binding only if the United States was a party to the Protocol.[507]

3.3.3.1. "Dumping" and "Wastes or Other Matter Provisions"

The London Protocol prohibits the dumping of any wastes or other matter (with some exceptions, discussed *infra*). Like the London Convention, dumping under the London Protocol is defined as "any deliberate disposal into the sea of wastes or other matter from vessels, aircraft, platforms or other man-made structures at sea,"[508] however, the London Protocol also defines dumping to include "the storage of wastes or other matter in the seabed and the subsoil thereof from vessels, aircraft, platforms or other man-made structures at sea".[509] Although the London Protocol was not drafted with CO_2 storage in mind, there was concern that the provision related to "storage of wastes or other matter in the seabed and subsoil" appeared on its face to govern sub-seabed CO_2 storage. Even if CO_2 storage was not deliberate disposal, it was possible that it could be governed by the London Protocol if considered "storage".

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[505] London Protocol, *supra* note 446, art. 23.

[506] International Marine Organization, *Contracting Parties to the 1996 Protocol*, *at* http://www.londonconvention.org/PartiesToLC.htm#Contracting%20Parties%20to%20the%201996%20Protocol (last visited Nov. 28, 2006).

[507] *See, e.g.*, Vienna Convention on the Law of Treaties, *opened for signature* May 23, 1969, U.N. Doc. A/ Conf. 39/27 at 289 (1969), 1155 U.N.T.S. 331, art. 30(3).

[508] London Protocol, *supra* note 446, art. 1, § 4.

[509] *Id.*

CO_2 storage would be governed under the dumping provisions of the London Protocol if CO_2 was deemed to fall under the category of "wastes or other matter". Unlike the London Convention, which allows the dumping of wastes or other matter unless they are listed on a black list of prohibited substances, the London Protocol prohibits the dumping of wastes or other matter unless they are listed on a white list of approved substances.[510]

3.3.3.2. Amendment of London Protocol to Allow CO_2 Storage

At the First Meeting of Contracting Parties to the London Protocol, the parties agreed to amend the London Protocol to allow sub-seabed CO_2 storage.[511] This was done by amending the London Protocol's white list of approved substances. Specifically, "CO_2 streams from CO_2 capture processes" was added to the white list.[512] The amendments, which enter into force on February 10, 2007, state that "carbon dioxide streams may only be considered for dumping if disposal is into a sub-seabed geological formation; they consist overwhelmingly of carbon dioxide (they may contain incidental associated substances derived from the source material and the capture and sequestration processes used); and no wastes or other matter are added for the purpose of disposing of those wastes or other matter".[513]

Even with the amendment, a number of questions remain. For example, the amendments state that the CO_2 stream must consist "overwhelmingly" of CO_2, but does not provide an indication of what proportion would be "overwhelmingly". Similarly, the amendments state that the streams may contain "incidental" associated substances, but don't provide any guidance on how much of the associated substances would constitute more than "incidental". Thus, the

[510] *Id.* art. 4, § 1.
[511] INT'L MARITIME ORGANIZATION, IMO BRIEFING: NEW INTERNATIONAL RULES TO ALLOW STORAGE OF CO_2 IN SEABED ADOPTED (Briefing 43/2006, Nov. 8, 2006).
[512] *Id.*
[513] *Id.*

parties have agreed that guidance can be conducted regarding the meaning of the provisions in the amendments.[514] The guidance will be reviewed at the Second Meeting of Contracting Parties to the London Protocol in November 2007.[515]

3.3.3.3. Precautionary Approach

Under the London Protocol, contracting parties are to "apply a precautionary approach to environmental protection from dumping of wastes or other matter whereby appropriate preventative measures are taken when there is reason to believe that wastes or other matter introduced into the marine environment are likely to cause harm even when there is no conclusive evidence to prove a causal relation between inputs and their effects".[516] There are two differences between the precautionary approach of the London Protocol compared with that of the London Convention. First, in the London Protocol contracting parties are to "apply" a precautionary approach, while contracting parties to the London Convention are to be "guided" by a precautionary approach. Second, the precautionary approach is to be followed in the case of the London Protocol where "wastes or other matter" are introduced into the marine environment, while the London Convention uses a precautionary approach where "substances or energy" are introduced in the marine environment. In the case of the first difference, the London Protocol takes a slightly stronger precautionary approach because precaution is to be applied rather than guided, but it is unclear what the implications are for CO_2 storage beyond a more explicit application of precaution. In the case of the second difference, the issue has largely gone away with the London Protocol's inclusion of CO_2 storage under its white list of wastes which may be considered for dumping.

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514 *Id.*
515 *Id.*
516 London Protocol, *supra* note 446, art. 3, § 1.

3.3.3.4. Implementation and Enforcement

The London Protocol adopts virtually identical language as the London Convention with respect to its application and enforcement. However, the Protocol adds language with regard to the settlement of disputes. Disputes are to be resolved through "negotiation, mediation or conciliation, or other peaceful means" in the first instance, but if the dispute cannot be resolved within twelve months,[517] the dispute is to be settled by one of the dispute settlement procedures authorized under UNCLOS.[518] The implication for CO_2 storage is that the regulation of compliance under the London Protocol, like the London Convention, remains largely an issue of national law. Although the Protocol is more specific than the Convention with respect to its use of procedures for the settlement of disputes provided under UNCLOS, the implication of the Convention is that it would defer to UNCLOS procedures for disputes outside a contracting party's sovereign territory. Thus the differences between the Convention and the Protocol's enforcement procedures with respect to CO_2 storage are likely minimal.

3.3.4. CO_2 Storage in the OSPAR Convention Regime

The 1992 OSPAR Convention, which is regional in nature and addresses pollution only of the North-East Atlantic marine environment, entered into force on March 25, 1998 and has 15 countries as contracting parties.[519] The OSPAR Convention supersedes[520] the Oslo Convention for the Prevention of Marine Pollution by Dumping from Ships and Aircraft[521] and the Paris

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[517] *Id.* art. 16, § 1.
[518] *Id.* art. 16, § 2.
[519] OSPAR Comm'n, *Contracting Parties, at* http://www.ospar.org/eng/html/cp/welcome.html (last visited Nov. 24, 2005).
[520] OSPAR Convention, *supra* note 447, art. 31.
[521] Convention for the Prevention of Marine Pollution by Dumping from Ships and Aircraft, *opened for signature* Feb. 15, 1972, 932 U.N.T.S. 3.

Convention for the Prevention of Marine Pollution from Land-Based Sources,[522] both of which were seen as not stringent enough for controlling marine pollution.[523] The issue of CO_2 storage was first brought to the OSPAR Commission in 2002 following a proposal to conduct a CO_2 storage field experiment in Norway,[524] where the contracting parties resolved to "establish as soon as possible an agreed position on whether such placing of CO_2 in the sea…was consistent with the OSPAR Convention".[525] A Group of Jurists and Linguists considered the issue of CO_2 storage and it legal compatibility with the OSPAR Convention, and released a report on the subject at the Reykjavik Meeting of the OSPAR Convention, June 28 – July 1, 2004.[526] Its findings are discussed here and summarized in Table 3.4.

3.3.4.1. Pollution of the Maritime Area

The OSPAR Convention regulates three sources of pollution of the marine environment of the North-East Atlantic: pollution from land-based sources,[527] pollution by dumping or incineration,[528] and pollution from offshore sources.[529] Each source of pollution is regulated by a separate annex of the OSPAR Convention, with no overlap between the annexes, and the maritime area regulated by OSPAR is defined to include the seabed and subsoil. There is a general obligation for parties to apply the precautionary principle, defined under Article 2 of the Convention as:

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[522] Paris Convention for the Prevention of Marine Pollution from Land-Based Sources, *opened for signature* Feb. 21, 1974, 13 I.L.M. 352.
[523] OSPAR Convention, *supra* note 447, pmbl.
[524] Jim Giles, Norway Sinks Ocean Carbon Study, 419 NATURE 6 (Sept. 5, 2002); State Secretary Øyvind Håbrekke, Address at the OSPAR Workshop on the Environmental Impact of Placement of Carbon dioxide in Geological Structures in the Maritime Area (Oct. 26, 2004).
[525] Amparo Agrait, Address at the OSPAR Workshop on the Environmental Impact of Placement of Carbon dioxide in Geological Structures in the Maritime Area (Oct. 26, 2004).
[526] OSPAR COMM'N, REPORT FROM THE GROUP OF JURISTS AND LINGUISTS ON PLACEMENT OF CARBON DIOXIDE IN THE OSPAR MARITIME AREA (2004).
[527] OSPAR Convention, *supra* note 447, art. 3.
[528] *Id.*, art. 4.
[529] *Id.*, art. 5.

Table 3.4 Findings of the OSPAR Group of Jurists and Linguists

METHODS OF PLACEMENT IN THE MARITIME AREA	APPLICABLE OSPAR ANNEX	PURPOSES OF PLACEMENT	CONCLUSION
By pipeline pure and simple	Annex I	(a) Experiment (c) Mitigating climate change (d) Other mere disposal	Placements for purposes (a), (c) and (d) are not prohibited but are strictly subject to authorization or regulation.
By pipeline working with a structure in the maritime area that is not an offshore installation	Annex I	(a) Experiment (c) Mitigating climate change (d) Other mere disposal	Placements for purposes (a), (c) and (d) are not prohibited but are strictly subject to authorization or regulation.
By shipment in a vessel for placement from the vessel	Annex II	(a) Experiment (c) Mitigating climate change (d) Other mere disposal	Placements for purpose (a) are not prohibited, provided that they are in accordance with relevant provisions of the Convention. Placements for purposes (c) and (d) are prohibited.
By placement from a structure in the maritime area that is neither part of a pipeline system nor an offshore installation	Annex II	(a) Experiment (c) Mitigating climate change (d) Other mere disposal	Placements for purpose (a) are not prohibited, provided that they are in accordance with relevant provisions of the Convention. Placements for purposes (c) and (d) are prohibited.
By placement from an offshore installation	Annex III	(a) Experiment (b) Improving hydrocarbon production (c) Mitigating climate change (d) Other mere disposal	***In respect of CO_2 arising from offshore activities:*** Placements for purpose (a) are not prohibited, provided placement is in accordance with relevant provisions of the Convention. Placements for purposes (b), (c) or (d) are not prohibited, but are strictly subject to authorization or regulation. ***In respect of CO_2 arising from activities other than offshore activities:*** Placements for purpose (a) are not prohibited, provided placement is in accordance with relevant provisions of the Convention. Placements for purpose (b) are not prohibited, but are strictly subject to authorization or regulation. Placements for purposes (c) or (d) are prohibited.

> [P]reventive measures are to be taken when there are reasonable grounds for concern that substances or energy introduced, directly or indirectly, into the marine environment may bring about hazards to human health, harm living resources and marine ecosystems, damage amenities or interfere with other legitimate uses of the sea, even when there is no conclusive evidence of a causal relationship between the inputs and the effects.

OSPAR's precautionary principle is more specific than the London Convention and London Protocol. It specifies that preventive measures are to be taken (rather than being guided by or applying a precautionary approach), that the measures are to be taken when there are reasonable grounds for concern (rather than a "likely" cause of harm), and is more specific about the types of harm that could bring about the use of the precautionary principle. There was debate among the Jurists and Linguists as to how to apply the precautionary principle to CO_2 storage, particularly if CO_2 injected into the seabed was unlikely to escape, with the Group concluding that "evidence that there is a possibility of pollution or of some other adverse effect from the placement" often being relevant.[530]

3.3.4.2. Pollution from Land-Based Sources

The OSPAR Convention permits pollution from land-based sources, but it is "strictly subject to authorization or regulation by competent authorities". Land-based sources are "point and diffuse sources on land from which substances or energy reach the maritime area by water, through the air, or directly from the coast"[531] Land-based sources include "sources associated with any deliberate disposal under the sea-bed made accessible from land by tunnel, pipeline, or other means".[532] Thus, CO_2 storage using a pipeline, or system of pipelines, to transport the CO_2

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[530] OSPAR COMM'N, *supra* note 526, § 9.
[531] OSPAR Convention, *supra* note 447, art. 1.
[532] *Id.*

from land to the sub-seabed injection point in the maritime area would be permissible under the OSPAR Convention as long as it was strictly authorized or regulated.

3.3.4.3. Pollution by Dumping or Incineration

OSPAR has a separate annex for the prevention and elimination of pollution by dumping or incineration.[533] "Dumping" is defined to be "any deliberate disposal in the maritime area of wastes or other matter from vessels or aircraft, or from offshore installations".[534] Offshore installations have a very specific meaning under the OSPAR Convention, referring to "any man-made structure, plant or vessel placed in the maritime area" for the purposes of the "exploration, appraisal, or exploitation of hydrocarbons",[535] however, disposal related to offshore installations is regulated under a separate annex. As a result, the annex related to dumping or incineration regulates only dumping from vessels or aircraft. Like the London Convention and London Protocol, dumping does not include "placement for a purpose other than the mere disposal thereof".[536] Like the London Protocol, dumping under the annex is prohibited except for materials listed on a white list, included in Article 3 of Annex II to the Convention. Although CO_2 is not included on the white list, sub-seabed CO_2 storage from a vessel or aircraft is technically impractical and thus the annex has seemingly little relevance to CO_2 storage. However, the Group of Jurists and Linguists noted that placement from a structure that was neither a pipeline system nor an offshore installation (i.e. installation for the purposes of exploration, appraisal, or exploitation of hydrocarbons) would be governed under this annex.[537] This is because vessels are defined to include not only waterborne or airborne craft, but also

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[533] *Id* art. 4..
[534] *Id*. art. 1.
[535] *Id.*
[536] *Id.*
[537] OSPAR COMM'N, *supra* note 526, § 22.

“other man-made structure in the maritime area”.[538] Thus sub-seabed CO_2 storage taking place from a man-made structure in the maritime area that was unrelated to hydrocarbon activities would be prohibited under the Convention. The annex would prohibit not only structures constructed solely for CO_2 storage, but also structures that had an original purpose for the exploration, appraisal, or exploitation of hydrocarbons, but were later converted and used solely for CO_2 storage. If a pipeline could be built from land to the converted CO_2 storage structure located in the maritime area, it is conceivable that the structure could then come under the auspices of a pipeline system for the purposes being regulated under land-based sources annex. Of course, if the CO_2 storage activities were deemed to be “placement of matter for a purpose other than the mere disposal thereof”, they would not fall under the definition of dumping, however the Group of Jurists and Linguists found that the placement of CO_2 for the purpose of mitigating climate change was not “placement of matter for a purpose other than the mere disposal thereof”.[539]

3.3.4.4. Pollution from Offshore Sources

OSPAR defines a third annex for the prevention and elimination of pollution from an offshore source,[540] i.e. any man-made structure, plant or vessel in the maritime area for the purposes of exploration, appraisal or exploitation of liquid and gaseous hydrocarbons. The annex specifically excludes deliberate disposal of wastes or other matter from vessels or aircraft. The Group of Jurists and Linguists found that the injection of CO_2 for the purpose of improving hydrocarbon production would not be prohibited, but strictly subject to authorization or

[538] OSPAR Convention, *supra* note 447, art. 1.
[539] OSPAR COMM’N, *supra* note 526, § 20.
[540] OSPAR Convention, *supra* note 447, art. 5.

regulation.[541] CO_2 storage for the purpose of climate change mitigation would be permitted, but only if the CO_2 arose from the offshore exploration, appraisal or exploitation of liquid and gaseous hydrocarbons; injection of CO_2 from all other sources for the purpose of mitigating climate change would be prohibited.[542] Improved hydrocarbon production falls under the category of "placement of matter for a purpose other than the mere disposal thereof", while CO_2 storage associated with offshore sources falls under an exception in the OSPAR Convention for discharges and emissions of wastes or other matter from the normal operations of offshore installations.

3.3.4.5. Implementation and Enforcement

The implementation of OSPAR provisions related to CO_2 storage would be done on the national level. Under the Convention, any permissible discharges of waste or other matter must be authorized or regulated by the competent authority of the relevant contracting party.[543] Where implementation of the Convention leads to more than one contracting party having authority over the operation, the parties are to act in consultation with one another.[544]

Disputes between contracting parties are to be first presented for inquiry or conciliation within the OSPAR Commission.[545] Disputes which cannot be settled by the Commission are to be submitted to a three-member arbitral tribunal. The first case to be brought under OSPAR's arbitral tribunal provision occurred in 2003.[546] Unlike the London Protocol, the OSPAR Convention includes no provision authorizing dispute settlements before tribunals established

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[541] OSPAR COMM'N, *supra* note 526, § 25.
[542] *Id.* § 24.
[543] *See, e.g.,* OSPAR Convention, *supra* note 447, annex I, art. 2.
[544] *See, e.g.*, *id.*, annex II, art. 4.
[545] *Id.* art. 32.
[546] Permanent Court of Arbitration, Dispute Concerning Access to Information Under Article 9 of the OSPAR Convention, Ireland v. United Kingdom--Final Award (2 July 2003) 42 ILM 1118 (2003).

under UNCLOS.[547] Because OSPAR is only a regional agreement, disputes implicating OSPAR as well as global marine agreements could result in multiple arbitral tribunals.[548] CO_2 storage activities in the North-East Atlantic would be regulated by both global agreements and the OSPAR Convention.[549]

3.3.5. Implications for Current and Prospective Storage Operations

Although the legal status of CO_2 storage under UNCLOS, London Convention, London Protocol, and the OSPAR Convention is central to its future as a carbon management strategy, a concern for energy firms is how international law will impact current and prospective CO_2 storage operations. I consider three CO_2 storage operations in Europe that are either currently operating or proposed: Statoil's Sleipner project, Statoil's Snøhvit project, and BP's DF-1 project. All the projects involve sub-seabed CO_2 storage, but their purposes for and methods of CO_2 storage are different. In addition, all of the projects here are governed by UNCLOS, the London Convention, and the OSPAR Convention.

3.3.5.1. Statoil Sleipner Project

Statoil is a regional integrated oil company headquartered in Norway, and a dominant part of its activities constitute oil and gas recovery on the Norwegian Continental Shelf.[550] Prompted by a Norwegian tax on CO_2 emissions of about $40 per tonne, Statoil began the first commercial application of carbon capture and storage for greenhouse gas mitigation at its

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[547] Maki Tanaka, Lessons from the Protracted MOX Plant Dispute: A Proposed Protocol on Marine Environmental Impact Assessment to the United Nations Convention on the Law of the Sea, 25 MICH. J. INT'L L. 337, 340 n.12.
[548] *Id.*
[549] Thus, the British government petitioned the contracting parties of the London Convention to establish a working group regarding the application of the Convention with respect to sequestration, even though the Group of Jurists and Linguists already provided an interpretation of sequestration under the OSPAR Convention. This was done in anticipation of sequestration projects to be conducted in the North Sea, such as BP's DF-1 project discussed in Section 3.3.5.3 of this thesis.
[550] Frede Cappelen, Address at the International Energy Agency/Carbon Sequestration Leadership Forum Workshop on Legal Aspects of Storing CO_2 (Jul. 13, 2004).

Sleipner natural gas field in 1996.[551] Sleipner is located about halfway between Norway and Scotland, 2500 meters beneath the North Sea floor. The natural gas retrieved from the field has 9% CO_2 content and must be reduced to a CO_2 content of 2.5% to meet Norwegian commercial specifications, which is done by capturing CO_2 from the natural gas.[552] Although the captured CO_2 would ordinarily be vented to the atmosphere, Statoil stores the CO_2 in a deep saline formation to avoid the CO_2 tax. At Sleipner, the captured CO_2 is compressed and injected into the Utsira saline formation, which is located about 1000 meters beneath the seabed (see figure 1).[553] About 1 million metric tons of CO_2 per year are injected into the Utsira formation,[554] which is roughly a third of the CO_2 output of a 300-megawatt coal-fired power plant.[555] The Saline Aquifer CO_2 Storage ("SACS") project has monitored the behavior of the injected CO_2 since the beginning of Sleipner's operations in 1996, and the results to date indicate no leakage of the injected CO_2 from the geological formation.[556]

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[551] Howard Herzog, *What Future for Carbon Capture and Sequestration?* 35 ENVTL. SCI. & TECH. 148A, 151A (2001).
[552] *Id.*
[553] Tore Torp & John Gale, *Demonstrating Storage of CO_2 in Geological Reservoirs: The Sleipner and SACS Projects*, 29 ENERGY 1361, 1362 (2004).
[554] Sintef, Saline Aquifer CO2 Storage, *at* http://www.iku.sintef.no/projects/IK23430000/ (last visited Dec. 2, 2005).
[555] U.S. Energy Info. Admin., Emissions of Greenhouse Gases in the United States 2003, *at* http://www.eia.doe.gov/oiaf/1605/ggrpt/geologic.html (last visited Dec. 4, 2005).
[556] Arts, *supra* note 471.

Figure 3.4 Sleipner A and T Platform (Photo: Kim Laland - Bitmap, Statoil)[557]
Reproduced with permission of Statoil

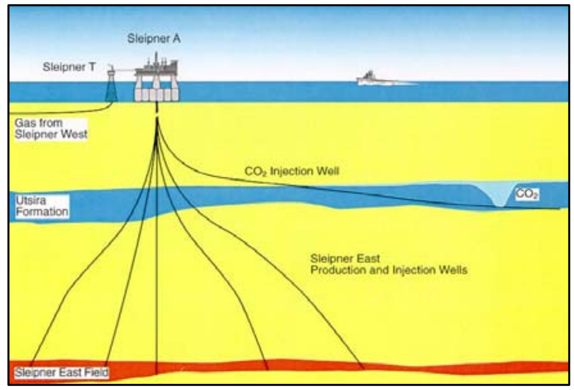

Figure 3.5 Sleipner CO_2 Injection (Picture: Statoil)[558]
Reproduced with permission of Statoil

The Sleipner project's activities related to sub-seabed CO_2 storage are consistent with UNCLOS. The natural gas recovery and CO_2 storage project takes place within the Norwegian EEZ and continental shelf. The best argument for its compliance under UNCLOS is that Norway is exploiting its Utsira saline formation natural resource, over which it has sovereign rights. The argument that the CO_2 is being injected for the purpose of "exploring and exploiting, conserving and managing" its natural gas resources is more tenuous because the CO_2 is injected after the natural gas is recovered, rather than being injected to enhance natural gas recovery. One could still argue that the disposal would not be considered "dumping" because the CO_2 is incidental to the normal operations of natural gas recovery.

Sleipner is also consistent with agreements for the prevention of marine pollution. Although the London Convention has been superseded by the London Protocol in Norway, the London Convention would probably not govern Sleipner even if it as controlling law, because of the Convention's provision that dumping is the deliberate disposal of wastes or other matter at

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[557] Statoil, Sleipner West, *at* http://www.statoil.com/STATOILCOM/SVG00990.nsf?opendatabase&lang=en&artid=1CDD5005E0691582C1256FEF003BEAB6 (last visited Feb. 14, 2006).
[558] Statoil et al, Saline Aquifer CO_2 Storage, *at* http://www.iku.sintef.no/projects/IK23430000/ (last visited Dec. 2, 2005).

sea. Assuming *arguendo* that the project was deemed to fall within the jurisdiction of the London Convention, it would come under the exception of "disposal of wastes or other matter directly arising from, or related to the exploration, exploitation and associated off-shore processing of sea-bed mineral resources". In the case of Sleipner, the CO_2 directly arises from or is related to the off-shore processing of natural gas from the Norwegian seabed.

Sleipner would qualify for an exception under the London Protocol for "disposal or storage of wastes or other matter directly arising from, or related to the exploration, exploitation and associated off-shore processing of seabed mineral resources", under the same rationale as the London Convention. In the case of the OSPAR Convention, the Sleipner project is an "offshore installation" as defined by the Convention, and injection of CO_2 into the seabed, even for climate change mitigation, is permissible. Like UNCLOS, in the cases of the London Convention, London Protocol, and OSPAR Convention, Sleipner would also be exempted because the CO_2 is incidental to the normal operations of natural gas recovery.

3.3.5.2. Statoil Snøhvit Project

Statoil also has plans for the first offshore development in the Barents Sea, Snøhvit, which will be the world's northernmost liquefied natural gas ("LNG") project.[559] There will be no fixed or floating units positioned in the Barents Sea; instead, natural gas recovery units will stand on the seafloor at a depth of about 250-350 meters (see Figure 2).[560] Natural gas will be produced from the Snøhvit, Askeladd and Albatross natural gas fields at a depth of 2300 meters, and transported by pipeline to Melkøya Island.[561] At an on-shore facility at Melkøya, CO_2 will

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[559] Statoil, Barents Opportunities Highlighted, *at* http://www.statoil.com/snohvit (last visited Dec. 4, 2005).
[560] Statoil, Field Development, *at* http://www.statoil.com/snohvit (last visited Dec. 4, 2005).
[561] Olav Kårstad, Address at the IPCC Workshop for Carbon Capture and Storage (Nov. 19, 2002).

be captured from the natural gas (which has a CO_2 content of about 5-8%)[562] and the natural gas liquefied to make LNG.[563] The CO_2 will then be piped back to the field for CO_2 storage and injected into the Tubåen formation at a depth of 2500 meters.[564] Statoil estimates that 700,000 tonnes of CO_2 will be stored annually.[565] The Snøhvit project is expected to commence operations in December 2007.[566]

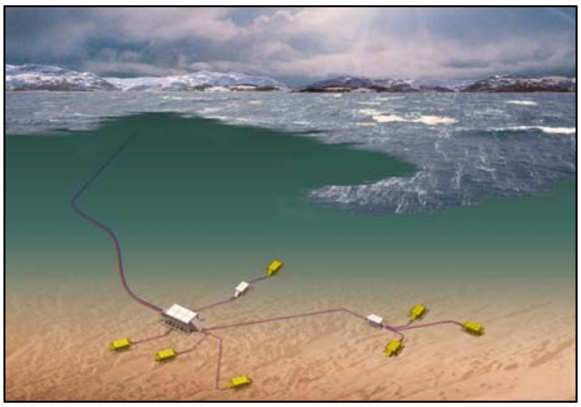

Figure 3.6 Snøhvit Project
(Picture: Statoil)[567]
Reproduced with permission of Statoil

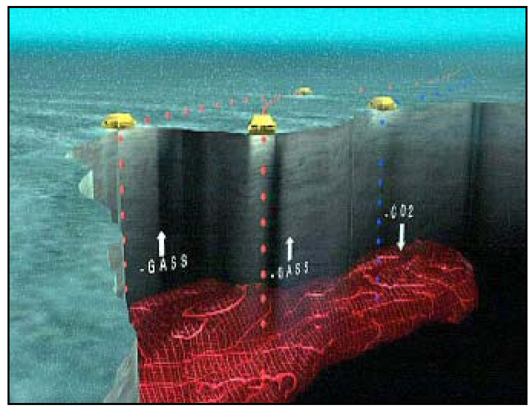

Figure 3.7 Snøhvit CO_2 Injection
(Picture: Statoil)[568]
Reproduced with permission of Statoil

The method of carbon capture and storage at Snøhvit is subtly different than at Sleipner. At Snøhvit, natural gas is recovered offshore, transported by pipeline to land, natural gas is processed and CO_2 is captured on land, and the CO_2 is then transported by pipeline to the offshore and injected into a saline formation located below the natural gas formation. In the case of Sleipner, natural gas is recovered and processed offshore, the CO_2 is captured offshore, and the CO_2 is injected into a formation above the natural gas formation. The key distinction is that processing takes place onshore for Snøhvit, but offshore for Sleipner.

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562 Statoil, Carbon Dioxide Storage, *at* http://www.statoil.com/snohvit (last visited Dec. 4, 2005).
563 T. Maldal and I.M. Tappel, *CO_2 Underground Storage for Snøhvit Gas Field Development,* 29 ENERGY 1403, 1404 (2004).
564 Address by Olav Kårstad, *supra* note 561.
565 Maldal & Tappel, *supra* note 563, at 1405.
566 Statoil, *supra* note 557.
567 Statoil, *supra* note 559.
568 *Id.*

Like Sleipner, Snøhvit appears to be consistent with UNCLOS under the argument that the activities take place within the Norwegian EEZ and continental shelf, and CO_2 is injected for the purpose of exploiting its Tubåen saline formation natural resource. Again, the London Convention is not applicable because it has been superseded by the London Protocol in Norway, and even assuming *arguendo* that it was controlling law, it would not apply to the project because it governs only the sea and not the seabed. In the alternative, if CO_2 is transported from a land-based pipeline directly to the sub-seabed injection point, it could side-step the Convention. With the amendment to the London Protocol, the project would comply because disposal is into a sub-seabed geological formation, the waste stream is CO_2, and presumably no other wastes will be added to the stream.

In the case of the OSPAR Convention, it is questionable whether the CO_2 would fall under the Convention's definition of an "offshore activity" because the activities must be carried out in the maritime area for the purposes of the exploration, appraisal or exploitation of liquid and gaseous hydrocarbons. Although the natural gas is recovered in the maritime area, the processing of natural gas and the associated offshore processing takes place on land. The CO_2 would then be deemed a "land based source" under the Convention. Fortunately for Statoil, land-based sources do not come under the OSPAR Convention's provisions for "dumping" and injection of the CO_2 would be permissible if it used a pipeline or pipeline system to transport the CO_2 to the injection point. If the CO_2 was transported to a platform used for natural gas recovery (an offshore installation) and was then injected, the activity would not be permitted under the Convention (unless the CO_2 was the result of an offshore activity) because the CO_2 would not be injected to enhance the production of hydrocarbons.

3.3.5.3. BP DF-1 Project

In June 2005, BP announced plans for DF-1, a decarbonized fuel project which would be the world's first industrial scale project to generate carbon-free electricity from hydrogen.[569] DF-1 aims to manufacture hydrogen by reforming North Sea gas and capture the resulting CO_2, generating "carbon-free" electricity by converting an existing gas-fired power station in Scotland to run on hydrogen, transporting the captured CO_2 via an existing offshore pipeline to the Miller Field in the North Sea, and using CO_2 for the purpose of EOR and extending the life of the field by about 20 years.[570] The DF-1 project will be the largest CO_2 EOR project in the North Sea, the first CO_2 pipeline in the North Sea, the first CO_2 storage in an offshore oil reservoir, and the largest hydrogen-fired power generation facility.[571] Natural gas processing will take place onshore, where hydrogen will be produced and CO_2 will be captured.

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[569] BP, Press Release: BP And Partners Plan Clean Energy Plant in Scotland, Increasing Oil Recovery And Reducing Emissions, at http://www.bp.com/genericarticle.do?categoryId=2012968&contentId=7006999 (June 30, 2005).
[570] Gardiner Hill, Address at Britain in Bergin (October 12, 2005).
[571] *Id.*

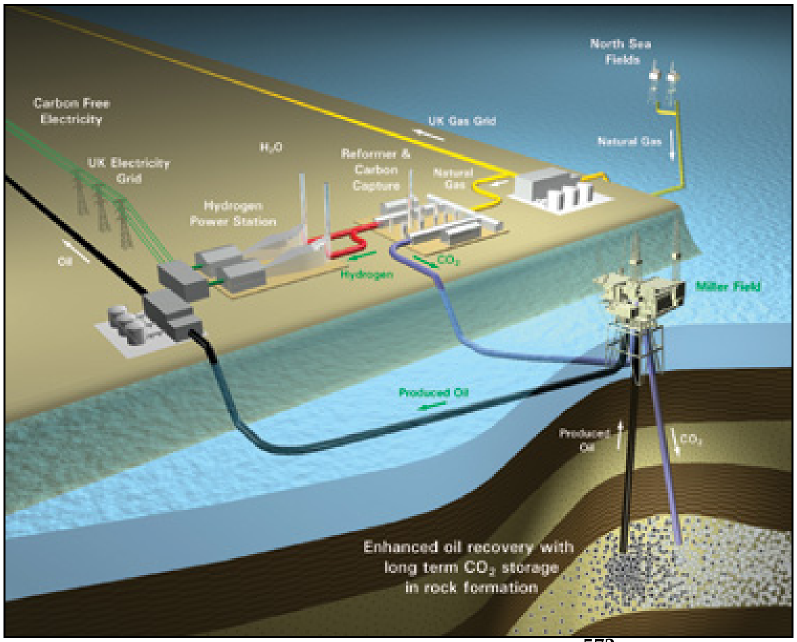

Figure 3.8 DF-1 Project (BP)[572]
Reproduced with permission of BP

Even though processing of natural gas takes place onshore, the DF-1 project side-steps the international legal issues faced by Snøhvit because CO_2 storage is coupled with EOR. DF-1 is permissible under UNCLOS because it is used for the exploitation of sea-bed mineral resources, i.e. the recovery of oil from the Miller Field. It avoids jurisdiction under the London Convention because CO_2 is injected into the seabed, but in the alternative the storage would be exempted under the London Convention's dumping provisions because of its use for the exploitation of oil resources. Although the London Protocol does govern the seabed, DF-1 is permissible because of the exception for the exploitation of sea-bed mineral resources, and in the alternative would be allowed under the Protocol's amendment for CO_2 storage. Finally, DF-1 is compliant with OSPAR, irrespective of whether the CO_2 is deemed a "land-based source" or an "offshore source" because of its use in improving hydrocarbon production.

[572] BP, Introducing Hydrogen Power: BP's Plan to Generate Electricity from Hydrogen and Capture Carbon Dioxide Could Set a New Standard for Cleaner Energy, *at* http://www.bp.com/genericarticle.do?categoryId=97&contentId=7006978 (last visited Dec. 2, 2005).

3.3.6. A Comment on the Direct Injection of CO_2 into the Ocean

The focus of the offshore storage regulatory analysis thus far has been on the injection of CO_2 into a geological formation located beneath the seabed. Although geological storage is the most likely near-term CO_2 storage option (and as such is the focus of this thesis), there may be potential for CO_2 to be injected directly into the water column and stored in the ocean waters. The "ocean storage" option is attractive for countries that do not have sufficient geological storage capacity or lack the geophysical attributes necessary for storage. The ocean is a natural carbon sink, and most of the CO_2 released into the atmosphere will eventually be taken up by the ocean. Although ocean storage could take a number of forms, the most likely option would be for the CO_2 to be transported by pipeline or vessel from shore and injected in droplet form into the ocean at a depth below 800 meters. Ocean storage would be constrained by the availability of CO_2 close to shore, which is estimated to be about 15-20% of total fossil fuel use.[573] A drawback of the ocean storage option is the potential for the injected CO_2 to harm marine organisms, but the extent of harm is unknown largely because of opposition to proposed field experiments.[574] This has presented a catch-22—the environmental consequences cannot be quantified without field experiments, but the field experiments cannot be conducted because the environmental consequences have not been quantified—the upshot being that ocean storage has not gained the level of stakeholder acceptability attained by geological storage.[575]

Even if strategies can be used to diminish the environmental consequences of ocean storage, there is still a question of whether injection of CO_2 into the ocean would even be permissible under international law. As in the sub-seabed geological storage context, the legality

[573] Howard Herzog, *Ocean Carbon Sequestration*, presented at the Workshop on Carbon Sequestration Science (2001).
[574] DE FIGUEIREDO *supra* note 14
[575] *Id.*

of ocean storage would be determined by international marine agreements (such as UNCLOS, the London Convention, and the London Protocol) and regional marine agreements (such as the OSPAR Convention). The permissibility of ocean storage would depend on the method of storage (pipeline vs. vessel), the purpose of storage (experiment vs. commercial-scale), and the treatment of ocean storage under a precautionary approach.

As in the sub-seabed context, UNCLOS would defer to the London Convention and London Protocol's dumping provisions. For countries following the London Convention, unlike in the sub-seabed context, the London Convention would have jurisdiction over ocean storage because CO_2 would be injected at "sea". Still, there are several reasons why certain forms of ocean storage might not fall under the London Convention's dumping provisions. First, if the CO_2 was not injected from a vessel, and instead a land-based pipeline was used to transport the CO_2 from shore to the injection point in the ocean, the London Convention would not apply because the method of storage would not fall under the Convention's definition of "dumping". Second, even if a vessel was used for storage, there is uncertainty whether CO_2 would be "waste or other matter" under the convention because CO_2 is not included on the Annex I list of substances that may not be disposed of at sea ("black list"). Note that CO_2 could come within the London Convention's definition of "wastes or other matter" if it is deemed an industrial waste generated by manufacturing or processing operations; this could occur, for example, if electricity generation was found to be a manufacturing or processing operation. Third, treatment of ocean storage under the London Convention may depend on how ocean storage is viewed under a precautionary approach, which would be defined as whether harm would be likely if CO_2 was introduced into the marine environment. With the current state of knowledge, the precautionary approach would probably cut against allowing ocean storage, but if field experiments found (or methods were developed to make) harm associated with ocean storage unlikely, then the precautionary approach as defined by the London Convention would allow for ocean storage.

The provisions of the London Protocol make certain forms of direct injection of CO_2 impermissible, but again there are methods of storage which would bypass the dumping provisions of the Protocol. The amendments to the London Protocol allowing CO_2 storage govern only sub-seabed storage and not direct injection. If a land-based pipeline was used to carry the CO_2 from shore to the injection point, the ocean storage might not fall within the Protocol's dumping jurisdiction. As in the case of the London Convention, the Protocol's jurisdiction will depend on the application of its precautionary approach, which is to be applied where wastes or other matter introduced into the marine environment are likely to cause harm. For the purposes of ocean storage, the London Convention and London Protocol use a virtually identical precautionary approach.

The Group of Jurists and Linguists to the OSPAR Convention have spoken directly to the issue of ocean storage and determined that whether ocean storage would be prohibited depended upon the method of placement in the maritime area and the purpose of placement. Ocean storage for the purposes of scientific experiment would be permissible regardless of the method of placement. Ocean storage for the purposes of climate change mitigation would not be prohibited under the Convention if the method of placement was a land-based pipeline or pipeline system, or if it was placed from an offshore installation associated with hydrocarbon using CO_2 arising from offshore hydrocarbon extraction or production activities. Ocean storage would be prohibited if it was placed from a vessel. from an offshore installation not associated with hydrocarbon production, or from an or from an offshore installation associated with hydrocarbon but using CO_2 not arising from offshore hydrocarbon extraction or production activities. In short, there are methods of large-scale ocean storage permissible under the OSPAR Convention.

3.3.7. Conclusion

Sub-seabed CO_2 storage is one of the most feasible near-term options for managing emissions of CO_2, and the analysis in this chapter suggests that there are methods of sub-seabed CO_2 storage that would be permissible under existing international law. There are two CO_2 storage options that appear particularly attractive. The first is CO_2 storage associated with offshore EOR. In the case of BP's DF-1 project, CO_2 is captured during the processing of offshore natural gas to create hydrogen, but from a legal standpoint, the CO_2 could come from any burning of fossil fuels since the only requirement under all of the agreements analyzed is that the CO_2 be used in the exploitation of offshore hydrocarbons. The second option would be to store CO_2 using a land-based pipeline directly to the sub-seabed injection point, which would allow CO_2 to be injected into deep saline formations and appears to be the method used by Statoil's Snøhvit project. In any case, with the amendment of the London Protocol, the legality of offshore CO_2 storage is strengthened.

In addition to its obvious impact on the future of sub-seabed CO_2 storage projects, the treatment of sub-seabed CO_2 storage under international law could very well impact the development of onshore CO_2 storage under national law. The development of CO_2 storage in general will depend in part on the first projects that attempt to store CO_2 on a large scale explicitly for the purposes of reducing emissions of CO_2 to the atmosphere. Sub-seabed CO_2 storage is particularly attractive because it eliminates the human health risks that onshore CO_2 storage faces from emissions of CO_2 from the geological reservoir to the surface. These projects will prove the capability of geological CO_2 storage generally, and will thus facilitate the development of onshore CO_2 storage (in addition to sub-seabed CO_2 storage). However, one could also argue that if there is ambiguity as to whether sub-seabed CO_2 storage would be permissible under international law, countries might choose to not pursue sub-seabed CO_2 storage, and instead those countries may decide to pursue a strategy of onshore CO_2 storage, particularly if those countries have significant onshore geological capacity for CO_2 storage.

Because the marine agreements analyzed in this chapter were not negotiated with CO_2 storage in mind, there remains some ambiguity as to how CO_2 storage would be regulated. For example, the future of sub-seabed CO_2 storage as a widely used technology option could very well depend on whether it is deemed dumping, storage, placement, or mere disposal under the various agreements. The main source of difficulty, as reflected in the Group of Jurists and Linguists report, is that there will be methods of sub-seabed CO_2 storage, which although technically feasible and perhaps even technically preferred, that are not allowed under existing international law, while other CO_2 storage methods may be permitted under international law, yet have seemingly the same environmental impact as those methods which are not permitted. As a result, countries seeking to undertake sub-seabed CO_2 storage activities would be well advised to seek clarification from the contracting parties of the applicable marine agreements as to their interpretation of CO_2 storage's legality, and it is not surprising that the leaders in this effort have been the Norwegian and British governments, given the interests of Statoil and BP in CO_2 storage.

Even with some vagueness in international law, sub-seabed CO_2 storage appears to have a promising future for countries seeking an eventual and sustained reduction of CO_2 emissions. The indication from the analysis in this thesis is that at least some forms of CO_2 storage will be treated favorably under international law. Statoil's Sleipner project has demonstrated the capabilities of sub-seabed CO_2 storage at a commercial-scale, and Statoil's Snøhvit and BP's DF-1 projects are positioned to improve our understanding of geological CO_2 storage technologies and their effectiveness. Thus CO_2 storage appears to be well on its way to establishing a pathway to a sustainable energy system.

3.4. Conclusion

The development of future CO_2 storage operations will depend on the structure of the onshore and offshore regulatory regimes. Onshore storage is fundamentally an issue of national law. In the United States, the onshore regulatory regime is defined by the SDWA and UIC Program and related state programs. Although the current onshore regime could be applied to a commercial CO_2 storage project taking place today, the regime should be revised to address certain design, operational, and post-injection issues that are inherent to CO_2 storage projects. There are a number of ways that such a regulatory regime could proceed, whether through existing classifications or establishing a new classification. In either case, the regulatory approach will need to take note of the experience that has been gained from the prior subsurface injection of fluids generally, and CO_2 in particular.

Offshore storage is fundamentally an issue of international law, as defined by UNCLOS, the London Convention, London Protocol, and regional agreements such as OSPAR Convention. Like the onshore regulatory regime, the offshore storage regulatory regime is still being defined with respect to CO_2 storage. Offshore storage conceivably poses less tortious liability exposure than onshore storage because storage locations are isolated, but the benefits might be offset by increased regulatory uncertainty of how international law would apply to CO_2 storage. The uncertainties have lessened with the recent passage of the amendments to the London Protocol which allow the storage of CO_2 beneath the seabed. There remain questions as to how the amendments will be interpreted, such as what it means for a CO_2 stream to consist overwhelmingly of CO_2 or to contain incidental associated substances, but the offshore regulatory regime appears well on its way to becoming better refined.

4. Perceived Risks of CO_2 Storage

4.1. Introduction

The eventual system used to manage CO_2 storage liability will depend on the uncertainties of the geophysical system and the risks of loss of CO_2 containment from the geological formation. Although the risks of leakage appear to be small, empirical data will be required to inform actuarial models of CO_2 storage risks and future liability policies. Because our knowledge of the risks is evolving, any CO_2 storage liability policies developed today will need to adapt to more information about the risks as it becomes available.

CO_2 storage with the express purpose of climate change mitigation has been demonstrated at a handful of sites in the world. Because of the limited empirical data underlying the risks of CO_2 leakage and their effect on liability, I use a survey of CCS experts to determine the greatest sources of risk facing CO_2 storage. The expert opinions as to the CCS risks are used later in the thesis to frame the CCS liability analysis and recommendations for future CCS liability policy.

In November 2005, a web-based survey was disseminated to CCS experts in industry and non-governmental organizations ("NGOs"). The purpose of the "stakeholder survey" was to see what role, if any, CCS might play in a more sustainable energy system. The survey was designed by researchers at MIT, University of Cambridge Judge Business School, Mizuho Information and Research Institute, and Chalmers University of Technology. The work was funded by the Alliance for Global Sustainability ("AGS") with the active support and involvement of industry and environmental groups.[576]

[576] The AGS members of the project were University of Tokyo, Chalmers University of Technology, and MIT. The external advisors to the AGS project were the Central Research Institute for the Electric Power Industry (Japan),

4.2. Survey Design and Methodology

The questions given to the survey panel are found in the Appendix to this thesis. The survey consisted of 31 multiple choice questions, but provided some opportunities for open-ended responses. Members of the panel were given the option to expand on their answers by participating in an individual follow-up interview.

The survey questions were grouped into two sections: (1) general background on climate change and (2) CCS. The CCS section had several subsections: general questions, the future of CCS, public attitudes towards CCS, and the approach of the survey participant's organization to CCS.

The survey was distributed by email to over 100 people in industry and NGOs in North America and Europe, and received 50 responses. The participants in the initial email distribution were hand-selected as representatives from industry and NGOs having a stake in the CCS issue. The industry panelists were generally in charge of environmental policy or business strategy for their company, while the NGO panelists were responsible for the environmental and/or climate change issues in their organization. Respondents were sent an electronic message inviting them to participate in the survey. The email served to alert the respondent to the survey and invite that person to complete it. All answers were coded so that it would not be possible to link the information to any individual, unless the individual expressed interest in participating in a follow-up interview.

The data in this thesis is reported on an aggregate basis as "Industry" or "NGO". In a demographics section of the survey, participants self-selected their organization's primary

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Mizuho Information and Research Institute (formerly Fuji Research Institute), National Institute of Advanced Industrial Science and Technology (Japan), Göteborg University, Vattenfall AB, University of Cambridge, Clean Air Task Force, Electric Power Research Institute, and Environment Northeast.

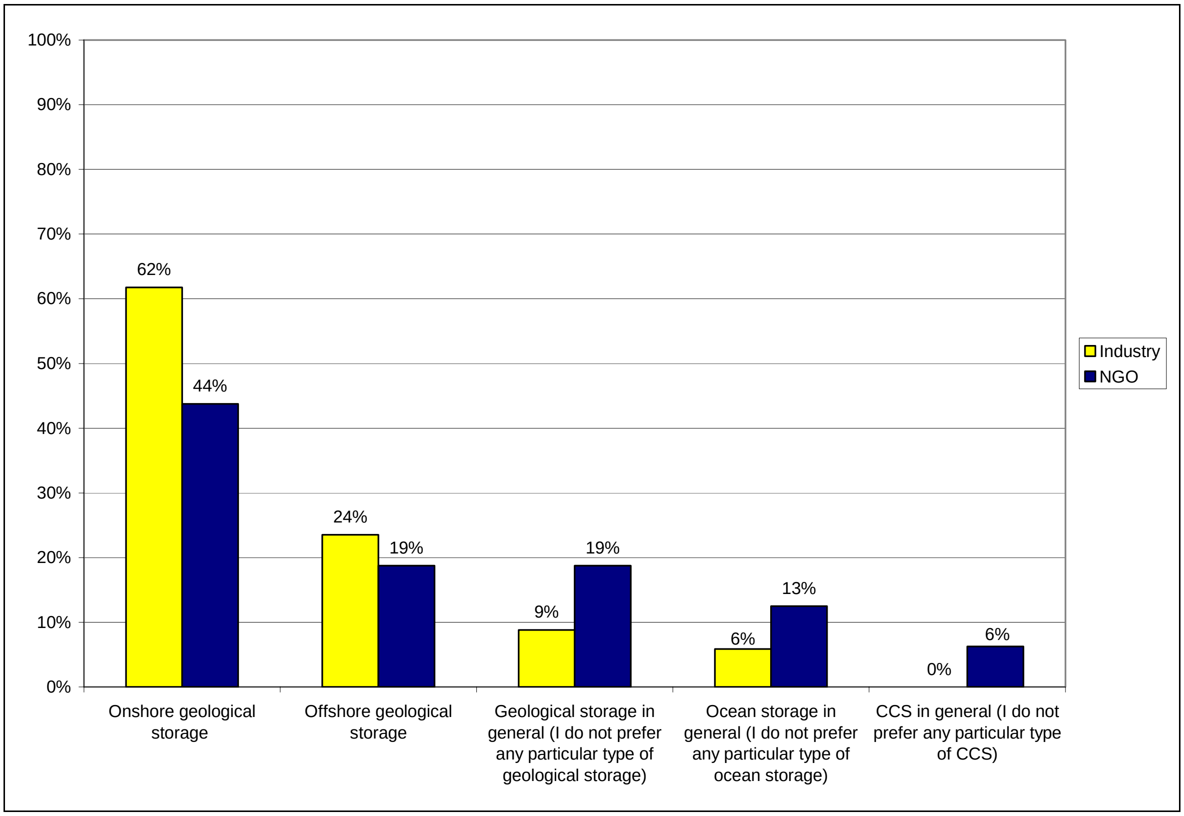
function from a list of possible choices. Those participants who answered NGO are grouped in the "NGO" category of the analysis in this thesis and those participants who answered any other category – Chemical, Electricity, Oil & Gas, Steel, Automotive, Other Manufacturing, Media, Research, and Other – are grouped in the "Industry" category. Of the 50 survey participants, 16 were in the NGO category and 34 were in the Industry category. Although the survey addressed a number of issues relevant to climate change and CCS, the analysis in this thesis is limited to those survey questions relevant to the liability issue.

4.3. Results

The industry and NGO groups both viewed geological storage as the most desirable or least undesirable form of CCS. As shown in Figure 4.1, 93% of industry and 84% of NGOs expressed some preference for a type of geological storage. Of the industry participants, 62% preferred onshore geological storage and 24% preferred offshore storage. This can be contrasted with the NGO participants, of which 44% expressed a preference for onshore geological storage and 19% expressed a preference for offshore storage. Interestingly, 13% of the NGOs surveyed considered ocean storage to be the most desirable or least undesirable form of CCS, compared with 6% of industry. Given the history of ocean storage, particularly the opposition by NGOs to ocean storage field experiments in Hawaii and Norway, the ocean storage survey responses are surprising.[577] However, this seeming anomaly could be a function of the small sample size of the survey groups.

[577] *See* DE FIGUEIREDO, *supra* note 14.

Figure 4.1 Which form of CCS do you consider to be most desirable or least undesirable?



Participants were next asked to compare in terms of preference various electric power sector technologies to fossil-fired power plants ("power plants" for the purposes of this chapter) with CCS generating about the same amount of electricity. The results are shown in Table 4.1 and Figure 4.2. The most striking differences between the industry and NGO responses were in their answers for natural gas turbines without CCS, wind power, solar power, and nuclear power. About half of the industry participants (53%) viewed natural gas turbines as less preferable or much less preferable than power plants with CCS, whereas 50% of the NGO participants viewed natural gas turbines to be similar to power plants with CCS and 25% viewed natural gas turbines to be more preferable than power plants with CCS. With respect to wind power, 100% of the NGO participants perceived wind and solar power as more preferable or much more preferable to power plants with CCS. Only 60% of the industry panel responded the same for wind and 70% for solar. Of the NGO participants, 100% viewed nuclear power as less preferable or much less preferable to power plants with CCS. Industry was fairly split on the nuclear power issue, with 24% viewing nuclear power as similar to power plants with CCS, and about equal percentages expressing positive or negative views of nuclear relative to CCS.

Table 4.1 How would you compare the following electric power sector technologies to fossil-fired plants with carbon capture and storage for generating about the same amount of electricity?

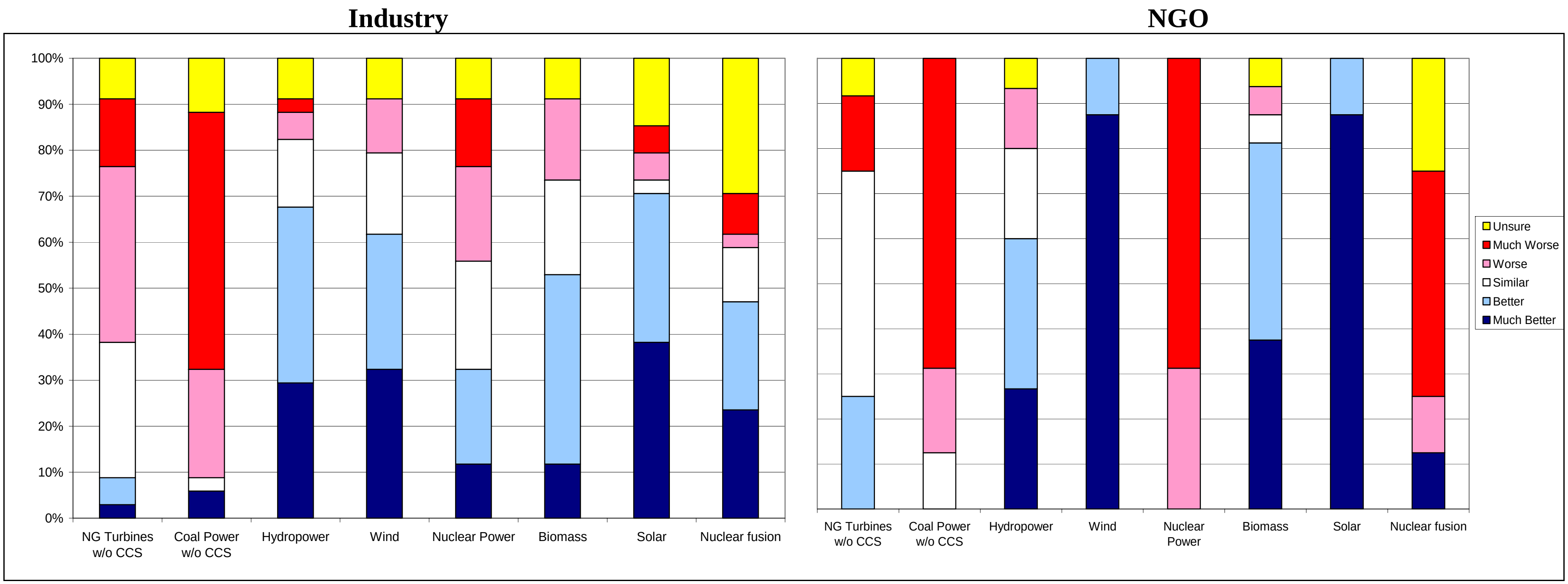
Industry

	Much more preferable than CCS	More preferable than CCS	Similar to CCS	Less preferable than CCS	Much less preferable than CCS	Unsure
Natural gas turbines (without CCS)	3%	6%	29%	38%	15%	9%
Conventional coal power (without CCS)	6%	0%	3%	24%	56%	12%
Hydropower	29%	38%	15%	6%	3%	9%
Wind turbines	32%	29%	18%	12%	0%	9%
Nuclear power	12%	21%	24%	21%	15%	9%
Biomass/bioenergy	12%	41%	21%	18%	0%	9%
Solar power	38%	32%	3%	6%	6%	15%
Nuclear fission	24%	24%	12%	3%	9%	29%

NGO

	Much more preferable than CCS	More preferable than CCS	Similar to CCS	Less preferable than CCS	Much less preferable than CCS	Unsure
Natural gas turbines (without CCS)	0%	25%	50%	0%	17%	8%
Conventional coal power (without CCS)	0%	0%	13%	19%	69%	0%
Hydropower	27%	33%	20%	13%	0%	7%
Wind turbines	88%	13%	0%	0%	0%	0%
Nuclear power	0%	0%	0%	31%	69%	0%
Biomass/bioenergy	38%	44%	6%	6%	0%	6%
Solar power	88%	13%	0%	0%	0%	0%
Nuclear fission	13%	0%	0%	13%	50%	25%

Figure 4.2 How would you compare the following electric power sector technologies to fossil-fired plants with carbon capture and storage for generating about the same amount of electricity?



Next, the survey participants were presented with five potential CCS risks and asked how serious they considered the risks to be. Their responses are shown in Table 4.2 and Figure 4.3. Generally, NGOs appeared to be more concerned about the risks than industry. The majority of the industry panelists responded that the risks presented were low or very low. In contrast, the majority of NGOs viewed the risks presented to be medium or low. Despite their difference, a potential takeaway from the survey is that the majority of industry and NGO panelists did not perceive the risks to be very high. Water contamination and sudden large scale releases received the most responses from NGOs as posing a high or very high risk, but this only constituted 19% of the NGO panelists. Ecosystem impacts and sudden large scale releases received the most responses from industry as posing a high or very high risk, but this constituted only 15% of the industry panelists. A sizeable number of both industry and NGO participants answered that there was insufficient data for considering the seriousness of CCS risks.

Table 4.2 How serious do you consider the following risks to be for CCS?

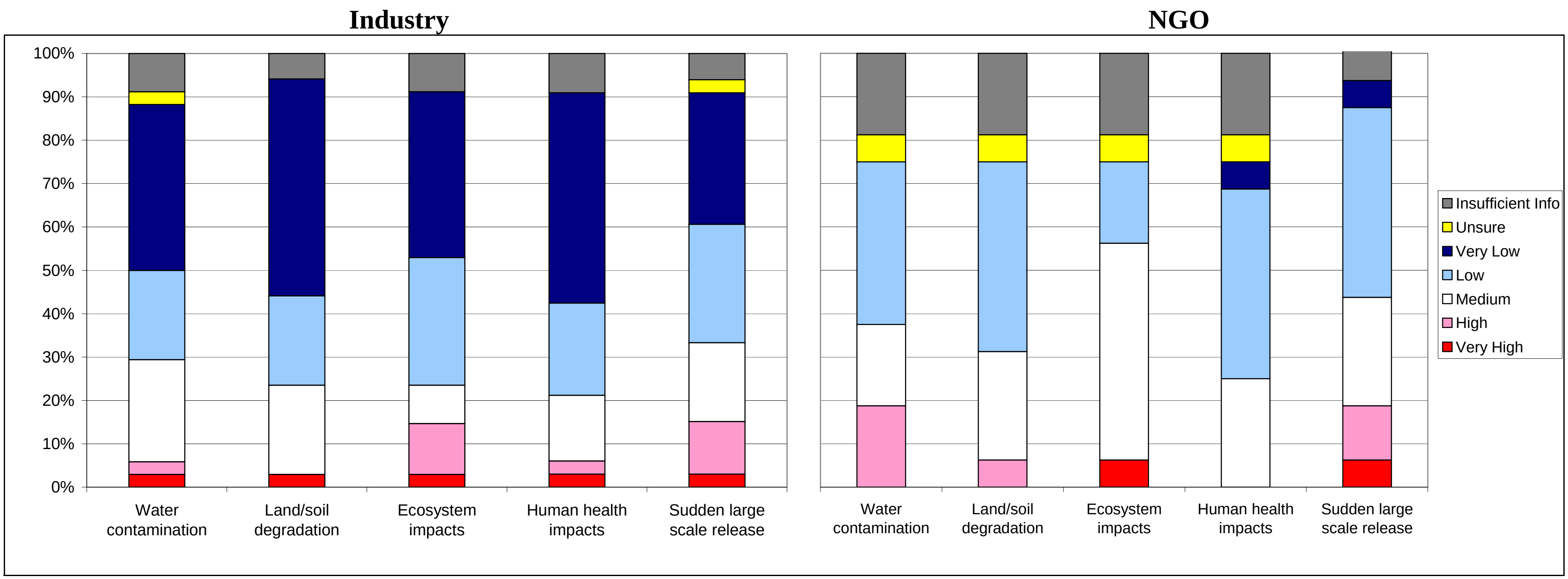
Industry

	Very High	High	Medium	Low	Very Low	Unsure	Insufficient Data
Water contamination	3%	3%	24%	21%	38%	3%	9%
Land/soil degradation	3%	0%	21%	21%	50%	0%	6%
Ecosystem impacts	3%	12%	9%	29%	38%	0%	9%
Human health impacts	3%	3%	15%	21%	48%	0%	9%
Sudden large scale release	3%	12%	18%	27%	30%	3%	6%

NGO

	Very High	High	Medium	Low	Very Low	Unsure	Insufficient Data
Water contamination	0%	19%	19%	38%	0%	6%	19%
Land/soil degradation	0%	6%	25%	44%	0%	6%	19%
Ecosystem impacts	6%	0%	50%	19%	0%	6%	19%
Human health impacts	0%	0%	25%	44%	6%	6%	19%
Sudden large scale release	6%	13%	25%	44%	6%	0%	13%

Figure 4.3 How serious do you consider the following risks to be for CCS?



The survey participants were then presented with five "sources of risk" for CCS. Their responses are shown in Figure 4.4. In contrast to the previous question, which asked participants about *harm* which could result from CCS activities, this question elicited responses on the *potential pathways that could lead to harm*. By far, the greatest concern of both the industry and NGO panelists was leakage from reservoirs. NGOs were equally concerned with seismic activity (44%) and accidents in transport and handling (44%). NGOs also expressed concern about injection at storage sites (38%). A slightly higher percentage of industry panelists (47%) expressed concern about seismic activity than NGOs, but a smaller percentage of industry was concerned with accidents in transport and handling (26%) and injection at storage sites (18%). A small group of industry and NGO participants was not concerned with any of the sources of risk.

Figure 4.4 Which do you believe to be the major sources of risk for CCS?

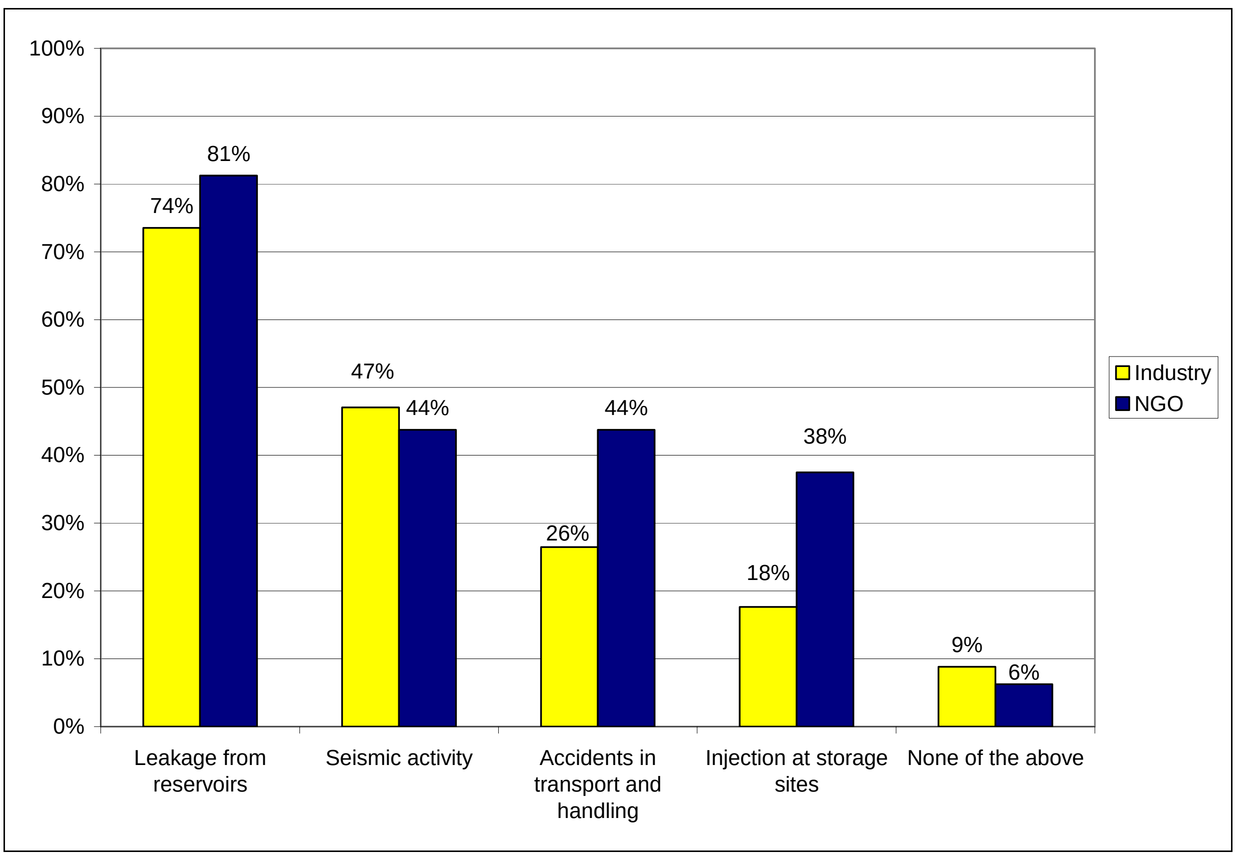
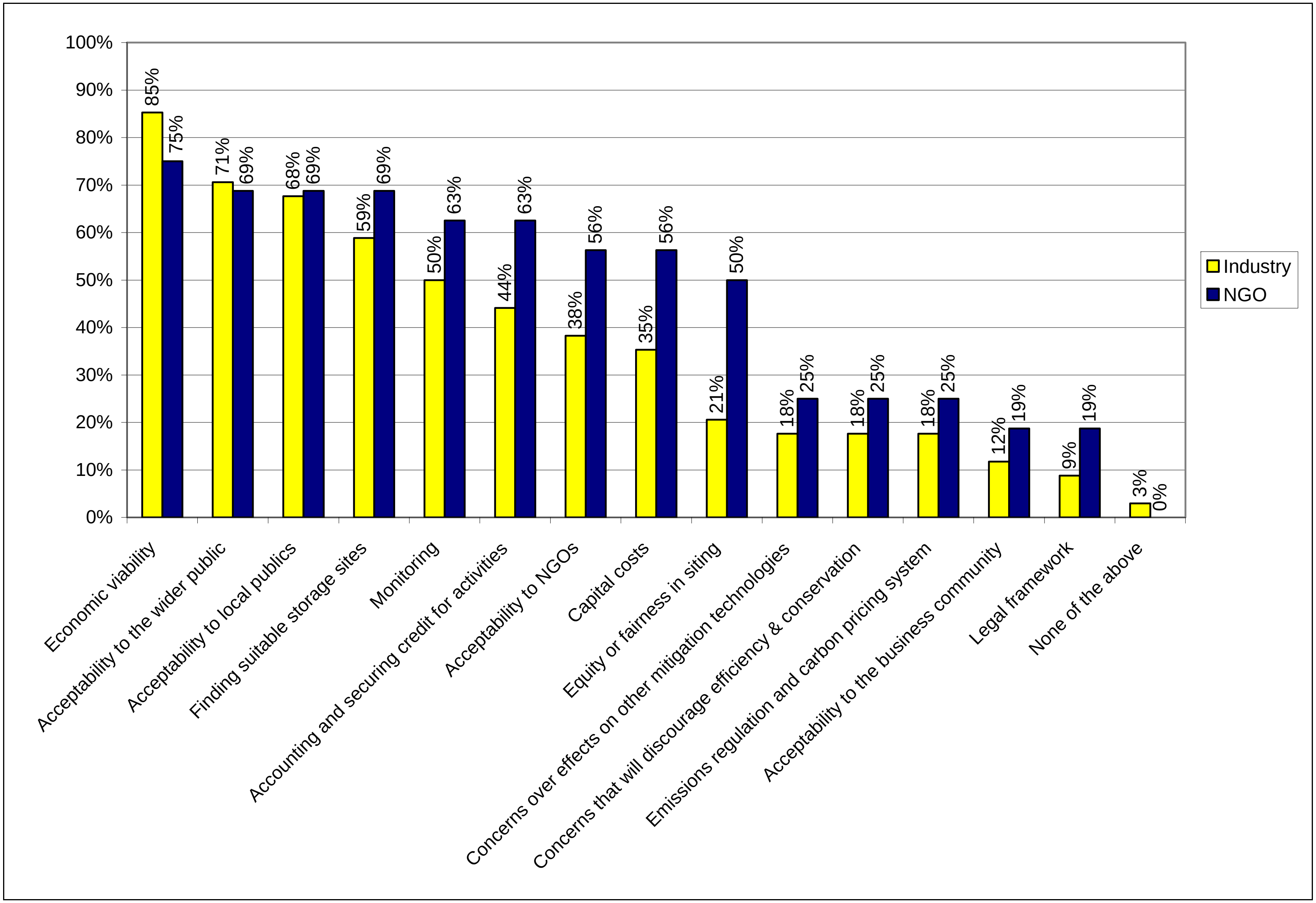


Figure 4.5 shows the responses of the survey panelists to a question asking what they consider to be the most significant concerns that would discourage wide-scale CCS penetration. Although the NGO group was generally more concerned about the issues presented than industry, the relative ranking of the issues was remarkably consistent. By far the greatest concern to the panelists was the economic viability of CCS, which was expressed by 85% of industry and 75% of NGOs. Public acceptability was also an issue of concern to both industry and NGOs. Of interest to the analysis in this thesis, the next highest ranking concerns were finding suitable sites, monitoring, and receiving carbon credits, which all received more responses on a percentage basis from the NGO panelists than from the industry panelists. The CCS legal framework, and by connection the CCS liability framework, appears to be a barrier that can be overcome. Only 9% of industry and 19% of NGOs perceived the CCS legal framework as posing a significant concern to CCS penetration.

Figure 4.5 Which of the following would you consider to be to be most significant concerns that would discourage wide-scale penetration of CCS?



4.4. Conclusion

In summary, a survey of 50 CCS experts from the industry and NGO communities suggests that the risks of CO_2 storage are not very high. When presented with five CCS risks widely considered to be of greatest concern – water contamination, land/soil degradation, ecosystem impacts, human health impacts, and large scale releases – only 3% of experts from industry and 6% of experts from NGOs expressed a view that one or more of these risks were very high. A sizeable percentage of industry (ranging from 6-9%) and NGOs (ranging from 13-19%) responded that they had insufficient data to express an opinion on the seriousness of the risks. This suggests that the perception of CCS risks, even among the experts in the field, will be refined as more data becomes available. Although CCS risks do not appear to be very high, there appears to be consensus that the major source of risk will be leakage from geological reservoirs. Seismic activity and accidents in the transport and handling of CO_2 also appear to be sources of concern. However, the development of a liability framework does not appear to be a show-stopper for CCS. The survey responses suggest that certain issues bearing on liability – monitoring, site selection, and a carbon credit regime – could affect CCS penetration, but the CCS experts appear to agree that penetration will not be discouraged by the development of a CCS legal framework.

5. Liability of CO_2 Storage for Tortious Damages

5.1. Introduction

This chapter considers the tortious liability of CO_2 storage, as distinct from contractual liability which is considered in the next chapter. Section 2.3.1.2 of this thesis found several tortious liability causes of action potentially applicable to CO_2 storage, including trespass, nuisance, negligence, and strict liability. This chapter examines the tortious liability of CO_2 storage as applied to identifiable sources of risk. Based on the results of the survey of industry and NGO experts summarized in Chapter 4, four sources of risk are examined: induced seismicity, groundwater contamination, harm to human health and environment, and property interests. For each risk, the scientific basis of the risk is examined, exemplary regulatory schemes are presented, and liability precedent is analyzed with respect to analogous subsurface injection activities.

5.2. Induced Seismicity

5.2.1. Introduction

A potential risk that CO_2 storage operations could confront is that seismic activity (earthquakes) could be induced from the injection and storage activities. Induced seismicity is a well-studied phenomenon. It has been observed as a consequence of filling large surface reservoirs with water, natural resource extraction (i.e. the development of mineral, geothermal and hydrocarbon resources), waste injection, underground nuclear explosions, and large-scale construction projects.[578] The discussion of induced seismicity in this thesis centers on seismic events induced from injection activities.

[578] Vitaly V. Adushkin et al, *Seismicity in the Oil Field*, OILFIELD REV., Summer 2000, *at* 2.

5.2.2. Background

Injection-induced seismicity was first observed in Denver, Colorado in the 1960s.[579] Waste fluids from chemical manufacturing operations were being injected into a deep disposal well at the Rocky Mountain Arsenal, located northeast of Denver.[580] Fluids were injected on a routine basis between March 1962 and September 1963 at a rate of 21 million liters per month. Injection stopped between October 1963 and August 1964 and fluid was placed into the well using gravity flow at a rate of 7.5 million liters.[581] This occurred until April 1965, when injection resumed at a rate of 17 million liters per month.[582]

At the same time of the Denver waste injection activities, two seismograph stations in the Denver area began to record earthquakes.[583] However, a search of historical records found no evidence of seismic activity before 1962 that were similar in nature to the earthquakes that had been occurring after 1962.[584] In 1965, geologist David Evans showed that there was a correlation between the injection activities at the Rocky Mountain Arsenal and seismic activity in Denver.[585] The results of his findings are shown in Figure 5.1.

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579 *See* J.H. Healy et al, *The Denver Earthquakes*, 161 SCI. 1301 (1968).
580 *Id.* at 1301.
581 *Id.*
582 *Id.*
583 *Id.*
584 *Id.*
585 *Id.* at 1302.

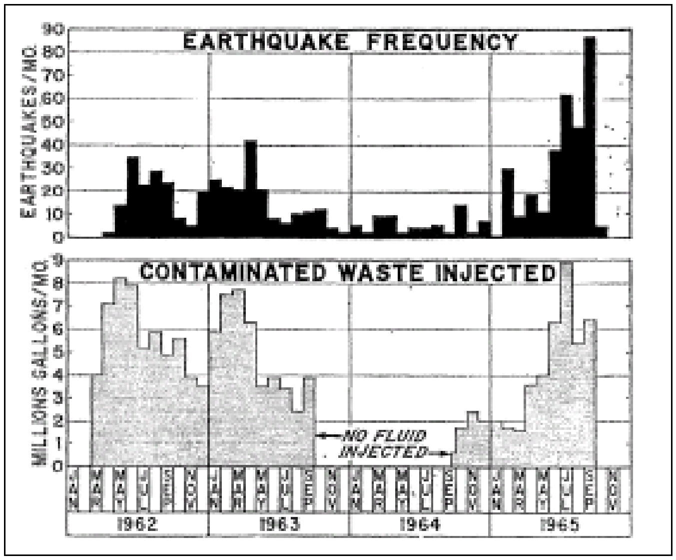

Figure 5.1 Waste Injection and Earthquake Frequency at Rocky Mountain Arsenal (Healy)[586]

Waste injection at the Rocky Mountain Arsenal was stopped in February 1966 because of concern that the Arsenal's waste injection activities were inducing the earthquakes in Denver.[587] Even though the waste injection activities terminated in February 1966, seismic activity in Denver continued through 1967.[588] Although, as shown in Table 5.1, most of the induced earthquakes were very small in magnitude (typically referred to as microseismic events), three relatively large earthquakes were recorded on April 10, 1967 (5.0 magnitude), August 9, 1967 (between 5.25 and 5.5 magnitude), and November 26, 1967 (5.1 magnitude).[589] By the mid 1970s, the seismic activity in Denver had almost completely ceased.[590]

[586] Reprinted with permission from J.H. Healy et al, *The Denver Earthquakes*, 161 SCI. 1301, 1302 (1968). Copyright 1968 AAAS.
[587] *Id.* at 1301.
[588] *Id.* at 1309.
[589] *Id.* at 1303.
[590] C.B. Raleigh et al, *An Experiment in Earthquake Control at Rangely, Colorado*, 191 SCI. 1230 (1976).

Table 5.1 Magnitude and Frequency of Denver Earthquakes (Healy)[591]

YEAR	MAGNITUDE								TOTAL
	1.5-1.9	2.0-2.4	2.5-2.9	3.0-3.4	3.5-3.9	4.0-4.4	4.5-4.9	5.0-5.4	
1962	72	29	4	2	1	1	-	-	189
1963	89	34	0	3	1	1	-	-	284
1964	26	8	6	-	-	-	-	-	72
1965	168	64	25	6	4	-	-	-	550
1966	61	18	3	2	1	-	-	-	186
1967	62	29	15	4	4	2	-	3	206
Total	478	182	62	17	11	4	-	3	1584

Because of concern that pressure increases from fluid injection induced the Denver earthquakes and that reductions in fluid pressure decreased the frequency of seismic events, U.S. Geological Survey ("USGS") scientists decided to conduct a field experiment that would increase and decrease fluid pressure from subsurface injection in a cyclical fashion.[592] The locations and characteristics of the induced earthquakes were determined by using a dense array of seismometers (devices for detecting seismic activity).[593] Hydrofracturing (the injection of high-pressure water to induce fractures in rock, also known as hydraulic fracturing) was used to measure stress in the rock at the depth of injection.[594] Additional laboratory tests provided estimates of the strength of the rock of the geological formation into which fluids were being injected.[595] The Rangely oil field in Colorado was chosen as the host site for the field experiment.[596] Earthquakes had been recorded at Rangely since 1962, which was when pressurized water began to be injected into the field for secondary oil recovery.[597] The USGS

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591 Healy et al, *supra* note 579, at 1302.
592 Raleigh et al, *supra* note 590, at 1230.
593 *Id.*
594 *Id.*
595 *Id.*
596 *Id.*
597 *Id.*

scientists sought to determine how variations in the pressurized water injection would affect seismic activity.[598]

The USGS scientists hypothesized that a pore pressure of about 260 bars (an increase of 90 bars from the pressure of 170 bars in the geological formation) would be sufficient to induce seismic activity at Rangely.[599] Their hypothesis was confirmed by the results of the field experiment, which showed that seismic activity was associated with a formation pressure of at least 275 bars.[600] The experimental results also showed that induced seismicity could be controlled by raising and lowering the pressure about a value of 260 bars.[601] The conclusion of the Rangely experiment is widely considered to be that variations in seismic activity can be produced by varying fluid pressure in a seismically active zone.[602] For CO_2 storage, the relevance of the Rangely experiment is that despite the variation in fluid injection pressure, most of the induced earthquakes were microseismic in nature, and the largest of the earthquakes was only of 3.1 magnitude. In the time since the Rangely experiment was conducted, CO_2, in addition to pressurized water, has been injected into the formation for EOR.[603] There has not been any reported seismic activity associated with the CO_2 injection activities at Rangely.

5.2.3. Scientific Basis for Induced Seismicity

Injection induced seismicity is thought to be a function of the fluid pressure in a geological reservoir.[604] The fluid pressure in a geological formation ("fluid pressure") is the sum

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[598] *Id.*
[599] *Id.* at 1234.
[600] *Id.*
[601] *Id.*
[602] *Id.* at 1236. This conclusion led to a school of thought that naturally occurring earthquakes could possibly be controlled by fluid injection. It was thought that the inducement of microseismic activity might avert a larger earthquake.
[603] *See* Table 7.10 and associated discussion.
[604] *See, e.g.*, J.R. Grasso, *Mechanics of Seismic Instabilities Induced by the Recovery of Hydrocarbons*, 139 PURE & APPLIED GEOPHYSICS 507, 511 (1992).

of the pressure from the fluid injection process ("surface injection pressure") and the weight of the fluid in the formation.[605] As the geological formation is subjected to increasing fluid pressure, the fluid pressure will be opposed by the normal stress (also known as "compressive stress") of the formation.[606]

A useful way of predicting induced seismicity is to use the "Mohr-Coulomb" failure model. Graphically, failure in the Mohr-Coulomb model can be determined using Mohr's circle. Failure (i.e. the shear stress sufficient to induce a seismic event) is a function of the shear strength of the material (τ_0), the normal stress (σ_n), and the coefficient of friction on the surface (μ).[607] When fluid is injected into a geological formation at pressure p, the normal stresses σ_n of the formation will oppose the hydrostatic pressure p from the fluid injection.[608] The effective normal stress and maximum principal stresses are reduced by the amount of hydrostatic pressure p.[609] Failure occurs where $\tau = \tau_0 + \mu(\sigma_n - p)$. Seismic events will be induced when pre-existing stress conditions on a fault are such that the magnitude of the induced stresses are sufficient to produce failure, or when CO_2 injection drives the natural stress condition closer to failure by increasing the pore pressure, which reduces the effective normal stress.[610]

5.2.4. Induced Seismicity and Hydraulic Fracturing

Seismic events could also be induced by hydraulic fracturing. As discussed in the case of induced seismicity at the Rangely oil field in Colorado, hydraulic fracturing is the result of injecting fluid into a geological formation at such a high pressure that a fracture is created in the

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[605] Scott D. Davis & Wayne g. Pennington, *Induced Seismic Deformation in the Cogdell Oil Field of West Texas,* 79 BULLETIN OF THE SEISMOLOGICAL SOCIETY OF AMERICA 1477, 1479 (1989).
[606] *Id.* at 1480.
[607] D.W. Simpson, *Triggered Earthquakes*, 14 ANN. REV. EARTH PLANET. SCI. 21, 23 (1986).
[608] *Id.* at 25.
[609] *Id.*
[610] *Id.*

rock of the geological formation.[611] Hydraulic fracturing is used in the oil and gas industry to increase the flow rate of oil or gas from low permeability reservoirs (reservoirs that have a high resistance to fluid flow).[612] In the case of oil recovery, hydraulic fracturing occurs by injecting a slurry, composed of sand and guar gum gel, into a wellbore at a pressure sufficient to create and propagate fractures.[613] The hydraulic fracturing creates cracks which are held open by the sand of the slurry after the gel has degraded and the wellbore pressure has been reduced.[614] The cracks result in the upward pressure of oil resources to the wellhead and increased permeability for fluid flow.[615] Whether hydraulic fracturing is suitable for a geological formation will depend on a number of factors, including permeability of the formation, *in situ* stress distribution, viscosity of the *in situ* fluids, skin factor (whether the reservoir has already been stimulated and/or damaged), reservoir pressure, reservoir depth, and the condition of the wellbore.[616] Hydraulic fracturing is not conducted where a reservoir is thin, has a low reservoir pressure, or is small in aerial extent.[617]

Hydraulic fracturing is known to be associated with microseismic events, generally during the initial stage of fracturing.[618] In fact, the majority of passive seismic monitoring experiments have been conducted in conjunction with hydraulic fracturing.[619] The microseismic monitoring is used to map the characteristics of the fractures, including parameters such as

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[611] SCHLUMBERGER, OILFIELD GLOSSARY (2006) (s.v. "hydraulic fracturing").
[612] U.S. Dep't of Energy, *Hydraulic Fracturing White Paper*, *in* EVALUATION OF IMPACTS TO UNDERGROUND SOURCES OF DRINKING WATER BY HYDRAULIC FRACTURING OF COALBED METHANE RESERVOIRS (U.S. Envtl. Protection Agency, EPA 816-R-04-003, June 2004), at A-2.
[613] Markus G. Pruder, *Did the Eleventh Circuit Crack "FRAC"? Hydraulic Fracturing After the Court's Landmark LEAF Decision,* 18 VA. ENVTL. L.J. 507, 511 (1999).
[614] *Id.*
[615] *Id.*
[616] U.S. Dep't of Energy, *supra* note 612, at A-2.
[617] *Id.* at A-3.
[618] Shunji Sasaki, *Characteristics of Microseismic Events Induced during Hydraulic Fracturing Experiments at the Hijiori Hot Dry Rock Geothermal Energy Site, Yamagata, Japan*, 289 TECTONOPHYSICS 171, 172 (1998).
[619] S.C. Maxwell & T.J. Urbancic, *The Potential Role of Passive Seismic Monitoring for Real-Time 4D Reservoir Characterization*, SPE RESERVOIR EVALUATION & ENGINEERING, Feb. 2005, at 70.

orientation, height, length, complexity, and temporal growth.[620] The monitoring is used for the purposes of altering the hydraulic stimulation parameters, if necessary. Sasaki notes that studies of induced seismicity associated with hydraulic fracturing have shown that "even though hydraulic fractures themselves are almost aseismic and are not directly responsible for observable microearthquakes, they can induce shear failure on joints and preexisting fractures that occur in rocks surrounding the main hydraulic fracture".[621]

5.2.5. Liability of Induced Seismicity

Research by Cypser and Davis has found that "there are no cases on record in which an appellate court has upheld the application of tortious liability to an induced earthquake situation".[622] This could be due to difficulties in attributing the cause of seismic activity to a particular injection or extraction activity. Induced seismicity is more likely to occur in areas that are already seismically active.[623] If an area is already notorious for its seismic activity (e.g., California), a potential plaintiff may have difficulties proving that a given fluid extraction or injection activity was the cause of a particular seismic event in the already seismically active region.

Most cases to date implicating induced seismicity have involved the siting of nuclear power plants, dams and injection wells.[624] These cases have all been brought before the projects had been sited and have not requested compensation for damages from induced seismicity.[625] However, a potential lawsuit by residents living near The Geysers Geothermal Field ("The

[620] *Id.* at 71.
[621] Sasaki, *supra* note 618, at 172 (1998).
[622] Darlene A. Cypser & Scott D. Davis, *Induced Seismicity and the Potential for Liability under U.S. Law*, 289 TECTONOPHYSICS 239, 241 (1998).
[623] *See, e.g.*, World Bank, Reservoir Induced Earthquakes (Induced Seismicity), *at* http://www.worldbank.org/html/fpd/em/hydro/rie.stm (last visited Nov. 27, 2006).
[624] Cypser & Davis, *supra* note 622, at 241.
[625] *Id.*

Geysers") in Northern California could become the first ever case of induced liability litigation.[626] The Geysers is a geothermal power facility with a capacity of about 750 megawatts of electricity.[627] The first power plant in the facility began operations in 1960 and seismic activity has been reported in the area since at least 1969.[628] Scientific studies revealed that the seismic activity has mostly been microseismic in nature, but there have been several induced earthquakes of magnitude 3.0 or greater.[629] Figure 5.2(a) shows seismic activity at The Geysers over the past year.

In 1997, wastewater began to be injected into the geothermal fields to maintain the production of steam from the fields.[630] After the water injection commenced, local communities claimed that the earthquakes in the area had greatly increased.[631] Platts reports that an average of 18 induced earthquakes per year of magnitude greater than 3.0 have occurred, and that there have been 3 earthquakes of magnitude greater than 4.0 in a ten-month period between 2003 and 2004.[632] As a result of the induced seismic events, two local community groups are seeking compensation from Calpine Corporation and the Northern California Power Agency, the two major owner/operators of The Geysers.[633] One of the community members has reported that he would like to the area to receive a portion of the $500,000 annual geothermal royalties to go into a fund to help homeowners make property repairs.[634] However, a study by Calpine, the Northern California Power Agency, the U.S. Geological Survey, and Lawrence Berkeley National

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[626] Platts, *Northern Calif. Residents Seek Compensation from Geothermal Owners for Seismic Activity*, GLOBAL POWER REPORT (Apr. 15, 2004), at 12.
[627] Calpine, *The Geysers*, *at* http://www.geysers.com/ (last visited Nov. 27, 2006).
[628] Bill Smith et al, *Induced Seismicity in the SE Geysers Field, California, USA*, PROC. WORLD GEOTHERMAL CONGRESS (2000), at 2887.
[629] *Id.*
[630] *Id.*
[631] Platts, *supra* note 626, at 12.
[632] *Id.*
[633] *Id.*
[634] *Id.*

Laboratory reports no earthquake faults active in The Geysers and that the seismic activity is not related to the wastewater injection.[635]

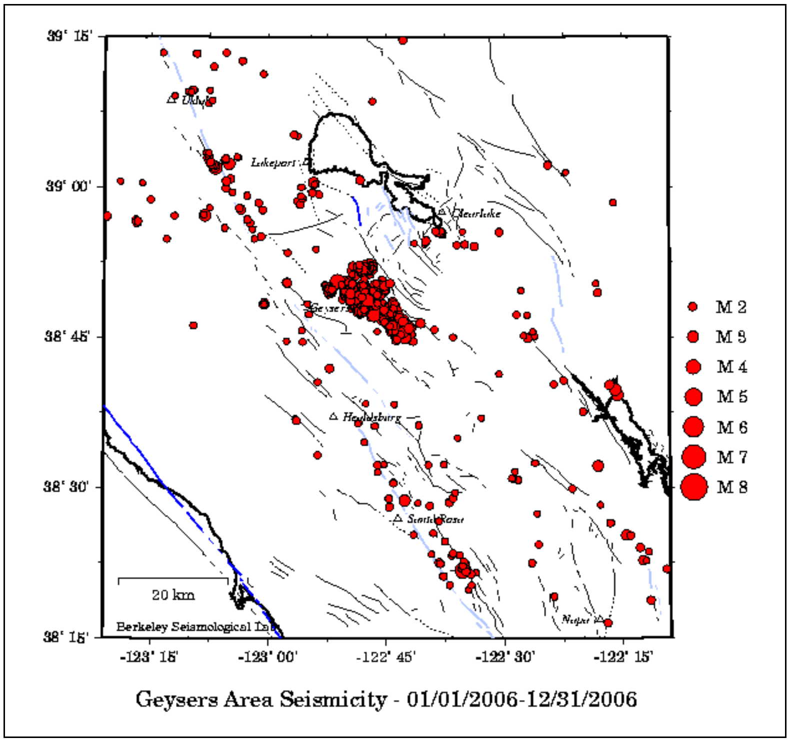

Figure 5.2 Seismic Activity at The Geysers (during the period January 1, 2006 – December 31, 2006) Courtesy of Berkeley Seismological Laboratory, University of California Berkeley[636]

5.2.6. Induced Seismicity Scenarios for CO_2 Storage

Sminchak and Gupta review potential scenarios that could lead to induced seismcity from CO_2 storage.[637] A graphical summary of their findings is shown in Figure 5.3. First, because supercritical CO_2 is less dense than water, Sminchak and Gupta argue that the CO_2 has the potential to induce seismicity by what they term “density-driven stress loading”.[638] This is

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[635] *Id.*
[636] Berkeley Seismological Lab, Weekly Seismicity Maps for the Geysers Area, *at* http://seismo.berkeley.edu/weekly/geyser.yearly_2006.gif (last modified Jan. 5, 2007).
[637] Joel Sminchak & Neeraj Gupta, *Aspects of Induced Seismic Activity and Deep-Well Sequestration of Carbon Dioxide*, 10 ENVTL. GEOSCIENCES 81, 82 (2003).
[638] *Id.* at 82.

essentially the stress from the force of the CO_2 migrating upwards and exerting pressure on the overlying caprock, in turn transferring stress to overlying faults.[639] Sminchak and Gupta note that density-driven stress loading is limited by solubility trapping mechanisms, i.e. the fact that "much of the fluid will mix and dissolve into the formation waters over time".[640]

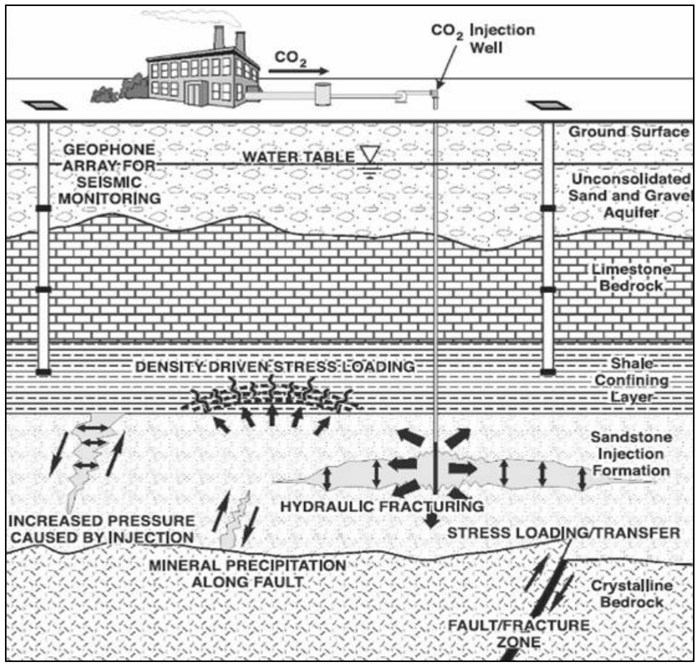

Figure 5.3 Induced Seismicity Scenarios for CO_2 Storage (Sminchak and Gupta)[641]
Joel Sminchak and Neeraj Gupta, Environmental Geosciences, AAPG © 2003. Reprinted by permission of the AAPG whose permission is required for further use.

Second, seismic activity could be induced from "mineral precipitation along a fault".[642] Supercritical CO_2 has the potential to dissolve, weaken, or transform minerals composing the rock matrix of the storage formation.[643] The reaction of the CO_2 with the rock matrix could cause the CO_2 to precipitate out minerals from the formation, decreasing the formation's porosity

639 *Id.*
640 *Id.*
641 *Id.* at 83.
642 *Id.* at 82, 87.
643 *Id.* at 87.

and permeability, leading to unexpected pressure buildup and possible seismic activity from faulting or fracture.[644]

Third, induced seismicity could occur due to hydraulic fracturing, as noted in Section 5.2.4 of this thesis. When CO_2 is injected into the subsurface at very high pressures, which is required in order for the CO_2 to maintain its supercritical properties, it is possible for the injection pressure to exceed the strength of the rock, leading to fractures.[645] Because supercritical CO_2 has the potential to weaken the rock matrix of the geological formation, the likelihood for hydraulic fracturing is higher than for other injectates that do not degrade the formation minerals.[646] Sminchak and Gupta point out that monitored hydraulic fracturing will be unlikely to produce seismic activity above a Richter magnitude of 1, but that unmonitored hydraulic fracturing poses concern.[647]

5.2.7. Conclusion

Injection-induced seismicity is a well-known phenomenon. The experience from the Rocky Mountain Arsenal and Rangely demonstrates that variations in fluid injection pressure can induce seismic activity. With respect to CO_2 storage this could occur not only through classical mechanisms such as density-driven stress loading and hydraulic fracturing, but also due to the acidic nature of the CO_2 injectate which could cause the surrounding rock matrix to break down. Even though the scientific basis is understood and there are tortious liability causes of action, such as nuisance or strict liability, that would appear to be applicable to the issue, there are no reported cases of injection-induced seismicity liability. One might contrast this with the classical strict liability literature, which is full of examples of explosions and vibrations leading to liability

[644] *Id.*
[645] *Id.*
[646] *Id.*
[647] *Id.* at 84.

and could be thought of as analogous to induced seismicity.[648] There are two potential reasons for the lack of liability cases. One potential reason might be problems in showing foreseeability, which is a prerequisite for negligence actions[649] It may be difficult to predict the frequency and magnitude of a given seismic event following a given subsurface injection. The second reason for the lack of cases might be problems in showing causation. Legal causation is premised on the *sine qua non* rule, also known as the "but for" rule, which holds that an operator's conduct is not the legal cause of damage if the damage would have occurred in the absence of the operator's actions.[650] Subsurface injection could induce seismic events that would have eventually occurred, as was suggested in the case of the Rocky Mountain Arsenal, or could cause a future seismic event to be shifted to the present.[651] Thus, even if it could be shown that the subsurface injection induced seismic activity, it still might be enough to prove liability.

5.3. Groundwater Contamination

5.3.1. Introduction

This section considers the potential for CO_2 storage liability from groundwater contamination. It begins with a discussion of the necessary prerequisites to tortious liability actions of groundwater contamination. It goes on to review the scientific basis for groundwater contamination from CO_2 storage in particular. It analyzes the critical issue for liability, namely proving causation of groundwater contamination. Finally, it examines groundwater contamination in the public enforcement context.

[648] *See, e.g.*, Exner v. Sherman Power Construction Co., 54 F.2d 51 (2d Cir. 1931).
[649] Cypser & Davis, *supra* note 622, at 247.
[650] Cypser & Davis, *supra* note 622, at 244.
[651] *Id. See also* Healy, *supra* note 579, at 1304; Simpson, *supra* note 607, at 34.

5.3.2. Background

The liability issue for groundwater contamination has been confronted by the judiciary for years, generally in the form of negligence or nuisance cases.[652] The groundwater property rights regime will affect which parties can bring a cause of action against the CO_2 storage operator for groundwater contamination. In the case of a privately-owned aquifer, a cause of action would likely need to be brought by the owner of the private groundwater. In the case of a publicly-owned aquifer, liability would be brought by the government, and/or private parties if the law allows for citizen suits. Groundwater ownership varies by state. The various groundwater ownership regimes followed in the United States are discussed in detail in Section 7.3.2.1 of this thesis.

Liability could go beyond the property rights issue. If a person was injured because she consumed drinking water that was contaminated due to CO_2 leakage, she would have a potential tortious claim against the CO_2 storage operator. For example, the injected CO_2 might have mobilized toxic metals which found their way into the groundwater supply.

Any cause of action for groundwater contamination will affected by the relevant jurisdiction's statute of limitations. In Texas, for example, there is a two-year statute of limitations for pollution of a subsurface fresh water aquifer.[653] In the Texas case of *Matysek v. Medders*, the plaintiff's groundwater contamination liability case was dismissed on statute of limitations grounds.[654] The Matysek family claimed that their groundwater aquifer had been

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[652] *See, e.g.*, United Fuel Gas Co. v. Sawyers, 359 S.W.2d 466, 467 (Tex. 1953) (noting that "the basis of liability for injury to property by pollution of subterraneous waters from oil, gas, salt water or like substances from wells must be either negligence or nuisance").
[653] *See* Matysek v. Medders, 443 S.W.2d 929, 929-30 (Tex. 1969); Gulf Oil Corp. v. Alexander, 291 S.W.2d 792, 794. (Tex, 1956).
[654] Matysek, 443 S.W.2d at 931.

contaminated by salt water from the Medders adjacent oil recovery operation.[655] As soon as the Matyseks noticed that their water began to taste salty and subsequent tests confirmed the excessive salt content, the statute of limitations on their liability cause of action began to run.[656] As the court described it, the "damages to their land accrued and limitations began to run at the time the injury became apparent".[657] Because the contamination was known to them more than two years before they brought suit, their case was barred on statute of limitations grounds.[658]

Aronovsky notes that liability for groundwater contamination presents challenges not confronted in other environmental liability contexts.[659] For example, unlike soil contamination where the pollution stays in one place, contaminated groundwater plumes have the potential to migrate.[660] Another problem is that the source of the groundwater contamination may be difficult to determine if there is more than one source of contamination or if the original point source cannot be located.[661] However, this may be no different than toxic tort cases involving low-level multi-chemical exposures, where a single cause of injury may be impossible to show.[662]

5.3.3. Scientific Basis for Groundwater Contamination Liability by CO_2 Storage

The ability of CO_2 to dissolve in water has both positive and negative implications for CO_2 storage. On one hand, the dissolution of CO_2 in the *in situ* water of a geological formation

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[655] *Id* at 929.
[656] *Id.* at 931.
[657] *Id.*
[658] *Id.*
[659] Ronald G. Aronovsky, *Liability Theories in Contaminated Groundwater Litigation*, 1 J. ENVTL. FORENSICS 97, 97 (2000).
[660] *Id.*
[661] *Id.*
[662] *See, e.g.*, Nicholas Ashford & Claudia Miller, *Low-Level Chemical Exposures: A Challenge for Science and Policy*, 32 ENVTL. SCI. & TECH. 508A (1998) (arguing that the "lack of clear biomarkers and time lags between exposures and disease onset make it technically and politically difficult to develop evidence needed for regulating many chemicals and industrial processes or to resolve compensation issues".)

is favorable because it traps the injected CO_2 and prevents the CO_2 from leaking back to the surface or migrating in the subsurface.[663] On the other hand, solubility trapping takes time and if the non-trapped CO_2 migrates from the geological reservoir via one of the pathways described in Section 2.2.3 and reaches a drinking water aquifer, the CO_2 could contaminate the drinking water supply. As a reminder, when CO_2 interacts with water, it forms carbonic acid, i.e. the water in the drinking water aquifer could become "carbonated".

There are other mechanisms for drinking water contamination in addition to the injected CO_2 contaminating the water supply directly. For example, the injected CO_2 could displace the *in situ* brine of the geological formation, and the brine could come into contact with the drinking water.[664] In analyzing analogous subsurface injection activities, the IPCC notes that "contamination of groundwater by brines displaced from injection wells is rare".[665] Another example would be for the CO_2 to mobilize toxic metals, sulphates, or chloride, which in turn enter the drinking water supply.[666] However, the IPCC notes that "few natural formations have mineral composition so susceptible to the effects of CO_2-mediated leaching".[667]

The IPCC has examined potential monitoring technologies for CO_2 contamination of groundwater. Some of the IPCC's findings are reported in Section 2.2.4.2 of this thesis. Obviously, one way of determining contamination would be to take groundwater samples of the aquifer of concern. The IPCC recommends testing the groundwater samples for major ions,[668] pH, alkalinity, stable isotopes,[669] and gases.[670] Ideally a groundwater sample would have been taken prior to commencing CO_2 storage operations so that it could be compared with post-

[663] See *supra* Section 2.2.2.1.
[664] IPCC Special Report, *supra* note 11, at 248.
[665] *Id.*
[666] *Id.* at 247.
[667] *Id.*
[668] Examples of major ions include: Na, K, Ca, Mg, Mn, Cl, Si, HCO_3^-, and SO_4^{2-}. *Id.* at 239.
[669] Examples include: ^{13}C, ^{14}C, ^{18}O, and ^{2}H. *Id.*
[670] Relevant gases include hydrocarbon gases, CO_2, and any carbon isotopes associated with the CO_2. *Id.*

injection samples. The IPCC also suggests that natural tracers[671] or introduced tracers[672] could be injected with the stored CO_2 to show subsurface movement of the CO_2, and if applicable, the source of the drinking water aquifer's carbonation.

5.3.4. Groundwater Contamination Liability and Causation

In groundwater contamination liability cases, a major point of contention is the causal relation between the allegedly contaminated groundwater and the source of contamination.[673] This is essentially the "specific causation" issue from toxic torts, i.e. the plaintiff must show that the plaintiff's injury was caused by the defendant's activities. Under the rationale of *Shell Petroleum v. Blubaugh*, merely showing CO_2 leakage from the storage reservoir would not be sufficient to prove liability:

> A showing that gas was escaping from the surface at the point where the abandoned wells were plugged does not justify the presumption that gas, oil or other pollutive substances escaped from said wells into the fresh water strata underneath the surface and followed such strata a distance of approximately one-half mile to plaintiff's water wells resulting in the damage complained of.[674]

It would need to be shown that the CO_2 leakage caused the particular harm in question, as demonstrated by scientific evidence to that effect. In *Shell Petroleum*, Mr. Blubaugh alleged that oil and salt water escaped from Shell Petroleum's oil operations and polluted the groundwater underlying his surface property.[675] The court refused to grant Mr. Blubaugh damages because he only showed that Shell Petroleum did not abandon its oil wells properly, but did not present

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[671] Examples include isotopes of C, O, H, and noble gases. *Id.*
[672] Examples include noble gases, SF_6 and perfluorocarbons. The IPCC cautions against the use of SF_6 and perfluorocarbons because of their high global warming potentials. *Id.*
[673] *See generally* L.S. Tellier, Annotation, Liability for Pollution of Subterranean Waters, 38 A.L.R.2d 1265 § 6 (2006).
[674] Shell Petroleum Corp. et al. v. Blubaugh, 102 P.2d 163, 166 (Okla. 1940).
[675] *Id.* at 164.

any evidence that substances escaped from Shell's abandoned wells into the groundwater of Mr. Blubaugh.[676]

Thus groundwater liability cases may come down to cases of the defendant poking holes in the plaintiff's model, or possibly dueling models (where the plaintiff presents a model showing that groundwater was contaminated by the defendant and the defendant presents a model showing that the groundwater not contaminated by the defendant). It then becomes the role of the trier of fact to sort out the dueling models and determine the cause of the groundwater pollution. The issue of suitability of groundwater contamination models was recently confronted in *Anthony v. Chevron* before Judge Emilio Garza of the Fifth Circuit Court of Appeals.[677]

In *Anthony*, the Anthony family brought a cause of action against Chevron alleging, in part, that Chevron had polluted the groundwater of the Anthony Family's ranch.[678] At trial, the judge held that the Anthony's had not provided sufficient evidence for a reasonable jury to conclude that Chevron caused the pollution of the Anthony aquifer and dismissed the Anthony Family's claims. The Anthony Family presented two expert witnesses. The first expert witness proposed three models for how Chevron's salt water injections could contaminate the Anthony Family aquifer one-half mile above the injection zone: 1) Chevron injected more salt water than oil and water that it removed, increasing the pressure in the formation and causing the salt water to migrate into the Anthony Family aquifer; 2) injected salt water flowed horizontally to a nearby producing well and migrated into the Anthony Family aquifer; and 3) Chevron hydraulically fractured the rock of the oil formation, but the fractures extended into the Anthony Family aquifer. Judge Garza found flaws in all three of the first expert's models, noting that the expert never provided sufficient evidence to make a prima facie case as to causation. In the first model,

[676] *Id.* at 167.
[677] Anthony v. Chevron USA, Inc., 284 F.3d 578 (2002).
[678] *Id.* at 580.

Judge Garza faulted the expert never determining the capacity of the oil reservoir or the pressure of the underground water. In the second model, Judge Garza noted that the expert never provided evidence that the salt water actually migrated upwards and horizontally into the Anthony Family aquifer. In the third model, Judge Garza observed that the alleged fracture actually extended to the Anthony Family aquifer.

The Anthony family presented a second expert witness addressing what would happen to the salt water once it actually reached the aquifer, characterizing the path of the salt water as a plume spreading through the aquifer. However, Judge Garza noted that the second expert relied on the first expert's assumption that the Chevron wells were the cause of the contamination and made no independent verification of this fact. In addition, the second expert made no determination of the size of the contamination plume, making it impossible for the trier of fact to determine the actual scope of damages.

Thus, Judge Garza concluded that the expert witnesses "presented no evidence … that the injection water ever found a pathway to the [Anthony Family aquifer], no evidence as to the extent of the resulting contamination, and no evidence that the effects of the contamination are permanent. A reasonable jury could not base a finding of liability on this evidence." Judge Garza affirmed the lower court's ruling in favor of Chevron.

5.3.5. Groundwater Contamination and Public Enforcement of Liability

As described in Section 3.2, public enforcement of CO_2 storage liability is managed through the UIC Program. Because of its statutory mandate, the UIC Program is focused primarily on the contamination of underground sources of drinking water. Under its current application to CO_2 storage, the UIC Program gives more limited treatment, if any, to other harms to human health, the environment, and property. Other federal statutes that are traditionally relied upon for public enforcement in the environmental arena, such as RCRA or the Clean Air Act, do not apply to CO_2 storage.[679]

The EPA Administrator has responsibility for enforcing UIC permits under Section 1423 of the Safe Drinking Water Act. If there is a violation of a UIC permit, such as by sequestered CO_2 or mobilized metals migrating into a drinking water aquifer, the EPA Administrator is to provide notice of the violation to the permit holder and the applicable state agency.[680] If the state has not commenced an enforcement action within thirty days of the notice, the EPA Administrator may bring civil and criminal actions against the alleged violator.[681] In the case of a civil action, the permit holder faces civil penalties of up to $25,000 per day of violation.[682] The Administrator may also issue an administrative order, assessing penalties of up to $5,000 per day of violation for Class II permits and up to $10,000 per day of violation for all other classes of permits.[683] Section 1423(c)(4)(B) sets forth the criteria to be used in assessing the administrative penalty, including:

> (i) the seriousness of the violation; (ii) the economic impact (if any) resulting from the violation; (iii) any history of such violations; (iv) any good-faith efforts to comply with the applicable requirements; (v) the economic impact of the penalty on the violator; and (vi) such other matters as justice may require.

If the violation is found to be willful, the Administrator may seek criminal penalties, including fines and imprisonment of up to three years.[684]

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[679] RCRA would not apply because carbon dioxide has not been deemed hazardous waste. Under the George W. Bush administration, EPA has taken the position that carbon dioxide is not an air pollutant subject to regulation under the Clean Air Act for any contributions its emissions may make to global climate change. Mass. v. E.P.A., 415 F.3d 50, 54 (D.C. Cir. 2005).
[680] 42 U.S.C. § 300h-2(a)(1).
[681] *Id.*
[682] 42 U.S.C. § 300h-2(b)(1).
[683] 42 U.S.C. § 300h-2(c)(1)-(2).
[684] 42 U.S.C. § 300h-2(b)(2).

The violation of a UIC permit may also be enforced through the Safe Drinking Water Act's citizen suit provision, which allows a citizen to bring a civil action "against any person … who is alleged to be in violation of the Act".[685] Prior to bringing action, the citizen is required to give sixty days notice to the EPA Administrator, the alleged violator, and the State in which the violation occurs.[686] The EPA administrator, Attorney General or the state may choose to prosecute the alleged violator, in which case the citizen suit would be precluded.[687] If the sixty days notice is provided and the EPA Administrator, Attorney General, or the State have not brought a civil action against the alleged violator, the citizen suit may proceed.[688] Although any civil penalties are payable to the United States Treasury, the citizen is entitled to costs of litigation, including reasonable attorney costs and expert witness fees.[689] Citizens may also seek injunctive relief through a temporary restraining order or preliminary injunction.[690]

The case of *U.S. v. Jolly* provides an example of how public enforcement of a UIC violation might proceed.[691] JAF Oil Company, owned by the defendant, Peter Jolly, operated eighty-nine Class II injection wells in Hancock County, Kentucky.[692] In 1985, the EPA notified JAF that its injection wells were not in compliance with UIC regulations.[693] Six years later, after failing to enter into an administrative order of consent with JAF, the EPA proposed a unilateral administrative order to remedy the UIC violations.[694] The proposed order was made subject to notice and comment, and JAF was notified of its right to a hearing within thirty days of the

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685 42 U.S.C. § 300j-8(a)(1)(B).
686 42 U.S.C. § 300j-8(b)(1)(A)(i)-(iii).
687 *Id.*
688 42 U.S.C. § 300j-8(b)(1)(B).
689 42 U.S.C. § 300j-8(d).
690 *Id.*
691 U.S. v. Jolly, 238 F.3d 425, 2000 WL 1785533 (6th Cir. 2000).
692 *Id.* at *1.
693 *Id.*
694 *Id.*

proposed order.[695] Although JAF did not request a hearing, it submitted written comments.[696] The EPA subsequently issued a final order, requiring JAF to comply with provisions that would bring the injection wells into compliance.[697] The order did not assess any civil penalties, but warned that failures to comply could lead to penalties if the EPA brought a future civil action.[698] After the final administrative order was issued, JAF was dissolved and Jolly continued operating the eight-nine injection wells under a new Nevada corporation named Strategic Investments.[699] The injection wells continued to violate UIC requirements and the EPA brought a civil action against JAF, Strategic Investments, and Jolly to enforce the final administrative order.[700]

In its complaint brought in the U.S. District Court for the Western District of Kentucky, the Government sought injunctive relief and civil penalties for the defendants' failure to meet the final administrative order's compliance deadlines and for violating UIC regulations.[701] The UIC violations included failure to maintain adequate financial assurance, failure to submit reports of required monitoring, failure to properly case and cement the wells, and failure to conduct mechanical integrity audits.[702] The district court granted summary judgment for the Government, issued a permanent injunction against all underground injection activities, and imposed a civil penalty of $500,000 against each of the three defendants.[703] On appeal, the Sixth Circuit considered whether Jolly was denied due process when the EPA issued the final

[695] *Id.*
[696] *Id.*
[697] *Id.*
[698] *Id.*
[699] *Id.* at *2.
[700] *Id.*
[701] *Id.*
[702] *Id.*
[703] *Id.*

administrative order, and whether the district court's injunction and civil penalties were an abuse of discretion.[704]

With respect to the due process issue, the court reviewed the procedures for the EPA's enforcement of a UIC violation.[705] The court noted that the EPA had the choice of either issuing an administrative order for compliance, or bringing a civil or criminal action.[706] Because the EPA had chosen to issue an administrative order, it was required to provide written notice to Jolly of the proposed order and the right to request a hearing.[707] Jolly had thirty days after receiving notice of the proposed order to bring an appeal.[708] Once the final administrative order was issued, the court found that the exclusive means of judicial review was by appeal within thirty days of issuance.[709] Because Jolly had failed to file an appeal within thirty days of the final order, the court found that Jolly was precluded from challenging the order's validity.[710] The court then addressed Jolly's argument that the civil penalties imposed were an abuse of discretion.[711] Specifically, Jolly argued that his family had suffered from a variety of health problems and that he was unable to pay the penalties.[712] The Government had actually requested penalties of $200 million, or $25,000 per day for each violation over a seven year period.[713] The district court reviewed the Section 1423(c)(4)(B) statutory factors for determining civil penalties, including Jolly's argument of inability to pay.[714] However, the court also noted Jolly's history of bad faith compliance over seven years, his disregard of corporate formalities, and the seriousness

[704] *Id.*
[705] *Id.* at *3.
[706] *Id.*
[707] *Id.*
[708] *Id.* at *4.
[709] *Id.*
[710] *Id.*
[711] *Id.* at *5.
[712] *Id.*
[713] *Id.*
[714] *Id.*

of his offenses.[715] As a result, the Sixth Circuit found that the $500,000 penalty was not an abuse of discretion.[716]

5.3.6. Conclusion

Liability for groundwater contamination is one of the most common sources of subsurface injection liability. Liability could take the form of private actions on the grounds of negligence or nuisance, or public actions for violations of a UIC permit. Private liability actions are contingent on a showing of causation. Liability is contingent upon showing not only that CO_2 leaked from the storage reservoir, but also that the operator's CO_2 caused the groundwater contamination in question. Groundwater contamination liability is typically proven on the basis of indirect evidence, namely models and monitoring data that goes to show that the defendant's activities contaminated the groundwater supply in question. Thus in the *Anthony* case, the plaintiff expert witness proposed several models by which the defendant contaminated the plaintiff groundwater supply. Judge Garza was forced to meticulously review the assumptions underlying the models to determine their adequacy, and in the end he found that the flaws in the model were so great that a finding of liability would not be reasonable. Garza's reasoning attempted to link the conclusions of the model to expected evidence. For example, one would need to provide evidence of the size of a hydraulic fracture if an argument was being made that the groundwater was contaminated by means of a hydraulic fracture that propagated from the defendant's property to the plaintiff's property. In the public context, liability simply depends on whether the UIC permit in question is violated. UIC regulations establish certain standards and operating requirements for subsurface injection. Any violation of the permit may automatically result in civil and/or criminal penalties. Thus, the prosecutor in a public liability case for

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715 *Id.* at *6.
716 *Id.*

groundwater contamination has a simpler case to prove than a case of groundwater contamination in the private context.

5.4. Harm to Human Health and the Environment

5.4.1. Introduction

This section examines the tortious liability related to harm to human health and the environment. It begins with an examination of how liability rules have been established, both in terms of the establishment and admission of evidence relating to human health and environmental risks, and the characterization of scientific evidence by regulators and the judiciary. The section next analyzes the effects of CO_2 exposures to human health, including a summary of the major scientific studies related to acute and chronic exposures. Finally, it reviews the effects of CO_2 exposures to the environment.

5.4.2. Liability for Harm to Human Health and the Environment

There are two major themes that underlie liability litigation for harm to human health and the environment. One set of issues relate to the establishment and admission of scientific evidence underlying human health and environmental risks. A second set of issues deal with the way that scientific evidence is characterized by the regulatory and judicial system and its effects on public suits for injunctive relief or private suits for damages. I examine each in turn, with an emphasis on liability for harm to human health, which tends to be more litigated than environmental harm.

5.4.2.1. Establishment and Admission of Evidence Relating to Human Health and Environmental Risks

Cases of human health and environmental liability litigation often turn on evidentiary considerations. For example, in cases involving harm to harming human health allegedly due to a CO_2 storage operation, the plaintiffs will present evidence that their health was adversely affected due to CO_2 leakage. What must the plaintiffs demonstrate in order to be entitled to relief, and how does the court determine whether the plaintiff's allegations are among the types of harms that the defendant operator is responsible for compensating?

The examination of the plaintiff's claims will concentrate on a host of factual questions, some of which will be scientific in nature. Often, the parties will need to assemble evidence to support their claims or refute their adversary's claims. This is typically done by bringing in scientific experts to analyze the facts at issue, possibly create a model or scenario which places the facts in context, and defend their analysis. These experts will proffer evidence relating to general causation (whether the symptoms exhibited of a kind that can logically be associated with exposure to CO_2) and specific causation (whether the harm occurred in this particular case). The issue of specific causation becomes a moot point if general causation cannot be shown. In addition, it will not be sufficient if the plaintiff merely establishes that the CO_2 might have caused the injuries they claim to suffer from. Instead, they will need to show by a preponderance of the evidence that the linkage is attributable to CO_2 rather than attributable to some other known causes.

In CO_2 storage liability cases, some evidence will be case specific, such as the proximity of the plaintiff to the CO_2 storage site, or the magnitude and length of CO_2 exposure. By contrast, the questions of general causation and specific causation are likely to depend on evidence that already exists and that other scientists have already collected. This research would typically conducted by federally funded researchers, independent scholarly research (i.e. non-federally funded), and studies by administrative agencies.

There are two universes of studies that are generally relied upon by regulators and the judiciary: laboratory studies in animals and epidemiological studies of human populations. Animal studies, which typically use genetically identical rodents, are used to determine the effect of dosing for the symptoms or diseases in question. Animal studies generally have two disadvantages compared to human studies: the results must be extrapolated to another species (humans) and the high doses customarily used in animal studies require consideration of the dose-response relationship and whether a threshold no-effect dose exists.[717] Human studies are the gold standard; there are practically no cases where a plaintiff has successfully recovered on the basis of animal studies, even if the animal studies are powerful on the issue of general causation. Human studies are generally designed as case-control studies or cohort studies. In case-control studies, the investigator identifies a group of people that suffer from a particular disease and compares them with a group of people as identical as possible, but that do not have the disease.[718] The investigator tries to determine the differences between the groups. In cohort studies, two groups of people who are identical in major parameters are compared and the investigator tries to determine whether differences in disease experience can be associated with differences in exposure patterns.[719] Most tortious litigation relies on cohort studies because the

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[717] Michael D. Green et al, *Reference Guide on Epidemiology*, *in* REFERENCE MANUAL ON SCIENTIFIC EVIDENCE at 346 (2d ed., Federal Judicial Center, 2000).
[718] *Id.* at 342-43.
[719] *Id.* at 340-42.

temporal relationship between exposure and disease can often be established more readily and it is useful for ruling out competing explanations.[720]

In federal courts, the admissibility of scientific evidence is based on the Federal Rules of Evidence and the *Daubert* line of cases. The admissibility of scientific evidence is directly related to the use of expert witnesses since it will be the expert witnesses who will be testifying to the scientific evidence. According to Rule 702 of the Federal Rules of Evidence:

> If scientific, technical, or other specialized knowledge will assist the trier of fact to understand the evidence or to determine a fact in issue, a witness qualified as an expert by knowledge, skill, experience, training, or education, may testify thereto in the form of an opinion or otherwise, if (1) the testimony is based upon sufficient facts or data, (2) the testimony is the product of reliable principles and methods, and (3) the witness has applied the principles and methods reliably to the facts of the case.

Historically, the courts had relied on the *Frye* "general acceptance" standard for scientific evidence. According to the *Frye* test, evidence was admissible if the theory was generally accepted by the field to which it belonged.[721] *Daubert v. Merrell Dow Pharmaceuticals* established that Rule 702 superseded the general acceptance standard.[722] The *Daubert* court offered four factors for courts to use, among others, in determining the validity of the testimony:[723]

- Has the theory been tested?
- Has the theory been subjected to peer review and publication?
- What is the rate of error and standards for controlling the technique's operation?

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[720] *Id.*
[721] Frye v. U.S., 293 F. 1013, 1014 (D.C. Cir. 1923) ("the thing from which the deduction is made must be sufficiently established to have gained general acceptance in the particular field in which it belongs".
[722] Daubert v. Merrell Dow Pharmaceuticals, Inc., 509 U.S. 579, 597 (1993) (" 'General acceptance' is not a necessary precondition to the admissibility of scientific evidence under the Federal Rules of Evidence, but the Rules of Evidence — especially Rule 702 — do assign to the trial judge the task of ensuring that an expert's testimony both rests on a reliable foundation and is relevant to the task at hand. Pertinent evidence based on scientifically valid principles will satisfy those demands.").
[723] *Id.* at 593-595.

- Is the theory generally accepted?

In effect, *Daubert* moved the federal courts from a general acceptance standard for scientific evidence, where the judiciary relied on the scientific community for determining admissibility, to the new *Daubert* standard, where the judge is expected to independently assess the scientific method used in the case at hand. Thus the judge has become an "evidentiary gatekeeper" for scientific evidence.[724]

5.4.2.2. Characterization of Scientific Evidence by Regulators and the Judiciary

Liability turns not only on the admissibility of evidence, but also on how evidence is characterized. Scientific evidence is used by administrative agencies for determining acceptable levels of regulation and by the judiciary in deciding private recovery of damages.

In regulatory decision making, there is a great deal of experience related to using scientific evidence in the context of chemical exposures. The general approach is for agencies to examine animal studies, epidemiological studies, or environmental studies, and to determine whether exposures to the chemical in question caused harm.[725] In some cases, the discretion of the agency is limited by statute. For example, in the well publicized Benzene case, the Supreme Court held that before the U.S. Occupational Safety and Health Administration ("OSHA") can promulgate health or safety standards, the Occupational Safety and Health Act requires that OSHA make a finding that there are significant risks present and the risks can be eliminated by a change in practices.[726] With respect to human health risks, an agency will typically determine a level of exposure where there are no adverse effects in animals (the "no observable effects level"

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[724] Stephen Breyer, *Introduction*, *in* REFERENCE MANUAL ON SCIENTIFIC EVIDENCE *supra* note 717, at 5. *See also* Stephen Breyer, *The Interdependence of Science and Law*, 280 SCI. 537 (1998).
[725] Green et al, *supra* note 717.
[726] Industrial Union Dep't, AFL-CIO v. Amer. Petroleum Inst., 448 U.S. 607 (1980).

or "NOEL") and then extrapolate an exposure level that is safe for humans.[727] In determining the exposure level, the agency will generally reduce the NOEL by several orders of magnitude, for example including a safety factor of 10 to account for heterogeneity, a safety factor of 10 to account for the potential increased vulnerability of humans compared to animals, and a safety factor of 10 to account for at-risk populations (the so-called $10\times10\times10$).[728]

In liability litigation cases before the judiciary, cases turn on proving general and specific causation. As applied to CO_2 storage, liability litigation would center on whether the defendant was responsible for injecting the CO_2 into the storage formation and whether it was the defendant's CO_2 to which the plaintiff was exposed. General causation would turn on whether CO_2 was capable of causing the injury which the plaintiff alleged to suffer from. This would be proven through the use of epidemiological studies and distinguishing the causal relationship from mere associations.[729] Under specific causation, the plaintiff would need to show that on the basis of a preponderance of the evidence (i.e. more likely than not), the plaintiff's injuries were caused by exposure to the defendant's CO_2. If successful, in addition to recovery for damages from current injuries, the plaintiff could potentially also recover for possible future harm. Examples of recoveries for future harm include recovery for increased risk of disease, recovery for emotional distress stemming from the exposure, and recovery for future medical monitoring.[730]

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[727] Bernard D. Goldstein & Mary Sue Henifin, *Reference Guide on Toxicology*, *in* REFERENCE MANUAL ON SCIENTIFIC EVIDENCE *supra* note 717, at 407.
[728] *See, e.g.*, Richard A. Merrill, *Food Safety Regulation: Reforming the Delaney Clause*, 18 ANN. REV. PUBLIC HEALTH 313, 333 (1997)
[729] *See, e.g.*, Sir Austin Bradford Hill, *The Environment and Disease: Association or Causation?* 58 PROC. ROYAL SOCIETY OF MED. 295 (1965).
[730] *See, e.g.*, In re Paoli Railroad Yard PCB Litigation, 916 F.2d 829 (3d Cir. 1990); Frank Potter et al v. Firestone, 863 P.2d 795 (Cal. 1993).

5.4.3. Effects of CO_2 Exposures to Human Health

The exposure of humans to elevated concentrations of CO_2 can have adverse consequences to health, and under certain circumstances can be fatal. CO_2 is an asphyxiant, respiratory stimulant, and central nervous system stimulant and depressant.[731] Its effects on human health depend on the concentration and duration of exposure.[732] Knowledge of the effects of CO_2 on human health comes from animal studies, reports of CO_2 workplace exposures, and epidemiological studies of populations situated near natural CO_2 releases.

The National Institute for Occupational Safety and Health ("NIOSH"), the agency responsible for conducting research on work-related injuries and illnesses,[733] has documented a number of studies on the acute and chronic effects of CO_2 exposures.[734] This data was used by NIOSH in setting workplace exposure guidelines for CO_2, currently 0.5% (5,000 parts per million) as an 8-hour time-weighted average (TWA) concentration.[735] NIOSH estimates that approximately two million workers are exposed to CO_2 in the United States.[736] A summary of the NIOSH findings for acute exposures is shown in Table 5.2 and for chronic exposures in Table 5.3. A study by Benson et al also examines the risks of CO_2 exposure to human health.[737]

Benson et al find that humans can tolerate acute exposures of CO_2 of up to 1% concentration without any physiological effects and up to 3% without long-term physiological

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[731] NAT'L INST. FOR OCCUPATIONAL SAFETY & HEALTH, OCCUPATIONAL HEALTH GUIDELINE FOR CARBON DIOXIDE 1 (HEW Publication No. (NIOSH) 76-194, Aug. 1976).
[732] IPCC Special Report, *supra* note 11, at 391.
[733] Nat'l Inst. for Occupational Safety & Health, NIOSH Origins and Mission, *at* http://www.cdc.gov/niosh/about.html#org (last visited Nov. 25, 2006).
[734] *See* NAT'L INST. FOR OCCUPATIONAL SAFETY & HEALTH, *supra* note 731.
[735] Occupational Safety & Health Admin., Carbon Dioxide (Revised Sept. 20, 2001), *at* http://www.osha.gov/dts/chemicalsampling/data/CH_225400.html. As a basis of comparison, the atmospheric concentration of CO_2 in the year 2000 was 0.0368% (368 parts per million). *See supra* note 2.
[736] NAT'L INST. FOR OCCUPATIONAL SAFETY & HEALTH, *supra* note 731, at 19.
[737] SALLY BENSON ET AL, LESSONS LEARNED FROM NATURAL AND INDUSTRIAL ANALOGUES FOR STORAGE OF CARBON DIOXIDE IN DEEP GEOLOGICAL FORMATIONS (Lawrence Berkeley Nat'l Lab. Report LBNL-51170, 2002).

effects.[738] Prolonged acute exposures of CO_2 above 5% concentration can lead to mental impairment, above 10% can lead to unconsciousness, and above 30% can lead to death.[739] With respect to chronic exposures, NIOSH has documented neurological and respiratory effects for continuous exposures to concentrations of 1.5-3% over several days, including headaches and decreased respiratory response.[740] The IPCC notes that chronic exposures to concentrations of less than 1% may lead to changes in respiration and blood pH, which can lead to increased heart rate, discomfort, nausea, and unconsciousness.[741] Thus there are three ways that CO_2 exposure could potentially affect human health: low concentration exposures for prolonged periods of time, intermediate exposures in environments lacking oxygen ("anoxic"), or high concentration exposures for short periods of time.[742]

Although the release of CO_2 at Lake Nyos is sometimes offered as an example of the consequences of a catastrophic CO_2 release, the circumstances surrounding the Lake Nyos incident are very different than what would occur at a CO_2 storage site. Lake Nyos is located along the Cameroon Volcanic Line and is believed to have been formed by a volcanic eruption hundreds of years ago.[743] The lake became supersaturated with CO_2 which seeped in from magma deposits beneath the lake bed.[744] In 1986, a catastrophic outgassing of CO_2 was triggered at the lake and the CO_2 migrated into two nearby valleys killing over 1,700 people.[745] The CO_2 accumulations have since been stabilized through a degassing program.[746] While the

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738 *Id.* at 23.
739 *Id.*
740 NAT'L INST. FOR OCCUPATIONAL SAFETY & HEALTH, *supra* note 731, at 27, 29.
741 IPCC Special Report, *supra* note 11, at 391.
742 *Id.*
743 George W. Kling et al, *The 1986 Lake Nyos Gas Disaster in Cameroon, West Africa*, 236 SCI. 169, 169 (1987).
744 Tom Clarke, *Taming Africa's Killer Lake*, 409 NATURE 554, 554 (2001).
745 *Id.*
746 *See, e.g.*, George W. Kling et al, *Degassing of Lake Nyos*, 368 NATURE 405, 405 (1994).

Lake Nyos incident offers a vivid image of the catastrophic effects of CO_2,[747] there is little scientific basis to expect that the natural outgassing of a volcanic lake will pose similar risks to CO_2 leakage from a geological formation.[748] The Lake Nyos outgassing occurred because slow continuous accumulation of CO_2 over time exceeded the lake's holding capacity, like a balloon popping when it is filled with too much air.[749] In contrast, CO_2 that is stored in a geological formation would tend to diffuse rather than concentrate.[750]

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[747] Curt Stager, *Silent Death from Cameroon's Killer Lake*, 172 NAT'L GEOGRAPHIC 404 (1987).
[748] D.M. Reiner & H.J. Herzog, *Developing a Set of Regulatory Analogs for Carbon Sequestration,* 29 ENERGY 1561, 1565 (2004).
[749] JASON J. HEINRICH ET AL, ENVIRONMENTAL ASSESSMENT OF GEOLOGIC STORAGE OF CO_2 8 (Mass. Inst. of Tech. Lab. for Energy. & the Env't Publication No. MIT LFEE-2003-002, 2003).
[750] *Id.*

Table 5.2 Effects of Acute CO_2 Exposures to Humans (adapted from NIOSH)[751]

CONCENTRATION / DURATION	# OF SUBJECTS	EFFECTS	REFERENCE
30%/38 sec	17	Narcosis, ECG abnormalities in 16 of 27 episodes experienced by 25- to 48-year-old subjects	Macdonald [752]
30%/50-52 sec	37	Unconsciousness in 24-28 sec; abnormal EEG's; cardiac irritability	Friedlander [753]
30%, 20%/1 min	8	Unconsciousness and convulsions within 1 minute	Lambertsen [754]
27.9%/16-35 sec 27%/20-52 sec	3	Throat irritation, increased respiration; dimness of vision; dizziness; unconsciousness	CAT [755]
7-14%/10-20 min	12	Increased plasma catecholamines and steroids; increased sympathoderenal activity; loss of consciousness above 10%; headache, sweating, etc. above 7%	Sechzer [756]
15%, 10%/1.5 min	8	Neurologic signs: eye flickering, myoclonic twitches, dilated pupils, restlessness	Lambertsen [757]
10.4%/3.8 min 7.6%/7.4 min	44	Increased systolic and diastolic blood pressure; increased pulse rate; increased respiratory minute volume; headache; dizziness; faintness	Dripps [758]
7.5%, 5.4%, 3.3%, 1.5%/15 min at each	42	Decreased total eosinphils; increased blood sugar; muscle potential and O_2 consumption indicative of ANS response; decreased flicker fusion frequency; increased alpha blocking latency; 7.5% threshold for symptoms; depression of CNS activity	Schaefer [759]
7.5%, 5.4%, 3.3%, 1.5%/15 min at each	60	Increased alveolar pCO_2, decreased response to 5% CO_2 challenge in low-ventilatory-response subjects; lesser effects in high-ventilatory-response subjects	Schaefer [760]
7%, 5%/15-30 min	12	Increased cerebral blood flow (75%); increased CO_2 and H^+ in arterial blood	Kety [761]
6%/6-8 min	148	More decided ECG alterations in older group (mean age 60.9 yr) than in young group (mean age 23.3 yr)	Okajima [762]
5%/30 min	19	Decreased vascular resistance, all subjects; increased renal blood flow, 6 normal subjects; constriction of renal vasculature, 13 renal disease subjects	Yonezawa [763]
2.5-6%/75 min	6	Total suppression of shivering response in 3 of 6 healthy young (mean age 24) subjects in a cold (5 C) room, breakthrough shivering after 30 min	Bullard [764]

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751 NAT'L INST. FOR OCCUPATIONAL SAFETY & HEALTH, *supra* note 731, at 99.
752 F.M. MacDonald & E. Simonson, *Human Electrocardiogram During and After Inhalation of Thirty Percent Carbon Dioxide*, 6 J. APPL. PHYSIOL. 304 (1953).
753 W.J. Friedlander & T. Hill, *EEG Changes During Administration of Carbon Dioxide*, 15 DIS. NERV. SYST. 71 (1954).
754 C.J. Lambertsen, *Therapeutic Gasses: Oxygen, Carbon Dioxide, and Helium*, *in* DRILL'S PHARMACOLOGY IN MEDICINE (J.R. Di Palma ed.) (4th ed., Mc-Graw Hill, New York, 1970).
755 COMMITTEE ON AVIATION TOXICOLOGY, AERO MEDICAL ASS'N, AVIATION TOXICOLOGY: AN INTRODUCTION TO THE SUBJECT AND A HANDBOOK OF DATA (1953).
756 P.H. Sechzer et al, *Effect of CO_2 Inhalation on Arterial Pressure, ECG and Plasma Catecholamines and 17-OH Corticosteroids in Normal Man*, 13 J. APPL. PHYSIOL. 454 (1960).
757 Lambertsen, *supra* note 754.
758 R.D. Dripps & J.H. Comroe Jr., *The Respiratory and Circulatory Response of Normal Man to Inhalation of 7.6 and 10.4 percent CO_2 with a Comparison of the Maximal Ventilation Produced by Severe Muscular Exercise, Inhalation of CO_2 and Maximal Voluntary Hyperventilation*, 149 AM. J. PHYSIOL. 43 (1947).
759 K.E. SCHAEFER, THE EFFECTS OF CO_2 AND ELECTROLYTE SHIFTS ON THE CENTRAL NERVOUS SYSTEM, IN SELECTIVE VULNERABILITY OF THE BRAIN IN HYPOXEMIA (J.P. Schade & W.H. McMehemy, eds.) (1963).
760 K.E. SCHAEFER, EFFECTS OF CARBON DIOXIDE AS RELATED TO SUBMARINE AND DIVING PHYSIOLOGY (Naval Medical Research Lab. Memorandum Report 58-11, 1958).
761 S.S. Kety & C.F. Schmidt, *The Effects of Altered Arterial Tensions of Carbon Dioxide and Oxygen on Cerebral Blood Flow and Cerebral Oxygen Consumption of Normal Young Men*, 27 J. CLIN INVEST. 484 (1948).
762 M. Okajima & E. Simonson, *Effect of Breathing Six Percent Carbon Dioxide on ECG Changes in Young and Older Healthy Men*, 17 J. GERONTOL. 286 (1962)
763 A. Yonezawa, *Influence of Carbon Dioxide Inhalation on Renal Circulation and Electrolyte Metabolism* [translated], 32 JPN. CIR. J. 1119 (1968)
764 R.W. Bullard & J.R. Crise, *Effects of Carbon Dioxide on Cold-Exposed Human Subjects*, 16 J. APPL. PHYSIOL. 633 (1961).

Table 5.3 Effects of Chronic CO_2 Exposures to Humans (adapted from NIOSH)[765]

CONCENTRATION / DURATION	# OF SUBJECTS	EFFECTS	REFERENCE
4%/2 wk	6	No psychomotor impairment; no decrement in complex-task performance by healthy young subjects	Storm[766]
3.9%/5 days, 11 days 2.7%/30 days	12	Increased arterial and CSF bicarbonate; Decreased CSF pH; some cardiac abnormalities; headaches	Sinclair[767]
3%/8 days	Unknown	Tolerance after 3 days; Increased respiratory threshold; increased CO_2 and HCO_3 in blood	Schaefer[768]
3%/78 hours	2	On acclimation, decreased response to CO_2 challenges	Chapin[769]
3%/5 days	7	No changes in ammonia or titratable acidity; no changes in serum electrolytes, blood sugar, BUN, serum creatinine, or liver function; no significant changes in exercise or psycho-motor studies	Glatte[770]
1.5%/42 days	23	Original "Operation Hideout" report: Increased alveolar CO_2; increased ventilatory rate; increased O_2 consumption; initially increased, then decreased respiratory CO_2 excretion	Faucett[771]
1.5%/42 days	23	Inorganic phosphorus changes parallel to pH changes in other "Operation Hideout" reports, plasma calcium-pH dependent	Schaefer[772]
1.5%/42 days	23	Uncompensated phase (days 1-23); decreased plasma pH, decreased inorganic phosphorus, decreased urine pH, decreased bicarbonate excretion, decreased pulmonary CO_2 excretion; compensated phase (days 24-42); increased plasma calcium, increased pH, increased bicarbonate excretion, increased urinary pH	Schaefer[773] Schaefer[774] Schaefer[775]
1.5%/42 days	23	Increased minute volume; increased respiratory rate; increased anatomical dead space; increased tidal volume; decreased CO_2 excretion, uncompensated phase; increased O_2 consumption, compensated phase	Schaefer[776]
1.5%/42 days	23	Increased alveolar CO_2; increased ventilation; initially increased O_2 consumption; initially increased, then decreased CO_2 excretion; decreased sensitivity to 5% CO_2 challenge	Friedlander[777]
0.8-1.2%/21-57 days	31	Compensated and uncompensated acidoses in long patrols; compensation by day 51; bone storage of CO_2 1st 4 week, then excretion from bone with calcium	Messier[778]
1%, 2%/30 days	4	Decreased blood pH; Increased pCO_2 of blood and alveolar air; decreased ability to perform strenuous exercise after prolonged CO_2 exposure	Zharov[779]

765 NAT'L INST. FOR OCCUPATIONAL SAFETY & HEALTH, *supra* note 731, at 102.
766 W.F. Storm & C.L. Giannetta, *Effects of Hypercapnia and Bedrest on Psychomotor Performance*, 45 AEROSP Med 431 (1974).
767 R.D. Sinclair et al, *Carbon Dioxide tolerance Levels for Space Cabins*, *in* PROC. 5TH ANNUAL CONFERENCE ON ATMOSPHERIC CONTAMINATION IN CONFINED SPACES (1969).
768 K.E. Schaefer, *Respiratory and Acid-Base Balance During Prolonged Exposure to a 3% CO_2 Atmosphere*, 251 PFLUEGERS ARCH GESAMTE PHYSIOL. MENSCHEN TIERE 689 (1949).
769 J.L. CHAPIN ET AL, CHANGES IN THE SENSITIVITY OF THE RESPIRATORY CENTER IN MAN AFTER PROLONGED EXPOSURE TO 3% CO_2 (Wright Patterson Air Force Base Technical Report No. 55-357, 1955).
770 H.A. GLATTE ET AL, CARBON DIOXIDE TOLERANCE STUDIES (Brooks Air Force Base Report No. SAM-TR-67-77, 1967).
771 R.E. FAUCETT & P.P. NEWMAN, OPERATION HIDEOUT—PRELIMINARY REPORT (Naval Medical Research Lab. Report No. 228, 1953).
772 K.E. Schaefer et al, *Calcium Phosphorus Metabolism in Man during Acclimation to Carbon Dioxide*, 18 J. APPL. PHYSIOL. 1079 (1963).
773 K.E. Schaefer et al, *Blood pH and pCO_2 Homeostasis in Chronic Respiratory Acidosis Related to the Use of Amine and Other Buffers*, 92 ANN. N.Y. ACAD. SCI. 401 (1961).
774 K.E. Schaefer, *Acclimation to Low Concentration of Carbon Dioxide*, 32 IND. MED. SURG. 11 (1963).
775 K.E. Schaefer et al, *Acid-Base Balance and Blood and Urine Electrolytes of Man During Acclimation to CO_2*, 19 J. APPL. PHYSIOL. 48 (1964).
776 K.E. Schaefer et al, *Respiratory Acclimation to Carbon Dioxide*, 18 J. APPL. PHYSIOL. 1071 (1963).
777 W.J. Friedlander & T. Hill, *EEG Changes During Administration of Carbon Dioxide*, 15 DIS. NERV. SYST. 71 (1954).
778 A.A. Messier et al, *Calcium, Magnesium, and Phosphorus Metabolism, and Parathyroid-Calcitonin Function During Prolonged Exposure to Elevated CO_2 Concentrations on Submarines*, 6 UNDERSEA BIOMED RES. S57 (1979).

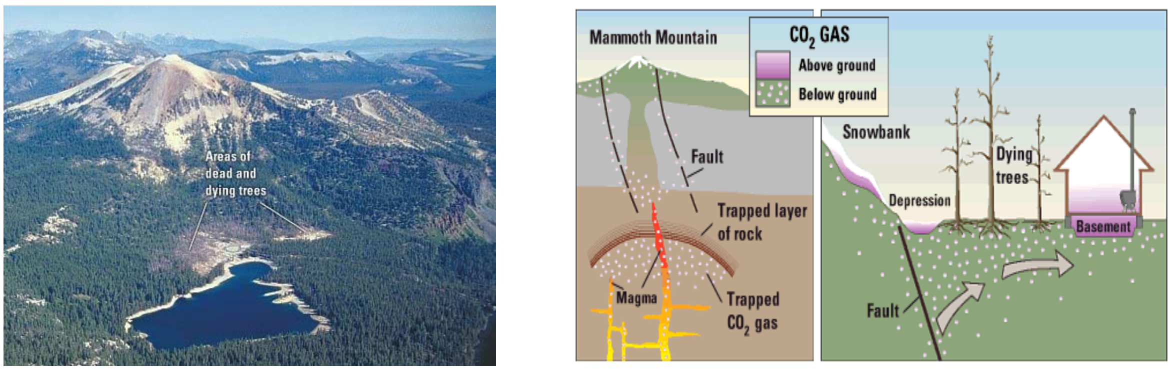
CONCENTRATION / DURATION	# OF SUBJECTS	EFFECTS	REFERENCE
0.9-1.9%/30 days	7	Increased alveolar CO_2; increased pulmonary ventilation	Kuznetsov[780]
0.9%, 0.8%/20 days	10	Increased physiologic dead space of 61 and 60%, respectively, during 29 routine patrols	Gude[781]
10%, 7.5%, 5.0%, 2.5%	17	Subjects 9 normal, 8 asthmatic: evidence of increased airway constriction	Tashkin[782]
Unknown	420	All patients with chronic pulmonary insufficiency: plasma bicarbonate rise curvilinear to pCO_2; blood pH rise linear to pCO_2	Van Ypersele de Strihou[783]
Unknown	22	Subjects 12 normal, 10 emphysematous: chronic pulmonary insufficiency similar to chronic hypercapnia; lowered respiratory sensitivity	Brodovsky[784]

5.4.4. Effects of CO_2 Exposures to the Environment

The potential for CO_2 to be released from the storage reservoir also raises concerns for degradation of the environment. CO_2 can be beneficial to plant life in moderate amounts, e.g. 0.05-0.08% concentration over an atmospheric background of 0.037% concentration.[785] However, CO_2 exposure can be harmful to the environment at high concentrations. The effect of high concentration CO_2 exposures on flora and flauna has not been extensively studied,[786] but an often cited example is the case of Mammoth Mountain, a young volcano located in eastern California. In 1990, a year after a number of small earthquakes occurred beneath the volcano, U.S. Forest Service rangers noticed 100 acres of dead and dying trees on the mountain.[787] See Figure 5.4(a). The U.S. Geological Survey ("USGS") concluded that the roots of the trees were being killed by high concentrations of CO_2 in the soil.[788] The most likely cause was that CO_2

[779] S.G. Zharov et al, *Effect on Man of Prolonged Exposure to Atmosphere with a High CO_2 Content*, *in* PROC. INT'L CONGRESS ON AVIATION AND SPACE MEDICINE (1963).
[780] A.G. Kuznetsov & I.R. Kalinchenko, *Prolonged Stay of Humans in a Gaseous Medium Containing a High CO_2 Concentration*, 52 FIZIOL ZH SSSR IM I.M. SECHENOVA 1460 (1966).
[781] J.K. GUDE & K.E. SCHAEFER, THE EFFECT ON RESPIRATORY DEAD SPACE OF PROLONGED EXPOSURE TO A SUBMARINE ENVIRONMENT (Naval Submarine Medical Center Report No. 587, 1969).
[782] D.P. Tashkin & D.H. Simmons, *Effect of Carbon Dioxide Breathing on Specific Airway Conductance in Normal and Asthmatic Subjects*, 106 AM. REV. RESPIR. DIS. 729 (1972).
[783] C. Van Ypersele de Strihou et al, *The Carbon Dioxide Response Curve for Chronic Hypercapnia in Man*, 275 NEW ENGLAND J. MED. 117 (1966).
[784] D. Brodovsky et al, *The Respiratory Response to Carbon Dioxide in Health and in Emphysema*, 39 J. CLIN. INVEST. 724 (1960).
[785] BENSON ET AL, *supra* note 737, at 29.
[786] *Id.*
[787] U.S. GEOLOGICAL SURVEY, INVISIBLE CO_2 GAS KILLING TREES AT MAMMOTH MOUNTAIN, CALIFORNIA (U.S. Geological Survey Fact Sheet 172-96, June 2001), *available at* http://pubs.usgs.gov/fs/fs172-96/.
[788] *Id.*

from the magma beneath the mountain migrated upwards through a fault and seeped into the soil.[789] See Figure 5.4(b). The CO_2 in the soil denied tree roots of oxygen and interfered with their nutrient uptake, which eventually led to the tree kills.[790]



(a) (b)

Figure 5.4 CO_2 Emissions at Mammoth Mountain (USGS)[791]
(a) Areas of dead and dying trees at Mammoth Mountain
(b) Mechanism for CO_2 release at Mammoth Mountain

Animals have a much lower tolerance for CO_2 than plants.[792] Benson et al have summarized the risks of CO_2 exposure to simple and complex organisms.[793] They find that the ability to withstand elevated concentrations of CO_2 depends on physiology. For example, air breathing animals have the least tolerance to CO_2 exposure; prolonged exposure to concentrations of 20-30% can be lethal.[794] Insects and soil-dwelling organisms can withstand higher CO_2 concentrations than air-breathing animals.[795] Single-celled organisms can generally withstand concentrations of up to 50% CO_2 and some microbes can survive in virtually 100% CO_2 as long as trace amounts of oxygen are available.[796] The findings of Benson et al are

[789] *Id.*
[790] *Id.*
[791] *Id.*
[792] BENSON ET AL, *supra* note 737, at 29.
[793] *Id.*
[794] *Id.*
[795] *Id.*
[796] *Id.* at 24.

consistent with those of NIOSH, which documented over twenty-five studies on the effects of acute and chronic CO_2 exposures to on animals.[797]

5.4.5. Conclusion

Liability for harm to human health and the environment is premised on showing both general causation and specific causation. In the CO_2 storage context, proving general causation requires showing that the injuries complained of could logically be associated with CO_2 exposure. This would be shown through scientific studies related to CO_2 exposure generally. There are numerous studies that have examined acute and chronic exposures of CO_2 to human health, and which could be used to show general causation. The data comes primarily from animal studies, workplace exposure reports, and epidemiological studies. There are also a number of documented scientific studies related to CO_2 exposures and harm to the environment. Specific causation would require proving that the defendant's CO_2 caused the injuries complained of in the case in question. This requires case-specific evidence. Both general and specific causation require scientific evidence be admitted to the court. Some courts follow the *Frye* standard that the methodology must be generally accepted. Other courts, including the federal judiciary, apply the *Daubert* factors, where the judge independently asses the scientific evidence for the case at hand. Even if the scientific evidence is admitted, proof would need to be established on a preponderance of the evidence and causal relationships would need to be distinguished from mere associations. Thus there are three hurdles to proving liability for harm to human health and the environment: establishment of evidence showing causation, admission of evidence, and characterization of evidence by the relevant fact finder.

5.5. Liability and Property Interests

[797] *See* NAT'L INST. FOR OCCUPATIONAL SAFETY & HEALTH, *supra* note 731, at 72-90, 100-01, 104.

5.5.1. Introduction

There are three sources of liability deriving from the property interests of the geological formation and injected CO_2: geophysical surface trespass, geophysical subsurface trespass, and liability from confusion of goods. Geophysical surface trespass and geophysical subsurface trespass are tortious liabilities deriving from trespass.[798] Liability from confusion of goods derives from the mixture of things of the same nature but belonging to different owners so that the identification of the things is no longer possible.[799]

5.5.2. Geophysical Surface Trespass

Geophysical surface trespass takes place when a trespassing party uses the surface to conduct seismic and other surface or near-surface geophysical operations.[800] In general, this is for the purpose of identifying geological formations that may be favorable for retaining oil or gas.[801] A logical extension to geological CO_2 storage would be trespass associated with geophysical operations to determine the suitability of a geological storage reservoir. Traditionally, when a mineral interest is severed from the surface interest, the mineral interest includes those surface rights necessary to find and develop the minerals.[802] Thus seismic geophysical operations conducted on the surface by the mineral interest owner would not constitute a geophysical surface trespass.[803]

Geophysical surface trespass can be divided into three types: surface geophysical exploration where a trespass is involved, surface geophysical exploration with no physical entry, and surface geophysical exploration that causes physical damage. Surface geophysical

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[798] A trespass is an unlawful act committed against the property of another, generally in the context of wrongful entry on another's real property. BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "trespass").
[799] *Id.*
[800] OWEN L. ANDERSON ET AL., HEMINGWAY OIL AND GAS LAW AND TAXATION § 4.1(B) (4th ed. 2004).
[801] *Id.*
[802] *Id. See also* Hunt Oil Co. v. Kerbaugh, 283 N.W.2d 131, 135 (N.D. 1979).
[803] ANDERSON ET AL, *supra* note 800, § 4.1(C).

exploration where a trespass is involved occurs where geophysical tests have been run on lands without proper authorization, causing the geophysical explorer to become a trespasser.[804] The trespasser may be able to recover actual damage done to the land, lost value of exploration rights, and possibly lost value of the right to execute leases (if the geophysical exploration deems the subsurface unsuitable for storage operations, or valueless for oil and gas production).[805] For the case of surface geophysical exploration with no physical entry, the landowner has generally been denied recovery, but recovery could theoretically derive from the fact that valuable subsurface information has been obtained, allowing for recovery under theories of invasion of privacy, theft of trade secrets, unjust enrichment, or interference with prospective advantage.[806]

Where surface geophysical operations cause physical damage (such as blasting during a seismic survey causing cracks in a neighboring house or the drying up of wells), one could recover for actual damages as long as a causal connection has been proven between the geophysical operations and resulting damage, and it has been demonstrated that the operator did not comply with the standard of conduct required in such operations.[807] The geophysical operator (e.g., the operator of the seismic equipment) would then be found liable on the grounds of strict liability, where liability is imposed for inherently dangerous activities.[808]

5.5.3. Geophysical Subsurface Trespass

Geological CO_2 storage faces two potential types of geophysical subsurface trespass: subsurface trespass that results in production or drainage of stored CO_2 from the storage

[804] *Id.* at § 4.1(B).
[805] *Id.*
[806] *Id.* at § 4.1(C).
[807] *Id.* at § 4.1(D).
[808] *Id.*

reservoir, and trespass caused by underground intrusion of injected CO_2. Some exemplary cases of geophysical subsurface trespass in the context of oil recovery are noted in Section 7.4.4.2.

Liability for subsurface trespass that results in production or drainage will depend on whether the trespasser acted in good faith.[809] In the case of oil and gas production, the good faith trespasser has generally been allowed to offset against the value of the extracted oil and gas the reasonable costs of drilling, completing, and operating wells producing the oil and gas.[810] However, the bad faith trespasser will be liable for the full value of the products converted, without deduction of costs of any kind.[811] In addition, if gas is wrongfully withdrawn and commingled with other gas owned by the bad faith trespasser, the bad faith trespasser will be liable for the value of all the gas produced and sold from both wells.[812] The test for good faith is whether there is some reasonable doubt of the other party's exclusive or dominant right, with the action of the trespasser classified as having an innocent unintentional, or honest belief.[813]

A second type of geophysical subsurface trespass occurs with the underground intrusion of injected CO_2. This liability derives from CO_2 injected into a storage reservoir and migrating into lands where the property interests have not been acquired. The oil industry has confronted this liability in the course of secondary and tertiary recovery operations, where fluids are injected into a reservoir to increase the amount of recoverable oil and the possibility exists for fluids to migrate through the subsurface and trespass upon a neighboring property.[814] The issue of trespass caused by underground intrusion for secondary recovery operations has been addressed by *Railroad Commission of Texas v. Manziel*, which held that injection associated with a state-

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[809] *Id.* at § 4.1(B)(1)
[810] *Id.*
[811] *Id.*
[812] *Id.*
[813] *Id.* at § 4.1(B)(2). *See also* Swiss Oil Corp. v. Hupp, 69 S.W.2d 1037 (Ky.App. 1934).
[814] *See* ANDERSON ET AL, *supra* note 800, § 4.2(C).

authorized secondary recovery project would not cause a trespass, even where fluids moved across property lines; technical rules of trespass have no bearing on the issue.[815] According to the resulting rule of non-liability, which has come to be known as the negative rule of capture, less valuable substances can migrate through the subsurface and replace more valuable substances without incurred liability.[816] Where an oil field has been unitized, meaning the combination of multiple tracts to form a large unit for the purpose of conducting a field-wide oil recovery operation,[817] there would not be liability for underground intrusion. As a result, secondary and tertiary recovery operations are traditionally conducted on a unitized field, which is accomplished through a voluntary agreement among the property interest owners or through a compulsory process before the oil and gas conservation agency.[818]

5.5.4. Confusion of Goods

Liability for confusion of goods occurs when different persons' goods are intermixed such that the property of each cannot be distinguished.[819] For example, this would be the case of injected CO_2 intermixing with native gas in a reservoir where the full property interests have not been obtained. Where the substances are deemed willfully, fraudulently, or wrongfully inseparably intermingled, the person forfeits his right in the goods to the innocent party. Forfeiture does not occur where the confusion is not done willfully, with a fraudulent or other improper purpose. Confusion of goods assumes that the intermixed goods are unidentifiable; where the goods mingled are readily identifiable, no forfeiture applies. For geological CO_2 storage, the extent of liability for confusion of goods would need to be determined on a case-by-

[815] Railroad Comm'n of Tex. v Manziel, 361 S.W.2d 560, 568 (Tex. 1962).
[816] PATRICK H. MARTIN & BRUCE M. KRAMER, 1-2 WILLIAMS & MEYERS, OIL AND GAS LAW § 204.5 (2004).
[817] ANDERSON ET AL, *supra* note 800, § 7.13.
[818] *Id.*
[819] 15A C.J.S. *Confusion of Goods* § 1

case basis; intermixing of CO_2 and the ability to identify it is a function of CO_2's miscibility with the native substance.

5.5.5. Potential for Legislation of Property Interests and Liability

Federal or state eminent domain legislation specific to geological CO_2 storage would be necessary to obtain property rights to the geological formation by involuntary means.[820] In addition, although property interests and liability for mineral rights have traditionally been addressed by common law, there exists the potential for legislation to define the circumstances of ownership and trespass. Eminent domain legislation and property rights clarification could be done on either the state or the federal level. Federal legislation would be limited to those circumstances where the CO_2 storage is deemed to be within interstate commerce or having a substantial effect on interstate commerce.[821]

State legislation could also be used to clarify property interests and liability. This has been proposed in a report by the Interstate Oil and Gas Compact Commission (IOGCC) CO_2 Geological Sequestration Task Force.[822] According to the report, ownership of storage rights (reservoir pore space) and payment for use of those storage rights is a noteworthy post-injection storage consideration that needs to be addressed by state legislation.[823] The IOGCC Task Force developed a conceptual framework for a CO_2 geological storage statute designed for U.S. states, with the centerpiece of the framework being eminent domain and the recognition of certain property rights over the geological formation and injected CO_2. According to the framework, the Model Oil and Gas Conservation Act already deals with geological storage of CO_2 through its provisions on the regulation of underground gas storage, the conceptual framework is necessary

[820] Strain v. Cities Service Gas Co., 83 P.2d 124, 126 (Kan. 1938).
[821] U.S. v. Lopez, 514 U.S. 549, 559 (1995).
[822] INTERSTATE OIL & GAS COMPACT COMM'N, *supra* note 403.
[823] *Id.* at 55.

to identify initial ownership of CO_2 storage rights with regard to the surface and mineral interest owners.[824]

Part I of the framework allows carbon capture and geological storage operators to exercise state eminent domain power over any subsurface stratum or formation found to be suitable and in the public interest for geological storage of CO_2.[825] The property interest provided is essentially an easement to the subsurface; for example, the mineral interest owner is still authorized to drill through the geological storage facility for hydrocarbon production purposes.[826] In the declaration of purpose to the conceptual framework, geological storage of CO_2 is deemed to be in the public interest because of the environmental and economic importance of CO_2, conservation of property for geological storage, the prevention of waste, and the protection of health, safety and the environment.[827] In addition, the framework states that by providing a mitigation strategy aimed at reducing CO_2 emissions into the atmosphere, which has been shown to be a contributing factor to global warming, geological storage of CO_2 is in the public interest.

As a prerequisite to exercising eminent domain power, the storage operator must obtain a certificate setting out that the storage facility is in the public interest, designate the amount of proven minerals located in the reservoir, demonstrate that CO_2 injection will not contaminate groundwater or mineral formations, and demonstrate that the storage facility will not unduly endanger lives or property.[828] The designation of proven minerals is necessary to determine compensation for the mineral interest owner. Any condemnation action requires reasonable notice and an opportunity for a hearing. Under the framework, valuation of the property interest

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[824] *Id.*
[825] *Id.* at 74.
[826] *Id.* Part I, § 3, at 75.
[827] *Id.* at 55.
[828] *Id.* Part I, § 4, at 76.

is to consider the amount of proven commercially producible accumulations of oil or natural gas remaining in the formation.[829]

The conceptual framework also contains provisions concerning cessation of injection activities and closure of the injection well.[830] When the owner of the storage facility has ceased injection operations, the owner is to file a notice of cessation of injection with the appropriate state regulatory body.[831] All property rights are to remain with the storage operator or to be transferred to a successor with the approval of the state regulatory body.[832]

According to Part II of the framework, ownership of injected CO_2 is to remain the property of the injector, and in no event shall the CO_2 be deemed the property of a surface owner or mineral owner.[833] If CO_2 migrates into an adjoining subsurface property where property rights have not been acquired, the injector will not lose title to the CO_2 if the injector can prove by a preponderance of the evidence that the CO_2 was originally injected into the geological storage facility.[834] The owner of the subsurface will be entitled to compensation for use or of damage to the surface or substratum, the value of the storage right and recover all costs and expenses.[835]

[829] *Id.* Part I, § 5, at 77.
[830] *Id.* Part I, § 6, at 77.
[831] *Id.*
[832] *Id.*
[833] *Id.* Part II, § 1, at 78.
[834] *Id.* Part II, § 3(a), at 78.
[835] *Id.* Part II, § 3(c), at 78.

5.5.6. Conclusion

In summary, because property law in the United States is predominantly an issue of state law, there are irregularities between jurisdictions concerning the property interests of geological CO_2 storage. In particular, there are three key areas of distinction: (1) the distinction between ownership rights needed for injection of CO_2 into a mineral formation and rights needed for injection into a deep saline formation; (2) the distinction between voluntary and involuntary methods of acquisition; and (3) the distinction between ownership of the geological formation and ownership of the injected CO_2. Although common law concerning natural gas storage will serve as precedent for establishing property interests over CO_2 storage, the issue remains whether federal or state legislation of natural gas storage will govern CO_2 storage. The IOGCC conceptual framework implies that state oil and gas conservation statutes already govern CO_2. Federal law has been seemingly inconsistent concerning the application of natural gas statutes to CO_2; for example, the Tenth Circuit has held that Safe Drinking Water Act legislation concerning "natural gas" storage did not encompass CO_2,[836] but that CO_2 did fall under legislation governing "natural gas" pipelines right-of-ways.[837] These decisions were based not on an evaluation of the health, safety and environmental effects of CO_2, but rather were based on statutory intent with regard to whether "natural gas" included naturally occurring gases such as CO_2. One can rationalize these decisions as the Tenth Circuit deferring to an agency's expertise; in both cases, the Tenth Circuit upheld the agency's determination regarding whether CO_2 was "natural gas" for the purposes of the relevant statute.

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[836] *ARCO Oil and Gas Co. v. EPA*, 14 F.3d 1431, 1436 (10th Cir. 1993) (affirming a decision of the Environmental Protection Agency that the definition of natural gas under the natural gas storage exemption of the Safe Drinking Water Act did not include carbon dioxide).

[837] *Exxon Corp. v. Lujan*, 970 F.2d 757, 763 (10th Cir. 1992) (affirming a decision of the U.S. Bureau of Land Management to issue a right-of-way for a carbon dioxide pipeline under the Mineral Leasing Act, rather than under the Federal Land Policy and Management Act).

5.6. Conclusion

This chapter examined the scientific basis and legal basis for a number of identifiable sources of tortious liability, including induced seismicity, groundwater contamination, harm to human health and the environment, and harm to property. The precedent shows very different approaches taken with respect to the characterization of evidence. In the case of induced seismicity, defendants have escaped liability even though scientific studies are well established about the links between subsurface injection and seismic events. Of the potential liabilities for subsurface injection, harm to groundwater and harm to property have proven to be the most common. Liability in both contexts has been based on the use of subsurface models that show the path of the injected CO_2 and monitoring that validates the claims of the models and provides evidence of harm. Liability for harm to human health and the environment has been based on showing general and specific causation based on *Frye* or the *Daubert* factors.

Although the courts are more explicit in some cases than others, the tortious liability examples require some showing of general causation. This means that it will need to be shown that CO_2 could cause the injuries or damage in question. If CO_2 is generally not able to cause the harm in question, there will be no liability. One source of distinction among the different evidentiary characterizations could be the ability to garner evidence that would go towards the general causation point. For example, there are a number of studies on the effects of CO_2 acute and chronic exposures on human health. There are fewer studies on injection-induced seismicity, especially where the injectate is CO_2. Nonetheless, there is scientific evidence that related to all the identifiable risks in question. Therefore the proposition of a general causation distinction among the characterizations of evidence is less compelling.

The ability to garner evidence on specific causation is a stronger difference. Not only must CO_2 be proven to generally cause the injuries or damage in question, but it must be proven according to the facts of the case. Where the effects are not directly observable, which is often the case for subsurface injection tortious liability, proving specific causation will depend on the use of predictive models and monitoring. As shown in *Anthony*¸ in analyzing models, the courts will look not only to the conclusions of the models, but also whether there is evidence that adequately supports the conclusions that are made. Defendants will escape liability if they can provide enough doubt that the assertions in the models are not sufficiently validated. Again, the methods used by the courts are not necessarily specific to any of the specific tortious liability sources. However, the ability to garner case-specific evidence that meets the threshold standards of proof for issues such as contamination of native minerals might be easier than evidence that would go towards showing that injection caused a specific induced seismic event.

Finally, distinctions could be drawn with respect to evidentiary admissibility standards. Although *Daubert* is most commonly referred to in cases of health and environmental liability, Rule 702 and the *Daubert* factors will come into play whenever scientific evidence is invoked. Unlike the previous distinctions, which assumed general and specific causal evidence already before the court, the *Daubert* factors relate to a preliminary assessment that must be made by a judge related to the validity of the scientific evidence. Because the tortious liability analyzed in this chapter rests explicitly on proving that the subsurface injection operator's activities caused the injuries in question, any unresolved causal issues in the proffered explanation lead to *Daubert* challenges. Exclusions of scientific evidence will hamper the plaintiff's ability to prove its case on a preponderance of the evidence.

6. Liability for Breach of CO_2 Storage Contracts

6.1. Introduction

CO_2 storage may not necessarily be permanent (known as the issue of "permanence"), which has implications for a storage operator's liability.[838] The motivation for CO_2 storage is its ability to mitigate climate change by preventing CO_2 from reaching the atmosphere. However, if for some reason the stored CO_2 is released from the geological formation, the CO_2 storage will only have been temporary and the incremental increase in CO_2 due to the release may contribute to future climate change. CO_2 storage contracts will be associated with certain standards of performance for leakage. If leakage exceeds the standards of performance, then there will be liability associated with the breach of the CO_2 storage contract.

This chapter begins with a review of the issue of permanence. It then examines how permanence interacts with the issue of contractual liability. It analyzes how CO_2 storage is accounted for inventory accounting purposes. Finally, it considers how permanence is being addressed in two areas of the Clean Development Mechanism of the Kyoto Protocol, and the implications for liability.

6.2. The Issue of Permanence

Most economic analyses suggest that CCS requires a carbon-constrained policy regime to achieve significant market penetration.[839] However, even if CO_2 storage is only temporary,

[838] *See, e.g.*, Howard Herzog et al, *An Issue of Permanence: Assessing the Effectiveness of Temporary Carbon Storage*, 59 CLIMATIC CHANGE 293, 296 (2003) ("carbon, once sequestered, creates a permanent liability for the owner"); Gregg Marland et al, *Accounting for Sequestered Carbon: The Question of Permanence*, 4 ENVTL. SCI. & POL'Y 259, 265 (2001) ("the essential issue for permanence is liability").

[839] *See, e.g.*, J.R. McFarland et al, *Economic Modeling of the Global Adoption of Carbon Capture and Sequestration Technologies, in* PROC. SIXTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. (J. Gale & Y. Kaya eds. 2000) ("CCS technologies could play a substantial role in reducing carbon emissions, but would only be economically viable with policy constraints on carbon dioxide emissions").

Herzog et al show that it may still have positive economic value.[840] Although Herzog et al apply the permanence issue to the context of ocean storage of CO_2, the premise of their argument and their mathematical formulation of permanence is equally applicable to the geological storage context as well. Herzog et al follow the approach of the IPCC Special Report on Land Use, Land-Use Change and Forestry[841] by treating CO_2 storage and CO_2 leakage as separate events.[842] In a regulatory regime where carbon credits are freely traded and there is no subsequent leakage from the formation, the value of CO_2 storage is the carbon price multiplied by the quantity of CO_2 stored.[843] Thus for a given quantity of CO_2, CO_2 storage has a higher economic value when carbon prices are high than when carbon prices are low. Future leakage will decrease the value of storage. Assuming that liability due to leakage is a function of a future carbon price, the value of CO_2 storage will decrease by the future carbon price multiplied by the quantity of CO_2 that leaked from the reservoir.[844]

Using the IPCC assumption that the storage and leakage components of storage can be treated separately, the value of storage can be expressed mathematically as:

$$V = P_0 Q_0 - \sum_{1}^{t^*} P(t) Q(t) (1+r)^{-t} \qquad \textbf{6.1}$$

This formulation assumes that the CO_2 is stored at a single point in time (time 0), but that leakage may over a future time period until t*, the time at which CO_2 storage is deemed to be permanent. At time 0, a quantity Q_0 of CO_2 is stored at the carbon price P_0. The initial value of storage at time 0 is therefore $P_0 Q_0$. Leakage decreases the value of storage over time. The

[840] Herzog et al, *supra* note 838, at 296.
[841] INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, IPCC SPECIAL REPORT ON LAND USE, LAND-USE CHANGE AND FORESTRY § 2.3.6.1 (2000) [hereinafter IPCC Special Report on LULUCF].
[842] Herzog et al, *supra* note 838, at 296.
[843] *Id.* at 297-98
[844] *Id.*

decreased value is a function of the future carbon price $P(t)$, the quantity of CO_2 that leaks from the storage formation in the future $Q(t)$, and the discount rate r. P_0Q_0 is the storage component of value and $\sum_1^{t^*} P(t)Q(t)(1+r)^{-t}$ is the leakage component of value. Whether temporary CO_2 storage has value depends on how the storage component of value compares with the leakage component of value. If the storage component of value is greater than the leakage component of value ($P_0Q_0 > \sum_1^{t^*} P(t)Q(t)(1+r)^{-t}$), then the value of CO_2 storage is positive and there is value to storing CO_2 even though some CO_2 may leak in the future. However, if the storage component of value is less than the leakage component of value ($P_0Q_0 < \sum_1^{t^*} P(t)Q(t)(1+r)^{-t}$), then the value of CO_2 storage is negative and the operator would be better off delaying the CO_2 storage decision.

6.3. Approaches to the Issue of Liability and Permanence

The formulation of value specified above assumes that future leakage $Q(t)$ can be accurately accounted for and that there will be an associated liability. Assuming a business model where the CO_2 storage operator sells credits to a buyer at the carbon price in exchange for storing the CO_2, there are three ways in which liability could be imposed. The first way is a "seller beware" approach (*caveat venditor*). The seller (in our case, the CO_2 storage operator) would be required to replace the amount of CO_2 that leaked from the formation or acquire an amount of credits on the market equivalent to the quantity of CO_2 that leaked. A variation on the seller beware approach would be a mechanism where the seller acquires insurance or puts up a bond to assure the integrity of the credits.

A second means of imposing liability is a "buyer beware" approach (*caveat emptor*). Here, the seller would not be liable for future leakage. Instead, in the event of leakage, the buyer of the carbon credits would need to acquire additional credits on the market equivalent to the amount of CO_2 that leaked from the formation. This could be thought of as analogous to the "buyer beware" doctrine in contract law that has historically governed the sale of goods without implied warranties.[845]

A third way of imposing liability is a discounting approach (which might be described as "nobody beware"). Instead of imposing liability *ex post* (i.e., after leakage has occurred), the discounting approach assumes a future rate of leakage and imposes a penalty on the credits at the time of exchange. Under this approach, the credits would be discounted by some expected rate of leakage. The rate could vary depending on the geophysical properties of the reservoir. The buyer would not receive credit for 100% of the CO_2 that was stored, but instead would receive credit for a lesser amount.

6.4. Accounting for CO_2 Storage

The accounting regime for CO_2 storage must account for the amount of CO_2 initially stored and any CO_2 that leaks from the geological reservoir in the future. There are two ways of accounting for CO_2 storage.[846] One way is to treat CO_2 storage as avoided emissions. This formulation treats CO_2 that was captured and stored as though it was never emitted in the first place; the emissions were "avoided". The operator of the stationary source (e.g., power plant) would only report the CO_2 actually emitted to the atmosphere and would not take into account

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[845] The use of implied warranties of merchantability and fitness for a particular purpose has effectively ended the buyer beware rule.

[846] *See, e.g.*, Chisato Yoshighara, *Draft Accounting Rules for Carbon Capture and Storage Technology*, *in* PROC. SEVENTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. (E.S. Rubin et al eds. 2004); SUSANNE HAEFELI ET AL, CARBON DIOXIDE CAPTURE AND STORAGE ISSUES – ACCOUNTING AND BASELINES UNDER THE UNITED NATIONS FRAMEWORK CONVENTION ON CLIMATE CHANGE (UNFCCC) (Int'l Energy Agency, May 2004).

the CO_2 that was captured but not emitted. The other way of accounting for CO_2 storage is to treat it as an emissions reduction. The capture and storage components of CCS would be reported separately. The full amount of CO_2 produced by the stationary source would be reported, regardless of whether it was captured or emitted to the atmosphere. The amount of CO_2 stored would be also be reported and applied as a debit against the amount of CO_2 produced.

In April 2006, the IPCC revised its Guidelines for National Greenhouse Gas Inventories ("IPCC Inventory Guidelines").[847] The Guidelines, which are revised about every ten years, are an internationally-agreed upon methodology for calculating and reporting GHG emissions and removals within a country.[848] The Guidelines are used by signatories to the UNFCCC, who are required to annually report a national inventory of anthropogenic GHG emissions and sinks.[849] The 2006 IPCC Inventory Guidelines represent the first time that CO_2 storage has been included for reporting.

The IPCC Inventory Guidelines divide CCS into four subsystems: the capture and compression system, transport system, injection system, and storage system.[850] The boundary between the injection system and storage system is defined by the geological storage reservoir.[851] The Guidelines only account for leakage if the CO_2 leaks from the storage formation to the surface; the Guidelines do not account for subsurface migration of CO_2 that does not reach the surface.[852] The leakage pathways considered by the Guidelines for the storage subsystem are shown in Table 6.1. The Guidelines use the term "emission" to refer to leakage from the geological reservoir to the surface and/or atmosphere. Thus, the Guidelines for the CO_2 storage

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[847] INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, 2006 IPCC GUIDELINES FOR NATIONAL GREENHOUSE GAS INVENTORIES (2006) [hereinafter IPCC Inventory Guidelines].
[848] *Id.* at 4.
[849] UNFCCC, *supra* note 3, art. 4(1)(a).
[850] IPCC Inventory Guidelines, *supra* note 847, at 5.5.
[851] *Id.*
[852] *Id.* at 5.11.

subsystem examine "fugitive emissions from the end equipment once the CO_2 is placed in storage".[853]

The IPCC Inventory Guidelines use a so-called "Tier 3" methodology in accounting for CO_2 storage.[854] See Figure 6.1. First, the geology of the storage site and surrounding strata must be "properly and thoroughly" characterized.[855] Second, the leakage potential of the storage site must be assessed by modeling the CO_2 injection operation and predicting the movement and future behavior of the CO_2 over time.[856] Third, the storage site must be monitored, with the results of the monitoring used to validate and/or update the subsurface injection models.[857] Finally, the results of the model are reported for inclusion in the country's national GHG inventories. Because the IPCC Inventory Guidelines use a Tier 3 methodology for CO_2 storage, the reporting must be accompanied by an uncertainty assessment, where input parameters to the subsurface injection model are varied and analyzed for the impact on the model's short-term and long-term results.[858]

[853] *Id.* at 5.7.
[854] *Id.* at 5.13.
[855] *Id.*
[856] *Id.*
[857] *Id.* at 5.13-14.
[858] *Id.*

Table 6.1 Emission Pathways Identified by IPCC Inventory Guidelines[859]

TYPE OF EMISSION	POTENTIAL EMISSIONS PATHWAYS/SOURCES
Direct leakage pathways created by wells and mining	Operational or abandoned wells
	- Well blow outs (uncontrolled emissions from injection wells)
	- Future mining of CO_2 reservoir
Natural leakage and migration pathways (that may lead to emissions over time)	Through the pore system in low permeability cap rocks if the capillary entry pressure is exceeded or the CO_2 is in solution
	If the cap rock is locally absent
	Via a spill point if reservoir is overfilled
	Through a degraded cap rock as a result of CO_2/water/rock reactions
	Via dissolution of CO_2 into pore fluid and subsequent transport out of the storage site by natural fluid flow
	Via natural or induced faults and/or fractures
Other fugitive emissions at the geological storage site	Fugitive methane emissions could result from the displacement of CH_4 by CO_2 at geological storage sites. This is particularly the case for ECBM, EOR, and depleted oil and gas reservoirs.

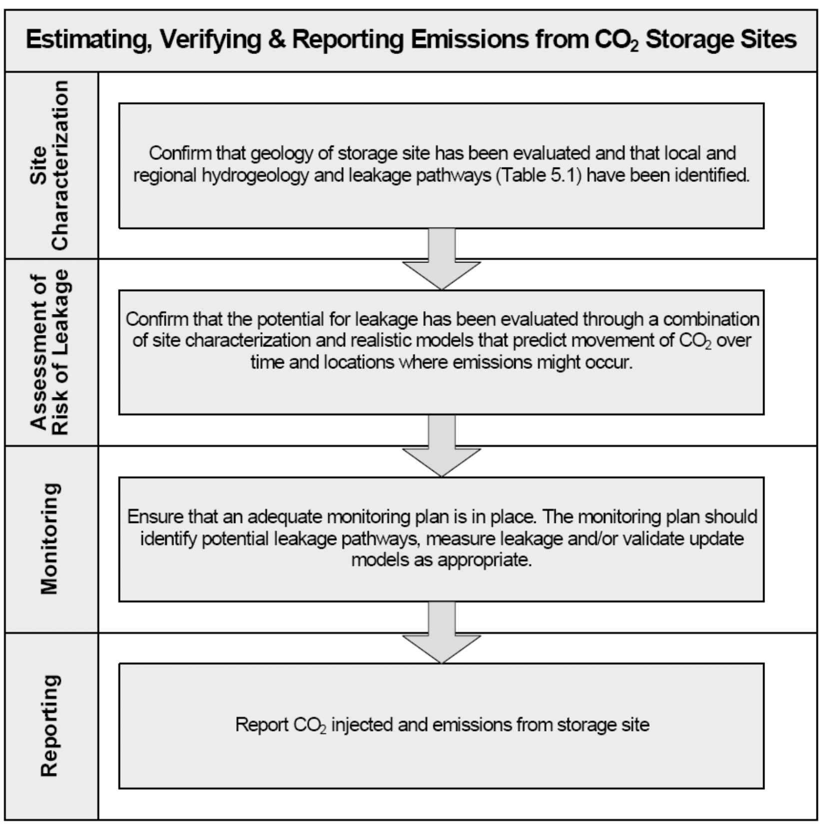

Figure 6.1 Accounting Procedures under IPCC Inventory Guidelines (IPCC)[860]

[859] Adapted from *id.* at 5.12.
[860] *Id.* at 5.13. Reprinted by permission of IPCC.

Under the IPCC Inventory Guidelines, a compiler of the national GHG inventories in each country is responsible for maintaining records related to a country's CO_2 storage operations and verifying that the Guidelines are being adhered to.[861] The compiler has several tasks. First, the inventory compiler keeps a record of every geological storage operation in the country, including information on the location of the site, the type of operation (e.g., whether it is associated with EOR), the year in which CO_2 storage began, the sources of CO_2 being stored, and infrastructure related to transportation and injection of the CO_2.[862] Second, the inventory compiler determines whether an adequate geological site characterization report has been produced for each storage site, including all the data necessary for a numerical model of the site.[863] Third, the compiler determines whether the CO_2 storage operator has assessed the potential for leakage at the storage site.[864] For example, the operator should perform short-term and long-term simulations of the injection and storage process, including sensitivity analyses.[865] Fourth, the compiler determines whether each site has a suitable monitoring plan.[866] Monitoring plans should include approaches for measuring background fluxes of CO_2 at the storage site, measuring the mass of CO_2 injected at each well, monitoring for emissions from the injection system, monitoring for fluxes through the surface, post-injection monitoring, and verification of emissions estimates.[867] The IPCC Inventory Guidelines note that it may be appropriate to decrease post-injection monitoring over time where measurements are adequately predicted by the simulation models, and to resume monitoring in response to unexpected events, such as

[861] *Id.* at 5.15.
[862] *Id.*
[863] *Id.*
[864] *Id.*
[865] *Id.*
[866] *Id.*
[867] *Id.*

seismic activity.[868] Fifth, the compiler collects annual emissions estimates from the operator of the CO_2 storage site.[869] The emissions estimates are the results from the model of the subsurface injection operation.[870] Also reported will be the amount of CO_2 injected, source of the injected CO_2, cumulative amount of CO_2 stored to date, monitoring technologies used, and verification procedures.[871] The total national emissions from CO_2 storage reported in the national GHG inventories are the sum of the emission estimates from each CO_2 storage site.[872] Finally, the compiler verifies the quality of the reported data.[873] The verification involves comparing the amount of CO_2 reported captured and sent for storage with the amount of CO_2 injected, received for storage, and leakage.[874] The amount of CO_2 captured and sent to pipelines should be greater than or equal to the amount injected, received for storage, and leakage.[875]

The IPCC Inventory Guidelines also set forth an accounting methodology where CCS takes place in multiple countries. Three cross-border scenarios are contemplated. In one scenario, CO_2 is captured in Country A, but stored in Country B.[876] See Figure 6.2(a). The capture and transport components should be reported by Country A, and the injection and storage components should be reported by Country B.[877] The second scenario is where CO_2 stored in Country A leaks to the surface in Country B.[878] See Figure 6.2(b). Country A is responsible for reporting the emissions to the surface, even though the emissions occurred in Country B.[879] Where the leakage is anticipated by the subsurface injection models, Country A should ensure

[868] *Id.*
[869] *Id.* at 5.16.
[870] *Id.*
[871] *Id.*
[872] *Id.*
[873] *Id.*
[874] *Id.*
[875] *Id.*
[876] *Id.* at 5.20.
[877] *Id.*
[878] *Id.*
[879] *Id.*

that Country B is using proper monitoring techniques.[880] The final scenario is where more than one country uses a common geological storage site.[881] For example, CO_2 may be generated in Countries A, B, and C, but stored in Country B. See Figure 6.2(c). Country B, where the CO_2 storage takes place, is responsible for reporting emissions from the reservoir.[882] Emissions which occur outside of the country are to be reported in accordance with the second scenario.[883] If the storage reservoir is located in more than one country, then the countries should agree that each country report a fraction of the total emissions.[884]

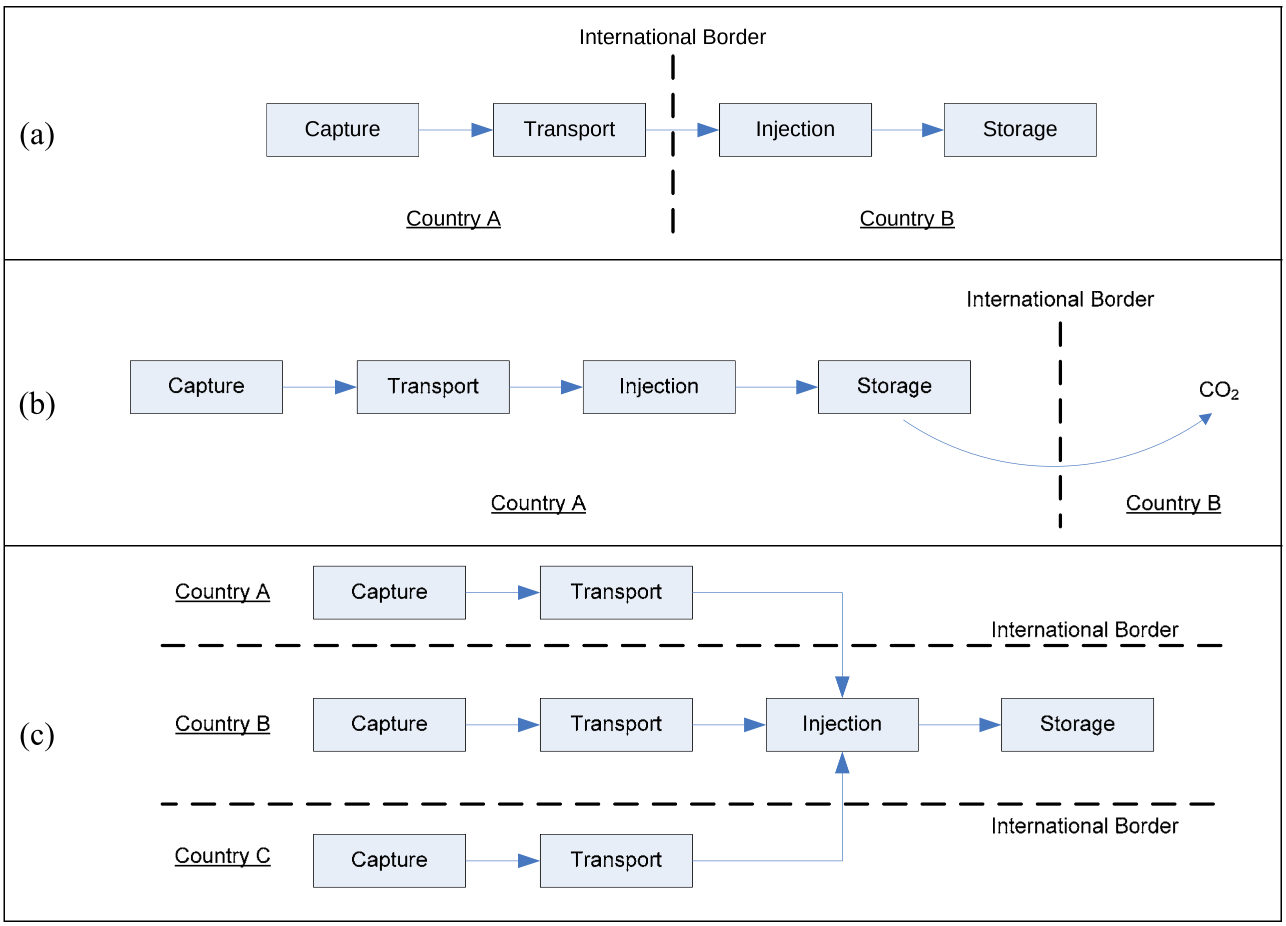

Figure 6.2 Accounting Scenarios for Transboundary CCS Projects

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[880] *Id.*
[881] *Id.*
[882] *Id.* at 5.21.
[883] *Id.*
[884] *Id.*

6.5. LULUCF Activities under the CDM

Under the Kyoto Protocol, countries account for afforestation,[885] reforestation,[886] and deforestation[887] in determining net changes in GHG emissions for achieving compliance with their emission reduction commitments.[888] These land use, land-use change and forestry ("LULUCF") activities act as offsets to CO_2 emissions, either by increasing CO_2 uptake or by reducing CO_2 emissions.[889]

Marland and Schlamadinger describe the three purposes underlying the LULUCF provisions of the Kyoto Protocol.[890] First, allowable LULUCF activities under the Protocol must be "direct human-induced".[891] Because CO_2 is beneficial to plant growth, increased atmospheric concentrations of CO_2 could increase the carbon sink, but credit is only provided for activities directly induced by humans to reduce CO_2 levels.[892] Second, the activities must provide "verifiable" changes to carbon stocks. This implies the need for measuring CO_2 uptake due to

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885 "Afforestation is the direct human-induced conversion of land that has not been forested for a period of at least 50 years to forested land through planting, seeding and/or the human-induced promotion of natural seed sources." United Nations Framework Convention on Climate Change, Conference of the Parties, Preparations for the First Session of the Conference of the Parties Serving as the Meeting of the Parties to the Kyoto Protocol (Decision 8/CP.4), Matters Relating to Land-Use, Land-Use Change and Forestry, Draft Decision -/CP.6 (FCCC/CP/2001/L.11/Rev.1, Jul. 27, 2001), *available at* http://unfccc.int/resource/docs/cop6secpart/l11r01.pdf.
886 "Reforestation is the direct human-induced conversion of non-forested land to forested land through planting, seeding and/or the human-induced promotion of natural seed sources, on land that was forested, but that has been converted to non-forested land." *Id.*
887 "Deforestation is the direct human-induced conversion of forested land to non-forested land." *Id.*
888 Kyoto Protocol to the United Nations Framework Convention on Climate Change, Dec. 10, 1997, 37 I.L.M. 22, art. 3.3 [hereinafter Kyoto Protocol] ("The net changes in greenhouse gas emissions by sources and removals by sinks resulting from direct human-induced land-use change and forestry activities, limited to afforestation, reforestation and deforestation since 1990, measured as verifiable changes in carbon stocks in each commitment period, shall be used to meet the commitments under this Article of each Party included in Annex I.").
889 United Nations Framework Convention on Climate Change, *Land Use, Land-Use Change and Forestry (LULUCF), at* http://unfccc.int/methods_and_science/lulucf/items/3060.php (last visited Nov. 9, 2006).
890 Gregg Marland & Bernhard Schlamadinger, *The Kyoto Protocol Could Make a Difference for the Optimal Forest-Based CO_2 Mitigation Strategy: Some Results from GORCAM*, 2 ENVTL. SCI. & POL'Y 111, 112 (1999).
891 *Id.*
892 *Id.*

LULUCF activities, rather than what would occur without the direct human-induced activities.[893] Third, the LULUCF provisions were motivated by considerations of equity, namely that parties should not be able to largely avoid actions in reducing CO_2 emissions by relying on LULUCF activities.[894]

At the Seventh Conference of the Parties ("COP-7") to the United Nations Framework Convention on Climate Change ("UNFCCC"), it was agreed that for the first Kyoto commitment period (2008-2012), LULUCF activities would be limited to afforestation and reforestation for Clean Development Mechanism ("CDM") projects.[895] The CDM allows countries with commitments under the Kyoto Protocol ("Annex I countries") to claim credit for emission reduction projects it carries out in non-Annex I countries.[896]

The process for obtaining approval of a LULUCF CDM project proceeds as follows. Parties submit their proposed LULUCF project to the CDM Executive Board.[897] The CDM Executive Board is a distinct legal entity authorized to certify what constitutes a certified

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893 *Id.*
894 *Id.*
895 "The Conference of the Parties … decides:
(a) That the eligibility of land-use, land-use change and forestry project activities under the clean development mechanism is limited to afforestation and reforestation;
(b) That for the first commitment period, the total of additions to a Party's assigned amount resulting from eligible land use, land-use change and forestry project activities under the clean development mechanism shall not exceed one per cent of base year emissions of that Party, times five;
(c) That the treatment of land use, land-use change and forestry project activities under the clean development mechanism in future commitment periods shall be decided as part of the negotiations on the second commitment period …" United Nations Framework Convention on Climate Change, Modalities and Procedures for a Clean Development Mechanism as Defined in Article 12 of the Kyoto Protocol, Decision 17/CP.7, § 7 (FCCC/CP/2001/13/Add.2, Jan. 21, 2002), *available at* http://unfccc.int/resource/docs/cop7/13a02.pdf#page=20. *See also* Foreign Aff. & Int'l Trade Canada, Ninth Conference of the Parties (CoP9) Summary of the Decision on Land-Use, Land-Use Change and Forestry Activities Under the Clean Development Mechanism (Feb. 24, 2004), *at* http://www.dfait-maeci.gc.ca/cdm-ji/cop9-en.asp.
896 Kyoto Protocol, *supra* note 888, art. 12.
897 United Nations Framework Convention on Climate Change, Modalities and Procedures for Afforestation and Reforestation Project Activities under the Clean Development Mechanism in the First Commitment Period of the Kyoto Protocol, Decision 19/CP.9, Annex A, para. 4 (FCCC/CP/2003/6/Add.2, Mar. 30, 2004), *available at* http://unfccc.int/resource/docs/cop9/06a02.pdf#page=13 [hereinafter CDM LULUCF Procedures].

emission reduction ("CER").[898] The proposals must include documentation on the socioeconomic and environmental impacts of the project, accompanied by environmental impact assessments where applicable.[899] Proposals must also include a baseline project scenario, i.e. what would occur in the absence of the proposed LULUCF activity.[900] In addition, proposals must include a monitoring plan that specifies the methods used for measuring GHG removals by the LULUCF activity.[901] Finally, the proposals must select a crediting period for receiving the CER credit. Participants have two options for a crediting period: either a maximum of 20 years, which may be renewed twice (for a total of 60 years); or a maximum of 30 years, which may not be renewed.[902] Once submitted, a designated operational entity is assigned to the proposed project, with the responsibility of conducting an independent evaluation to verify and certify the net anthropogenic GHG removals.[903] After being validated by the operational entity, the project can be formally accepted by the Executive Board – a process known as registration.[904]

Like CO_2 storage, LULUCF activities present a permanence problem.[905] The Kyoto Protocol allows countries to receive credits for LULUCF activities that reduce CO_2 emissions. However, there is a possibility that the CO_2 that is sequestered by the LULUCF activity could return to the atmosphere in the future.[906] For example, a country could receive CER credits for an afforestation project, but a subsequent forest fire could destroy the project, causing the credits received to exceed the amount of CO_2 sequestered.

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[898] *See* United Nations Framework Convention on Climate Change, CDM Executive Board, *at* http://cdm.unfccc.int/EB (last visited Nov. 11, 2006). *See also* A. DENNY ELLERMAN, TRADABLE PERMITS FOR GREENHOUSE GAS EMISSIONS: A PRIMER WITH PARTICULAR REFERENCE TO EUROPE 8 (MIT Joint Program on the Science & Policy of Global Change Report No. 69, Nov. 2000).
[899] CDM LULUCF Procedures, *supra* note 897, Annex A, para. 12(c).
[900] *Id.*, para. 19.
[901] *Id.*, para. 25
[902] *Id.*, para. 23.
[903] *Id.*, para. 5.
[904] *Id.*, para. 11.
[905] *See, e.g.*, Gregg Marland et al, *Accounting for Sequestered Carbon: The Question of Permanence*, 4 ENVTL. SCI. & POL'Y 259 (2001). *See also* IPCC Special Report on LULUCF, *supra* note 841, at § 5.4.
[906] *Id.*

At the Ninth Conference of the Parties to the UNFCCC ("COP-9"), it was decided that the permanence issue for CDM LULUCF activities would be addressed through a verification and certification process.[907] A designated operational entity conducts an independent review of the LULUCF project periodically and provides written assurance of the net anthropogenic GHG removals since the start of the project.[908] The independent review is the "verification" step and the written assurance is the "certification" step.[909] Verification and certification is to be carried out every five years until the end of the crediting period.[910]

The permanence issue is also addressed by the CER credits issued. CDM LULUCF participants may choose between receiving a temporary certified emission reduction ("tCER") or a long-term certified emission reduction ("lCER"). As the names imply, the lCER carries with it greater long-term responsibilities than the tCER.

The tCER is a credit that expires at the end of the Kyoto commitment period following the commitment period it was issued.[911] For example, if the tCER is obtained for the first commitment period, 2008-2012, it would expire at the end of the second commitment period, which runs from 2013-2017. Verification occurs every five years, with credits being reissued for the same carbon stock plus any increase in net removals since the start of the project.[912] The tCER cannot be carried over into any subsequent commitment periods.[913] Countries are to maintain a tCER replacement account in case the tCER needs to be replaced prior to its expiration. Parties may replace one tCER with one assigned amount unit ("AAU"), emission reduction unit ("ERU"), removal unit ("RMU"), CER, or tCER. AAUs are units issued from an

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[907] CDM LULUCF Procedures, *supra* note 897, Annex A, para. 31.
[908] *Id.*, para. 6, 34.
[909] *Id.*, para. 31.
[910] *Id.*, para. 32.
[911] *Id.*, para. 1(g).
[912] *Id.*, para. 32, 36(a).
[913] *Id.*, para. 41.

Annex I country's initial emission allowances.[914] ERUs are credits generated through joint implementation, where Annex I countries may receive credit for projects in other Annex I countries that reduce emissions or increase removals by carbon sinks.[915] RMUs are credits issued by Annex I countries on the basis of LULUCF activities.[916]

The lCER is a credit that expires at the end of the crediting period for which it was issued.[917] For example, if a 20-year crediting period is chosen, the lCER would be valid for 20 years. Verification, which would take place every five years like the tCER, would analyze whether there were any increases or decreases in CO_2 removal.[918] If verification found an increase in CO_2 removal, then previously issued credits would remain valid and new credits would be issued corresponding to the increased removal.[919] If, on the other hand, verification found a decrease in removals, then the credits corresponding to the decreased removal would need to be replaced.[920] Thus, if verification showed no net decrease in CO_2 removals, then the lCERs would remain valid for the crediting period, say 20 years.[921] If on the other hand, verification showed a decrease in half of the carbon stock, then half of the original credits would be valid and half of the credits would need to be replaced.[922] As with tCERs, countries must maintain a replacement account for lCERs in case the lCERs need to be replaced before their expiration.[923] Parties may replace one lCER with one AAU, CER, ERU, RMU, or lCER from

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914 United Nations Framework Convention on Climate Change, Emissions Trading, *at* http://unfccc.int/kyoto_protocol/mechanisms/emissions_trading/items/2731.php (last visited Nov. 15, 2006).
915 *Id. See also* United Nations Framework Convention on Climate Change, Kyoto Protocol, *at* http://unfccc.int/kyoto_protocol/background/items/3145.php (last visited Nov. 15, 2006).
916 United Nations Framework Convention on Climate Change, *supra* note 914.
917 CDM LULUCF Procedures, *supra* note 897, Annex A, para. 1(h).
918 *Id.*, para. 41.
919 *Id.*, para. 36(a).
920 *Id.*, para. 36(b).
921 Based on an example from Foreign Aff. & Int'l Trade Canada, *supra* note 895.
922 *Id.*
923 CDM LULUCF Procedures, *supra* note 897, Annex A, para. 49.

the same project activity, and the transfer must take place within 30 days of the country being notified that it must replace the lCERs.[924]

6.6. CO_2 Capture and Storage under the CDM

As of the time of this writing, the CDM Executive Board had not made a final decision on its treatment of CCS. However, two geological CO_2 storage projects[925] and one ocean CO_2 storage project[926] have been submitted for consideration, and there have been several recent developments generally relating to the inclusion of CCS activities under the CDM. At its first meeting in Montreal, the Conference of the Parties serving as the Meeting of the Parties to the Kyoto Protocol (COP/MOP-1) invited parties to provide submissions to the UNFCCC Secretariat by February 13, 2006 on the consideration of CCS as CDM project activities, taking into account issues relating to project boundary, leakage, and permanence.[927] Also at the request of

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[924] *Id.*

[925] The first proposal is the White Tiger Oil Field carbon capture and Storage project in Vietnam (Case NM0167). The project proposes to capture CO_2 from a power plant, transport it by pipeline for injection into geological reservoirs, including EOR. *See* United Nations Framework Convention on Climate Change, NM0167: The White Tiger Oil Field Carbon Capture and Storage (CCS) Project in Vietnam, *at* http://cdm.unfccc.int/methodologies/PAmethodologies/publicview.html?OpenRound=13&OpenNM=NM0167&cases=B#NM0167 (last visited Nov. 19, 2006). The second proposal is for a liquefied natural gas (LNG) complex and geological storage in Malaysia (Case NM0168). The project proposes to capture a mixture of acid gases from natural gas processing plants and LNG plants, and store the gas mixture in underground aquifers or abandoned oil and gas reservoirs. *See* United Nations Framework Convention on Climate Change, NM0168: The Capture of the CO_2 from the Liquefied Natural Gas (LNG) Complex and its Geological Storage in the Aquifer Located in Malaysia, *at* http://cdm.unfccc.int/methodologies/PAmethodologies/publicview.html?OpenRound=14&OpenNM=NM0168&cases=B#NM0168 (last visited Nov. 19, 2006).

[926] This project is described as anthropogenic ocean sequestration by changing the alkalinity of ocean surface water (Case SSC_038). It proposes to capture CO_2 from a power plant and pump it through flowing sweater in which limestone in porous baskets in place, which would result in the CO_2 contained in the flue gas being converted to bicarbonate. Note that the analysis in this thesis concentrates on geological storage of CO_2. *See* United Nations Framework Convention on Climate Change, Anthropogenic Ocean Sequestration by Alkalinity Shift, *at* http://cdm.unfccc.int/methodologies/SSCmethodologies/Clarifications/#SSC_049 (last visited Nov. 19, 2006).

[927] Report of the Conference of the Parties serving as the meeting of the Parties to the Kyoto Protocol on its First Session, held at Montreal from 28 November to 10 December 2005, Further Guidance Relating to the Clean Development Mechanism, Decision 7/CMP.1, para. 6 (2005) [hereinafter COP/MOP-1 Report], *available at.* http://unfccc.int/resource/docs/2005/cmp1/eng/08a01.pdf#page=93. *See* United Nations Framework Convention on Climate Change, Consideration of Carbon Capture and Storage as Clean Development Mechanism Project Activities, Submissions from Parties (Mar. 13, 2006), *at* http://unfccc.int/files/meetings/workshops/other_meetings/application/pdf/ccs_party_submission.pdf.

COP/MOP-1, a workshop was organized to consider CCS as CDM project activities. The workshop was held in conjunction with the twenty-fourth session of the Subsidiary Body for Scientific and Technological Advice ("SBSTA") in May 2006.[928] In September 2006, the CDM Methodology Panel ("CDM Meth Panel") provided recommendations based on its assessment of the proposed CCS projects and issues related to CCS project activities under the CDM.[929] Finally, the issue of CCS as CDM project activities was considered at the second meeting of the COP/MOP (COP/MOP-2), in conjunction with the Twelfth Conference of the Parties to the UNFCCC (COP-12).[930] This section of the thesis summarizes the discussions surrounding CCS activities under the CDM and the decisions that have been made to date.

The parties to the Kyoto Protocol have identified several key issues facing CCS project activities under the CDM. One issue is the definition of the CCS project boundary. Under the Marrakesh Accords, the "project boundary" for a CDM project is required to "encompass all anthropogenic emissions by sources of GHGs under the control of the project participants that are significant and reasonably attributable to the CDM project activity".[931] At the SBSTA workshop, the Secretariat identified three common concerns among the February 2006 party submissions related to project boundaries. First, there was a common sentiment that the project boundary include the various components of CCS, including the source of CO_2, capture,

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[928] *Id.*, para. 5. *See* Conference of the Parties serving as the meeting of the Parties to the Kyoto Protocol on its Second Session, held at Nairobi from 6 November to 17 November 2006, Report on the Workshop on Carbon dioxide Capture and Storage as Clean Development Mechanism Project Activities, Note by the Secretariat (FCCC/KP/CMP/2006/3, Aug. 15, 2006), *at* http://unfccc.int/resource/docs/2006/cmp2/eng/03.pdf [hereinafter SBSTA Workshop Report].

[929] Report of the Twenty-Second Meeting of the Methodologies Panel, Annex 12, Recommendation on CO_2 Capture and Storage as CDM Project Activities Based on the Review of Cases NM0167, NM0168 and SSC_038 (Sept. 2006), *available at* http://cdm.unfccc.int/Panels/meth/MP22_repan12_CCS_NM0167_NM0168_SSC038.pdf [hereinafter CDM Meth Report].

[930] Report of the Conference of the Parties serving as the meeting of the Parties to the Kyoto Protocol on its Second Session, held at Nairobi from 6 November to 17 November 2006, Further Guidance relating to the Clean Development Mechanism, Decision -/CMP.2 (2006) [hereinafter COP/MOP-2 Decision], *available at* http://unfccc.int/files/meetings/cop_12/application/pdf/cmp_8.pdf.

[931] COP/MOP-1 Report, *supra* note 927, Decision 3/CMP.1, para. 52.

transport facilities, and the storage site.[932] See Figure 6.3(a). There were questions whether the project boundary should include not only the physical boundary of the storage reservoir, but also the area through which CO_2 emissions could potentially escape, which might extend beyond the storage reservoir *per se*.[933] Second, the party submissions noted that the project boundary scope must consider those situations where the storage reservoir spans international boundaries.[934] See Figure 6.3(b). Workshop participants noted that this could be solved either by placing the reservoir within the jurisdiction of the non-Annex I parties, or by leaving the decision to those countries whose jurisdictions the reservoir falls.[935] Third, the party submissions noted that the project boundary scope must consider situations where project activities use the same or overlapping reservoirs.[936] See Figure 6.3(c).

[932] SBSTA Workshop Report, *supra* note 928, para. 10(a).
[933] *Id*., para. 11.
[934] *Id*., para. 10(b).
[935] *Id*., para. 12.
[936] *Id*., para. 13.

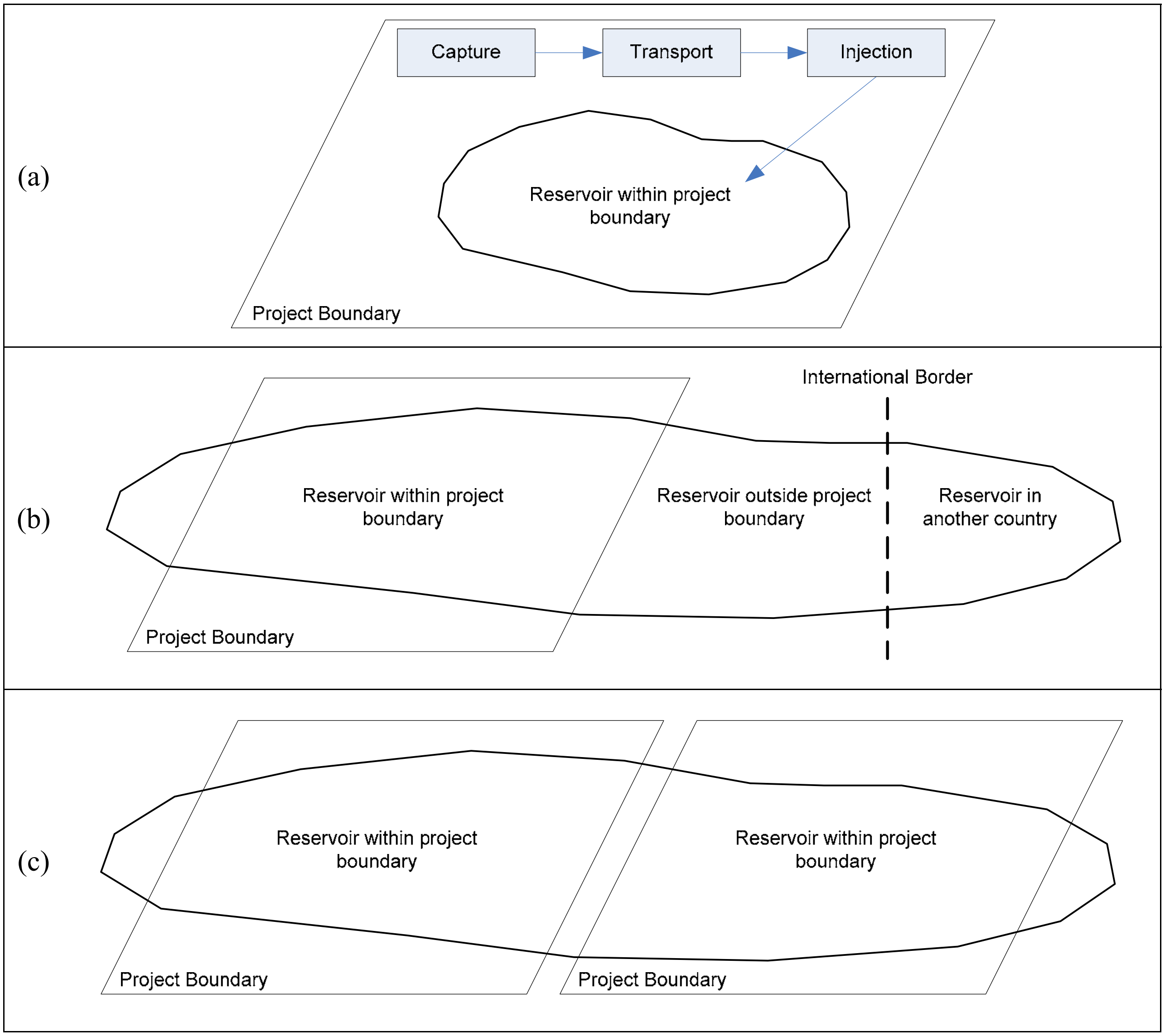

Figure 6.3 Project Boundary Issue for CCS CDM Projects

Another issue is leakage, defined under the Marrakesh Accords as "the net change of anthropogenic emissions by sources of greenhouse gases which occurs outside the project boundary, and which is measurable and attributable to the CDM project activity".[937] Leakage in this specific Kyoto Protocol sense should be distinguished from the physical leakage of CO_2 from the storage reservoir. One issue is whether emissions from EOR should be accounted for as

[937] COP/MOP-1 Report, *supra* note 927, Decision 3/CMP.1, para. 51.

leakage. Some argue that emissions from EOR should be treated as leakage "because EOR will result in increased oil production, consumption and resultant emissions in non-Annex I parties, which do not have emission reduction targets under the Kyoto Protocol".[938] However others argue that emissions from EOR should not be accounted for:

> [E]missions from oil produced due to EOR should not be accounted for because there is no evidence that EOR will result in significant increase of oil production; the extracted oil might replace more-carbon-intensive fossil fuels, thus reduce emissions; emissions from oil produced through EOR should be accounted for at the consumption location and, therefore, accounting for them in the CDM project would result in double counting of emissions; and the assessment of an increase in emissions would require a detailed analysis, taking into account market price of fossil fuels and technology improvement aspects, where, the impact might be insignificant.[939]

There will also be leakage due to the energy required to capture CO_2.[940] The consensus view among the SBSTA workshop participants on both EOR and emissions from energy required to capture CO_2 was that the decision would be made on a case-by-case basis, but that general guidelines should be developed.[941]

The final key issue identified by the parties was permanence, which relates to the physical escape of injected CO_2 from the storage reservoir. There is no agreed upon definition for permanence under the Kyoto Protocol, although the issue has arisen for LULUCF activities.[942] The Secretariat describes permanence as a qualitative way of characterizing "whether a reservoir is able to store CO_2 for a long time".[943] Thus the permanence issue is

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[938] SBSTA Workshop Report, *supra* note 928, para. 15(b).
[939] *Id.*, para. 15(a).
[940] *Id.*, para. 16.
[941] *Id.*, para. 15(c), 16.
[942] Secretariat of the United Nations Framework Convention on Climate Change, Some Terms, Summary of Party Submissions, Comparison of Methodologies, *at* Workshop on Considering CCS as a CDM Project Activity (May 2006), *at* http://unfccc.int/files/meetings/workshops/other_meetings/application/pdf/session1_pres2_ccs-cdm_ver4.pdf.
[943] *Id.*

essentially the accounting treatment of physical leakage from the reservoir. For the purposes of the CDM, the escape of injected CO_2 from the storage reservoir is termed "seepage".[944] The party submissions applied the permanence issue to six areas: methodological aspects of seepage; definition of the storage site selection criteria; suitable reservoirs and methods of storage; monitoring techniques and requirements; implications of force majeure and accidents; and the accountability and responsibility for seepage during and after the crediting period. It is generally agreed that proper site selection can minimize the potential for future seepage.[945] The major sources of debate on permanence are monitoring and liability/accounting for seepage. With respect to monitoring, monitoring time frames and technologies received the most attention among the party submissions.[946] On liability, parties are concerned with how liability should be addressed during and beyond the crediting period.[947] The fundamental issue is whether project participants could be held liable if seepage occurs beyond the crediting period.[948] At the SBSTA workshop, suggestions for addressing the long-term seepage issue included using a discount rate, cancelling CERs should seepage occur, issuing temporary CERs, using insurance, and creating a remediation fund in the event of seepage.[949]

In September 2006, the CDM Meth Panel provided a recommendation on CCS as CDM project activities based on the review of the three projects that had been submitted to date.[950] The Meth Panel found that the proposed CDM projects did not adequately address the methodological issues, and that further guidance from the COP/MOP or a technical body would

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944 *Id.*
945 SBSTA Workshop Report, *supra* note 928, para. 20.
946 *See, e.g.*, SBSTA Workshop Report, *supra* note 928, para. 25.
947 SBSTA Workshop Report, *supra* note 928, para. 26.
948 *Id.*
949 SBSTA Workshop Report, *supra* note 928, para. 28.
950 CDM Meth Report, *supra* note 929.

likely be necessary for the resolution of some of the issues.[951] The Meth Panel divided the methodological issues for CCS projects into two categories: methodological issues that are comparable to those faced by other CDM methodologies and methodological issues that go beyond the nature of other proposed CDM methodologies.[952] I focus my summary on the novel issues, which echoed many of the same issues raised by the party submissions.

The Meth Panel divided the novel issues into seepage, permanence, and accounting. On the seepage issue, the Meth Panel identified the need for appropriate site selection criteria for distinguishing acceptable reservoirs from those that are likely to leak to an unacceptable extent, the need for a regularly evolving set of protocols for evaluating proposed monitoring methodologies, and determining an acceptable level of seepage risk.[953] On the permanence/liability issue, the Meth Panel noted a number of questions related to accounting for seepage emissions during the crediting period and after the end of the last crediting period.[954] These questions included:

- How should (non-trivial) seepage emissions from storage reservoirs be accounted for (during and) after the end of the last crediting period or before and after sealing/abandonment of the reservoir?
- Do the uncertainties justify considering an alternative accounting framework for emission reductions/removals from CCS project activities?
- Who should be responsible (and liable) for any necessary remediation measures after well closure and/or after the end of the crediting period?
- How can it be ensured that necessary remediation measures are undertaken?
- What is the interaction with national regulation on these issues (many countries with underground or offshore operations have mining laws that regulate site abandonment and long-term liability)?

[951] *Id.* at 1.
[952] *Id.*
[953] *Id.* at 4-6.
[954] *Id.* at 7.

Finally, the Meth Panel noted the novel issues relating to the definition of a project boundary, such as several projects that use the same CO_2 reservoir, stored CO_2 that migrates from one country to another country, and the aerial extent of the subsurface that should be considered in defining the storage area boundary.[955]

The issue of CCS as a CDM project activity was considered by the COP/MOP-2 in Nairobi in November 2006, but the parties decided to defer a decision in order to gain further knowledge and understanding of the issues.[956] The COP/MOP-2 identified nine issues that remain uncertain and for which it sought guidance:[957]

- Long-term physical leakage (seepage) levels of risks and uncertainty
- Project boundary issues (such as reservoirs in international waters, several projects using one reservoir) and projects involving more than one country (projects that cross national boundaries)
- Long-term responsibility for monitoring the reservoir and any remediation measures that may be necessary after the end of the crediting period
- Long-term liability for storage sites
- Accounting options for any long-term seepage from reservoirs
- Criteria and steps for the selection of suitable storage sites with respect to the potential for release of greenhouse gases
- Potential leakage paths and site characteristics and monitoring methodologies for physical leakage (seepage) from the storage site and related infrastructure for example, transportation
- Operation of reservoirs (for example, well-sealing and abandonment procedures), dynamics of carbon dioxide distribution within the reservoir and remediation issues
- Any other relevant matters, including environmental impacts

Parties have been invited to make submissions to the secretariat regarding these issues by September 21, 2007.[958] The submissions will be considered by the SBSTA-27, which will make

[955] *Id.* at 8-9.
[956] COP/MOP-2 Decision, *supra* note 930, para. 19.
[957] *Id.*, para. 21.
[958] *Id.*, para. 22

recommendations on CCS as CDM project activities.[959] The SBSTA recommendations will be considered for an eventual decision by COP/MOP-4 in 2008.[960]

6.7. Conclusion

Liability appears to be the central concern in the permanence debate. As outlined in Section 6.1, liability could take the form of a "seller beware", "buyer beware", or "upfront discounting" approach. In the seller beware scenario, the issue is essentially one of contractual performance. The buyer and a seller enter into a contract, where the buyer agrees to purchase carbon credit from the seller at the carbon price in exchange for the seller storing the buyer's CO_2 in the subsurface. There will be some standards of performance associated with that contract – what is commonly referred to as a rate of acceptable leakage. The standard of performance could be externally imposed by governmental or intergovernmental standards, or if the law allows, agreed among the contractual parties. If leakage from the reservoir exceeds the contractual standard of performance, then the seller will need to cover the contract by storing more CO_2 or purchasing more credits on the market. In the buyer beware scenario, the seller would not be liable for leakage, but instead the buyer would be required to cancel the carbon credits corresponding to the quantity of CO_2 that leaked and/or purchase additional credits on the market.

Between the seller beware and buyer beware approaches, the seller beware approach appears to be the better strategy. If the seller of carbon credits is not liable for future leakage, then the seller has no incentive to choose a site that minimizes the rate of leakage. This problem could be mitigated by having certain performance standards or site selection criteria that all storage sites must meet, which would decrease the possibility of moral hazard. However, the

[959] *Id.*, para. 24
[960] *Id.*

standards could just as easily be applied to the seller beware scenario as well. Because the least cost avoider in this context is the seller, it would be most efficient to place liability with the seller. In the seller beware scenario, the seller has an incentive to choose less risky storage sites because the seller wants to minimize future liability. In both the seller beware and buyer beware scenarios, I assume that there is a standard of performance associated with the CO_2 storage project and that deviations from the standard can be quantified for imposing liability. In the discussions for allowing CCS as a CDM activity, commonly debated topics include what the standard of performance for CO_2 storage should be and identifying monitoring criteria for ensuring the integrity of CO_2 storage contracts.

The upfront discounting approach assumes that monitoring at a resolution necessary to ensure contractual performance is either not possible or too troublesome to be worth the effort. The discounting approach may present a moral hazard similar to the buyer beware approach. If the seller faces no additional liability for future leakage, then the seller has no incentive to take extra precautions. As in the buyer beware approach, the moral hazard could be mitigated by requiring that the seller comply with certain protocols that have the effect of minimizing future leakage.

The IPCC Inventory Guidelines provide one approach to the issue of liability and permanence. Although no country has purported that the IPCC Inventory Guidelines will be used as the accounting basis for determining liability, it is the only internationally agreed upon accounting methodology for CO_2 storage. Thus countries might choose to use the IPCC Inventory Guidelines rather than developing another set of accounting protocols for CO_2 storage. The IPCC Inventory Guidelines use a Tier 3 methodology, which requires that operators use predictive models, as validated by monitoring, to report future leakage (which may be zero). The national compiler of GHG data aggregates the results of these models among all individual storage sites to determine the amount of leakage from storage sites that occurs nationally. These nationally aggregated results are used for GHG reporting under the UNFCCC.

Because the IPCC Inventory Guidelines report leakage on the basis of expectations rather than actual leakage, it could create perverse incentives with respect to liability. First, given a range of possible models, operators would have an incentive to choose the model that most underestimates future leakage, since it is estimated leakage that is reported and not actual leakage. Under a system of liability governed by the rules of the IPCC Inventory Guidelines, liability would be on the basis of this reported leakage. In addition, there could be situations where storage sites have actual leakage that is greater than what the model predicts (the operator is not liable for leakage that did occur) and other situations where storage sites have actual leakage that is l than what the model predicts (the operator is liable for leakage that did not occur). This has due process implications since liability would not be based on actual leakage, but instead would be based on what the models predict leakage to be. Monitoring could serve as a check on the potential gaming of models, but again there will be a perverse incentive to choose the modeling plan that most underestimates leakage. This discussion is not meant to imply that the use of predictive models is never appropriate in the context of permanence and liability. Instead, developers of liability rules for permanence should be cognizant of the potential perverse incentives that could arise from the use of models for imposing liability and develop ways of ensuring the integrity of the system.

There is also an issue of how to manage permanence temporally. For example, a concern raised by the CDM Meth Panel was the issue of liability during the crediting period versus liability after the crediting period. The various approaches to liability outlined above (seller beware, buyer beware, and discounting) are not necessarily independent of one another. For example, one could use a seller beware or buyer beware approach during the crediting period, but use a discounting method to account for long-term leakage until the time that CO_2 storage is deemed to be permanent. Another way of addressing the temporal issue would be to follow the LULUCF CDM precedent of having different categories of credits corresponding to different lengths of time. The LULUCF CDM regime uses temporary and long-term credits (tCERs and lCERs), where temporary credits have a shorter life than long-term credits, but have fewer long-term obligations for covering credits in the event of future leakage.

In summary, permanence is a key issue affecting the liability of CO_2 storage. Given that most assessments of CO_2 storage suggest that the likelihood of health, safety, and environmental damage is low assuming proper site characterization,[961] one might expect the liability associated with permanence to be of greater economic consequence to firms than future tortious liability. Although permanence has been addressed in the past for LULUCF activities, CO_2 storage raises novel issues related to project boundaries, leakage, accounting, and liability. As the approval process for CO_2 storage under the CDM regime moves forward, we may see the first internationally agreed upon resolutions of the permanence issue.

[961] *See, e.g.*, IPCC Special Report, *supra* note 11, at 244.

7. Case Studies of Subsurface Injection Liability

7.1. Introduction

This chapter considers three case studies of subsurface injection liability. The first case is acid gas injection. The technical background for acid gas injection is described, sources of acid gas injection liability are analyzed, and a comparative analysis is conducted between acid gas liability regimes in Alberta, Canada, Texas, and Wyoming. The second case study is of natural gas storage. The technical background of natural gas storage is reviewed, common law ownership issues are analyzed, the issue of natural gas storage as a basis for CO_2 storage on federal lands is examined, sources of natural gas storage liability are analyzed, and liability litigation is considered with an emphasis on a recent case before the Kansas Supreme Court. The final set of case studies examine secondary recovery and enhanced oil recovery. Background on both sets of cases is provided, the sources of liability are considered, federal and state regulatory regimes are analyzed, liability precedent is examined, and prospective CO_2 storage projects are considered.

7.2. Liability of Acid Gas Injection

7.2.1. Background

Although CO_2 capture and storage is a relatively new technology, CO_2 has been injected into subsurface geological formations since 1989 as part of "acid gas" streams, a process known as acid gas injection. Natural gas often contains varying percentages of hydrogen sulfide (H_2S) and CO_2. To meet commercial specifications, H_2S and CO_2 are removed from the natural gas; the removed H_2S and CO_2 are known as acid gas. The acid gas may also contain small amounts of other gases, such as carbonyl sulfide or sulfur oxides. As shown in Figure 7.1, prior to acid gas removal, the natural gas is called sour gas; after acid gas is removed, the natural gas is called sweet gas. Acid gas injection can also take place in the context of electricity production. For example, in integrated gasification combined cycle (IGCC) power plants, the fuel (generally coal) is converted to a syngas, and sulfur is removed from the syngas before electricity is generated. In the cases of both natural gas refining and electricity production, solvents are used to absorb the acid gas. The solvents can be chemical solvents based on aqueous methyldiethanolamine (MDEA) or physical solvents using a Selexol process.

National legislation has increasingly prevented acid gas from being vented to the atmosphere because of environmental concerns. There are two options for treatment of acid gas, as shown in Figure 7.1. The most common option is to use a Claus process ("sulfur recovery unit" in Figure 7.1) which produces elemental sulfur from H_2S by substoichiometric (starved air) combustion.[962] The elemental sulfur may be fixed in liquid or solid form, or as sulfuric acid. Because of the thermodynamics of the Claus process, it does not achieve a high degree of sulfur recovery without treatment of the tail gas; the tail gas contains H_2S, CO_2, and residual sulfur oxides. In the tail gas treatment process, the sulfur species is hydrogenated to produce H_2S, which is generally recycled to the sulfur recovery unit. The other outputs of the tail gas treatment unit can either be vented to the atmosphere, or captured in the case of CO_2.

[962] OLA MAURSTAD, AN OVERVIEW OF COAL-BASED INTEGRATED GASIFICATION COMBINED CYCLE TECHNOLOGY (MIT Laboratory for Energy & the Environment Working Paper No. MIT LFEE 2005-002 WP, 2005).

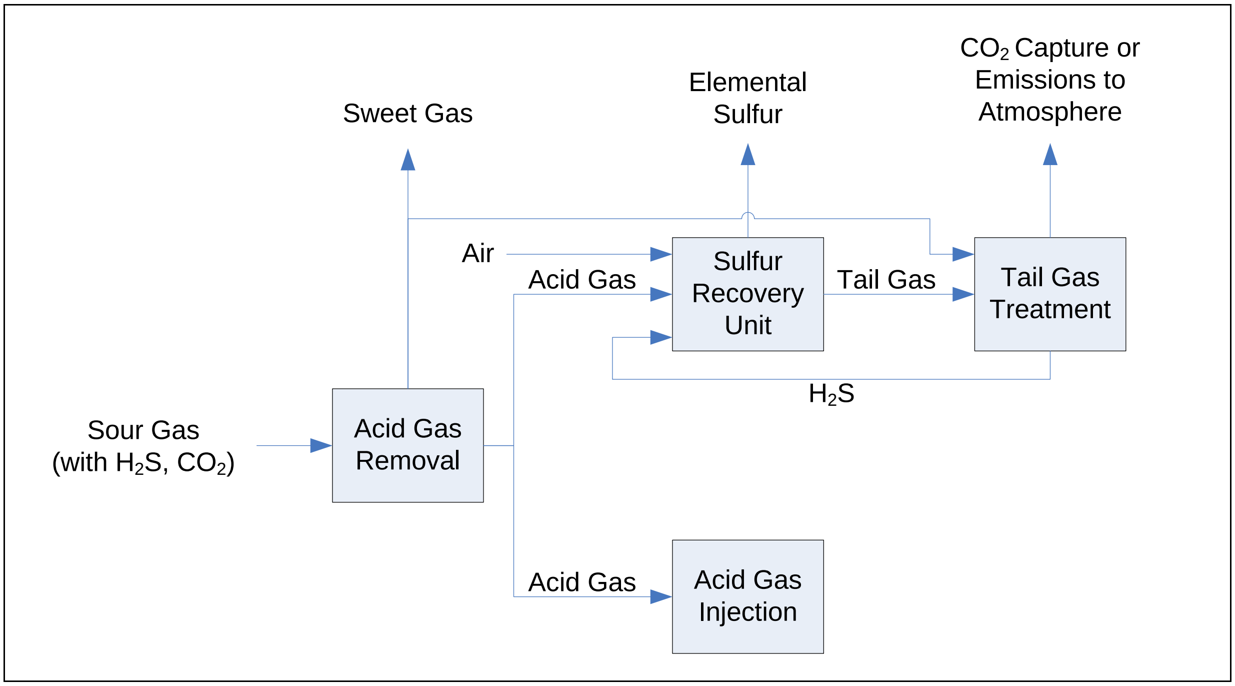

Figure 7.1 Acid Gas Treatment Options in Natural Gas Processing

An alternative to treating acid gas using a Claus process is to inject the acid gas into a geological formation. Acid gas injection can be a favorable option for a number of reasons. First, elemental sulfur prices have fallen over the past ten years[963] and the elemental sulfur producer often has to subsidize the sulfur recovery operation from sales of the natural gas or electricity.[964] Second, the injection of H_2S into oil fields has been found to improve oil recovery, meaning that acid gas injection is an alternative to injecting naturally occurring CO_2 for EOR.[965] Third, because CO_2 is often a significant component of acid gas, acid gas injection is a favorable treatment option if any legislation places constraints on CO_2 emissions; tail gas treatment generally involves venting of CO_2 to the atmosphere, although it is technically feasible for the CO_2 to be captured.

[963] *See e.g.*, Joyce A. Ober, Sulfur, *in* U.S. GEOLOGICAL SURVEY MINERALS YEARBOOK 74.3 (2005).
[964] Amit Chakma, Acid Gas Re-Injection – A Practical Way to Eliminate CO_2 Emissions from Gas Processing, 38 ENERGY CONV. MGMT. S205, S207 (1997).
[965] *See e.g.*, Mark Puckett, Hydrocarbon Resources: Technology for Global Growth, Address at the SPE Asia Pacific Oil & Gas Conference (2005).

The design of an acid gas injection operation will depend on the properties of the acid gas, including its non-aqueous phase behavior, hydrate formation, density, and viscosity.[966] H_2S and CO_2 are the key components in acid gas, and water and methane are important secondary components.[967] Bachu et al have developed a set of criteria for optimizing the efficiency of acid gas injection.[968] First, the acid gas should be injected as a dense-fluid phase to increase capacity and minimize buoyancy. Second, injection should occur at bottom-hole pressures greater than the formation pressure in order to increase injectivity. Third, injection should occur at temperatures greater than 35°C to avoid hydrate formation which could plug the wellbore. Fourth, the acid gas should have water content lower than the saturation limit to avoid corrosion.

The process of acid gas injection shares a number of similarities with the process of CO_2 storage. Acid gas injection is subject to the many of the same trapping mechanisms as CO_2 storage, including physical trapping by the overlying caprock, hydrodynamic traps in the brine of a geological formation, and mineral trapping over long periods of time.[969] Because acid gas generally has a lower minimum miscibility pressure than conventional hydrocarbons, acid gas injection, like CO_2 storage, can be used for EOR.[970] As with CO_2 storage, acid gas injection can take place both in oil and gas fields and deep saline formations.

[966] Stefan Bachu et al, Acid Gas Injection in the Alberta Basin: A Commercial-Scale Analogue for CO_2 Geological Sequestration in Sedimentary Basins, *in* PROC. SECOND ANNUAL CONF. CARBON SEQUESTRATION 4 (U.S. Dep't of Energy, 2003).
[967] John J. Carroll, Physical Properties Relevant to Acid Gas Injection, *in* PROC. XIV INT'L GAS CONVENTION (2000).
[968] *Id.*
[969] Stefan Bachu & William D. Gunter, Overview of Acid-Gas Injection Operations in Western Canada, *in* PROC. SEVENTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. (E.S. Rubin et al eds. 2004).
[970] *Id.*

7.2.2. Sources of Acid Gas Injection Liability

7.2.2.1. Properties of Acid Gas

Acid gas is toxic because of the presence of H_2S, a poisonous, flammable, colorless gas with a characteristic odor of rotten eggs.[971] Acid gas will vary in its H_2S composition depending on its source. For example, data from 48 acid gas injection operations in western Canada indicates acid gas composition varying between 83% H_2S and 14% CO_2 to 2% H_2S and 95% CO_2.[972] Although the pathways of leakage for CO_2 storage are similar to those of acid gas injection, acid gas injection poses a relatively larger liability for the same quantity of fluid injected because of the potential for H_2S to degrade the environment and the toxic effects of H_2S on human health.

H_2S is a by-product or intermediate in a variety of commercial processes, and its risks are well known. H_2S is principally derived from the purification of natural and refinery gases.[973] H_2S is also found as a by-product of kraft pulp and paper manufacturing and carbon disulfide production, and as an intermediate in the production of sulfuric acid and inorganic sulfides.[974] Historically, the risks of H_2S have stemmed from its accidental release to the atmosphere or improper disposal.[975] With respect to acid gas injection, therefore, the known H_2S risks derive from human and environmental exposure. Acid gas injection is potentially subject to other risks faced by CO_2 storage, such as induced seismicity, but there have been no known documented cases of these other risks to date.

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[971] U.S. DEP'T OF HEALTH AND HUMAN SERVICES, DRAFT TOXICOLOGICAL PROFILE FOR HYDROGEN SULFIDE 9 (2004).
[972] Bachu & Gunter, *supra* note 969.
[973] WORLD HEALTH ORGANIZATION, HYDROGEN SULFIDE: HUMAN HEALTH EFFECTS 4 (Concise Int'l Chemical Assessment Document 53, 2003)
[974] *Id.*
[975] *Id.*

7.2.2.2. Human Health

There are three sources of H_2S exposure to humans: inhalation exposure, oral exposure, and dermal exposure.[976] Inhalation is the most common route of exposure, and has tended to be an issue in communities located near certain industrial sites, including pulp and paper mills, gas refineries, and geothermal power plants.[977] The respiratory tract and nervous system tend to be the most sensitive targets for acute high concentration exposures of H_2S, defined by the U.S. Department of Health and Human Services (HHS) to be concentrations exceeding 500 ppm for less than 1 hour.[978] Exposure to high concentrations can be fatal, and even where there is an apparent recovery, many individuals report permanent or persistent neurological effects, respiratory distress, and/or cardiovascular effects.[979] Acute inhalation exposures at lower H_2S concentrations have been found to cause less severe neurological and respiratory effects.[980] Acute inhalation exposure at very low concentrations has not been well studied, and although exposure to very low concentrations has been associated with neurological symptoms, the mechanism of neurological damage is not known.[981] There is also very little toxicological information about chronic exposure to H_2S; HHS argues that epidemiological studies are needed on chronic inhalation exposure, particularly because there are known human populations with unusually high exposure to H_2S.[982] The most well known study on the subject, a retrospective epidemiological study in a geothermally active area of New Zealand by Bates et al, found increased mortality from respiratory system diseases compared with the general New Zealand population, however the findings are problematic because the prevalence of smoking was not

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[976] *Id.* at 8
[977] *Id.* at 7.
[978] U.S. DEP'T OF HEALTH & HUMAN SERVICES, *supra* note 971, at 10.
[979] *Id.*
[980] *Id.*
[981] IDAHO DEP'T. OF ENVTL. QUALITY, LITERATURE REVIEW OF THE HEALTH EFFECTS ASSOCIATED WITH THE INHALATION OF HYDROGEN SULFIDE 3 (2001).
[982] U.S. DEP'T. OF HEALTH & HUMAN SERVICES, *supra* note 971, at 105.

evaluated as a potential confounder.[983] Evidence on oral exposure to H_2S is limited to a single animal study, which found a digestive disorder resulting from H_2S in feed.[984] Epidemiological studies on dermal/occular exposure have found a number of ocular effects for residents exposed to H_2S, with the prevalence of the symptoms increasing with H_2S concentration.[985] The effect of various H_2S exposure levels on human health has been summarized by the World Health Organization (WHO) and is shown in Table 7.1.

[983] Michael N. Bates et al, Air Pollution and Mortality in the Rotorua Geothermal Area, 21 AUSTRALIAN & NEW ZEALAND J. PUB. HEALTH 581, 584-585 (1997). *See also* U.S. DEP'T OF HEALTH & HUMAN SERVICES, *supra* note 971, at 23.
[984] H. Wetterau et al, [Tests for the Application of Dried Green Fodder with Higher Hydrogen Sulfide Content], 5 FETTURNG 383 (1964) [German]; U.S. DEP'T OF HEALTH & HUMAN SERVICES, *supra* note 971, at 23.
[985] U.S. DEP'T OF HEALTH & HUMAN SERVICES, *supra* note 971, at 56.

Table 7.1 Effect of Various H_2S Exposure Levels on Human Health (adapted from WHO)[986]

EXPOSURE (MG/M^3)	EFFECT/OBSERVATION	REFERENCE
0.011	Odor threshold	Amoore & Hautala[987]
2.8	Bronchial constriction in asthmatic individuals	Jappinen et al[988]
5.0	Increased eye complaints	Vanhoome et al[989]
7 or 14	Increased blood lactate concentration, decreased skeletal muscle citrate synthase activity, decreased oxygen uptake	Bambhani & Singh[990] Bambhani et al[991]
5-29	Eye irritation	IPCS[992]
28	Fatigue, loss of appetite, headache, irritability, poor memory, dizziness	Ahlhorg[993]
>140	Olfactory paralysis	Hirsch & Zavala[994]
>560	Respiratory distress	Sployar[995]
≥700	Death	Beauchamp et al[996]

986 Adapted from WORLD HEALTH ORGANIZATION, *supra* note 973, at 14.
987 J.E. Amoore & E. Hautala, Odor as an Aid to Chemical Safety: Odor Thresholds Compared with Threshold Limit Values and Volatilities for 214 Industrial Chemicals in Air and Water Dilution, 3 J. APPLIED TOXICOLOGY 272 (1983).
988 P. Jappinen et al, Exposure to Hydrogen Sulphide and Respiratory Function, 47 BRITISH J. INDUSTRIAL MED. 824 (1990).
989 M. Vanhoorne et al, Epidemiological Study of Eye Irritation by Hydrogen Sulfide and/or Carbon Disulphide Exposure in Viscose Rayon Workers, 3 ANNALS OF OCCUPATIONAL HYGIENE 307 (1995).
990 Y. Bhambhani & M. Singh, Physiological Effects of Hydrogen Sulfide Inhalation during Exercise in Healthy Men, 71 J. APPLIED PHYSIOLOGY 1872 (1991).
991 Y. Bhambhani et al,Effects of 10-ppm Hydrogen Sulfide Inhalation in Exercising Men and Women, 39 J. OCCUPATIONAL & ENVTL. MED. 122 (1997); Y. Bhambhani et al, Effects of 5 ppm Hydrogen Sulfide Inhalation on Biochemical Properties of Skeletal Muscle in Exercising Men and Women, 57 AM. INDUSTRIAL HYGIENE ASSOC. J. 464 (1996).
992 INTERNATIONAL PROGRAMME ON CHEMICAL SAFETY, HYDROGEN SULFIDE (Envtl. Health Criteria 19, 1981).
993 G. Ahlborg, Hydrogen Sulfide Poisoning in Shale Oil Industry, 3 ARCHIVES OF INDUSTRIAL HYGIENE & OCCUPATIONAL MED. 247 (1951).
994 A.R. Hirsch & G. Zavala, Long Term Effects on the Olfactory System of Exposure to Hydrogen Sulphide, 56 OCCUPATIONAL & ENVTL. MED. 284 (1999).
995 L.W. Spolyar, Three Men Overcome by Hydrogen Sulfide in Starch Plant, 11 INDUSTRIAL HEALTH MONTHLY 116 (1951).
996 R.O. Beauchamp Jr, et al, A Critical Review of the Literature on Hydrogen Sulfide Toxicity, 13 CRITICAL REVIEWS IN TOXICOLOGY 25 (1984).

7.2.2.3. Environmental Degradation

Although acid gas typically exists in a liquid phase, acid gas could be injected in its gas phase. For example, of 44 acid gas injection operations in western Canada, acid gas existed as a liquid at 40 sites and as a gas at 4 sites.[997] Because acid gas is primarily composed of H_2S and CO_2, acid gas released to the surface will be released as a gas. The primary concern is the H_2S component because of its toxicity. H_2S released to the surface will remain in the atmosphere for about 18 hours.[998] There is also the potential for acid gas to contaminate groundwater sources. Contamination could derive from leaching metals due to acid gas corroding the injection well and migrating into a drinking water aquifer, or acid gas contaminating the drinking water aquifer directly. H_2S and CO_2 are soluble in water and act as an acid.[999] There is also the potential for soil contamination by means of deposition from the atmosphere or migration through groundwater.[1000] H_2S contamination has been identified in at least 35 of the 1,647 hazardous waste sites that are included on the EPA National Priorities List (NPL) under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA).[1001] It was identified in the air at 23 of the 35 NPL sites, in the groundwater at 3 sites, in the surface water at 1 site, in the soil at 13 sites, and in the sediment at 3 sites.[1002]

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[997] Stefan Bachu and John J. Carroll, In-situ Phase and Thermodynamic Properties of Resident Brine and Acid Gases (CO_2 and H_2S) Injected into Geological Formations in Western Canada, *in* PROC. SEVENTH INT'L CONF. GREENHOUSE GAS CONTROL TECHS. (E.S. Rubin et al eds. 2004).
[998] U.S. DEP'T OF HEALTH & HUMAN SERVICES, *supra* note 971, at 2.
[999] *Id.* at 119.
[1000] *Id.* at 122.
[1001] *Id.* at 117.
[1002] *Id.* at 120-122.

7.2.3. Managing Acid Gas Injection Liability: Alberta, Canada

7.2.3.1. Current Operations

From a worldwide perspective, acid gas injection has taken place primarily in the Alberta basin of Canada, largely due to regulations in Alberta mandating sulfur recovery from stationary sources. British Columbia has also developed sulfur recovery regulations;[1003] Alberta tends to be the leader in oil and gas regulation in Canada, with the other provinces following Alberta's direction. The Alberta regulatory guidelines, originally set forth in an August 1988 informational letter and revised in an August 2001 interim directive, require that all new gas plants with a sulfur throughput of at least 1 tonne per day recover sulfur from their gas streams.[1004] Sulfur is deemed recovered if it is converted into elemental sulfur, injected as sour or acid gas, or recovered and recombined with the bulk gas stream.[1005] The Alberta Energy and Utilities Board (EUB) has licensed 35 acid gas injection plants, 5 of which were previously grandfathered[1006] sulfur recovery or acid gas flaring plants converted to acid gas injection.[1007] In total, 51 acid gas injection sites have been approved in Western Canada, although only 44 are in active operation; 1 operation was never implemented, 3 operations had their approvals rescinded because the geological formations had reached their approved capacity or because the facility

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[1003] The International Energy Agency (IEA) has noted 7 acid gas injection projects in British Columbia. IEA GREENHOUSE GAS R&D PROGRAMME, ACID GAS INJECTION: A STUDY OF EXISTING OPERATIONS, PHASE I: FINAL REPORT 6 (Report No. PH4/18, 2003).

[1004] ALBERTA ENERGY AND UTILITIES BOARD, INTERIM DIRECTIVE ID 2001-3, SULPHUR RECOVERY GUIDELINES FOR THE PROVINCE OF ALBERTA (2001); H.L. LONGWORTH, UNDERGROUND DISPOSAL OF ACID GAS IN ALBERTA, CANADA: REGULATORY CONCERNS AND CASE HISTORIES 181 (Society of Petroleum Engineers Report No. 35584, 1996)

[1005] ALBERTA ENERGY AND UTILITIES BOARD, INTERIM DIRECTIVE ID 2001-3, SULPHUR RECOVERY GUIDELINES FOR THE PROVINCE OF ALBERTA 5 (2001).

[1006] Over time, grandfathered plants are expected to increase sulfur recovery based on certain regulatory guidelines, and all grandfathering ends effective December 31, 2016. Grandfathered plants that exceed minimum sulfur recovery expectations earn bankable sulfur emission reduction credits which may be applied to meet future increased sulfur recovery requirements. *Id.*

[1007] ALBERTA ENERGY AND UTILITIES BOARD, SULPHUR RECOVERY AND SULPHUR EMISSIONS AT ALBERTA SOUR GAS PLANTS 10 (2005).

producing acid gas for the operation was decommissioned; and 3 operations were suspended due to reservoir over-pressuring.[1008] The IEA Greenhouse Gas R&D Programme found that 55% of the acid gas injection operations take place in deep saline formations and 45% take place in oil and gas fields.[1009] Bachu et al have documented the H_2S/CO_2 composition at 44 sites in Western Canada, finding that the projects range in composition from 1% H_2S/98% CO_2 to 95% H_2S/5% CO_2.[1010] Many of these acid gas injection projects are essentially CO_2 injection projects. A graphic of acid gas injection composition at the various sites based on the data compiled by Bachu et al is shown in Figure 7.2.[1011]

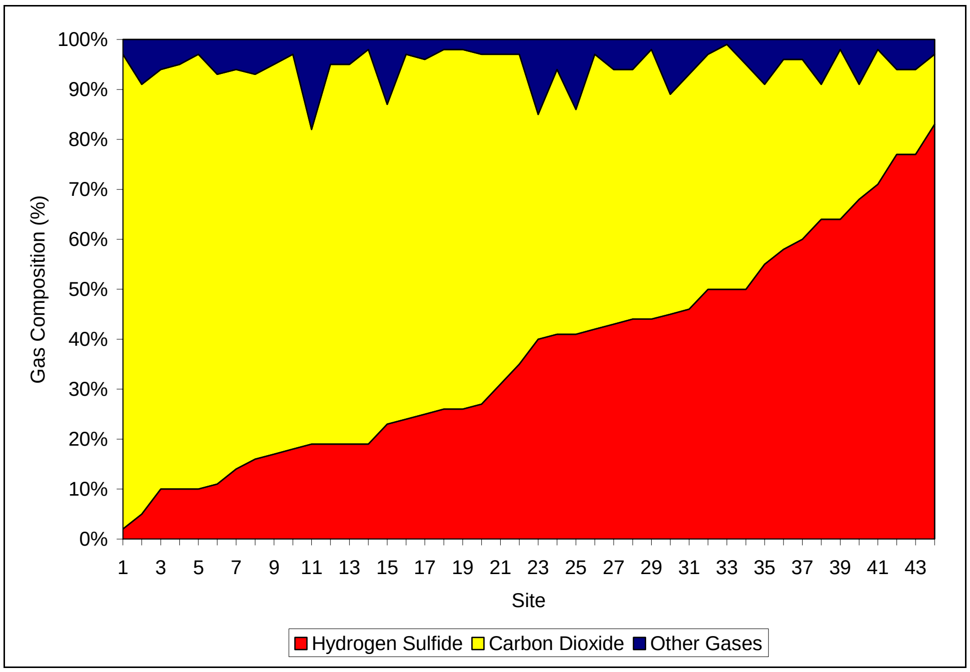


Figure 7.2 Acid Gas Composition at Forty-Four Sites in Western Canada[1012]

[1008] INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, IPCC SPECIAL REPORT ON CARBON DIOXIDE CAPTURE AND STORAGE 212 (2005) [hereinafter IPCC Special Report].
[1009] IEA GREENHOUSE GAS R&D PROGRAMME, *supra* note 1003, at ii.
[1010] IEA GREENHOUSE GAS R&D PROGRAMME, *supra* note 1003, at 13.
[1011] Bachu & Carroll, *supra* note 997.
[1012] Data from Bachu & Carroll, *supra* note 997.

Table 7.2 Acid Gas Injection Plants in Alberta[1013]

OPERATION	SULFUR INJECTED IN 2004 (T/D)
Grandfathered Acid Gas Injection Plants	
Bellshill Lake - Viking Holdings	AGI started Jan 2005
Brazeau R. - Keyera	170.68
Retlaw (Turin) - Taylor Management	0.79
Virginia Hills (Hope Creek) - Apache	2.15
Vulcan - (Long Coulee) ConocoPhillips	1.96
Non-Grandfathered Acid Gas Injection Plants[1014]	
Bistcho Lk - Paramount	10.79
Bigoray - Enerpro Midstream	26.62
Boundary Lk S (Clear Hills) - CNRL	9.74
Dizzy (Steen River) Penn West	3.73
Dunvegan - Devon	0.54
Eaglesham - (West Culp) Devon	1.81
Galahad - Husky	2.78
Golden Spike - Atco Midstream	2.92
Gordondale - Duke	21.59
Kelsey (Rosalind) - Thunder	1.64
Leduc-Woodbend (Calmar) - Midcoast Canada	2.64
Marlowe (Dizzy) - Bearspaw	0.00
Mulligan (Fourth Creek) - Duke	7.45
Normandville - Devon	0.07
O'Chiese - Burlington	0.38
Paddle River - Keyera	0.76
Pembina - Enerpro Midstream	13.27
Pembina - Imperial	2.28
Pouce Coupe - Duke	8.58
Provost (Hansman Lk) - Husky	4.84
Provost (Thompson Lk) - Husky	5.07
Puskwaskau - Devon	0.25
Rainbow - ExxonMobil	9.17
Rainbow - Husky	119.36
Rycroft - Devon	5.15
Watelet (Glen Park) - Atco Midstream	0.96
Wayne-Rosedale - EnCana	1.88
Wembley - ConocoPhillips	44.23
Zama - Apache	42.69

[1013] ALBERTA ENERGY AND UTILITIES BOARD, SULPHUR RECOVERY AND SULPHUR EMISSIONS AT ALBERTA SOUR GAS PLANTS, ANNUAL REPORT 11 (ST101-2005, 2005).
[1014] Grandfathered acid gas injection plants are those that were previously sulfur recovery or acid gas flaring that are now acid gas injection. They do not meet sulfur recovery requirements for new plants. All other acid gas injection facilities are non-grandfathered plants.

7.2.3.2. Regulatory Approval

Under Section 39(1)(d) of the Alberta Oil and Gas Conservation Act, all acid gas injection operations must be approved by the EUB.[1015] Prior to applying for regulatory approval, the acid gas injection applicant must fulfill certain minimum notification requirements. This includes notifying all well licensees, all mineral lessees, all mineral lessors, the unit operator (if applicable), and the approval holder (if applicable). If the acid gas is injected into a depleted hydrocarbon field, the applicant must contact the members of the EUB-designated pool. If acid gas is injected into a deep saline formation, the area of contact is a radius of 1.6 km from the section containing the acid gas injection well.

The regulatory approval requirements for acid gas injection are set forth in EUB Directive 065 and cover four areas: containment, reservoir, hydraulic isolation, and notification for equity and safety.[1016] Details of the regulatory requirements are provided in Table 7.3. The purpose of the containment requirements is to provide evidence that there will be no migration to hydrocarbon-bearing zones or groundwater.[1017] Applicants are to address phase behavior, pressure, and migration issues in demonstrating the integrity of the reservoir.[1018] The reservoir requirements also provide evidence that the acid gas injection will not exceed the fracture pressure of the geological formation.[1019] The hydraulic isolation provisions ensure that acid gas contained in the geological formation will not contaminate other subsurface zones or

[1015] "No scheme for…the storage or disposal of any fluid or other substance to an underground formation through a well…may be proceeded with unless the Board, by order, has approved the scheme on any terms and conditions that the Board prescribes." Alberta Oil and Gas Conservation Act, R.S.A., ch. O-6, § 39(1)(d) (2000).
[1016] ALBERTA ENERGY AND UTILITIES BOARD, DIRECTIVE 065, RESOURCES APPLICATIONS FOR CONVENTIONAL OIL AND GAS RESERVOIRS 118 (2004).
[1017] *Id.*
[1018] *Id.* at 119.
[1019] *Id.*

groundwater.[1020] Finally, the notification provisions are meant to provide notice to potentially affected parties concerning emergency response.[1021]

Table 7.3 Requirements for Regulatory Approval of Acid Gas Injection in Alberta[1022]

CONTAINMENT REQUIREMENTS	• Geological interpretation of the acid gas injection formation, including: ⇒ a net pay isopach map (a contour map depicting the net thickness of the formation); ⇒ a structural contour map; ⇒ a cross-sectional depiction showing: a stratigraphic interpretation of the zones of interest, an interpretation of the fluid interfaces present, completion/treatments to the wellbore, cumulative production, finished drilling date and Kelly bushing elevation, and the scale of the log readings. ⇒ tabulation of interpreted net pay, porosity and water saturation for each well • Information on the bounding formations, including: ⇒ continuity and thickness of base and caprock ⇒ lithology ⇒ integrity of the base and caprock ⇒ if fracturing is evident, explanation of how containment can be assured ⇒ a comment on the stratigraphic, structural, or combination reservoir trap type and its containment features
RESERVOIR REQUIREMENTS	• Analysis of the native reservoir fluid • Acid gas properties, including: ⇒ composition ⇒ viscosity, density, gas injection formation volume factor, and compressibility factors, and ⇒ phase behavior through the range of pressures and temperatures to which the injected fluid will be subjected • Analysis of laboratory testing for determining injected fluid interaction with matrix, caprock matrix and native fluids • Migration calculation showing radius of influence, as well as a discussion if migration could occur due to displacement, gravity, fingering, etc. • Complete pressure history of the pool, with material balance calculations if proposed disposal zone is a depleted hydrocarbon pool • Bottomhole injection pressure, maximum sandface pressure, caprock threshold pressure, fracture propagation pressure, and formation fracture pressure • Injectivity of the reservoir, proposed daily maximum injection rate, cumulative disposal volume, and expected life of the scheme
HYDRAULIC ISOLATION REQUIREMENTS	• All completion data, well logs, testing requirements, and associated discussion • Provide the following information: well location, status of well, completion intervals, and all casing information
NOTIFICATION REQUIREMENTS: EQUITY/SAFETY	• Evidence of operator's right to dispose into the proposed zone • Map showing boundaries of the disposal area, and 1.6km radius indicating well licensees, mineral right lessees, and lessors recorded; and a statement confirming that all potentially adversely affected parties have been notified of the proposed scheme • Statement indicating that notification of Emergency Response Plan (ERP) has been made to all potentially adversely affected parties.

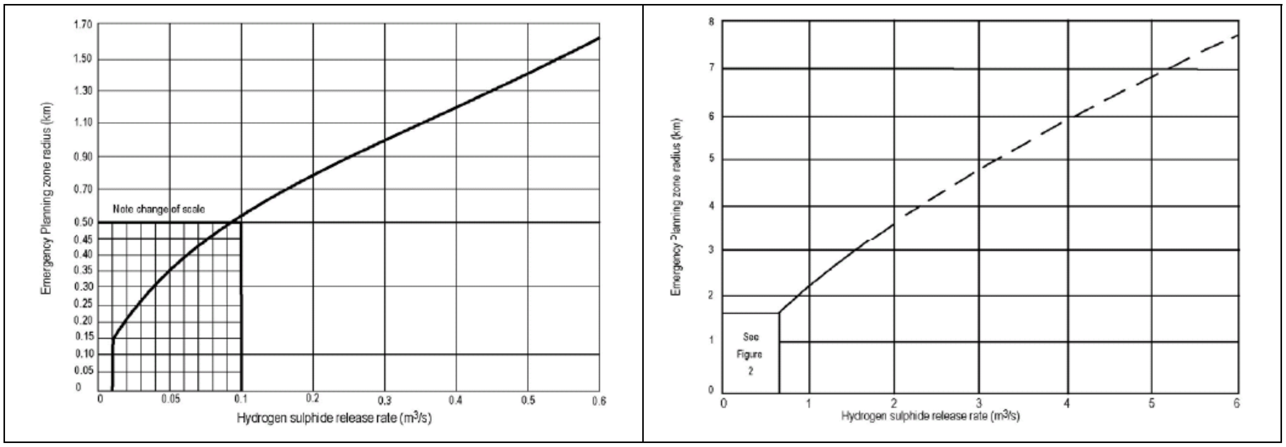
[1020] *Id.* at 120.
[1021] *Id.* at 122.
[1022] *See id.* at 118-123.

7.2.3.3. Emergency Response Plan

An environmental response plan (ERP) is a document developed to protect the public from fatalities and irreversible health effects in the event of an emergency.[1023] ERP requirements are set forth by EUB Directive 071. Although Directive 071 provides specific ERP requirements for sour wells and hydrocarbon storage in caverns, requirements for acid gas injection storage are not explicitly set forth. Directive 071 was issued prior to Directive 065; Directive 065 specifies licensee application requirements. As noted in Section 7.2.3.2 of this thesis, applicants must demonstrate that potentially affected parties have been informed acid gas injection operation's ERP.[1024] The implication from the Directives, therefore, is that an ERP is required for acid gas injection, even though this is not explicitly stated in Directive 071. Because there are no requirements specific to acid gas injection, it would be treated under the general ERP requirements.

There are two initial planning requirements for ERPs. The first is to determine an emergency planning zone (EPZ), which is an area surrounding the well where immediate response actions are taken in the event of an emergency.[1025] The size of the EPZ will depend on the maximum potential release rate of acid gas from the wellhead; the EPZ determination for H_2S projects is shown in Figure 7.3. The second requirement is for the licensee to determine those members of the public and local government that should be consulted and included in the ERP.[1026]

[1023] ALBERTA ENERGY AND UTILITIES BOARD, DIRECTIVE 071, EMERGENCY PREPAREDNESS AND RESPONSE REQUIREMENTS FOR THE UPSTREAM PETROLEUM INDUSTRY 1 (2005).
[1024] ALBERTA ENERGY AND UTILITIES BOARD, *supra* note 1016, at 123.
[1025] ALBERTA ENERGY AND UTILITIES BOARD, *supra* note 1023, *at* 4.
[1026] *Id.* at 6.



(1) (2)

Figure 7.3 Determination of Emergency Planning Zone for H_2S (EUB)[1027]
(1) EPZ for Release Rates of 0.01-0.6 m^3/s; (2) EPZ for Release Rates of 0.6-6 m^3/s

The next step is to develop a corporate-level ERP, which is a document that provides information on classifying incidents, possible responses to incidents, responsibilities of corporate personnel, emergency response centers, and communication with members of the public and local government.[1028] Classification of incidents depends on whether the incidents can be handled on site through normal operating procedures or whether more complex resolution methods are required.[1029] Criteria for determining classification include risk, control, containment, and impact on safety and the environment.[1030] Finally, the ERP must be approved for compliance by the EUB, and all potentially adversely affected parties must be notified of the ERP.[1031]

[1027] *Id.* at 42.
[1028] *Id.* at 11.
[1029] *Id.*
[1030] *Id.* at 12.
[1031] *Id.* at 11; ALBERTA ENERGY AND UTILITIES BOARD, *supra* note 1016, at 123.

7.2.3.4. Suspension

In December 2004, the EUB set forth requirements in Directive 013 for the suspension of inactive acid gas injection wells.[1032] These requirements are part of a larger framework for suspension of wells. Before the directive was implemented, Alberta had 42,000 wells that had been inactive for longer than one year, many of which had been inactive for over 25 years.[1033] A motivation for Directive 013 was the fact that "numerous acid gas disposal wells had been put into operation" over the previous 15 years.[1034] In developing the directive, the EUB also noted that "the implementation of carbon dioxide (CO_2) injection for the purposes of enhanced recovery or simply CO_2 storage will likely introduce new issues and concerns related to well suspension".[1035]

Acid gas injection wells have been deemed "high risk" by the EUB for the purposes of suspension.[1036] Four factors determine the risk category of a well: H_2S content (which determines the risk to the public and subsequent workers); capability of the well to flow to the atmosphere (which determines the difficulty of capping a well should an uncontrolled flow occur); type of well (an acid gas injection well "greatly influences" the health and environmental risks); and the casing integrity and downhole configuration (barriers of flow to the atmosphere and below ground can reduce the risk of an uncontrolled flow).[1037] An injection well is subject to suspension once it has been deemed inactive, which in the case of acid gas injection wells

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[1032] ALBERTA ENERGY AND UTILITIES BOARD, DIRECTIVE 013, SUSPENSION REQUIREMENTS FOR WELLS (2004). Suspension is the temporary cessation of operations at a well, whereas abandonment is the permanent dismantlement of a well. Alberta Oil and Gas Conservation Act, R.S.A., ch. O-6, § 1(1)(a), 1(1)(xx) (2000).

[1033] ALBERTA ENERGY AND UTILITIES BOARD, BULLETIN 2004-29, DIRECTIVE 013: SUSPENSION REQUIREMENTS FOR WELLS 1 (2004).

[1034] *Id.*

[1035] *Id.*

[1036] ALBERTA ENERGY AND UTILITIES BOARD, *supra* note 1032, at .3.

[1037] ALBERTA ENERGY AND UTILITIES BOARD, *supra* note 1033, at 1.

occurs if the well has not reported any type of volumetric activity for six consecutive months.[1038] Because acid gas injection wells have been deemed high risk, they are subject to stricter downhole requirements, MMV requirements, and inspection frequency than wells which are of a lower risk (such as groundwater wells).

The suspension requirements for inactive wells are summarized in Table 7.4. Licensees are required to plug the inactive well, and have two options for doing so. The first option is to use a packer and a tubing plug.[1039] As noted in the discussion of EPA's UIC requirements in Chapter 0, a packer is a mechanical device that seals the outside of the tubing to the inside of the long string casing of the injection well.[1040] The packer functions to seal off part of the borehole. The second option is to use a bridge plug capped with 8 linear meters of cement.[1041] If the first option is chosen (packer and tubing plug), MMV regulatory requirements are fulfilled by pressure testing the annulus and tubing to 7 MPa for 10 minutes, with a frequency of inspection of once per year.[1042] If the second option is chosen (bridge plug capped with cement), the casing is to be pressure tested to 7 MPa for 10 minutes, and the frequency of inspection is once every 5 years.[1043] In the case of both options, any wellbore fluid is to be inhibited with a non-freezing fluid in the top 2 meters.[1044] Standard wellheads are set forth by regulation; they are to be serviced and their sealing elements pressure tested at the time of suspension and at each subsequent inspection.[1045] All outlets of the well are to be plugged and all valves must be

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1038 ALBERTA ENERGY AND UTILITIES BOARD, *supra* note 1032, at 1-2.
1039 *Id.* at 3.
1040 *See* Chapter 0, *supra* note 103.
1041 A bridge plug is a downhole tool that is located and set to isolate the lower part of the wellbore. It enables the lower wellbore to be sealed from the upper zone. SCHLUMBERGER, *supra* note 611 (s.v. "bridge plug").
1042 ALBERTA ENERGY AND UTILITIES BOARD, *supra* note 1032, at 3.
1043 *Id.*
1044 *Id.*
1045 *Id.*

functional.[1046] The actions taken for inspection or suspension must be reported within 30 days following completion of the requirements.[1047]

If a licensee seeks to reactivate a suspended acid gas injection well, the licensee must undertake the following procedures. First, the licensee must inspect, service, and pressure test the wellhead. Second, the licensee must pressure test the casing to 7 MPa for 10 minutes.[1048] If this test fails, then the problem must be investigated and repaired.[1049] Third, if tubing is present, the tubing must be pressure tested to 7 MPa for 10 minutes.[1050] If this test fails, the problem must be investigated and repaired.[1051] Fourth, the licensee must inspect and service control systems and lease facilities.[1052] Finally, the licensee must report reactivation of the well on Alberta's Digital Data Submission system and retain records.[1053] A previously suspended acid gas injection well would attain active status after it has operated for a minimum of 360 hours (15 days) per month for 3 consecutive months.[1054]

[1046] *Id.*
[1047] *Id.*
[1048] *Id.* at 4.
[1049] *Id.*
[1050] *Id.*
[1051] *Id.*
[1052] *Id.*
[1053] *Id.*
[1054] *Id.*

Table 7.4 Suspension Requirements for Inactive Acid Gas Injection Wells in Alberta[1055] -

Downhole requirements	Option 1 -- Packer and a tubing plug Option 2 -- Bridge plug capped with 8 m linear cement
Inspection, monitoring, pressure testing requirements	Option 1 -- Pressure test annulus and tubing to 7 MPa for 10 minutes Option 2 -- Pressure test casing to 7 MPa for 10 minutes
Inspection frequency	Option 1 -- 1 year Option 2 -- 5 years
Reporting	Within 30 days after completion of inspection or suspension operations. Within 30 days after resumption of production/injection
Wellbore fluid	Wellbore fluid is to be inhibited with a nonfreezing fluid in the top 2 m.
Wellheads	Standard wellheads as outlined in O&G Regs. 6.100(3), 6.130(1)(2), 7.050(3), 7.060(8), ID 98-02, ID 97-6, IRP (ARP) 2, IRP 5 and API - 6A. CSA Z341 (Caverns)
Wellhead maintenance	There shall be no wellhead leaks. Regular wellheads require servicing and pressure testing of sealing elements at time of suspension and at each subsequent inspection. All outlets except surface casing vents are to be bull plugged or blind flanged with needle valves. Valves must be functional (open/close). Grease and service as required to maintain functionality.
Security	All wellheads are to be conspicuously marked or fenced such that they are visible in all seasons with well identification sign in plain view. In agricultural areas, farming operations must be restricted to safe distances from the wellhead. Pumpjacks must be left in a secure condition. Valve handles must be chained and locked, or as an alternative, valve handles may be removed.
Surface casing vent flows	Systems must be open and comply with the Oil and Gas Regulations 6.100 (1) (2) (3). Vent flows, if detected, are to be handled as described in ID 2003-01: *1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Vent Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements.*

[1055] ALBERTA ENERGY AND UTILITIES BOARD, SUSPENSION REQUIREMENTS FOR WELLS 3 (EUB DIRECTIVE 013, 2005).

7.2.3.5. Abandonment

Abandonment of an acid gas injection well occurs where it has been permanently dismantled so that it is permanently incapable of injecting acid gas.[1056] There are a number of steps that licensees must follow for well abandonment in Alberta, and the regulatory requirements are set forth in Directive 020.[1057] First, the licensee must identify the type of well abandonment to be undertaken.[1058] The EUB sets forth different requirements depending on whether the abandonment is an "open-hole well abandonment" or a "cased-hole well abandonment". Open-hole well abandonment occurs for a well that has been drilled, but not cased because it was not brought into operation.[1059] Cased-hole abandonment occurs for a completed well (one that has been both drilled and cased).[1060] Second, the licensee must determine if the abandonment operation is routine or non-routine. Routine abandonment means that the well meets all requirements related to the type of well being abandoned, the location of the well, the impact of the well on oil sands zones, and the condition of the wellbore.[1061] If well abandonment is routine, EUB regulatory approval is not required prior to commencing abandonment.[1062] However, if the well abandonment is found to be non-routine, approval from the EUB is required before abandonment can proceed.[1063] Third, if the well abandonment is found to be routine, or if the non-routine abandonment has been approved by the EUB, the licensee must conduct certain tests on the well, including testing fluid levels for open-hole wells, surface casing vent flow for cased-hole wells, and gas migration for any well within the required

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[1056] C.B. POWTER (COMPILER), GLOSSARY OF RECLAMATION AND REMEDIATION TERMS USED IN ALBERTA, 7TH ED. 1 (Alberta Environment Pub. No. T/655, Report No. SSB/LM/02-1, 2002).
[1057] ALBERTA ENERGY AND UTILITIES BOARD, DIRECTIVE 020, WELL ABANDONMENT GUIDE (2003).
[1058] *Id.* at 3.
[1059] POWTER, *supra* note 1056, at 51.
[1060] *Id.* at 12.
[1061] ALBERTA ENERGY AND UTILITIES BOARD, *supra* note 1057, at 3.
[1062] *Id.*
[1063] *Id.*

test area.[1064] Finally, the licensee must inform all affected parties of the planned abandonment prior to undertaking any work, and report abandonment of the well to the EUB within 30 days of completing abandonment.[1065]

7.2.3.6. Liability for Suspension, Abandonment, and Reclamation

The EUB has authority to mandate a licensee (or approval holder[1066]) to suspend or abandon a well when it is necessary to protect the public or the environment.[1067] The board may also demand that a working interest participant suspend or abandon the well.[1068] A working interest participant is a person who owns an interest in the well, [1069] and may not necessarily be same as the licensee (the person listed in EUB records as having received regulatory approval to operate the well). If the licensee or working interest participant does not comply with the EUB order, the EUB may authorize a third party to suspend or abandon the well, with the costs attributable to the licensee and/or working interest participant.[1070] EUB generally only orders a third party to suspend or abandon a well if the well is an orphan well, or if the licensee is "seriously noncompliant" with regulations.[1071]

The costs of suspension and abandonment are to be paid by the working interest participants of the well according to their proportionate share of ownership.[1072] Proportionate

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[1064] *Id.*
[1065] *Id.* at 4.
[1066] According to the Alberta Oil and Gas Conservation Act, a licensee is the holder of a license according to the records of the EUB, whereas an approval holder is the holder of an approval granted pursuant to the Oil and Gas Conservation Act , any predecessor of the Act, or any regulation under any of the Acts. Alberta Oil and Gas Conservation Act, R.S.A., ch. O-6, § 1(1)(e), 1(1)(cc) (2000).
[1067] *Id.* at § 27(1).
[1068] *Id.* at § 27(2).
[1069] *Id.* at § 1(1)(fff).
[1070] *Id.* at § 28, 30(2).
[1071] Brezina & Gilmour, Protecting and Supporting the Orphan Fund: Recent Legislative and AEUB Policy Amendments Designed to Address Unfunded Liabilities of Oil and Gas Facilities in Alberta, 41 ALBERTA L. REV. 29, 35.
[1072] The cost allocation also applies to any reclamation costs of the well. The focus in this section will be on suspension and abandonment.

share of ownership means the percentage share equal to the participant's undivided interest in the well.[1073] When a licensee or working interest participant suspends or abandons a well, the costs of suspension or abandonment are reported to EUB, and EUB allocates the costs to each working interest participant.[1074] If a working interest participant fails to pay its share of costs for suspension or abandonment, it is subject to a penalty equal to 25% of its share of costs.[1075] The costs of suspension or abandonment, plus any penalty are a debt payable to the licensee or working interest participant that carried out the suspension or abandonment.[1076] If EUB, or a third party authorized by EUB, carried out the suspension or abandonment, the proportionate share of costs plus penalty are a debt payable to EUB.[1077]

Working interest participants are also responsible for reclamation costs. Reclamation is governed by the Alberta Environmental Protection and Enhancement Act,[1078] and is regulated by Alberta Environment rather than the EUB. Responsibility for reclamation costs includes the reasonable costs actually incurred in reclaiming a well.[1079] Because of the broad definition of reclamation costs, reclamation costs may include not only the costs of land surface reclamation, but also the costs of groundwater and soil remediation.[1080] The costs of groundwater and soil remediation are often much greater than the costs of abandonment and land surface reclamation.[1081]

Licensees, approval holders and working interest participants are also subject to "continuing liability". Continuing liability means that the licensee or working interest

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[1073] Brezina & Gilmour, *supra* note 1071, at 36.
[1074] Alberta Oil and Gas Conservation Act, § 30(2)
[1075] *Id.* § 30(3).
[1076] *Id.* § 30(4).
[1077] *Id.*
[1078] Alberta Environmental Protection and Enhancement Act, R.S.A., ch. E-12, § 137 (2003).
[1079] Alberta Oil and Gas Conservation Act, § 1(1)(vv) (2000).
[1080] Brezina & Gilmour, *supra* note 1071, at 36.
[1081] *Id.* at 37.

participant is still financially responsible for the well even after abandonment. The Alberta Oil and Gas Conservation Act defines continuing liability as follows:

> Abandonment of a well or facility does not relieve the licensee, approval holder or working interest participant from responsibility for the control or further abandonment of the well or facility or from the responsibility for the costs of doing that work.[1082]

There are two aspects of continuing liability. First, the licensee, approval holder or working interest participant has a responsibility for the control or further abandonment of the well even after the well has been abandoned. Control and further abandonment are separate responsibilities. The statute does not define what it means to have a responsibility to control a well or what that responsibility entails, but based on the statutory construction, we can assume it means something other than responsibility for further abandonment. One possibility is that it is related to suspension and/or reclamation, which are not specifically mentioned in the definition of continuing liability. Second, the licensee, approval holder or working interest participant is responsible for the costs of controlling or further abandoning the well. Although not stated in the statute, the costs are most likely allocated on a proportionate basis. Continuing liability for abandoned wells is a concept unique to Alberta. By contrast, if a well is deemed abandoned in the United States, the underground injection permit holder is generally not financially responsible for the well after its abandonment.

[1082] Alberta Oil and Gas Conservation Act, § 29.

7.2.3.7. Licensee Liability Rating

The Alberta Licensee Liability Rating (LLR) Program (Directive 006) was developed to minimize liability from unfunded well, facility, and pipeline abandonment and reclamation.[1083] All EUB licensees are required to report financial information to the EUB regarding their assets and liabilities. The program also applies to all potential license transfers. The EUB compares the deemed assets and deemed liabilities of the licensee to define the LLR:[1084]

$$\text{Licensee Liability Rating} = \frac{\text{Deemed Assets}}{\text{Deemed Liabilities}} \tag{7.1}$$

If a licensee's deemed liabilities exceed its deemed assets, the licensee is required to place a security deposit with EUB equal to the difference between its deemed assets and deemed liabilities.[1085] Security deposits may only be in the form of cash or letters of credit that meet EUB regulatory requirements.[1086] Security deposits are administered on a licensee basis rather than by individual well.[1087] The security deposit may be used to address either potential abandonment or potential reclamation costs if the licensee fails to comply with the order of the appropriate regulatory agency.[1088]

The deemed assets of an acid gas injection well are determined by its netback. Netback, a financial term used by the oil and gas industry, is the profit per unit of volume injected (or produced). As shown in Equation 7.2, netback for an acid gas injection well is calculated from

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1083 ALBERTA ENERGY AND UTILITIES BOARD, DIRECTIVE 006, LICENSEE LIABILITY RATING (LLR) PROGRAM AND LICENCE TRANSFER PROCESS 1 (2003).
1084 *Id.* at 10.
1085 *Id.* at 2.
1086 *Id.* at 22.
1087 *Id.*
1088 *Id.*

the ratio of net revenues to production volume.[1089] The net revenues are the revenues of the well minus expenses and specific general and administrative (G&A) costs.[1090] The financial information to determine netback is to be reported every month to the EUB.[1091]

$$\text{Netback} = \frac{\text{Net Revenues}}{\text{Production Volume}} = \frac{\text{Revenues - Expenses - Specific G \& A Costs}}{\text{Production Volume}} \qquad \textbf{7.2}$$

As shown in Equation 7.3, the deemed assets of an acid gas injection well are determined by the volume injected from the preceding 12 calendar months multiplied by the netback multiplied by 3 years.[1092] If the licensee has oil or gas production associated with the acid gas injection, the cash flow associated from the oil or gas production volumes is determined by an alternate formula, which uses an industry average netback to determine deemed assets.[1093]

$$\text{Deemed Assets} = \text{1-Month Netback} \times \text{12-Month Production Volume} \times \text{3 years} \qquad \textbf{7.3}$$

As shown in Equation 7.4, the deemed liabilities of an acid gas injection well[1094] are the sum of the abandonment and reclamation liability, adjusted for present value and salvage (PVS).[1095] Abandonment liability, which is a site-specific determination, is based on the estimated cost to abandon the well based on the depth of the well, the requirement to protect

[1089] *Id.* at 12.
[1090] *Id.* at 32.
[1091] *Id.* at 2.
[1092] *Id.* at 10.
[1093] In such a scenario, the deemed asset is calculated by multiplying the licensee's reported production of oil or gas from the preceding 12 calendar months by the 5-year rolling average industry netback by 3 years. Production volume is recorded in cubic meters oil equivalent (m^3 OE), defined as the 12-month production of oil plus gas volumes reduced by a shrinkage factor and a gas/oil conversion factor. The shrinkage factor and gas/oil conversion factor are based on a rolling 5-year provincial industry average. *Id.* at 11.
[1094] The LLR system applies to both wells and facilities; the discussion here is limited to its application to wells.
[1095] ALBERTA ENERGY AND UTILITIES BOARD, *supra* note 1083, at 16.

groundwater,[1096] and whether there is gas migration or surface casing vent flows.[1097] Reclamation liability is the reclamation cost specified by the Regional Reclamation Cost Map for the area in which the well is located.[1098] The PVS factor reflects the timing of abandonment and reclamation, and the future value of equipment salvage.[1099] The PVS factors are summarized in Table 7.5.

Table 7.5 Present Value and Salvage (PVS) Factors

WELL STATUS	PVS FACTOR
Active well[1100]	0.75
Inactive well[1101]	1.0
Abandoned unreclaimed well[1102]	1.0
Designated problem site[1103]	1.0
Potential problem site[1104] on transfer	1.0
Potential problem site post-transfer (until site-specific liability assessment complete)	1.0
New well[1105]	1.0

1096 The requirement to protect groundwater is included if the surface casing depth is less than the deepest groundwater aquifer requiring protection. *Id.*

1097 *Id.*

1098 *Id.* at 17.

1099 *Id.* at 15.

1100 An active well is a well that has reported production or injection in the last 12 calendar months or is classified as an observation well by the EUB. *Id.* at 14.

1101 An inactive well is a well that has not reported production or injection in the last 12 calendar months. *Id.*

1102 An abandoned unreclaimed well is a well that according to EUB records has been "surface abandoned", but is unreclaimed according to the records of Alberta Environment or Alberta Sustainable Resource Development. A well could be unreclaimed if it is not in receipt of a reclamation certificate, not exempted from reclamation, or is not in receipt of an overlapping reclamation certificate exemption issued for its surface location. *Id.*

1103 A designated problem site is a site that has an abandonment liability greater than or equal to 4 times the amount normally calculated for that type of site in that regional abandonment cost area, or reclamation liability equals or exceeds 4 times the amount normally calculated for that type of site in that regional reclamation cost area. *Id.* at 15.

1104 A potential problem site is a site that has a potential abandonment liability greater than or equal to 4 times the amount normally calculated for that type of site in that regional abandonment cost area, or a potential reclamation liability greater than or equal to 4 times the amount normally calculated for that type of site in that regional reclamation cost area. *Id.*

1105 A new well is a well that has not been abandoned within 12 calendar months of is finished drilling date. *Id.*

$$\text{Deemed Liabilities} = A + B + C + D + E + F \qquad \textbf{7.4}$$

where
A = total calculated active well abandonment and reclamation liability × PVS of 0.75
B = total calculated inactive well abandonment and reclamation liability × PVS of 1.0
C = total calculated abandoned but uncertified well regional reclamation liability × PVS of 1.0
D = total of designated problem site liability determined by site-specific liability assessment × PVS of 1.0
E = total of potential problem site liability:

- *for monthly LLR assessment purposes where site has not been transferred:* calculated well or facility abandonment and reclamation liability × site's PVS factor; or
- *for license transfer assessment purposes or where the site has been transferred for monthly LLR assessment purposes until the required environmental site assessment has been completed:* calculated well or facility abandonment and reclamation liability with either or both component multiplied (based on purpose of site assessment) by 20 × PVS of 1.0

F = total calculated new well abandonment and reclamation liability × PVS of 1.0

A licensee that fails to provide the required security deposit to EUB based on its LLR is considered to be in noncompliance with the LLR program and is subject to the escalating consequences of EUB's enforcement provisions., known as the major enforcement ladder.[1106] The licensee will receive a Major Level 2 noncompliance letter if the EUB has not received the security deposit payment for the previous monthly LLR assessment.[1107] If the EUB has not received the security deposit payment by the day specified in the Level 2 letter, the licensee will receive a Major Level 3 noncompliance letter.[1108] If the EUB has not received the security payment by the day specified in the Level 3 letter, the licensee will receive a Major Level 4 noncompliance letter, where the EUB will issue a Miscellaneous Order to pay the outstanding security deposit within a specified period of time.[1109] If the licensee does not comply with the Miscellaneous Order, the EUB will issue closure orders on the well, and may ultimately order abandonment.[1110] The EUB will also impose a "Refer" status on the licensee, designating the

[1106] *Id.* at 28.
[1107] *Id.*
[1108] *Id.*
[1109] *Id.*
[1110] *Id.*

licensee's inability or unwillingness to comply with EUB requirements. A licensee's Refer status will be a consideration in any EUB applications submitted by the licensee.[1111] A licensee will be removed from the major enforcement ladder when it satisfies the requirements for removal from its level of noncompliance and remains compliant with the LLR Program requirements for the following three consecutive monthly LLR assessments.[1112]

7.2.3.8. Orphan Well Fund

The Alberta Oil and Gas Conservation Act established an orphan fund to pay for the suspension, abandonment and reclamation costs for orphan wells and their related facilities, and to pay for the costs attributable to any defaulting working interest participant's share of suspension, abandonment and reclamation costs.[1113] The orphan fund applies to all injection well licensees, and is not specific to acid gas injection. The orphan fund is supported by levies placed on EUB licensees and one-time licensee fees. The levy is determined by EUB annually on the basis of the estimated costs of suspension, abandonment and reclamation of orphan wells, orphan fund deficiencies from the previous fiscal year, and surplus for emergency or non-budgeted expenditures.[1114] Any licensee that fails to pay the orphan fund levy is subject to a penalty of 20% of the amount of the levy.[1115] For the 2005-2006 fiscal year, the orphan fund levy is:[1116]

[1111] *Id.*
[1112] *Id.* at 29.
[1113] Alberta Oil and Gas Conservation Act, § 70(1).
[1114] *Id.* § 73(2)
[1115] *Id.* § 74(2).
[1116] Alberta Oil and Gas Conservation Regulation 151/71 § 16.530(1) (2005).

$$\text{Fiscal Year 2005-2006 Orphan Fund Levy} = \frac{A \times CAN\$12{,}000{,}000}{B} \qquad \textbf{7.5}$$

where
A = licensee's deemed liability on February 5, 2005 for all facilities, wells and unreclaimed sites licensed to the licensee, as calculated in accordance with Directive 006; and
B = sum of the industry's liability on February 5, 2005 for all licensed facilities, wells and unreclaimed sites, as calculated in accordance with Directive 006

Although the EUB collects orphan fund levies, it has delegated responsibility for administration of the fund to the Alberta Oil and Gas Orphan Abandonment and Reclamation Association, known as the Orphan Well Association (OWA).[1117] EUB and Alberta Environment are responsible for identifying and investigating potential orphan sites, with EUB determining which sites are orphan sites and Alberta Environment responsible for conducting reclamation work.[1118] OWA is comprised of three member organizations -- the Canadian Association of Petroleum Producers, the Small Explorers and Producers Association of Canada, and the EUB -- and its directors comprise three representatives from the Canadian Association of Petroleum Producers, two representatives from the Small Explorers and Producers Association of Canada, and one representative from the EUB.[1119] In 2005, OWA had revenues of CAN$13,913,000 and expenditures of CAN$9,504,000.[1120] The majority of its revenues came from the orphan fund levy, and the majority of its expenditures were from well abandonment, followed closely by site reclamation.[1121] As a point of reference, a typical well abandonment costs about CAN$25,200, but if the well abandonment is complicated, the cost can reach over CAN$150,000.[1122] With respect to site reclamation, expenditures for remediation were an average of about CAN$18,543

[1117] Alberta Orphan Fund Delegated Administration Regulation 45/2001 (2005).
[1118] ORPHAN WELL ASS'N, 2004/05 ANNUAL REPORT 2 (2005).
[1119] *Id.* at 3.
[1120] *Id.* at 22.
[1121] *Id.*
[1122] *Id.* at 6.

per site in the 2004/2005 fiscal year and site investigations ranged from about CAN$4,000 to CAN$12,000 per site.[1123] The average site remediation expenditures from 2004/2005 were low relative to previous years because the sites required only small clean up work and were otherwise ready for reclamation.

7.2.3.9. Discussion

The *de jure* approach to acid gas injection liability in Alberta is a hybrid of regulation, financial assurance, and compensation fund. The requirements that applicants prove containment of acid gas in the geological formation and suspend inactive injection wells have the effect of limiting the probability that acid gas will leak from the geological formation, and therefore limit the potential tortious liability of licensees. Many of the regulatory requirements are analogous to the Underground Injection Control (UIC) regime in the United States, which sets forth technical standards for injection wells to protect underground sources of drinking water, however not only do the Alberta regulations go beyond groundwater protection, but they also include detailed requirements about when injection wells should be suspended and/or abandoned, a requirement not seen in the minimum UIC standards. (Comparing Alberta regulations to UIC requirements might not be a completely fair since UIC is a national program, while the Alberta regulations are provincial. However, there is no requirement that states go beyond the minimum requirements set forth by UIC and it is quite possible state UIC programs are identical to the federal UIC program. In addition, for states that have not received primacy, the EPA would regulate injection wells under the federal standards.) The regulatory requirement that applicants must develop an ERP and provide notice of the plan to local officials and all

[1123] *Id.* at 13.

residents living within a specified distance from the injection well has the effect of limiting the liability of the licensee in the event that there is a loss of containment of the acid gas.

Alberta has implemented financial assurance requirements in the form of the LLR system, which is meant to assure that licensees will have financial resources for abandonment. One might think of the rating system as analogous to the UIC financial assurance requirements for Class I injection wells, but the determination in Alberta is significantly more rigorous. The LLR, which is determined on a monthly basis, is a function of the cash flow of the injection well and the estimated costs for abandonment and reclamation. Although the rating takes into account potential degradation of the environment, there is no statutory mandate that EUB take into account damage to human health in the rating calculation and the resulting security deposit requirement. Although Alberta regulations provide for continuing liability, meaning that abandonment of an injection well does not absolve the licensee of future financial responsibility and the licensee is potentially liable for any costs associated with inadequate abandonment of the injection well, it is impossible to judge the efficacy of such a requirement when there has been no litigation in Alberta associated with a licensee's continuing liability. The statutory requirement for continuing liability does not address the issue of the adequacy of post-abandonment financial resources. As a result, continuing liability is not taken into account in the LLR other than in the initial determination for abandonment and reclamation costs. It is possible that the security deposit may be understated and licensees may not have the financial resources for all potential liabilities of the injection well. There are also questions as to the applicability of a continuing liability regime in other jurisdictions which have higher rates of litigation, such as in the United States.

Finally, Alberta legislation has created an orphan program which functions essentially as a compensation fund for wells where the licensee cannot be found or is insolvent. The orphan fund is not specific to acid gas injection, and thus acid gas injection well licensees pay into the same fund as licensees for other types of subsurface injection. All licensees, regardless of the adequacy of their LLR, are required to pay into an orphan well fund, which is administered by a governmental corporation. The amount to be paid is a function of the licensee's deemed liability as compared with the industry's deemed liability, i.e. the licensee's proportionate share of total liability. One might expect that the system of continuing liability serves to limit the expenditures paid out of the orphan well fund, particularly since continuing liability covers working interest participants and not merely licensees.

7.2.4. Managing Acid Gas Injection Liability: Texas and Wyoming

7.2.4.1. Current Operations

Although Western Canada has the most experience with acid gas injection worldwide, there is familiarity with acid gas injection in the United States, primarily in Texas and Wyoming. The Office of General Counsel of the Railroad Commission of Texas ("RRC"), which regulates H_2S injection in Texas, documents at least six H_2S injection projects submitted as proposals for decision and approved as orders under authority of the Texas Administrative Code, a regulatory framework discussed in Section 7.2.4.3 of this thesis.[1124] Detailed information about the approved projects is not publicly available, but reports from the Technical Examiner in the Office of General Counsel indicate that the acid gas injection activities are generally associated

[1124] Railroad Comm'n of Texas, Office of General Counsel, Oil and Gas Proposals for Decision and Orders, Index for § 3.36: Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas, *at* http://www.rrc.state.tx.us/divisions/support-divisions/gc/pfdord/ogpfdord/ogpor36/r36indx.html (last visited Feb. 1, 2006).

with natural gas processing and that CO_2 is often a substantial component of the acid gas.[1125] A review of the Technical Examiner's findings of fact indicates that there are more acid gas injection operations than those documented by the Office of General Counsel's docket. For example, one of the applications for acid gas injection at the Slaughter Field in Hockley County, Texas, indicates there were four acid gas injection operations in the Slaughter Field area at the time of the 2001 application,[1126] however, only one other Slaughter Field acid gas injection operation approval appears on the docket.[1127]

In Wyoming, ExxonMobil recently started an acid gas injection project at its LaBarge facility. The project consists of two injection wells designed for injection of up to 65 million standard cubic feet per day (MMscf/D) per well of a mixture of 65% H_2S and 35% CO_2.[1128] The original LaBarge plant was built in 1986, and because its sulfur plants were aging and the market for elemental sulfur appeared unviable, ExxonMobil chose an acid gas injection and cogeneration option for managing its sulfur emissions.[1129] LaBarge injects acid gas into the same geological formation from which the hydrocarbons were produced, the Madison Formation, a carbonate geological formation composed of anhydrite and dolomite sequences within a limestone structure.[1130] ExxonMobil generates electricity for the project from 3-34

[1125] *See e.g.,* The Application of Yates Energy Corporation to Consider Approval of Hydrogen Sulfide Injection, Pursuant to Statewide Rule 36 for the H. F. Borchers Lease, Well No. 1, Dubose (Edwards -A-) Field, Gonzales County, Texas (Oil and Gas Docket No. 01-0222516, 1999); The Application of Union Oil of California for Injection of Fluids Containing Hydrogen Sulfide in the Reinecke Field, Borden County, Texas (Oil and Gas Docket No. 8A-0222023, 1999).
[1126] Railroad Comm'n of Texas, The Application of Occidental Permian for Authority Pursuant to Statewide Rule 36 to Inject Hydrogen Sulphide Gas on its Central Mallet and Northwest Mallet Units, Slaughter Field, Hockley County, Texas (Oil and Gas Docket No. 8A-0226191, 2001).
[1127] Railroad Comm'n of Texas, Application of Andarko Petroleum Corp. for Authorization Pursuant to Statewide Rule 36 to Inject fluids Containing Hydrogen Sulfide on the Boyd Lease in the Slaughter Field, Cochran County, Texas (Oil and Gas Docket No. 8A-0228080, 2000).
[1128] Glen Benge and E.G. Dew, Meeting the Challenges in Design and Execution of Two High Rate Acid Gas Injection Wells, DRILLING & COMPLETIONS J. (2006).
[1129] CITY OF GREEN RIVER, CITY COUNCIL PROCEEDINGS (March 5, 2002).
[1130] *Id.*

MW turbines.[1131] Benge and Dew document the challenges of designing and executing acid gas injection wells at LaBarge, emphasizing considerations of well design, casing selection, and cement design.[1132] They note that although LaBarge was not a CO_2 injection operation *per se*, the project design was influenced by the presence of CO_2 in the acid gas stream.[1133] For example, CO_2 affects cement design because CO_2 converts calcium silicates in Portland cement to calcium carbonate, which increases its permeability and could potentially lead to emissions from the geological formation.[1134]

7.2.4.2. EPA Underground Injection Control (UIC) Program

In the United States, acid gas injection operations must meet the minimum requirements of the UIC Program.[1135] The underground injection of fluids associated with hydrocarbon production is ordinarily regulated as a Class II well.[1136] As noted in Section 3.2.3, Class II wells have relaxed regulatory requirements compared to other classes of UIC wells. States need only demonstrate that they have an effective program to prevent underground injection which endangers underground sources of drinking water.[1137] For all other classes of wells, states must demonstrate that their program is at least as stringent as UIC standards put forth by the EPA.[1138] Where the fluids contain waste waters from gas plants which are classified as "hazardous" waste, Class II status would not ordinarily apply, and the underground injection would be governed by Class I requirements.[1139] Although H_2S has been deemed hazardous waste by the EPA,[1140]

[1131] Wyoming Department of Environmental Quality, Emissions Data Assessment, Appendix G (2003), *available at* http://deq.state.wy.us/aqd/prop/2003AppG.pdf.
[1132] Benge & Dew, *supra* note 1128.
[1133] *Id.*
[1134] *Id.*
[1135] 40 C.F.R. § 144.1 *et seq.*
[1136] 40 C.F.R. § 144.6(b).
[1137] 42 U.S.C. § 300h-4.
[1138] 42 U.S.C. § 300h-1.
[1139] 40 C.F.R. § 144.6(b)(1).

Congress amended Section 3001(b)(2)(A) of the Resource Conservation and Recovery Act ("RCRA") with the Solid Waste Disposal Act Amendments of 1980 ("SWDAA")[1141] to exempt drilling fluids, produced waters, and other wastes associated with exploration, development, and production of crude oil, natural gas, and geothermal energy from regulation as hazardous wastes. Section 8002(m) of the SWDAA requires the EPA Administrator to provide a report to Congress on these wastes and provide an opportunity for public comment. In 1988, the EPA determined that gases from the production stream, including H_2S, would be exempted from hazardous waste status.[1142] In 1993, the EPA clarified that determination, noting that the production of elemental sulfur from H_2S at a gas plant would also be exempted from classification as hazardous waste.[1143] Because H_2S in conjunction with hydrocarbon exploration or production is not hazardous, acid gas injection is regulated as a Class II well and subject to its relaxed regulatory requirements. Both Texas and Wyoming have primacy over underground injection taking place in their state.

7.2.4.3. Regulatory Framework of Texas

7.2.4.3.1. H_2S Operations

In Texas, acid gas injection is governed by Title 16, Section 3.36 of the Texas Administrative Code, commonly known as "Rule 36". Rule 36 regulates "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas", and governs both sour gas production and acid gas injection where the H_2S concentration is at least 100 ppm.[1144] Under

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[1140] Hydrogen sulfide is designated as Hazardous Waste No. U135. *See* 40 C.F.R. § 261.33.
[1141] Not to be confused with the Safe Drinking Water Act, abbreviated "SDWA" in this thesis.
[1142] U.S. Envtl. Protection Agency, Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25447, 25453 (1988).
[1143] U.S. Envtl. Protection Agency, Clarification for Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 58 Fed. Reg. 15284, 15287 (1993).
[1144] Tex. Admin. Code § 3.36(a)(2)(C) (2006).

Rule 36, acid gas injection operators must determine the H_2S concentration in their acid gas.[1145] Next, operators are to determine a "radius of exposure",[1146] which is constructed with the potential point of acid gas escape as its center.[1147] The radius is to be determined for concentrations of 100 ppm and 500 ppm as follows:[1148]

$$\text{100 ppm Radius of Exposure} = (1.589 \times H_2S \times Q)^{0.6258} \tag{7.6}$$

$$\text{500 ppm Radius of Exposure} = (0.4546 \times H_2S \times Q)^{0.6258} \tag{7.7}$$

Where
Q = maximum volume determined to be available for escape [cubic feet per day]; and
H_2S = mole fraction of hydrogen sulfide in the gaseous mixture available for escape

The volume (Q) in Equations 7.6 and 7.7 is determined from the adjusted open-flow rate of the well.[1149] If the radius of exposure is found to be greater than 50 feet, operators are required to post clearly visible warning signs on public roads within the area of exposure, secure the injection well as appropriate, and use materials which are resistant to H_2S stress and cracking.[1150] Operators are required to develop a written contingency plan for alerting and protecting the public following the accidental release of a potentially hazardous volume of acid gas, with the plan including procedures for safety personnel, a call list of local officials, a plat detailing the area of exposure, and provisions for briefing the public.[1151] Finally, if the 100 ppm radius of exposure exceeds 50 feet and includes any part of a public area except a public road, or if the 500 ppm radius of exposure exceeds 50 feet and includes any part of a public road, or if the 100 ppm

[1145] *Id.* at § 3.36(c)(1).
[1146] *Id.* at § 3.36(c)(2).
[1147] *Id.* at § 3.36(b)(3).
[1148] *Id.* at § 3.36(c)(2)(A)-(B).
[1149] *Id.* at § 3.36(c)(3)(B).
[1150] *Id.* at § 3.36(c)(6).
[1151] *Id.* at § 3.36(c)(9).

radius of exposure exceeds 3,000 feet, the application for the acid gas injection operation requires a public hearing before it may be approved.[1152]

7.2.4.3.2. Plugging and Financial Security

Other aspects of acid gas injection are governed by the RRC's standard requirements for underground injection. Operators are responsible for plugging their wells, and the requirements for plugging are set forth in Section 3.14 of the Texas Administrative Code ("Rule 14"). Rule 14 sets forth the proper materials and procedures for plugging. The operator is to give the RRC at least five days notice before plugging the injection well, with the notice setting out the proposed plugging procedure. The operator may not begin plugging the well until the application is approved.[1153] Once the injection well is plugged, the operator is to file a plugging record with the RRC.[1154] The RRC is authorized to plug any inactive well if the well is likely to cause groundwater pollution, and may seek reimbursement from the well operator for any state funds expended.[1155] The RRC sets forth financial security requirements for operators under Section 3.78 of the Texas Administrative Code ("Rule 78"). The amount of financial security required depends on the number of wells that the person is operating, and is at least $25,000.[1156] The financial security can be fulfilled with a performance bond, letter of credit, or cash deposit.[1157]

7.2.4.3.3. Oil Field Cleanup Fund and Orphaned Well Reduction Program

Under Texas law, a responsible person for an injection well is required to comply with any order of the RRC to control or clean up oil and gas wastes. Failure to comply with a RRC

[1152] *Id.* at § 3.36(c)(7).
[1153] *Id.* at 16, § 3.14(a)(4).
[1154] *Id.* at § 3.14(b)(1).
[1155] *Id.* at § 3.14(b)(4)-(5).
[1156] *Id.* at § 3.78(g)(1)(B).
[1157] *Id.* at § 3.78(d).

order can lead to a lien against the hydrocarbon interests at the site in an amount of the costs to clean up the site.[1158] If the responsible person cannot be identified or is insolvent, Texas has two programs for plugging and remediating these orphan wells. The first is the Oil Field Cleanup Fund, which is funded primarily by regulatory fees, permit fees, and bond fees, but also receives appropriations from the Texas legislature.[1159] If the fund exceeds $20 million, regulatory fees for the fund are no longer collected, but if the fund later falls below $10 million, fund collection is resumed.[1160] The RRC has authority to remedy a well if it is leaking (or likely to leak), and the leakage is likely to cause a serious threat of pollution or injury to public health.[1161] The RRC uses a priority system, where wells are plugged in the order of their threat to environment, health and safety; the presence of H_2S is a factor in determining priority.[1162] The Oil Field Cleanup Program is required to provide an annual report to the Texas Legislature, which oversees management of the fund. In its latest publicly available report, the Program notes that it plugged 1,525 wells and remediated 313 sites.[1163]

The second program for remediating orphan wells in Texas is the Orphaned Well Reduction Program, established in 2005, which gives operators certain benefits if they agree to adopt orphaned wells.[1164] If the operator brings the well back into continuous operation, or plugs the well in accordance with the RRC's rules, the operator is eligible to receive a payment from the RRC equal to the depth of the well multiplied by 50 cents for each foot of well depth,[1165] an exemption from oil field cleanup regulatory fees for all future production from the well, and an

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[1158] Tex. Nat. Res. Code tit. 16, § 91.115 (d) (2006). *See also* EDWARD K. ESPING, 56 TEX. JUR. 3D OIL AND GAS § 571 (2005).
[1159] Tex. Nat. Res. Code § 91.111. *See also* JOHN G. SOULE ET AL, 46 TEX. PRAC., ENVTL. L. § 25.11 (2d ed., 2005).
[1160] Tex. Nat. Res. Code § 91.111(b).
[1161] *Id.* at § 89.043(b).
[1162] RAILROAD COMM'N OF TEXAS, OIL FIELD CLEANUP PROGRAM, ANNUAL REPORT – FISCAL YEAR 2004 7 (2005).
[1163] *Id.* at 5, 12.
[1164] Tex. Nat. Res. Code § 89.047 (2006).
[1165] Not to exceed $500,000 as an aggregate amount. Tex. Nat. Res. Code § 89.047(j).

exemption from severance taxes for all future production from the well.[1166] A severance tax is a tax on the oil and gas extracted from a reservoir; in Texas, it is currently 4.6% of the market value of the oil[1167] and 7.5% of the market value of the gas.[1168] The payment from the RRC applies not only to wells that produce oil and gas, but also wells that are used to dispose oil and gas wastes, or are related in purpose to the production of oil or gas.[1169]

7.2.4.4. Regulatory Framework of Wyoming

Wyoming does not have regulations specific to acid gas injection, and therefore acid gas would be regulated by Wyoming's underground injection control program for Class II wells, administered by the Wyoming Oil and Gas Conservation Commission.[1170] All other well classes are administered by the Wyoming Department of Environmental Quality.[1171] Class II applicants are to show that the injection well will not endanger underground sources of drinking water, which is demonstrated in an application for individual new or existing wells (known as a Form 14B application).[1172] Applicants are to present information on the casing, cementing and completion of the well, information about the deepest underground source of drinking water, and procedures for abandonment.[1173] When an operator intends to abandon an injection well, the operator must file a notice of intention to abandon the well ("Form 4") with the Commission and must obtain approval from the Commission before the abandonment can commence.[1174] Following abandonment, a Subsequent Report of Abandonment (also Form 4) must be filed with

[1166] Tex. Nat. Res. Code § 89.047(h).
[1167] Texas Comptroller of Public Accounts, Crude Oil Production Tax, *at* http://www.window.state.tx.us/taxinfo/crude/index.html (last visited Feb. 1, 2006).
[1168] Texas Comptroller of Public Accounts, Natural Gas Production Tax, *at* http://www.window.state.tx.us/taxinfo/nat_gas/index.html (last visited Feb. 1, 2006).
[1169] Tex. Nat. Res. Code § 89.047(i)(2).
[1170] Wyo. Stat. § 30-5-104 (2006).
[1171] *Id.* at § 35-11-302.
[1172] 055-000-004 Code Wyo. R. § 1(a).
[1173] *Id.* at § 1(tt)(i).
[1174] 025-126-003 Code Wyo. R. § 15.

the Commission specifying the method of abandonment, materials used, and location of the abandoned wells.[1175] After the Subsequent Report of Abandonment has been approved, the operator will receive a release of its financial assurance.[1176]

All well operators are to provide financial assurance in the form of a bond, certificate of deposit, cash, or letter of credit.[1177] The financial assurance must remain until the well has been permanently plugged and abandoned; the financial assurance is forfeited if the operator does not comply with the Commission's rules.[1178] The amount of financial assurance depends on the depth of the well: $10,000 for each well of less than 2,000 feet and $20,000 for each well of more than 2,000 feet. In the alternative, where the operator maintains multiple wells, the operator may place a blanket bond of $75,000 to cover all wells.[1179] Operators are also assessed a severance tax for all oil and gas produced, sold or transported; Wyoming's severance tax is currently 6% for crude oil and 4% for natural gas production.[1180] A portion of those funds are used for plugging wells which are orphaned or where the operator is financially unable to abandon the well,[1181] however, Wyoming expressly disclaims liability for failure to adequately plug or reclaim any wells.[1182]

7.2.4.5. Discussion

In the United States, liability for acid gas injection is regulated under the auspices of the UIC Program, generally on the state level by state underground injection laws. Because the injection is associated with the processing of natural gas and/or EOR, the Safe SDWA allows

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[1175] *Id.* at § 17(a).
[1176] *Id.* at § 17(b).
[1177] *Id.* at § 4(b)(i), 5(a), 6(a).
[1178] *Id.* at § 4(b)(i), 7(b).
[1179] *Id.* at § 4(a).
[1180] Petroleum Ass'n of Wyo., Wyoming Oil and Gas Facts and Figures 2005 Edition, *at* http://www.pawyo.org/facts.aspx (last visited Feb. 4, 2006).
[1181] Wyo. Stat. § 30-5-104(d)(vii) (2006).
[1182] *Id.*

states to use the relaxed Class II standards for permitting acid gas injection wells. The analysis in this thesis focuses on acid gas injection in Texas and Wyoming, where Class II wells are regulated by state oil and gas agencies; all other injection wells are regulated by state environmental protection agencies. Although liability is addressed through oil and gas regulations, varying approaches are used; Texas uses a rules-based approach to acid gas injection whereas Wyoming is more of a standards-based approach.[1183] Texas has regulations that spell out detailed requirements for acid gas injection applicants, such as the materials that are to be used, contingency plan requirements, and conditions for public hearings. Wyoming, on the other hand, does not have requirements specific to acid gas injection storage; instead, it permits acid gas injection under its standard state Class II injection scheme requirements. Applicants are to show that the injection well will not endanger underground sources of drinking water. Although Wyoming certainly has regulations that serve to mitigate pollution from underground injection wells, the regulations do not set forth standards taking into account the challenges associated with injecting H_2S into the subsurface. Instead, Wyoming puts discretion in the hands of the state agency during the approval process in deciding the potential for groundwater contamination from the acid gas injection project. Because Wyoming has approved only two acid gas injection projects,[1184] most recently the ExxonMobil project at LaBarge, the discretionary approach to acid gas injection is perhaps a more efficient use of the Wyoming Oil and Gas Conservation Commission's resources than a rules-based approach because of the upfront costs associated with developing acid gas injection regulations. From a long-term liability perspective, the differences

[1183] For an analysis on the use and theoretical underpinnings of rules versus standards in policymaking, see generally, Pierre J. Schlag, Rules and Standards, 33 UCLA L. REV. 379 (1985); Colin S. Diver, The Optimal Precision of Administrative Rules, 93 YALE L.J. 65 (1983); Douglas G. Baird & Robert Weisberg, Rules, Standards, and the Battle of the Forms: A Reassessment of § 2-207, 68 VA. L. REV. 1217 (1982); RONALD DWORKIN, TAKING RIGHTS SERIOUSLY (1978); Duncan Kennedy, Form and Substance in Private Law Adjudication, 89 HARV. L. REV. 1685 (1976).
[1184] CITY OF GREEN RIVER, *supra* note 1129, at 2.

between Texas and Wyoming's approaches to acid gas injection are not dramatic because both states follow their normal Class II requirements for abandonment and orphan well programs developed for injection wells associated with hydrocarbon production. In both Texas and Wyoming, orphan well programs are funded by permit application fees and severance taxes on produced hydrocarbons, although Texas has recently created an additional program meant to encourage the adoption of orphaned wells. In general, the main differences are at the application stage rather than abandonment.

7.2.5. Implications for CO_2 Storage

Acid gas injection appears to be an appropriate technical analog for CO_2 storage. In Western Canada, for example, CO_2 is a significant constituent of the acid gas, if not the majority constituent, meaning that acid gas injection is merely CO_2 co-injected with other fluids. In addition, because CCS will likely build on the existing statutory and regulatory framework for subsurface injection, an analysis of acid gas injection may provide some insights as to how legislatures and regulators will approach CCS. Although acid gas has toxic properties not present in CO_2, at least in the United States, acid gas is not considered a hazardous waste as long as it is associated with hydrocarbon production, and at the federal level, would be subject to the same minimum requirements that CO_2 would be subject to if CCS took place today in conjunction with EOR. This is not to say that states, or even industry, might not seek to take precautions beyond the minimum federal requirements in order to further minimize potential liability, but such actions are not mandated by federal law. Because of its toxicity, one might expect acid gas injection to pose a relatively greater tortious liability than CO_2 storage and that relatively greater precautions would need to be taken, but that comparison might not be reflective of total tortious liability if the scale of CO_2 storage is anticipated to be significantly greater than that of acid gas injection and/or taking place closer to more populated areas.

All of the acid gas injection regulatory schemes analyzed incorporate some aspects of existing oil and gas law. Alberta has the most detailed regulations governing acid gas injection, which is to be expected since Alberta also has the most acid gas injection projects. In the United States, Wyoming has chosen to address acid gas injection under its general Class II underground injection control requirements, while Texas governs some aspects under its general Class II requirements but also has some rules specific to acid gas. At least in the context of the United States, this analysis raises the question: why have regulations specific to acid gas injection, when acid gas injection could just be regulated under routine Class II requirements? The answer is probably one of economic efficiency. In Wyoming, having a regulatory or liability regime specific to acid gas injection is not efficient if there are only two acid gas injection projects in the entire state; the upfront costs associated with creating the regulations probably exceed the downstream benefits gained from regulatory guidance specific to acid gas injection. Where there are several acid gas injection projects, there may be efficiencies gained from the upfront cost of creating acid gas injection regulations; instead of regulators continually having to develop standards for acid gas injection operations, they can rely on the regulations that have already been developed. In all of the jurisdictions analyzed in this thesis, there have been no cases of tortious-related litigation associated with loss of acid gas containment from the geological reservoir, but because acid gas injection is relatively new, it is probably premature to judge the efficacy of rule-based versus standard-based approaches to acid gas injection liability.

The analysis of the Alberta regime shows a number of methods being used to manage acid gas injection liability, and demonstrates that using one approach to minimize liability does not preclude the use of other approaches as well. The LLR is a way of assuring that licensees will have sufficient financial resources for abandonment, and could easily be translated to the CO_2 storage setting. The drawback to the rating system is that operators might be concerned with the commercially-sensitive nature of the financial information submitted to public officials. An alternative is a UIC-like financial assurance program, which allows operators to provide other forms of financial assurance such as surety bonds or letters of credit. Because the LLR is assessed monthly and is more rigorous in terms of its requirements, the probability of an operator's financial insolvency is probably lower in the case of Alberta relative to the United States.

By holding all working interest participants responsible for suspension, abandonment and reclamation costs, on a continuing liability basis, and with substantial penalties for avoiding payment, the Alberta regime presents a comprehensive way of addressing liability, and makes the use of the orphan fund unlikely. Under the orphan fund, acid gas injection fees cross-subsidize potential liability for other types of subsurface injection; payment into the orphan fund compensates for the abandonment and remediation of currently existing orphaned wells, rather than the acid gas injection orphan fund fees being segregated to fund abandonment and reclamation of future acid gas injection orphan wells. While the financial assurance and orphan fund mechanisms are probably easily translated into a jurisdiction such as the United States, the continuing liability component appears politically infeasible. In the context of CO_2 storage, it would mean that the operator would be perpetually liable for any tortious or contractual damages associated with loss of containment of the CO_2 from the geological reservoir, and failure to take responsibility could mean the inability to receive future permits for any kind of subsurface injection, CO_2 or otherwise. This is contrary to the experience of injection well operators in the

United States, who are used to government taking financial responsibility for injection wells post-abandonment. Perhaps a continuing liability provision is feasible if there is no enforcement of the provision or provides industry with a cap on the extent of liability, but the prospect of an open-ended perpetual liability would make operators less likely to pursue CO_2 storage. There is also the problem of incorporating continuing liability in a liability rating system tied to the deemed assets and liabilities of the injection enterprise, which presumably lacks revenues following abandonment of the well, making it more likely that a working interest participant would be held liable.

The differing acid gas injection regimes in the United States raise the question of whether the existing UIC regime is sufficient for managing acid gas injection liability (and CO_2 storage liability), or whether the regime needs to be modified to take into account characteristics of the injected fluid or operation that might affect liability. In Texas, regulators have chosen to use the Class II regime as a basis for regulation, but including additional requirements that all acid gas injection operations must meet by law. In Wyoming, regulators have chosen to regulate acid gas injection under the routine Class II framework. To a certain extent, the issue might be one of how big a role regulators expect acid gas injection to play in the state. If there are very few acid gas injection projects taking place in the state, the regulatory burden might be too great to have additional regulatory requirements or state UIC sub-classifications, especially given the flexibility afforded to state agencies under the current federal UIC framework for Class II wells. On the other hand, regulatory flexibility of acid gas injection also means that regulation might be inconsistent across states, but which was a policy judgment made by Congress. Finally, this analysis shows the significance of CO_2 storage being associated with hydrocarbon production and being regulated as a Class II well. The flexibility provided for regulation of acid gas injection is largely because the acid gas injection takes place under the Class II injection well status. This is particularly advantageous for H_2S injection, which otherwise would be regulated under the more stringent Class I hazardous waste status. Even so, for CO_2, which has not been deemed a hazardous waste, the flexibility of subsurface injection standards is still an advantage to state regulators. If the EPA decided to create a new classification for CO_2 storage, state programs would need to be approved by the EPA before CO_2 injection could take place and all state programs would need to abide by the minimum requirements set forth by the EPA. States would be free to go beyond the minimum federal requirements, but obviously there would be a loss in the regulatory flexibility of state agencies as compared with their authority over Class II wells.

7.3. Liability of Natural Gas Storage

7.3.1. Background

Since 1915,[1185] the natural gas industry has stored natural gas in geological formations. Traditionally, natural gas storage has been used to manage the swing capacity required to meet peak demand for winter heating,[1186] but because of the increasing use of natural gas for electricity generation, storage is now not only used to meet the winter heating demand, but also to supply gas to meet the daily swing demand for natural gas-fired power plants.[1187] There is also a growing use of storage to manage the price volatility of natural gas markets and to exploit arbitrage opportunities (i.e. take advantage of short-term changes in the price of natural gas).[1188] Typically, natural gas is injected into geological formations when production exceeds demand (e.g. in the summer months), and natural gas is withdrawn from geological formations when the demand for natural gas exceeds production (e.g. in the winter months). The seasonal variability of the amount of natural gas in storage is shown in Figure 7.4.[1189] Although natural gas is also stored in small amounts by local natural gas distribution companies and at liquefied natural gas ("LNG") terminals,[1190] the focus of this analysis will be on the large-scale storage of natural gas

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[1185] The first natural gas storage project began in 1915 in Welland County, Ontario, Canada. The first natural gas storage project in the United States began the following year near Buffalo, New York. U.S. FEDERAL ENERGY REGULATORY COMM'N, CURRENT STATE OF AND ISSUES CONCERNING UNDERGROUND NATURAL GAS STORAGE 4 (Docket No. AD04-11-000, 2004).

[1186] Alexander Bary et al, Storing Natural Gas Underground, SCHLUMBERGER OILFIELD REVIEW, Summer 2002, *at* 3; SIMMONS & CO., UNDERGROUND NATURAL GAS STORAGE 1 (2000).

[1187] SIMMONS & CO., *supra* note 1186, at 2.

[1188] *Id.* at 9.

[1189] U.S. FEDERAL ENERGY REGULATORY COMM'N, *supra* note 1185, at 4; SIMMONS & CO., *supra* note 1186, at 1 (2000).

[1190] *See, e.g.*, U.S. FEDERAL ENERGY REGULATORY COMM'N, EXISTING AND PROPOSED NORTH AMERICAN LNG TERMINALS (July 5, 2006), *at* http://www.ferc.gov/industries/lng/indus-act/terminals/exist-prop-lng.pdf. *See also* U.S. ENERGY INFO. ADMIN., THE GLOBAL LIQUEFIED NATURAL GAS MARKET: STATUS & OUTLOOK (DOE/EIA-0637, 2003).

in geological formations in the United States, which is responsible for about two-thirds of the 550 natural gas storage operations worldwide.[1191]

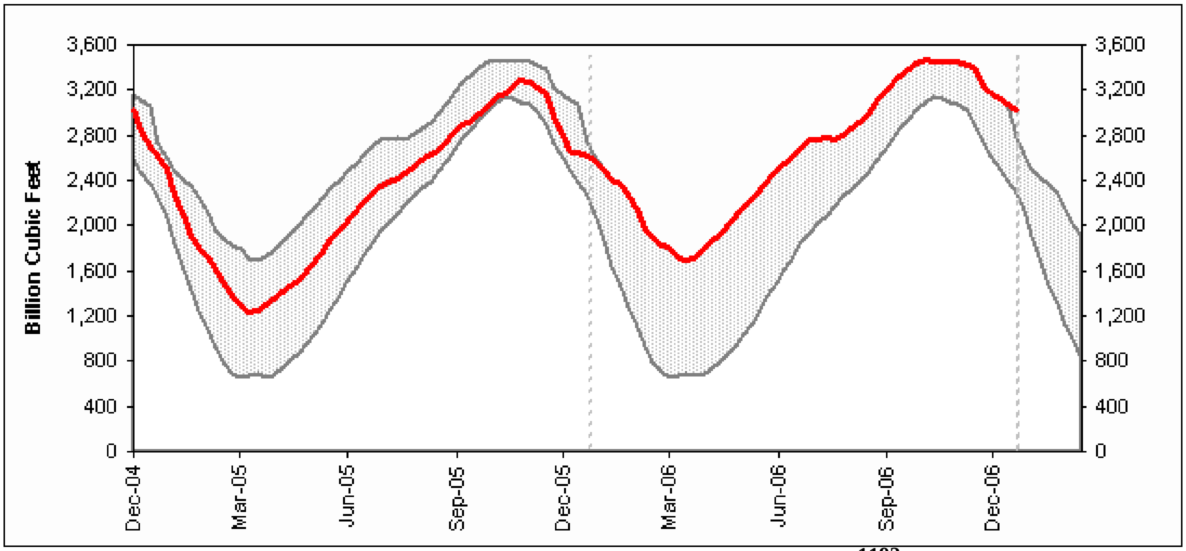

Figure 7.4 Working Gas in Storage (EIA)[1192]

Red line indicates weekly working gas in storage in time period December 29, 2004-December 29, 2006. Shaded area indicates the historical range of weekly values from 2000-2004.

There are three types of geological formations that are used for natural gas storage, as shown in Figure 7.5: depleted oil and gas fields, deep saline formations, and salt caverns. The storage formation will be selected based on geophysical characteristics (e.g., porosity and permeability)[1193] and existing infrastructure (e.g., pipelines and injection wells). Historically, depleted oil and gas fields have been the most commonly used formation for natural gas storage because of their extensive existing pipeline and injection well infrastructure, as well as their

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[1191] Bary et al, *supra* note 1186, at 4. Also note that, in a sense, natural gas is "stored" in its original natural gas formation when it is not developed or produced. *Id.*

[1192] U.S. Energy Info. Admin., Weekly Natural Gas Storage Report (July 8, 2006), *at* http://tonto.eia.doe.gov/oog/info/ngs/ngs.html.

[1193] Porosity determines the amount of natural gas that can be held in the formation. Permeability determines the rate at which natural gas may be injected into and withdrawn from the formation. Natural Gas Supply Ass'n, Storage of Natural Gas, *at* http://www.naturalgas.org/naturalgas/storage.asp (last visited July 8, 2006).

known geology.[1194] However, a shortcoming of depleted oil and gas fields is that the working gas volumes can only be cycled once per season.[1195] While this is suitable for the traditional uses of storing natural gas for the winter months, it may not be satisfactory for operators seeking to use storage to hedge against intermittent spikes in demand for natural gas during the summer months due to the increased demand for electricity.

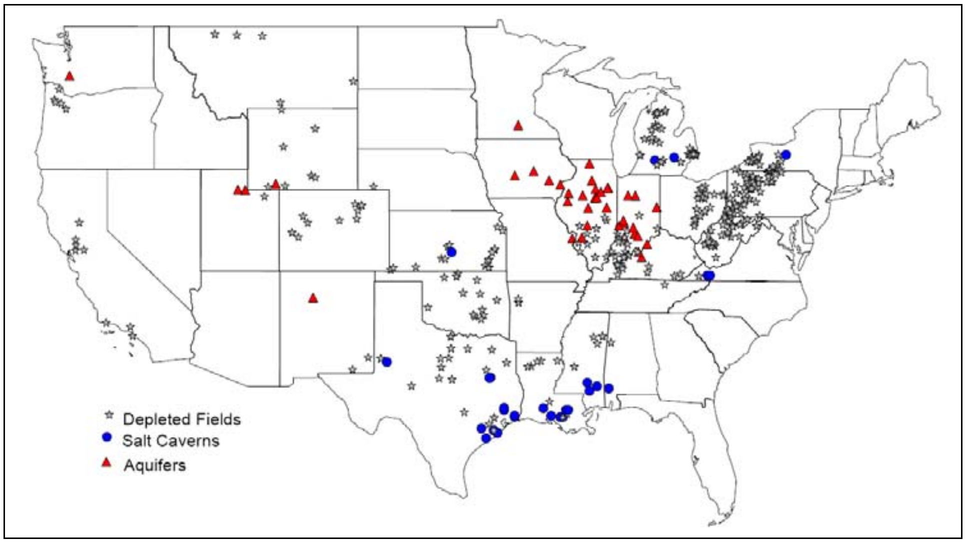

Figure 7.5 Natural Gas Storage in the United States (EIA)[1196]

[1194] *See infra* Table 7.7.

[1195] The withdrawal of natural gas from a storage reservoir is generally measured in terms of "deliverability", or the amount of natural gas that can be delivered from the storage facility on a daily basis. Deliverability is a function of the porosity and permeability of the reservoir. U.S. Energy Info. Admin., The Basics of Underground Natural Gas Storage (Aug. 2004), *at* http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html. Deliverability will also depend on the amount of gas in the reservoir. *See infra* notes 1199-1202 and accompanying text.

[1196] U.S. ENERGY INFO. ADMIN., NATURAL GAS ANNUAL 2004 30 (2005).

Table 7.6 Natural Gas Storage in the United States (DOE-EIA)[1197]
(As of December 31, 2004; Capacity in Billion Cubic Feet)

	Salt Caverns		Aquifers		Depleted Fields	
State	Number of Caverns	Capacity	Number of Aquifers	Capacity	Number of Fields	Capacity
Alabama	1	8	0	0	1	3
Arkansas	0	0	0	0	2	22
California	0	0	0	0	11	478
Colorado	0	0	0	0	9	101
Illinois	0	0	17	767	12	216
Indiana	0	0	12	81	10	32
Iowa	0	0	4	273	0	0
Kansas	1	1	0	0	17	288
Kentucky	0	0	3	10	20	211
Louisiana	6	63	0	0	8	530
Maryland	0	0	0	0	1	62
Michigan	2	4	0	0	43	1006
Minnesota	0	0	1	7	0	0
Mississippi	3	41	0	0	4	105
Missouri	0	0	1	32	0	0
Montana	0	0	0	0	5	374
Nebraska	0	0	0	0	1	39
New Mexico	0	0	1	5	2	79
New York	1	2	0	0	22	202
Ohio	0	0	0	0	24	572
Oklahoma	0	0	0	0	13	384
Oregon	0	0	0	0	5	24
Pennsylvania	0	0	0	0	49	749
Tennessee	0	0	0	0	1	1
Texas	14	116	0	0	20	558
Utah	0	0	2	12	1	118
Virginia	2	4	0	0	1	4
Washington	0	0	1	41	0	0
West Virginia	0	0	0	0	31	512
Wyoming	0	0	1	10	7	104
Total	30	240	43	1238	320	6777

[1197] U.S. Dep't of Energy, Energy Information Administration, Natural Gas Annual 2004 30 (2005).

Deep saline formations provide a storage option with higher deliverability than depleted oil and gas fields, but tend to be more expensive to develop because of the lack of existing pipeline and injection infrastructure.[1198] Deep saline formations also require a greater amount of "cushion gas" than depleted oil and gas reservoirs.[1199] Cushion gas is gas that must remain in the geological formation to provide enough pressure to extract the remaining natural gas; the gas that can be extracted from the formation is called "working gas".[1200] In depleted oil and gas reservoirs, about half of the natural gas injected into the formation must be kept as cushion gas, but in deep saline formations, the cushion gas might need to be as high as 80% of the gas injected.[1201] Because of the high cushion gas requirements, natural gas storage in deep saline formations tends to take place in areas where there are no nearby depleted oil and gas reservoirs appropriate for storage.[1202] As shown in Figure 7.5, deep saline formations for natural gas storage in the United States are located primarily in the Midwest, where saline formations began to be used for storage in the 1950s.[1203]

Salt caverns offer the highest deliverability of the three potential storage formations and thus are the preferred geological formation for operators requiring frequent cycling of stored gas.[1204] They also have the lowest amount of cushion gas, typically 20-30% (and can approach 0% during emergencies).[1205] Bary et al note that salt caverns offer low porosity and permeability

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[1198] Natural Gas Supply Ass'n, *supra* note 1193.
[1199] *Id.*
[1200] U.S. Energy Info. Admin., *supra* note 1195.
[1201] Natural Gas Supply Ass'n, *supra* note 1193.
[1202] *Id.*
[1203] HEINRICH ET AL, *supra* note 749, at 22.
[1204] Bary et al, *supra* note 1186, at 4. As a basis for comparison, the EIA notes that salt caverns cycle their inventories 2.1 times per year, compared with 0.78 for depleted oil and gas fields and 0.60 for deep saline formations. JAMES TOBIN & JAMES THOMPSON, NATURAL GAS STORAGE IN THE UNITED STATES IN 2001: CURRENT ASSESSMENT AND NEAR-TERM OUTLOOK 3 (U.S. Energy Info. Admin., 2001).
[1205] U.S. FEDERAL ENERGY REGULATORY COMM'N, *supra* note 1185, at 4.

to liquid and gaseous hydrocarbons, which is good for preventing leakage from the formation.[1206] However, an analysis by Hopper implies that salt caverns may be more susceptible to catastrophic losses, noting that every case of catastrophic loss associated with the single-point failure of natural gas storage has involved a salt cavern, even though salt caverns represent only 7% of all storage.[1207] Hopper argues that salt caverns typically have only one wellbore which is used both for injection and withdrawal of natural gas, while oil and gas fields have multiple wellbores which can be used for gas recovery in case of an emergency.[1208] This is important because if failure of a wellbore occurs in a formation with multiple wellbores, the working gas can be extracted relatively easily, but if wellbore failure occurs in a formation with only a single wellbore, it may be impossible to contain the leak if the well catches fire.[1209] There is no technical reason that salt caverns cannot have multiple wellbores, but Hopper claims that they are not installed to minimize cost.[1210] Another disadvantage of salt caverns is that they are typically located in the south (especially near the Gulf of Mexico),[1211] which is not close to the winter heating market, but this might not pose a problem if the natural gas in storage is intended for electricity generation or arbitrage, which we might expect would be the case for salt caverns given their capability for frequent cycling.

The U.S. Energy Information Administration ("EIA") compiles data on natural gas storage inventories in the United States. In its most recent annual report for natural gas, as shown in Table 7.7, the EIA found total natural gas capacity to be over 8,000 billion cubic feet

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1206 Bary et al, *supra* note 1186, at 4.
1207 John M. Hopper, Gas Storage and Single-Point Failure Risk, ENERGY MARKETS (2004), *at* http://www.falcongasstorage.com/fw/filemanager/fm_file_manager_download.asp?FileName=article_singlepointfailurerisk.pdf&FilePath=/_filelib/FileCabinet/Articles/. Hopper is President of Falcon Natural Gas Storage, whose natural gas storage facilities consist entire of depleted oil and gas fields and not salt caverns.
1208 *Id.*
1209 *Id.*
1210 *Id.*
1211 Bary et al, *supra* note 1186, at 4.

(bcf). With total U.S. natural gas consumption of 21,931.7 bcf in 2005[1212] and expected to increase to 26,500 bcf by 2017,[1213] it is likely that the natural gas storage market will expand.[1214] In 2004, there were 320 depleted oil and gas field storage sites with a capacity of 6,776.9 bcf, 43 deep saline formations with a capacity of 1,238.2 bcf, and 30 salt caverns with a capacity of 240.0 bcf. The EIA defines "capacity" as the "maximum operating capacity". This includes both cushion gas and working gas. Thus the actual capacity available for both injection and withdrawal from the formation is significantly lower than the EIA capacity figures.

Table 7.7 Natural Gas Storage in the United States (EIA)[1215]
(Capacity in billion cubic feet)

	2000	2001	2002	2003	2004
Total Storage Capacity	**8,240.9**	**8,415.3**	**8,207.1**	**8,205.7**	**8,255.0**
Depleted Oil and Gas Fields	6,788.1	7,001.7	6,747.1	6,734.0	6,776.9
Aquifers	1,263.7	1,195.1	1,234.0	1,237.1	1,238.2
Salt Caverns	189.0	218.4	226.0	234.6	240.0
Total Number of Active Fields	**413**	**418**	**407**	**391**	**393**
Depleted Oil and Gas Fields	336	351	340	318	320
Aquifers	49	39	38	43	43
Salt Caverns	28	28	29	30	30

There are a number of reasons why natural gas storage is an appropriate subsurface analog for CO_2 storage. First, subsurface injection of natural gas occurs in the same types of geological formations being considered for CO_2 storage, i.e., both use deep saline formations and depleted oil and gas fields as storage formations. Also, in both natural gas storage and CO_2 storage, the characterization of the storage sites involves the same criteria, e.g. permeability,

1212 U.S. Energy Info. Admin., Natural Gas Consumption by End Use (June 29, 2006), *at* http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.
1213 U.S. ENERGY INFO ADMIN., *supra* note 8, at 85.
1214 HEINRICH ET AL, *supra* note 749, at 22.
1215 U.S. ENERGY INFO. ADMIN., UNDERGROUND NATURAL GAS STORAGE CAPACITY (June 29, 2006), *at* http://tonto.eia.doe.gov/dnav/ng/ng_stor_cap_dcu_nus_a.htm.

porosity, thickness, caprock integrity, and lithology.[1216] Second, the leakage pathways for natural gas and CO_2 are similar because both are stored in geological formations,. For example, where storage occurs in depleted oil and gas fields, the presence of abandoned wells can pose a leakage threat in both the natural gas storage and CO_2 storage contexts. Third, natural gas storage has a different regulatory and liability scheme than other types of subsurface injection,[1217] and can provide some insight into how CO_2 storage might be regulated if it is exempted from the EPA UIC Program. In fact, the IOGCC has proposed that CO_2 storage be regulated under natural gas storage laws. If the IOGCC proposal is successful, it would mean that the regulatory and liability regime analyzed here for natural gas storage would eventually govern CO_2 storage.[1218]

7.3.2. Property Interests

Ownership is the most litigated aspect of natural gas storage liability.[1219] Like CO_2 storage, property interests in the natural gas storage context play a role in determining the cost of geological storage through the acquisition of necessary geological reservoir property rights and the value of storage through ownership of injected gas. In the case of CO_2 storage, ownership also has implications for who is financially responsible for the stored CO_2 in the long-term. Two critical property interests issues arise for natural gas storage: (1) the property rights governing the geological storage reservoir (including characterization of relevant property interests and methods of acquiring the interests by voluntary and involuntary means), and (2) property interests in the injected natural gas. The property law governing subsurface storage formations

[1216] Lithology is the rock type from which the geologic formation was derived.
[1217] Recall that Congress exempted natural gas storage from the underground injection control provisions of the SDWA. *See supra* Section 3.2.3. *See also* 42 U.S.C. § 300h(d)(1).
[1218] *See supra* Section 3.2.4.
[1219] Based on Lexis and Westlaw searches for natural gas storage cases reported in state and federal reporters. It is possible that other aspects of natural gas storage have also been litigated, but did not reach a final verdict because the cases were settled out of court or were dropped by the plaintiff.

explained in this subsection is generally applicable to all subsurface contexts, not just natural gas storage, but ownership over the injected natural gas is specific to the natural gas storage context.

There remain questions as to whether natural gas storage regulation is the correct precedent for CO_2 storage (i.e. whether CO_2 storage should be exempted from SDWA and UIC requirements), but there is a strong argument to be made that the property rights regimes should be similar.[1220] Ownership of the pore space of a geological reservoir does not depend on whether natural gas or CO_2 is being injected into the reservoir.[1221] However, as will be discussed later in this subsection, ownership of the injected natural gas will depend on whether the property rights regime refers to injected gas as "gas" generally, or specifies the composition of the natural gas.

There are several caveats to the property rights analysis in this subsection when it is applied to the CO_2 storage context. First, this analysis does not consider the property rights governing permits for stored CO_2. CCS economic studies often consider the role of CCS in a carbon-constrained world using emission trading scenarios.[1222] Emission trading allocates property rights in the form of emission allowances, and parties may be liable for noncompliance.[1223] The property interest rules for carbon permits will be a function of the relevant climate policy regime and must take into account issues such as permit allocation, regulatory evolution, transaction costs, and capital stock turnover.[1224] Regardless, it is within the authority of a legislature to create whatever rule governing CO_2 storage ownership that it deems fit, irrespective of the market for emission permits. In fact, because emission trading will be

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[1220] In addition to the discussion in this thesis, for an analysis of CO_2 storage and property law, see generally Wilson & de Figueiredo, *supra* note 42. For a discussion on the liability implications of ownership, see *supra* Section 5.5.
[1221] Although, as will be discussed later in this subsection, subsurface injection of natural gas or CO_2 could be affected if there are pre-existing *in situ* substances in the storage formation.
[1222] *See e.g.*, Jim McFarland et al., *Economic Modeling of Carbon Capture and Sequestration Technologies*, *in* PROC. FIRST NAT'L CONF. CARBON SEQUESTRATION (2001), *available at* http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/2c3.pdf.
[1223] David G. Victor, *Enforcing International Law: Implications for an Effective Global Warming Regime*, 10 DUKE ENVTL. L. & POL'Y F. 147, 174 (1999).
[1224] *Id*. at 175-179.

conducted on a regional, national, or international level, and property rights issues are generally governed on the state level, it is quite possible that there could be a divergence between ownership for state property rights purposes and ownership for emission trading purposes. Second, this analysis does not consider the issue of taxation. When a geological formation or injected natural gas (or CO_2) becomes a person's property, there will be property tax implications associated with that ownership. Third, the examination of property rights here is specific to the United States. In many countries where CCS has been proposed, such as Norway,[1225] England,[1226] and Australia,[1227] the crown has retained its property interests to the subsurface.[1228] In the United States, the issue of property rights is largely one of state law. However, because some countries, like the United States, follow English traditions with respect to property law, this analysis may be applicable outside of the United States as well.

7.3.2.1. Ownership of the Geological Storage Reservoir

The determination of the ownership interest for the storage reservoir depends on the type of geological formation into which the natural gas is being injected. When natural gas is injected into a mineral formation, (such as a depleted oil or gas reservoir), property interests are governed by the relevant mineral law. When natural gas is injected into a deep saline formation, property interests will be affected by the relevant water law. Although the specific terms "mineral law" and "water law" are irrelevant in determining how the regimes actually operate, I use the terminology to note that mineral formations and deep saline formations operate under separate rules. Ownership rules, regardless of the type of formation, will vary on a state-by-state basis.

[1225] Norway State Secretary Øyvind Håbrekke, Address at the OSPAR Workshop on the Environmental Impact of Placement of Carbon Dioxide in Geological Structures in the Maritime Area (Oct. 26, 2004).
[1226] U.K. DEPARTMENT OF TRADE AND INDUSTRY, OUR ENERGY FUTURE – CREATING A LOW CARBON ECONOMY 90 (2003).
[1227] AUSTRALIAN GOVERNMENT, SECURING AUSTRALIA'S ENERGY FUTURE 143 (2004).
[1228] Henry E. Smith, *Exclusion and Property Rules in the Law of Nuisance*, 90 VA. L. REV. 965, 1028 (2004).

Once the ownership interests have been determined, there are a number of ways in which the property interests can be acquired, including voluntary methods, eminent domain, or adverse possession.

7.3.2.1.1. Ownership of the Mineral Formation

There are two property interests of significance in determining ownership of the geological storage reservoir that has contained oil or gas. The first is the mineral interest, which comprises the right to explore and remove minerals from the land.[1229] The mineral interest may be associated with a royalty interest, which is the right to receive a share of the exploited mineral proceeds.[1230] Most states regard a "mineral interest" as including not only stationary minerals such as coal,[1231] but also fugacious minerals, such as oil and gas, unless intent to the contrary is expressed.[1232] The second property interest of significance is the surface interest, which consists of all other ownership in the land.[1233]

In the simplest case, the mineral interest and surface interest of a property are held by a single owner in what is known as a "fee simple". A fee simple is the broadest property interest allowed by law and is unlimited in duration.[1234] If the mineral and surface interests are held together in fee simple, one need only acquire the interest to the formation from the fee owner. If the fee owner grants an exclusive right to drill into the formation, there will be no liability for

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1229 BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "mineral interest").
1230 *Id.*
1231 Although I do not address the property rights implications of subsurface injection into an unmineable coal seam, the analysis is virtually identical to the oil and gas field analysis presented in this subsection. This is because property law does not distinguish between the various *in situ* minerals contained by the mineral formation.
1232 *Id.*
1233 BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "surface interest").This follows the common law doctrine *cujus est solum, ejus est usque ad coelum et ad inferos* ("to whomever the soil belongs, he also to the sky and to the depths").
1234 BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "fee simple").

trespass.[1235] If there are numerous fee owners, transaction costs will increase and difficulties could arise if one of the fee owners refuses to give consent for storage.[1236]

It would be unlikely that an entity seeking to use a geological formation for natural gas storage would acquire the property rights as a fee simple because the land area overlying the storage formation could be quite large and only a limited portion of the overlying land would be necessary for storage operations.[1237] It is more likely that the potential storage owner would seek to obtain a lease or storage deed.[1238] In a lease, the owner of the land (the "lessor") receives a series of payments from the tenant (the "lessee") in exchange for development rights to the land for a period of time. In a storage deed, the fee owner conveys the property interest to the geological formation and those surface rights which may be necessary for conducting storage operations.[1239]

The mineral interest may be severed from the surface interest, meaning that the mineral and surface interests are held by different owners.[1240] Severance may have occurred through a mineral deed, a mineral deed and subsequent oil and gas lease, or by an oil and gas lease alone.[1241] State rules for property ownership differ when the mineral and surface interests are severed as to whether the geological formation is owned by the mineral owner or by the surface owner.

The English rule, which is the minority rule in the United States, but is the rule of law in Canada and England, holds that the owner of the mineral interest has ownership over the

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[1235] Wade H. Creekmore, Jr. & William B. Harvey, Comment, *Subsurface Storage of Gas*, 39 MISS. L.J. 81, 91 (1967).
[1236] *Id.*
[1237] Alan Stamm, *Legal Problems in the Underground Storage of Natural Gas*, 36 TEX. L. REV. 161, 164 (1957).
[1238] *Id.*
[1239] *Id.* at 165.
[1240] Roger Scott, *Underground Storage of Natural Gas: A Study of Legal Problems*, 19 OKLA. L. REV. 47, 57 (1966).
[1241] Wade H. Creekmore, Jr. & William B. Harvey, Comment, *Subsurface Storage of Gas*, 39 MISS L. J. 81, 91 (1967).

geological formation, even after all the minerals have been removed.[1242] This is because the mineral owner has the exclusive right of possession of the whole space, and is entitled to the entire and exclusive use of that space for all purposes.[1243] The English rule assumes that the mineral owner does not take title to oil or gas until the owner reduces it to possession. *Central Kentucky Natural Gas Co. v. Smallwood* was one of the first applications of the English rule in the United States,[1244] but the Kentucky judiciary, in a case thirty-five years later, limited the *Smallwood* holding where storage reservoirs were capable of being defined with certainty and reservoir integrity was capable of being maintained.[1245] Note that even where the mineral interest owner has ownership over the subsurface formation, CCS operations may still require property interests over the land surface for drilling injection wells, pipelines to carry CO_2 to the formation, and necessary equipment such as compressor stations or monitoring devices.[1246]

In the majority of states, the owner of the surface interest owns the geological formation. This is known as the American rule. The West Virginia case of *Tate v. United Fuel Gas Co.* is exemplary of the American rule.[1247] The fee simple owner conveyed the surface interest of the land to the plaintiff Tate's predecessor in title, but excepted from the deed was the right to produce and remove the "oil, gas and brine and all minerals, except coal underlying the surface of the land".[1248] The deed included a clause that the term "mineral" did not include "clay, sand, stone or surface minerals except such as may be necessary for the operation for the oil and gas and other minerals reserved and excepted herein".[1249] Tate acquired the surface interest to the

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[1242] Jack Lyndon, *The Legal Aspects of Underground Storage of Natural Gas – Should Legislation Be Considered Before the Problem Arises?* 1 ALBERTA L. REV. 543, 545 (1961).
[1243] *Central Kentucky Natural Gas Co. v. Smallwood*, 252 S.W.2d 866, 868 (Ky. 1952).
[1244] *Id.*
[1245] *Texas American Energy Corp. v. Citizens Fidelity Bank & Trust Co.*, 736 S.W.2d 25, 28 (Ky. 1987).
[1246] Creekmore & Harvey, *supra* note 1241, at 91.
[1247] 71 S.E.2d 65 (1952).
[1248] *Id.* at 67.
[1249] *Id.* at 68.

land, including the same exceptions set forth in the original deed.[1250] The mineral interest owners executed an oil and gas lease with United Fuel Gas, as well as a gas storage agreement granting United Fuel Gas the right to inject and store gas in the formation.[1251] Although no gas was produced from the formation, United Fuel Gas used the formation to store gas that had been produced elsewhere.[1252] Tate claimed that he was the rightful owner of all the clay, sand and stone within and underlying the land.[1253] The court concluded that because the term "mineral" in the deed was limited so as not to include "clay, sand, stone or surface minerals", the surface interest owner Tate retained ownership of the geological formation.[1254] The court found that the restriction in the deed was limited to the production of minerals, and was not intended for the storage of gas produced elsewhere.[1255]

Although the subsurface geological formation is owned by the surface interest owner under the American rule, the mineral interest owner still has a property interest in exploring and removing minerals from the land. As shown in Figure 7.6, the property interests that need to be acquired are a function of: (1) whether the reservoir is depleted of minerals; and (2) whether the mineral interest has been severed from the surface interest. If the mineral interest has not been severed, meaning that the surface interest and mineral interest are owned as one, the interest of this owner (shown in Figure 7.6 as "Surface Owner") must be acquired; this is irrespective of whether the reservoir has been depleted of minerals. If the mineral interest has been severed, whether the mineral interest must be acquired depends on whether the reservoir is depleted of minerals. If the reservoir is depleted of minerals, the mineral interest owner no longer has the

[1250] *Id.*
[1251] *Id.*
[1252] *Id.*
[1253] *Id.*
[1254] *Id.* at 73.
[1255] *Id.*

right of use of the formation space, and the surface interest need only be acquired. If the reservoir still contains minerals, both the surface interest and the mineral interest must be acquired.

	Unsevered Mineral Interest	**Severed Mineral Interest**
Non-Depleted Reservoir	Surface Owner	Surface Owner Mineral Owner
Depleted Reservoir	Surface Owner	Surface Owner

Figure 7.6 Relevant Property Interests for Acquisition of a Geological Reservoir

Technically, the geological formation will never be fully depleted of minerals.[1256] In the future, new methods of mineral extraction could be developed to exploit the presently unrecoverable minerals.[1257] Therefore, there will likely be a transaction cost associated with purchasing the rights of the mineral interest owner, who would claim that the reservoir is not depleted of minerals and seek compensation for the remaining minerals.

7.3.2.1.2. Ownership of the Saline Formation

In general, water property law differentiates between "surface water" and "groundwater". Surface water is water lying on the surface of the Earth but not forming part of a watercourse or

[1256] Orpha A. Merrill, Note and Comments, *Oil and Gas: Substratum Storage Problems*, 7 OKLA. L. REV. 225, 227 (1954).
[1257] *Id.*

lake, while groundwater is water found in layers of permeable rock or soil.[1258] Groundwater is typically classified as either an "underground stream" or "percolating water". An underground stream, defined as water with a defined channel,[1259] is treated by the law as surface water.[1260] Percolating water, defined as water that seeps through the soil without a defined channel,[1261] operates under a separate legal regime.[1262] Groundwater which is not contained in an underground stream, is assumed to be percolating water by default.[1263] The fact that "underground streams" and "percolating water" are considered by the law to be the only sources of groundwater has been criticized by hydrologists as lacking a scientific basis.[1264]

Water contained in a deep saline formation suitable for geological CO_2 storage would be defined as percolating water. The law does not differentiate between freshwater and saline aquifers with respect to ownership. In addition, there is an inherent uncertainty concerning the determination of property rights for a saline formation with respect to CO_2 storage because of the lack of case law on point.[1265] Instead, the law has focused on property rights over the taking and use of groundwater for consumption.[1266]

The determination of property rights over a saline formation is comparable to the mineral formation case. In the majority of states, the owner of the surface interest has the right to make any use of the subsurface space, including the saline formation.[1267] Just as in the case of a

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1258 BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "water").
1259 *Id.*
1260 Eric Behrens & Matthew G. Dore, *Rights of Landowners to Percolating Groundwater in Texas*, 32 S. TEX. L. REV. 185, 199 (1991).
1261 BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "water").
1262 Behrens & Dore, *supra* note 1260, at 187.
1263 J. P. Massie, Annotation, *Subterranean and Percolating Waters,* 55 A.L.R. 1385 (2004).
1264 Behrens & Dore, *supra* note 1260, at 187.
1265 Tara L. Taguchi, *Whose Space Is It Anyway? Protecting the Public Interest in Allocating Storage Space in California's Groundwater Basins*, 32 SW. U. L. REV. 117, 119 (2003).
1266 Based on Lexis and Westlaw searches of past reported federal and state cases on groundwater and property rights.
1267 WILLIAM R. WALKER & WILLIAM E. COX, DEEP WELL INJECTION OF INDUSTRIAL WASTES: GOV'T CONTROLS AND LEGAL CONSTRAINTS 131 (1976).

mineral formation, where ownership of non-depleted minerals must be accounted for, any storage operation needs to take into account ownership of the water contained in the saline formation. There are a number of property regimes that states use to determine property rights over the water: absolute dominion, reasonable use, prior appropriation, correlative rights, or the Restatement rule.

Table 7.8 Groundwater Property Rights Doctrines[1268]

DOCTRINE	STATES
Absolute Dominion Rule	Connecticut, Indiana, Louisiana, Maine, Massachusetts, Mississippi, Rhode Island, Texas
Reasonable Use Rule	Alabama, Arizona, Florida, Georgia, Illinois, Kentucky, Maryland, New Hampshire, New York, North Carolina, Oklahoma, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia
Correlative Rights Rule	California, Hawaii, Iowa, Minnesota, New Jersey, Vermont
Restatement Rule	Michigan, Ohio, Wisconsin
Prior Appropriation Rule	Alaska, Colorado, Idaho, Kansas, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington
Combination of multiple rules	Arkansas, Delaware, Missouri, Nebraska, Wyoming

Under the absolute dominion rule (also known as the "absolute ownership" rule), the surface owner has "absolute dominion" over everything above, on, or below the land.[1269] Any water contained in an aquifer lying beneath the land is the property of the surface owner.[1270] The surface owner would have the right to use the water for any purpose, with no liability for damage to an adjoining owner.[1271] The absolute dominion rule holds that groundwater is the absolute property of the surface owner, as with the rocks and soil that compose the land.[1272] Therefore,

1268 WATER SYSTEMS COUNCIL, WHO OWNS THE WATER? 1-2 (2003)
1269 Alison Mylander Gregory, *Groundwater and its Future: Competing Interests and Burgeoning Markets*, 11 STAN. ENVTL. L.J. 229, 240 (1992). *See also* 78 AM. JUR. 2D *Waters* § 214 (2004).
1270 Gregory, *supra* note 1269, at 240.
1271 *Bristor v. Cheatham*, 255 P.2d 173, 178 (Ariz. 1953).
1272 *Maddocks v. Giles*, 728 A.2d 150 (Me. 1999). *See also* 78 AM. JUR. 2D *Waters* § 214 (2004).

for any state operating under the absolute dominion rule, acquisition of the surface right to the land would be a sufficient property right over water contained in an aquifer beneath the land.

Under the reasonable use rule, there is no restriction on the taking of groundwater, but any use must be in a reasonable and beneficial manner.[1273] A use not connected to beneficial enjoyment of the land from which it was obtained would be an unlawful purpose with respect to percolating waters. The reasonable use rule is pertinent where large quantities of water are extracted for use at a distance from the land where the water was extracted, and generally applies only when there is no connection with the use, enjoyment, or improvement of the land from which the water was extracted.[1274]

The correlative rights rule is an extension of the reasonable use rule. Surface owners hold proportionate proprietary shares in the aquifer, with the largest landowner having the largest share of the aquifer since the owner has the largest share of the land above it.[1275] During times of water scarcity, landowners are restricted to a fair and just proportion of the supply, which is determined by the proportionate share.[1276] The courts may weigh and balance the rights of competing uses to determine those that are proper.[1277] In California, the correlative rights rule has been extended by the doctrine of mutual prescription, allocating water by comparing reasonableness of use based on such factors as custom, social utility, safe yield, and need.[1278]

The Restatement rule, from Section 858 of the Second Restatement of Torts, is also an extension of the reasonable use rule. While the reasonable use rule requires water to be used on the land overlying the aquifer, the Restatement rule allows for water to be applied outside of the

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[1273] *Bristor*, 255 P.2d at 178.
[1274] 78 AM. JUR. 2D *Waters* § 215 (2004).
[1275] Earl Finbar Murphy, *The Recurring State Judicial Task of Choosing Rules for Groundwater Law: How Occult Still?* 66 NEB. L. REV. 120, 134 (1987).
[1276] Gregory, *supra* note 1269, at 241.
[1277] *Id.*
[1278] *City of Pasadena v. City of Alhambra*, 207 P.2d 17, 33 (Cal. 1949). *See also* Gregory, *supra* note 1269, at 242.

overlying land.[1279] Although the rule is a limitation of liability, its effect is as a rule governing property rights allocation.[1280] The Restatement rule is stated as follows:

> A possessor of land who, in using the subterranean water therein, intentionally causes substantial harm to a possessor of other land through invasion of the other's interest in the use of subterranean water in his land, is liable to the other if, but only if, the harmful use of water is unreasonable in respect to the other possessor.[1281]

As the rule has been interpreted, liability is imposed for any withdrawal which causes unreasonable harm to neighboring landowners by lowering the water table or reducing the pressure of the aquifer.[1282] Liability is also imposed for any withdrawal which exceeds a reasonable portion of the annual groundwater storage for the aquifer.[1283] The rule has not received widespread acceptance due to its lack of guidance and difficulties in application.[1284]

Under the prior appropriation rule, temporal precedence establishes property right over the groundwater.[1285] This is the so-called "first in time, first in right" rule. During times of water shortage, whoever drills into the aquifer first in time has priority over the taking of water contained in the aquifer.[1286] In some states, the courts have imposed reasonableness restrictions on the prior appropriation rule.[1287] For example, Colorado prohibits pumping if it would result in

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[1279] Dylan O. Drummond, Comment, *Texas Groundwater Law in the Twenty-First Century: A Compendium of Historical Approaches, Current Problems, and Future Solutions Focusing on the High Plains Aquifer and the Panhandle*, 4 TEX. TECH. J. TEX. ADMIN. L. 173, 197 (2003).
[1280] *Id.* at 200.
[1281] Rest. 2d. Torts § 858.
[1282] Drummond, *supra* note 1279, at 200.
[1283] *Id.*
[1284] Gregory, *supra* note 1269, at 242.
[1285] Drummond, *supra* note 1279, at 201.
[1286] Taguchi, *supra* note 1265, at 125.
[1287] Drummond, *supra* note 1279, at 201.

a forty percent depletion of groundwater over a twenty-five year period, and Idaho has prohibited all groundwater mining.[1288]

7.3.2.1.3. Methods of Acquiring Rights

There are three methods of acquiring ownership rights: voluntary methods, eminent domain, and adverse possession. Ownership acquired by voluntary methods involves negotiations with the interest owner to acquire storage rights to the reservoir under a lease or a deed. A second method of acquiring ownership, using the power of eminent domain, typically follows the unsuccessful use of voluntary methods, and must be specified by law. Ownership acquired by adverse possession requires the actual, open and notorious, hostile, exclusive, and continuous possession of the property.[1289]

The choice of acquiring ownership by lease or deed depends on the desire of the person controlling the needed property interest.[1290] A deed conveys all rights, title and interest in a formation, together with any necessary surface land.[1291] Payment would be made in the form of a lump sum and costs would be capitalized. A lease provides the right to conduct operations in the geological formation for a defeasible term, along with the right to use surface land which is reasonable and necessary to the exercise of the storage rights.[1292] Payments would be made on a periodic basis, with the costs accounted for as an expense.

A second method of acquiring ownership rights over the reservoir is through the power of eminent domain, or condemnation. Eminent domain power must be provided for by federal or

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[1288] *Id.* at 202.
[1289] *See infra* notes 1317-1320.
[1290] Scott, *supra* note 1240, at 64.
[1291] *Id.*
[1292] *Id.*

state legislation.[1293] In addressing the use of eminent domain power for natural gas storage, the Kansas judiciary in *Strain v. Cities Service Gas Co.* held that a general condemnation statute was insufficient for exercising eminent domain power for the purposes of acquiring a natural gas storage reservoir; eminent domain statutes are not to be "enlarged by implication".[1294] The power of eminent domain can only be exercised after the passage of legislation which is specific to the occasions, modes, conditions, and agencies for exercising the power.[1295] The *Strain* court held that:

> The use of the earth as a storage place for gas is an idea so novel, we cannot believe the legislature had such matter in contemplation when the power of eminent domain was given to pipe line companies. If the rights contended for by appellant are to be given to gas pipe line companies, it is a matter for the consideration of the legislature. The stretch the statute to cover the case here presented would be a little short of judicial legislation.[1296]

In 1938, Congress passed the Natural Gas Act, with language authorizing the federal power to condemn property for natural gas storage.[1297] In addition, several states have enacted eminent domain laws for acquiring underground storage rights.[1298] As a general rule, state eminent domain laws contain a recitation that underground storage of natural gas promotes conservation, the public interest, and the general welfare of the state;[1299] acquiring ownership through the Natural Gas Act requires that a "certificate of public convenience or necessity" be acquired from the Federal Energy Regulatory Commission upon a finding that the applicant's operations

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[1293] *Strain v. Cities Service Gas Co.*, 83 P.2d 124, 126 (Kan. 1938).
[1294] *Id.* at 127.
[1295] *Id.* at 126.
[1296] *Id.* at 127.
[1297] *See infra* Section 7.3.3.2. *See also Columbia Gas Transmission Corp. v. An Exclusive Gas Storage Easement*, 776 F.2d 125, 128 (1985).
[1298] Scott, *supra* note 1240, at 64.
[1299] *Id.* at 67.

conform with the Natural Gas Act.[1300] Although there is both federal and state legislation delegating eminent domain power for natural gas storage, there is no need for federal legislation if states legislate in this area.[1301] In an eminent domain action, the condemnor will generally acquire an easement in the subsurface stratum.[1302] Thus, the condemnee may drill through the condemned stratum to extract oil or gas from a deeper formation.[1303]

The power of eminent domain may be exercised in four possible ways.[1304] The most common way is through a condemnation proceeding, where a judge or arbiter determines the compensation to be paid to the property owner, the owner is paid, and title to the property transfers to the government.[1305] A second way is through the federal Declaration of Takings Act,[1306] where the government files a declaration of taking with the court, deposits an amount of money equal to the estimated value of the land, and takes immediate title and possession of the property; the deposited money is paid to the owner, and a condemnation proceeding is held to determine if the value of the property is higher than the estimate.[1307] The third possibility, a legislative taking, occurs when the legislature passes a statute vesting title of a property in the government immediately upon enactment, with the compensation to the landowner to be determined at a subsequent proceeding.[1308] The final and least common option, known as inverse condemnation, occurs where government takes physical possession of a property without any formal proceedings. The property owner has the right to sue the government for "inverse

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[1300] Fred McGaha, *Underground Gas Storage: Opposing Rights and Interests*, 46 LA. L. REV. 871, 886 (1986).
[1301] Scott, *supra* note 1240, at 71.
[1302] *Id.* at 66.
[1303] *Id.*
[1304] *See generally,* Steven D. McGrew, *Selected Issues in Federal Condemnations for Underground Natural Gas Storage Rights: Valuation Methods, Inverse Condemnation, and Trespass*, 51 CASE. W. RES. L. REV. 131, 148 (2000).
[1305] *Id.*
[1306] 40 U.S.C. § 3114.
[1307] McGrew, *supra* note 1304, at 148.
[1308] *Id.*

condemnation", i.e., taking the property without just compensation. The property owner would seek damages for that taking.[1309]

In general, the value that is paid by the government for the property rights appropriated is "fair market value".[1310] The level of compensation will depend on whether full ownership of the property has been granted (in which case a "takings" analysis determines the value) or whether a servitude has been obtained (in which case a "damages" analysis determines value). In a takings analysis, the fair market value is the price at which a buyer, willing but not obligated to buy, would pay a seller, willing but not obligated to sell the property.[1311] Determining the fair market value requires one to speculate the value of the mineral interest. Because mineral rights are seldom sold, but rather are normally leased, mineral interest owners often have difficulty in establishing their losses.[1312] The value of compensation may derive from evidence of comparable sales, the existence of sufficient minerals allowing for their commercial recovery, and that exploitation of minerals is consistent with the highest and best use of the land.[1313] In a damages analysis, where the property right remains with the owner subject to a servitude granted for the storage operations, the fair market value is determined by a before-and-after market value test, where compensation is the difference between the value of the property interest before the taking and the value of the property interest after the taking.[1314] Evidence for determination of this compensation could include the fair market value of the servitude based upon a capitalization of retail income for the right to store the gas, depreciation in the fair market value of the condemned tract as a whole by reason of the taking of the storage easement, and the

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[1309] *Id.*
[1310] Scott, *supra* note 1240, at 71.
[1311] Robert A. Dunkelman, *Consideration of Mineral Rights in Eminent Domain Proceedings,* 46 LA. L. REV. 827, 835 (1986).
[1312] *Id.* at 841
[1313] *Columbia Gas Transmission Corp. v. An Exclusive Natural Gas Storage Easement*, 620 N.E.2d 48, 49 (Ohio 1993). *See also* McGrew, *supra* note 1304, at 153.
[1314] Dunkelman, *supra* note 1311, at 836.

change in value of a mineral lease for the property (such as due to the increased cost in mining).[1315]

Finally, property ownership may be lost due to "adverse possession". Adverse possession is the loss of ownership due to the adverse use and possession of the servient lands sufficient to give rise to a cause of action.[1316] The adverse possessor must demonstrate "actual",[1317] "open and notorious",[1318] "hostile",[1319] and "adverse use"[1320] of the property during a continuous and uninterrupted statutory period. Generally, once adverse possession begins, it can be interrupted only by an actual or constructive ouster.[1321] Actual ouster is the physical removal of the adverse possessor from the premises, while constructive ouster involves a court order ejecting the adverse possessor from the premises.[1322]

The scope of ownership acquired by adverse possession depends on whether there has been a prior mineral severance. If the mineral interest has not been severed from the surface interest, adverse possession of the surface will encompass all of the land, including the minerals.[1323] In that situation, surface occupancy would provide sufficient notice to the true owner of the property interest. However, where the mineral interest has been severed from the surface interest, adverse possession of the surface will encompass only the surface and not the minerals.[1324] Adverse possession of the mineral interest would require acts sufficient to put the true owner on notice that someone is asserting rights to the mineral interest, rather than the

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[1315] *Columbia Gas Transmission Corp.*, 620 N.E.2d at 49. *See also* McGrew, *supra* note 1304 at 158.
[1316] ANDERSON ET AL, *supra* note 800, § 3.4(A).
[1317] Actual possession means physical occupancy or control over property. BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "possession").
[1318] Open and notorious possession means possession or control that is evident to others. *Id.*
[1319] Hostile possession means possession asserted against the claims of all others. *Id.*
[1320] Adverse use means a use without license or permission. *Id.* (s.v. "use").
[1321] ANDERSON ET AL, *supra* note 800, § 3.4(C).
[1322] *Id.*
[1323] *Id.* at § 3.4(B)
[1324] *Id.* at § 3.4(C)

surface interest.[1325] There may also be limitations that the adverse ownership has been acquired under good faith color of title, i.e. the adverse possessor holds a deed acquired in the good faith belief that the deed conveyed ownership of the property.[1326]

7.3.2.2. Ownership of Injected Natural Gas

Although the issue of ownership over injected CO_2 has not yet arisen in the courts, ownership over injected natural gas has been examined, and one might expect that the holdings concerning natural gas storage will serve as precedent for future CO_2 storage property disputes. The past decisions regarding ownership over injected natural gas rely on a couple fundamental rules of mineral law: the rule of capture and the doctrine of ownership-in-place (and the contrasting doctrine of non-ownership).

The rule of capture analogizes oil and gas to wild animals (*ferae naturae*).[1327] Like wild animals, the rule of capture considers oil and gas as fugacious and the landowner does not come into ownership of the property until it has been brought into personal possession by capture.[1328] The rule of capture was most notably articulated by the Pennsylvania judiciary in *Westmoreland & Cambria Natural Gas Co. v. De Witt*:

> Water and oil, and still more strongly gas, may be classed by themselves, if the analogy be not too fanciful, as *minerals ferae naturae*. In common with animals, and unlike other minerals, they have the power and the tendency to escape without the volition of the owner. Their 'fugitive and wandering existence within the limits of a particular tract was uncertain' as said by Chief Justice Agnew in Brown v. Vandegrift, 80 Pa. St. 147, 148. They belong to the owner of the land, and are part of it, so long as they are on or in it, and are subject to his control; but when they escape, and go into other land, or come under another's control, the

[1325] *Id.* at § 3.5(A)
[1326] *Id.* at § 3.5 (B)
[1327] Lewis M. Andrews, *The Correlative Rights Doctrine in the Law of Oil and Gas,* 13 S. CAL. L. REV. 185, 186 (1940). *See also* W. L. Summers, *Property in Oil and Gas,* 29 YALE L. J. 174, 176 (1919)
[1328] *Brown v. Spilman*, 155 U.S. 665, 669 (1895).

> title of the former owner is gone. Possession of the land, therefore, is not necessarily possession of the gas.[1329]

The consequence of the rule of capture is that there is no liability for drainage of oil and gas from under the lands of neighboring properties, so long as all relevant laws and regulations have been observed.[1330]

The rule of capture gives rise to the doctrine of non-ownership, which holds that the owner of a severed mineral interest does not have a present right to possess the oil and gas in place, but only has a right to search for, develop and produce the oil and gas.[1331] The doctrine of non-ownership can be contrasted with the doctrine of ownership-in-place, which holds that the owner has the right to use the land surface to produce oil and gas from property, but that the interest in the oil and gas terminates if the oil and gas flows out from under the owner's land.[1332] Thus, under the doctrine of ownership-in-place, the owner of the mineral interest owns the oil and gas beneath the surface; under the doctrine of non-ownership, the owner of the mineral interest does not own the oil and gas beneath the surface until it has been brought into personal possession.

In the early jurisprudence concerning ownership of injected natural gas, the courts held that title to natural gas was lost upon injection (i.e. lost when natural gas was injected into a storage formation). This doctrine, known as the non-ownership theory of injected gas,[1333] was first stated in the case of *Hammonds v. Central Kentucky Natural Gas Co.*[1334] In *Hammonds*, the

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[1329] *Westmoreland & Cambria Natural Gas Co. v. De Witt*, 18 A. 724, 725 (1889).
[1330] William O. Huie, *Apportionment of Oil and Gas Royalties*, 78 HARV. L. REV. 1113, 1128 (1965). *See also* Sydney W. Falk, Jr., Note, *Natural Gas Regulation and Vested Property Interests: Ratable Taking, Proration Standards, and Fieldwide Civil Liability*, 62 TEX. L. REV. 691, 734 (1983).
[1331] BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "nonownership theory").
[1332] *Id.*
[1333] This rule deals with *injection* of gas, and is not to be confused with the doctrine of non-ownership governing the *extraction* of oil and gas.
[1334] *Hammonds v. Central Kentucky Natural Gas Co.*, 255 S.W.2d 204 (Ky. 1934).

plaintiff Della Hammonds owned 54 acres in fee simple, but her subsurface property was surrounded by a 15,000 acre depleted natural gas field which the defendant Central Kentucky Natural Gas Co. was using for natural gas storage.[1335] Hammonds brought a trespass action against Central Kentucky Natural Gas Co. alleging that the stored natural gas was entering her subsurface property without her knowledge or consent.[1336]

The question presented to the court was whether gas, having once been reduced to possession and absolute ownership being vested, was restored to its original wild and natural status by being injected into a geological reservoir.[1337] The Kentucky judiciary relied on the rule of capture, the notion that natural gas becomes personal property only after it has been reduced to actual possession by extraction, and the doctrine of non-ownership, which assumes that natural gas has the tendency to escape without the volition of the owner.[1338] As interpreted by the *Hammonds* court, gas must be brought under dominion and into actual possession at the surface in order to gain title to the gas.

The judiciary used these principles to develop the non-ownership theory of injected gas. In particular, the court relied on the analogy of natural gas to wild animals:

> If one capture a fox in a forest and turn it loose in another, or if he catch a fish and put it back in the stream at another point, has he not done with that migratory, common property just what [Central Kentucky Natural Gas Co.] has done with the gas in this case? Did the company not lose its exclusive property in the gas when it restored the substance to its natural habitat?[1339]

The *Hammonds* court held that if gas was injected into a formation and “wandered” into the plaintiff’s land, the defendant would not be liable to her for the value of the use of her property

[1335] *Id.* at 204.
[1336] *Id.*
[1337] *Id.* at 205.
[1338] *Id.*
[1339] *Id.*

because the defendant lost ownership over the gas; the gas was restored to its wild and natural status (*mineral ferae naturae*).[1340] Ironically, although Central Kentucky Natural Gas Co. won the case (the company was not held liable for trespass), the holding of the case was of much greater loss to the firm. According to the court, the company lost title to the gas and, by extension, Hammonds would be free to retrieve to extract any of the natural gas injected into the formation by Central Kentucky Natural Gas Co. without incurring any liability.

The contrast to the *Hammonds* doctrine is the ownership theory of injected gas, which was first articulated in Pennsylvania by *White v. New York State Natural Gas Corp*.[1341] Under the ownership theory, title to injected gas is not lost by injection of the gas into a natural underground reservoir for storage purposes. The *White* court rejected the analogy of natural gas injected in a reservoir to wild animals, instead arguing that the stored natural gas was maintained in the possession of storage companies within a well-defined storage field.[1342] The Texas judiciary in *Lone Star Gas Co. v. Murchison* also rejected the *Hammonds* doctrine.[1343] According to the *Lone Star* court:

> Gas has no similarity to wild animals. Gas is an inanimate, diminishing non-reproductive substance lacking any will of its own, and, instead of running wild and roaming at large as animals do, is subject to be moved solely by pressure or mechanical means. It cannot be logically regarded as personal property of the human race as are wild animals, instead of being turned loose in the woods as the fanciful fox or placed in the streams as the fictitious fish, gas, a privately owned community, has been stored for use as required by the consuming public being, as alleged by appellant, subject to its control and withdrawal at any time. Logic and reason dictates the application of the *White* decision rather than *Hammonds*, to the end, that in Texas, the owner of gas does not lose title thereof by storing the same in a well-defined reservoir.[1344]

[1340] *Id.* at 206.
[1341] *White v. New York State Natural Gas Co.*, 190 F. Supp. 342 (Pa. 1960).
[1342] *Id.* at 348.
[1343] *Lone Star Gas Co. v. J. W. Murchison*, 353 S.W.2d 870 (Tex. 1962).
[1344] *Id.* at 879.

Notably, the Kentucky judiciary, using the *White* and *Lone Star* cases as precedent, decided to limit the scope of the Hammonds doctrine in the 1987 case of *Texas American Energy Corp. v. Citizens Fidelity Bank & Trust Co.*[1345] The court rationalized its new holding by arguing that in the *Hammonds* case, the storage company did not acquire all the property rights for the storage reservoir, whereas in the case at hand, the reservoir had total integrity and the storage company owned all property rights.[1346] Thus where an underground reservoir is capable of being defined with certainty and the integrity of the reservoir is capable of being maintained, the *Hammonds* doctrine does not apply.[1347] Title to the oil or gas is not lost and the fugacious minerals remain the property of the original owner.[1348] All states now follow the ownership theory of injected gas.

7.3.3. Regulation of Natural Gas Storage

7.3.3.1. Statutory Exemption from SDWA/UIC Requirements

Although natural gas storage was initially regulated by the SDWA, Congress amended the SDWA in 1980 and exempted natural gas storage from SDWA requirements, including the UIC Program. The House Committee on Interstate and Foreign Commerce justified the natural gas storage exemption as follows:

> Section 3 of the [SDWA Amendments] deletes the underground storage of natural gas from the statutory definition of underground injection. As proposed, the Administrator's regulations for underground injection control programs required that new and existing natural gas storage facilities meet certain construction and monitoring requirements. Persuaded that *sufficient evidence does not exist indicating that natural gas storage poses a threat to drinking water quality and recognizing that storage operators have an economic incentive to prevent gas*

1345 *Tex. Am. Energy Corp. v. Citizens Fidelity Bank & Trust Co.*, 736 S.W.2d 25 (Ky. 1987).
1346 *Id.* at 28.
1347 *Id.*
1348 *Id.*

> *leakages*, the Administrator in his final regulations deleted these requirements, but mandated that natural gas storage be further studied for a three-year period to determine the need for regulation. This latter mandate was motivated in large part by the Administrator's believe that all forms of underground injection must be in some way regulated under the Act.
>
> As a result, the natural gas storage industry is still faced with the possibility of federal regulation. This possibility could well discourage needed expansions of storage facilities to meet the needs of areas with substantial demands for natural gas. The committee believes that this uncertainty about future regulation is undesirable, given the lack of evidence tending to show that gas storage may pose a risk to health.
>
> The committee thus proposes to remove natural gas storage from the definition of underground injection. This exclusion is not intended to exempt from regulation underground injection other than gas storage which may be undertaken by gas storage operators. In addition, *the exclusion applies only to natural gas as it is commonly defined, and not to other injections of matter in a gaseous state*. Finally, the committee does not intended to preclude the Administrator from studying gas storage further, and from recommending legislative modification should credible evidence indicate that natural gas storage may in some way pose a threat to drinking water quality and thus to public health.[1349] [emphasis added]

The House Report notes that when implementing the original SDWA, the EPA Administrator removed natural gas storage from the UIC Program's jurisdiction, arguing that there was no evidence that natural gas storage posed a threat to drinking water quality and that storage operators would have an economic incentive to prevent leakage from the geological formation.[1350] In its place, the EPA Administrator created a three-year research study on the need for regulation of natural gas storage under the SDWA.[1351] Although not mentioned in the House Report, presumably the EPA study did not find that natural gas storage posed a threat to drinking water because the House Report mentions there is a "lack of evidence tending to show that gas storage may pose a risk to health".[1352] Elsewhere, the House report noted that the

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[1349] H.R. REP NO. 96-1348, *reprinted in* 1980 U.S.C.C.A.N. 6080, 6084-6085.
[1350] *Id.*
[1351] *Id.*
[1352] *Id.*

natural gas storage exemption was targeted at major oil and gas producing states, most of which already underground injection regulations in place.[1353] The exemption would allow these states to continue their natural gas storage programs unencumbered by additional federal requirements. Thus Congress amended the SDWA's definition of underground injection, removing natural gas storage from its jurisdiction.

7.3.3.2. Federal Legislation under the Natural Gas Act of 1938

The Natural Gas Act of 1938 provides federal eminent domain power for natural gas companies seeking to operate natural gas pipelines.[1354] Under the Natural Gas Act, a prerequisite to exercising eminent domain power is the acquisition of a Certificate of Public Convenience and Necessity from the Federal Energy Regulatory Commission ("FERC").[1355] Although not specifically stated in the language of the statute, the Natural Gas Act has been interpreted to also provide eminent domain power over natural gas storage.[1356] According to the Natural Gas Act, if property rights cannot be obtained by voluntary methods, the pipeline operator may exercise eminent domain for:

> [T]he necessary right-of-way to construct, operate, and maintain a pipe line or pipe lines for the transportation of natural gas, and the necessary land or other property, in addition to right-of-way, for the location of compressor stations, pressure apparatus, or *other stations or equipment necessary to the proper operation* of such pipe line or pipe lines …[1357] [emphasis added]

In *Columbia Gas Transmission Corp. v. An Exclusive Gas Storage Easement*, the Sixth Circuit Court of Appeals held that the language emphasized above ("other stations or equipment

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[1353] *Id*.
[1354] *Columbia Gas Transmission Corp. v. An Exclusive Gas Storage Easement*, 776 F.2d 125, 129 (6th Cir. 1985).
[1355] 15 U.S.C. § 717f(c).
[1356] *Columbia Gas Transmission Corp.*, 776 F.2d at 129.
[1357] 15 U.S.C. § 717f(h).

necessary to the proper operation") was sufficiently broad enough to encompass an underground natural gas storage facility, thus allowing for the exercise of eminent domain power if a Certificate of Public Convenience and Necessity had been obtained.[1358] Although the eminent domain language does not specifically mention the use of condemnation procedures for underground gas storage, the court held that it was within the spirit and intent of the Natural Gas Act because underground gas storage facilities are a necessary and integral part of the operation of piping gas from the area of production to the area of consumption.[1359] The Supreme Court agreed with this interpretation in dicta in the case of *Schneidewind v. ANR Pipeline Co.*[1360]

7.3.3.3. Regulation of Natural Gas Storage on the State Level

Because natural gas storage is exempted from federal SDWA and UIC requirements, natural gas storage regulations and treatment of liability will vary by state. In this section, I consider the regulation of natural gas storage by Texas and Illinois. I choose Texas because of its extensive use of depleted oil and gas fields for storage, and I choose Illinois because of its experience in storing natural gas in deep saline formations.

7.3.3.3.1. Texas

In Texas, natural gas storage is governed by the Texas Underground Natural Gas Storage and Conservation Act of 1977. The natural gas storage provisions as currently written would not apply to CO_2 storage because natural gas is defined as "any gaseous material composed primarily of methane in either its original or its manufactured state".[1361] Because the definition of natural

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1358 *Columbia Gas Transmission Corp.*, 776 F.2d at 128.
1359 *Id.* at 129.
1360 *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 295 n.1 (1988) ("Petitioners argued below that [ANR Storage Company] was not a natural gas company within the meaning of the [Natural Gas Act], contending that the storage of gas constitutes neither the transportation nor the sale of gas in interstate commerce. Both courts below rejected this argument … reasoning that "transportation" includes storage. … We agree.").
1361 Tex. Nat. Res. Code § 91.251 (2006).

gas specifically refers to methane, natural gas storage is statutorily excluded from applying to CO_2 storage. Natural gas storage is regulated by the Railroad Commission of Texas ("RRC"), which has authority over both storage *per se* and any equipment and facilities used for natural gas storage.[1362] As in the case of acid gas injection, the RRC also has oversight of the closure and abandonment of any natural gas storage facilities.[1363]

Under Texas law, the RRC is responsible for establishing safety standards and practices for natural gas storage operations.[1364] Its rules for storage in oil and gas fields are embodied in Rule 3.96 of the Texas Administrative Code. Prospective permit holders must file an application with the RRC designating the geological reservoir intended for storage.[1365] Along with the application, the applicant must provide information demonstrating the suitability of the formation for gas storage and information detailing the amount of recoverable *in situ* gas in the formation.[1366] The applicant must provide notice of the application to all mineral interest owners and leaseholders of the storage formation, leaseholders of minerals adjacent to the proposed reservoir, owners and leaseholders of the overlying land, and the pertinent local officials.[1367]

With respect to injection well safety requirements, all storage wells are required to have leak detectors, audible and visible warning systems, an emergency response system, and safety training of the operators. As with EPA UIC regulations, Texas sets forth requirements for injection well construction for natural gas storage. All injection wells must have a tubing and packer, with the packer higher than 200 feet below the top of the cement of the long string casing, but lower than 150 feet below the base of a fresh water aquifer.[1368] Injection well

[1362] Tex. Nat. Res. Code § 91.252.
[1363] Tex. Nat. Res. Code § 91.203(a).
[1364] Tex. Nat. Res. Code § 91.255.
[1365] Tex. Admin. Code § 3.96(c)(2) (2006).
[1366] *Id.*
[1367] Tex. Admin Code § 3.96(f)(1).
[1368] Tex. Admin. Code § 3.96(k)-(l). For a description of injection well terminology, see Section 2.2.3.

pressure is to be monitored continuously and the integrity is to be tested at least once every five years.[1369]

Liability for violations of any of the natural gas storage regulatory provisions is specified by statute. If the state chooses to bring a civil action against the alleged violator, liability could include an injunction from further natural gas storage activities and/or a penalty of $25,000 per day of violation, not to exceed $500,000. In addition, the RRC could seek an administrative penalty against the alleged violator of $10,000 per day, not to exceed $200,000. If the violation is deemed to be intentional the administrative penalty increases to $25,000 per day, not to exceed $300,000. Texas uses virtually the same language as the SDWA[1370] in the criteria that the RRC should use in determining the amount of penalty:

> (1) the seriousness of the violation, including the nature, circumstances, extent, and gravity of the prohibited act and the hazard or potential hazard created to the health, safety, or economic welfare of the public; (2) the economic harm to property or the environment caused by the violation; (3) the history of previous violations; (4) the amount necessary to deter future violations; 5) efforts to correct the violation; and (6) any other matter that justice may require.

Any penalties are subject to notice and public hearing, but as in the case of *Jolly*,[1371] the penalty may be assessed even if the alleged violator does not take advantage of his/her opportunity for a hearing.[1372]

7.3.3.3.2. Illinois

In Illinois, natural gas storage is governed by the Illinois Oil and Gas Act as it has been implemented in Title 62 of the Illinois Administrative Code. Unlike Texas, Illinois does not

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[1369] Tex. Admin. Code § 3.96(n).
[1370] *See* 42 U.S.C. § 300h-2(b). *See also supra* Section 5.3.5.
[1371] *See supra* Section 5.3.5.
[1372] Tex. Nat. Res. Code § 91.262.

define natural gas and so there is greater ambiguity as to its application to CO_2 storage.[1373] Like Texas, prospective storage operators must file a permit application with the state, including information on the location of the storage site, schematics on the construction of the well, details on relevant mineral estate owners, and information on the subsurface strata at the storage site.[1374]

Illinois does not distinguish between UIC-regulated injection wells and natural gas storage injection wells in its minimum design and construction requirements. In fact, in its regulations of natural gas storage wells, the rules specifically cross-reference the design and construction,[1375] operating,[1376] and well plugging[1377] requirements for oil and gas production wells.[1378] Thus although natural gas storage has been formally exempted from federal SDWA and UIC requirements, it makes no difference in the case of Illinois because all injection wells are subject to the same requirements, whether they are natural gas storage wells or otherwise.

7.3.4. Natural Gas Storage as a Basis for CO_2 Storage on Federal Lands

Geological CO_2 storage potentially changes the historical leasehold relationship between private operators and the federal government. In the typical hydrocarbon extraction circumstance, a federal lease to the subsurface minerals would be required to extract hydrocarbons from the subsurface. The federal government would receive revenues from the lease and royalties in return for the lessee being allowed to extract hydrocarbons. However, with EOR, the lessee would be injecting CO_2 fluids into the geological formation in addition to extracting oil. When coupled with CO_2 storage for climate change mitigation, the operator

[1373] For example, "gas storage well" is defined as "a well drilled for input and/or withdrawal of natural gas in a natural gas storage field", but the term "natural gas storage" is never defined. *See* Ill. Admin. Code § 240.1805 (2006).
[1374] Ill. Admin. Code § 240.1835.
[1375] Ill. Admin. Code § 240.610.
[1376] Ill. Admin. Code § 240.630(a)-(c).
[1377] Ill. Admin. Code § 240.1610.
[1378] Ill. Admin. Code § 240.1852.

would seek to leave the CO_2 stored in the leased geological formation once hydrocarbon extraction activities had been completed. Presumably, the lessee would be conducting CO_2 storage in conjunction with EOR because of a financial incentive to do so, for example the potential to receive a credit for avoided CO_2 emissions in a carbon-constrained policy regime such as a "cap-and-trade" system.[1379] At the end of the lease, the lessee would seek to retain its avoided CO_2 emissions credit, while transferring title in the stored CO_2 to the federal government. Thus the lessee would seek to retain the financial benefits of the CO_2 storage operation, while externalizing future liability.

Two questions arise from this hypothetical scenario of a CO_2 storage operation on federal lands. First, what, if any, statutory authority does the BLM have to allow a lessee to inject CO_2 (or more generally, fluids) for storage in subsurface geological formations on federal lands? Second, does the analysis change if the injected CO_2 is to remain in the subsurface beyond the end of the leasehold term, perhaps indefinitely? I address these questions with an analysis of BLM's statutory authority and responsibilities in this area, focusing on the Mineral Leasing Act of 1920 ("MLA") and related laws, but also analyzing the implications of the Federal Land Policy and Management Act of 1976 ("FLPMA") and the National Environmental Policy Act ("NEPA").

The MLA gives the Secretary of the Interior authority to foster and encourage the development of domestic mineral resources through the issuance of mineral leases for federal lands.[1380] Under the MLA, the federal government retains title to surface and mineral deposits,

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[1379] *See, e.g.*, Victor, *supra* note 1223, at 174-179 (examining the role of international emissions trading regimes for climate change policy).
[1380] 30 U.S.C. § 21a.

and private entities seeking to withdraw minerals must obtain prospecting permits and leases.[1381] Unlike the previous statutory authority governing hydrocarbon extraction on federal lands, which gave private entities the absolute right to purchase federal lands containing minerals, the MLA grants the Secretary broad discretion in granting permits and leases.[1382] The MLA has been modified by the Acquired Lands Act of 1947,[1383] which extends authority under the MLA to lands later acquired by the federal government, and the Federal Onshore Oil and Gas Leasing Reform Act of 1997,[1384] which requires that all leases first be auctioned to the highest bidder ("competitive bidding").

Although the majority of the MLA speaks to the issue of hydrocarbon extraction, there is a subsection in the oil and gas lands leasing portion of the MLA which speaks to the issue of subsurface storage activities:

> The Secretary of the Interior, to avoid waste or to promote conservation of natural resources, may authorize the subsurface storage of oil or gas, whether or not produced from federally owned lands, in lands leased or subject to lease under this chapter. Such authorization may provide for the payment of a storage fee or rental on such stored oil or gas or, in lieu of such fee or rental, for a royalty other than that prescribed in the lease when such stored oil or gas is produced in conjunction with oil or gas not previously produced. Any lease on which storage is so authorized shall be extended at least for the period of storage and so long thereafter as oil or gas not previously produced is produced in paying quantities.[1385]

The statutory provision applies to the "subsurface storage of oil or gas", and thus its applicability to CO_2 storage turns on whether "CO_2" would come under the MLA's definition of "gas". Although there is no case law which interprets the MLA's definition of gas under the subsurface

[1381] U.S. OFFICE OF TECH. ASSESSMENT, MANAGEMENT OF FUEL AND NONFUEL MINERALS IN FEDERAL LAND 87 (NTIS Order No. PB-295788, 1979).
[1382] *Id.*
[1383] 30 U.S.C. §§ 351-49.
[1384] 30 U.S.C. §§ 226(g)-(h).
[1385] 30 U.S.C. § 226(m).

storage provision, the Federal District Court of Wyoming in *Exxon v. Lujan* examined the issue of whether CO_2 pipelines were governed by MLA's right-of-way requirements for pipelines transporting "natural gas".[1386] The MLA's right-of-way provisions also refer to pipelines transporting "oil or gas",[1387] and thus while the case is not entirely on point, it provides some precedent. Exxon sought to strip CO_2 from natural gas processed at its Shute Creek facility in Wyoming, and transport the CO_2 by pipeline to its Rangely and Bairoil fields for use in EOR.[1388] Exxon applied to BLM for a CO_2 pipeline right-of-way under the FLPMA,[1389] but instead was granted a right-of-way under the MLA.[1390] The MLA right-of-way provisions govern oil and natural gas pipelines, while the FLPMA provisions govern pipelines other than oil and natural gas pipelines. Exxon opposed the right-of-way permit being granted under the MLA because the MLA imposed a common carrier requirement,[1391] which was not imposed by the FLPMA right-of-way provisions. The case involved Exxon's appeal of the BLM permit issuance, specifically whether a CO_2 pipeline could be characterized as a natural gas pipeline under the MLA.

The *Exxon* court found that the MLA never defined the word "gas" and that the plain meaning of "natural gas" was ambiguous with regard to whether it encompassed CO_2. To most lay people, natural gas is the methane gas used to heat their homes, but natural gas may contain components of a number of gases, including CO_2, and thus natural gas could very well mean

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[1386] 730 F.Supp. 1535 (D. Wyo. 1990), *aff'd by* 970 F.2d 757 (10th Cir. 1992).
[1387] *See, e.g.*, 30 U.S.C. § 185(r)(2)(A).
[1388] This is the same Rangely field described in Section 5.2.1 of this thesis.
[1389] 43 U.S.C. § 1761(a)(2) ("The Secretary…[is] authorized to grant, issue, or renew rights-of-way…for…pipelines and other systems for the transportation or distribution of liquids and gases…*other than* oil, natural gas, synthetic liquid or gaseous fuels, or any refined product produced therefrom, and for storage and terminal facilities in connection therewith.") (emphasis added).
[1390] 30 U.S.C. § 185(a) ("Rights-of-way through any Federal lands may be granted…for the transportation of oil, natural gas, synthetic liquid or gaseous fuels, or any refined product produced therefrom…").
[1391] 30 U.S.C. § 185(r)(1) ("Pipelines and related facilities authorized under this section shall be constructed, operated, and maintained as common carriers.").

gases that occur naturally.[1392] Because of the statutory ambiguity, the *Exxon* court looked to the legislative history of the MLA. After analyzing the Congressional debate of the predecessor statute to the MLA, the *Exxon* court found that if one were to categorize gases in the broadest possible manner at the time the MLA was enacted, "they would fall into two categories – natural gas; that is, gases that occur naturally, or artificial gas; namely, gases manufactured in the laboratory".[1393] The court further found that if Congress had wanted to define natural gas restrictively in the MLA, Congress knew of the term "hydrocarbon" and could have defined "natural gas" to mean "gaseous hydrocarbons", excluded smaller components of the natural gas such as CO_2, or simply used the term "hydrocarbon".[1394] The court also referred to a legal opinion from the Department of Interior's Office of the Solicitor, which argued that the MLA refers only to "gas" or "natural gas" without any qualifying adjectives, and that a nonrestrictive reading of the terms would be supported under the oil and gas leasing provision of the MLA.[1395] The *Exxon* court found that the term "natural gas" as used in the MLA had a "technical meaning, thus precluding reliance on its ordinary definition".[1396] Any use of the word "natural" was meant to distinguish the gas from that which was "artificially produced".[1397]

Extending the *Exxon* court's analysis of the MLA's right-of-way provisions to the subsurface storage provisions, it would appear that CO_2 falls within the MLA's definition of "gas" and that CO_2 storage would be governed by the MLA's provisions on the "subsurface storage of gas". The subsurface storage provisions do not specify whether the gas to be stored should be natural gas or artificially produced gas – the provisions only refer to "gas". The *Exxon*

[1392] 730 F.Supp. at 1540.
[1393] *Id.* at 1543.
[1394] *Id.*
[1395] U.S. Dep't of Interior, Ownership of and Right to Extract Coalbed Methane Gas in Federal Coal Deposits, 88 Interior Dec. 538 (1981).
[1396] *Exxon*, 730 F.Supp. at 1544.
[1397] *Id.* at 1545.

court would probably construe the provision to refer to both natural gas and artificially produced gas. In the alternative, if the "gas" provision only referred to "natural gas", *Exxon* supports the interpretation that under the MLA, CO_2 is treated as natural gas.

Even if the subsurface storage provisions of the MLA regulate CO_2 storage, the statutory provisions provide that the Secretary of the Interior may authorize storage "to avoid waste or to promote conservation of natural resources".[1398] This raises an issue of whether CO_2 storage is consistent with avoiding waste or promoting conservation of natural resources. The MLA provides no guidance as to how it would define "waste" or "promoting conservation". The plain meaning of the word "waste" would seem to govern CO_2 emissions, but CO_2 could be considered a waste irrespective of whether it would be emitted to the atmosphere or injected in the subsurface. It is not the case that CO_2 storage would be "avoiding" waste; instead it would be managing waste in such a way as to minimize damage to the climate. Some have even argued that CO_2 is not a "waste" at all, but rather is a valuable commodity that could be used for EOR.[1399] The second allowable purpose for subsurface storage under the MLA, the conservation of natural resources, would appear to be a better fit for CO_2 storage. The underlying goal of CO_2 storage is to avoid CO_2 emissions to the atmosphere in an effort to mitigate climate change. The concern with climate change is that the warming of the climate could lead to the damage of natural resources. Thus the storage of CO_2 could be seen as an effort to conserve natural resources in the face of climate change.

The MLA gives discretion to the Secretary of the Interior in establishing payment mechanisms for subsurface storage. According to the MLA, the Secretary "may provide for the

[1398] 30 U.S.C. § 226(m).
[1399] INTERSTATE OIL & GAS COMPACT COMM'N, *supra* note 403, at 27.

payment of a storage fee or rental … or, in lieu of such fee or rental, a royalty".[1400] The discretionary aspect is in the use of the word "may". The Secretary is not required to provide for payment, but he "may" do so. However, if the Secretary does provide for a storage lease, he is required to extend the lease for the period of storage.[1401] The MLA's subsurface storage provisions also include a caveat that the storage lease may be extended "so long thereafter as oil or gas not previously produced is produced in paying quantities".[1402] It is unclear how this limitation would apply to CO_2 storage since the CO_2 would remain in the subsurface and not be produced. If one construed the period of storage to be indefinite, one might be able to avoid the limitation since the caveat only applies to the time after the period of storage. In other words, if one defines the time period of storage so that there is no period of time "thereafter", the limitation would have no applicability. The MLA would not require that the CO_2 being injected arise from activities occurring on federal lands. Instead, the MLA allows subsurface storage, "whether or not [the gas is] produced from federally owned lands".[1403] One would expect that the typical CO_2 storage operation would inject CO_2 arising from activities on private lands, such as a fossil fuel power plant or natural gas processing facility.

BLM's treatment of underground natural gas storage provides an example of how the agency implements the MLA subsurface storage requirements. BLM's regulatory requirements for natural gas storage are outlined in the BLM Oil and Gas Adjudication Handbook.[1404] A private operator may enter into a gas storage agreement with BLM to store natural gas on federal

[1400] 30 U.S.C. § 226(m).
[1401] *Id.* ("any lease on which storage is so authorized *shall* be extended") (emphasis added).
[1402] *Id.*
[1403] *Id.*
[1404] U.S. Bureau of Land Mgmt., *E-3105-1: Approved Gas Storage Agreement*, *in* OIL AND GAS ADJUDICATION HANDBOOK, COOPERATIVE CONSERVATION PROVISIONS 53 (Rel. 3-293, BLM Manual Handbook 3105-1, July 8, 1994).

lands, regardless of whether the natural gas was actually extracted from the federal lands.[1405] The operator is required to pay an annual storage fee per net mineral acre for the subsurface space being used, an injection fee, and a withdrawal fee.[1406] Underground natural gas storage on federal lands is also subject to a bonding requirement.[1407] The storage operator must fulfill the BLM bonding requirement before the gas storage agreement can be approved.[1408] BLM accepts two types of bonds: surety bonds or personal bonds.[1409] The amount of the bond must be at least $25,000, and is calculated as a function of the annual storage fee and estimated quarterly injection and withdrawal fees.[1410]

Although the MLA's provisions specifically govern subsurface storage, any CO_2 storage activities on federal lands would also be subject to the FLPMA and NEPA. The FLPMA, which is considered to be BLM's "organic act",[1411] requires that the Secretary of the Interior "manage the public lands under principles of multiple use and sustained yield, in accordance with the land use plans developed by him".[1412] The development of mineral resources is considered to be among FLPMA's multiple uses, perhaps even the *de jure* and *de facto* dominant uses of BLM lands, but because of their non-renewable nature, minerals are incapable of being managed for sustained yield.[1413]

Under the FLPMA, any CO_2 storage or EOR/CO_2 storage operation, would need to analyzed under a land use plan. A land use plan is a document which describes allowable uses

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[1405] *Id.*
[1406] *Id.*
[1407] U.S. Bureau of Land Mgmt., *Bonds for Gas Storage Agreements*, *in* OIL AND GAS ADJUDICATION HANDBOOK, FLUID MINERALS BOND PROCESSING USER GUIDE 57 (BLM Manual Handbook 3104-1, Dec. 1996).
[1408] *Id.*
[1409] *Id.*
[1410] *Id.*
[1411] Roger Flynn, *Daybreak on the Land: The Coming of Age of the Federal Land Policy and Management Act of 1976*, 29 VT. L. REV. 815, 816 (2005).
[1412] 43 U.S.C. § 1732.
[1413] George Cameron Coggins, *The Law of Public Rangeland Management IV: FLPMA, PRIA, and the Multiple Use Mandate*, 14 ENVTL. L. 42-3 (1983).

for a land area, goals for the land's future condition, and next steps.[1414] Land use plans are adopted after notice and comment, and are designed to guide and control future management actions.[1415] In developing land use plans, the Secretary is to "use and observe the principles of multiple use and sustained yield",[1416] "consider present and potential uses of the public lands",[1417] and "weigh long-term benefits to the public against short-term benefits".[1418] Although CO_2 storage in conjunction with EOR appears to be in line with BLM's historical interpretation of multiple use and sustained yield, storing CO_2 in a geological formation indefinitely would preclude the geological formation from being used for another purpose, such as the temporary storage of hydrocarbons. Thus FLPMA's principle of considering potential future uses of public lands could cut against CO_2 storage. On the other hand, if CO_2 storage is effective in mitigating climate change, the technology could decrease the probability of environmental degradation due to climate change, benefiting potential uses of public lands. The outcome of the short-term/long-term benefit analysis is similarly unclear with respect to CO_2 storage. From a long-term perspective, CO_2 is being injected into the subsurface to mitigate the prospect of climate change, which would preserve the environment for future generations. On the other hand, in the short-term, there might be other potential uses of the subsurface formation that could have greater economic value than CO_2 storage.

CO_2 storage on federal lands would implicate NEPA as well. Courts are split as to whether a management plan requires the preparation of an environmental assessment or environmental impact statement because of the plan's purported lack of specificity,[1419] but the

[1414] Norton v. Southern Utah Wilderness Alliance, 542 U.S. 55, 59 (2004).
[1415] *Id.*
[1416] 43 U.S.C. § 1712(c)(1).
[1417] 43 U.S.C. § 1712(c)(5).
[1418] 43 U.S.C. § 1712(c)(7).
[1419] *Compare* Kleppe v. Sierra Club, 427 U.S. 390 (1976) (holding that a region-wide environmental impact statement was not required absent an existing proposal for region-wide action) *with* Sierra Club v. Peterson, 717

proposal for a specific CO_2 storage operation would certainly implicate NEPA as a major federal action significantly affecting the quality of the human environment. NEPA requires that the environmental effects of any agency's action be evaluated at the point of commitment.[1420] The issuance of a lease or permit for CO_2 storage, like the issuance of any other mineral lease, would arguably result in "irreversible and irretrievable commitments of resources to action affecting the environment".[1421]

Thus, the injection of CO_2 for storage purposes on federal lands appears to be consistent with the subsurface storage provisions of the MLA, and the BLM would need to follow the procedural requirements of FLPMA and NEPA before authorizing any CO_2 storage projects. However, there remains the issue that CO_2 would be stored in the subsurface indefinitely. This contrasts with current subsurface storage projects, such as natural gas storage, where the natural gas is stored in the subsurface only temporarily. Under the plain language of the MLA, "any lease on which storage is so authorized shall be extended at least for the period of storage".[1422] If the Secretary of Interior authorized a CO_2 storage lease, the Secretary would have a mandatory obligation to extend the lease for the "period of storage", arguably indefinitely. The CO_2 storage operator (the lessee) would probably not desire a perpetual CO_2 storage lease, but rather would seek to abandon the injection well at the end of the CO_2 injection operation, with title to the stored CO_2 being transferred to the federal government. Although the private operator would want credit for any avoided CO_2 emissions, the operator would not want to assume the long-term liability associated with the potential harm to human health, the environment, or property if the geological formation lost containment of the CO_2. The MLA does not contemplate what would

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F.2d 1409 (D.C. Cir. 1983) (holding that the issuance of oil and gas leases on lands within two national forests without requiring preparation of an environmental impact statement was a violation of NEPA).
[1420] *Peterson*, 717 F.2d at 1414.
[1421] Mobil Oil v. Federal Trade Commn., 562 F.2d 170, 173 (2d Cir. 1977).
[1422] 30 U.S.C. § 226(m).

become of ownership of the stored oil or gas if the private operator did not seek renewal of the lease, which is an inadequacy in the current statutory framework's application to CO_2 storage.

7.3.5. Sources of Natural Gas Storage Liability

There are two types of liability that derive from natural gas storage. One set of issues is the tortious liability related to property rights, effects on public health, and catastrophic damage. A second set of issues relate to contractual liability, namely breach of a natural gas storage contract due to leakage of the natural gas from the geological formation.

As discussed in Section 7.3.2, the most litigated issue of natural gas storage liability is the tortious liability arising from the property rights of surface and mineral rights owners. Liability of property rights has generally involved geophysical subsurface trespass,[1423] generally natural gas migrating into a part of the subsurface where ownership rights have not been acquired. In several cases, this has occurred together with the unauthorized withdrawal of stored natural gas.

Although subsurface injection liability often implicates groundwater contamination, there have been no reported cases of groundwater contamination and natural gas storage. This is consistent with the House Report's assertion that natural gas storage does not pose a threat to drinking water quality.[1424] Probably because natural gas storage is exempt from SDWA requirements, there have been few studies on the effects of natural gas storage on groundwater. According to a recent analysis by Swistock and Sharpe, natural gas alone is not dangerous in drinking water and dissipates quickly; instead, the risks of natural gas storage derive from the explosive nature of natural gas when it is in a confined area.[1425] The U.S. Geological Survey

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[1423] For more information on the potential tortious liability theories for property rights, see Section 5.5.
[1424] H.R. REP NO. 96-1348, *reprinted in* 1980 U.S.C.C.A.N. 6080, 6084-6085.
[1425] Bryan R. Swistock & William E. Sharpe, Methane Gas and its Removal from Wells in Pennsylvania (Pennsylvania State University Water Facts #24, 2006), *at* http://pubs.cas.psu.edu/FreePubs/pdfs/XH0010.pdf.

conducted a survey of natural gas (methane) in 170 groundwater wells in West Virginia.[1426] The study found methane present in 131 of 170 wells, but only 13 of the wells had methane concentrations at potentially explosive concentrations.[1427] The methane is thought to have migrated from adjacent coal formations.[1428]

A third tortious liability concern is the catastrophic effects of natural gas storage, for example due to fires and explosions. (However, because CO_2 is not flammable, natural gas storage catastrophic accidents are much different than what would occur in the CO_2 storage context.) As shown in Table 7.9, Hopper has summarized catastrophic natural gas storage events since 1972. The most recent catastrophic case of natural gas storage involving loss of life is discussed in detail in Section 7.3.6 of this thesis.

Table 7.9 Catastrophic Events of Natural Gas Storage, 1972-Present (Hopper)[1429]

Involving loss of life or serious injuries as well as property damage				
FACILITY	LOCATION	FUEL	DATE	DESCRIPTION OF EVENT
Yaggy	Hutchinson, KS	Natural gas	2001	Fire and explosion
Moss Bluff	Brenham, TX	LPG[1430]	1992	Fire and explosion
Mont Belvieu	Mont Belvieu, TX	LPG	1985	Fire and explosion
Mont Belvieu	Mont Belvieu, TX	LPG	1980	Fire and explosion
Involving loss of property only				
FACILITY	LOCATION	FUEL	DATE	DESCRIPTION OF EVENT
Moss Bluff	Liberty, TX	Natural gas	2004	Fire and explosion
Magnolia	Napoleonville, LA	Natural gas	2003	Gas leak and evacuation
Stratton Ridge	Freeport, TX	Natural gas	1990s	Cavern failure/abandonment
Mont Belvieu	Mont Belvieu, TX	LPG	1984	Fire and explosion
Eminence	Eminence, MS	Natural gas	1972	Loss of storage capacity

1426 U.S. Geological Survey, Methane in West Virginia Ground Water (USGS Fact Sheet 2006-3011, 2006), *at* http://pubs.usgs.gov/fs/2006/3011/.
1427 *Id.*
1428 *Id.*
1429 Hopper, *supra* note 1207.
1430 LPG stands for liquefied petroleum gas. For more information on LPG, see U.S. DEP'T OF ENERGY, OFFICE OF ENERGY EFFICIENCY AND RENEWABLE ENERGY, JUST THE BASICS: LIQUIFIED PETROLEUM GAS (Aug. 2003), *at* http://www.eere.energy.gov/vehiclesandfuels/pdfs/basics/jtb_lpg.pdf.

Finally, leakage from a natural gas storage formation may give rise to a contractual liability. If the storage operator does not have title to the injected natural gas, then the operator would mostly likely be operating in a contractual relationship with the owner of the natural gas. The operator would be liable to the rightful natural gas owner for any natural gas that escaped from the formation. This is analogous to the contractual liability that a CO_2 storage operator might face if the operator is injecting CO_2 under contract from the rightful owner of the CO_2.

7.3.6. Litigation of Natural Gas Storage Liability: The Case of Hutchinson, KS

A recent catastrophic natural gas storage accident in Hutchinson, Kansas provides an example of potential liability in this area.[1431] As shown in Figure 7.7, on Wednesday, January 17, 2001, an explosion occurred between the buildings of Woody's Hardware Store ("Woody's") and Décor Party Supplies of Kansas ("Décor"). The explosion was so strong that it blew out the windows of about twenty-five businesses in downtown Hutchinson.[1432] Firefighters two blocks away responded immediately and found Décor completely engulfed with 20-meter high flames.[1433] The flames were white-hot, which is unusual for an ordinary building fire.[1434] The firefighters immediately cut the electricity and natural gas supplies to the buildings.[1435] Although they poured about 4,000 gallons of water per minute onto the fire, the fire maintained its strength.[1436] The firefighters believed that the fire was fuel-fed, but were confused because all fuel supplies to the building had been cut.[1437]

[1431] Hayes Sight & Sound, Inc. v. ONEOK, Inc., 136 P.3d 428 (Kan. 2006).
[1432] *Id.* at 433.
[1433] *Id.*
[1434] *Id.*
[1435] *Id.*
[1436] *Id.*
[1437] *Id.*

Later that afternoon, a geyser erupted elsewhere in Hutchinson, rising about 25 to 30 feet from the ground.[1438] Officials determined that the geyser was composed of natural gas.[1439] Over the next five days, several more geysers of brine and gas erupted in Hutchinson.[1440] The natural gas erupted through previously abandoned wells, but only erupted through wells that did not have steel casings.[1441]

On the morning of Thursday, January 18, an explosion occurred at the Big Chief Mobile Home Park, about 2.5 miles from the explosion at Woody's and Décor.[1442] The mobile home park explosion resulted in the deaths of two people.[1443] The mobile home park was evacuated when it was learned that there were a number of brine wells nearby.[1444]

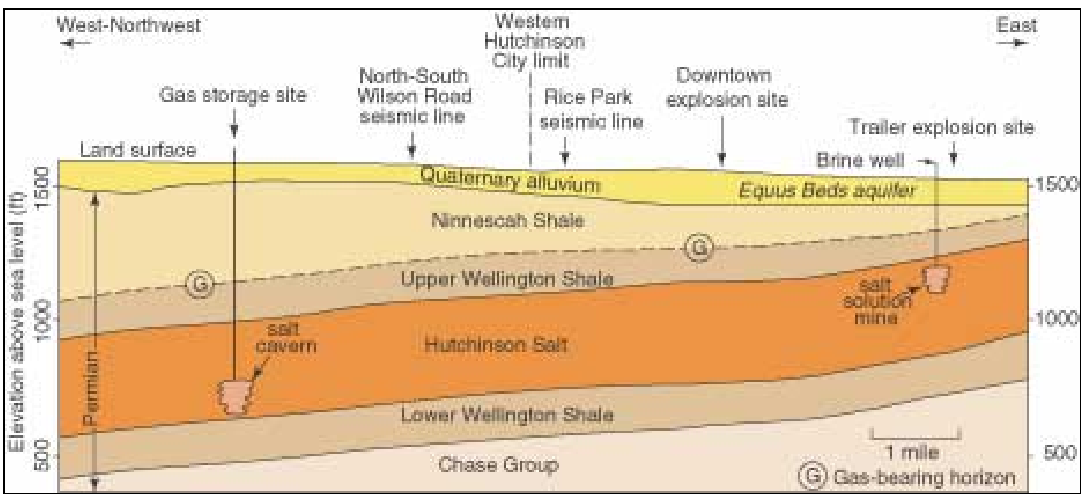

Figure 7.7 Hutchinson Natural Gas Storage Accident (Kansas Geological Survey)[1445]

[1438] *Id*. at 434.
[1439] *Id*.
[1440] *Id*.
[1441] *Id*.
[1442] *Id*.
[1443] *Id*.
[1444] *Id*.
[1445] Kansas Geological Survey, *Survey Responds to Hutchinson Natural Gas Explosion*, 7 GEOLOGIC RECORD 1, *available at* http://www.kgs.ku.edu/Publications/GeoRecord/2001/vol7.2/Page1.html. Reprinted with permission.

The Yaggy natural gas storage field ("Yaggy") is located about 8 miles outside of Hutchinson.[1446] Yaggy consists of 70 salt caverns originally developed to hold propane and later converted into a natural gas storage operation.[1447] The wells for propane storage had been abandoned and plugged in 1989.[1448] The Yaggy field was operated by MCMC, a subsidiary of the natural gas storage firm ONEOK.[1449] Once ONEOK and MCMC learned of the Hutchinson explosions, they ordered that natural gas be withdrawn from Yaggy.[1450] However, when confronted by city officials, the Vice President of Operations of ONEOK/MCMC told the city officials that "he had no knowledge of any leaks at any facility" and "denied knowing what the problem was but said MCMC would look into it".[1451] The city was told by outside experts that it should drill holes to allow the natural gas to vent to the atmosphere, but ONEOK officials refused to advise officials about where to drill or provide information about what it knew of the explosions. After three threats from city officials, ONEOK finally complied.[1452]

The natural gas was traced to a ruptured well in "Pod 1" of Yaggy.[1453] The injection wells at a natural gas storage site are organized into clusters called "pods".[1454] All injection wells must comply with the relevant maximum allowable operating pressure ("MAOP").[1455] The Kansas Department of Health and Environment ("KDHE") set the MAOP to be 0.75 psi per foot of depth.[1456] Yaggy is at a depth of about 745 feet and thus the MAOP at Yaggy is 558.75

[1446] *ONEOK*, 136 P.3d at 435.
[1447] Kansas Geological Survey, *supra* note 1445.
[1448] *ONEOK*, 136 P.3d at 434.
[1449] *Id.* at 433.
[1450] *Id.* at 434.
[1451] *Id.* at 435.
[1452] *Id.*
[1453] *Id.*
[1454] *Id.*
[1455] *Id.*
[1456] *Id.*

psi.[1457] Kansas regulations require that injection wells be equipped with monitoring alarms, and that the alarms not be set above the MAOP.[1458] Without telling Kansas regulators, ONEOK/MCMC decided to set the MAOP at its wells at 680 psi.[1459] A high alarm was set at 680 psi, a high-high alarm at 695 psi, and shutdown at 700 psi.[1460]

In January 2001, natural gas prices were at an all-time high.[1461] The controllers at Yaggy were instructed by their superiors to keep the natural gas at Pod 1 topped off.[1462] On the Sunday before the explosions at Hutchinson, the high-alarm at Pod 1 went off, meaning that the maximum allowable operating pressure MAOP had been exceeded.[1463] An hour later, the high-high alarm went off, and the controller stopped injecting gas into Pod 1.[1464] At the time of shutdown, the pressure in the well was 691.1 psi.[1465] About an hour later, the pressure dropped to 685.2 psi.[1466] Twelve hours later, the pressure in Pod 1 dropped to 676.5 psi, and a day later, the pressure dropped to 673-674 psi.[1467] These are unusual pressure drops. When injection is stopped, the pressure should drop 3-5 psi, but generally no more.[1468] ONEOK/MCMC officials did not investigate the pressure drops, and decided to resume injecting natural gas into Pod 1 until 11am of the morning of the Woody's and Décor explosion, which occurred at 10:47am.[1469]

It was later found that a rupture in Well S-1 in Pod 1 had occurred early on Sunday morning January 14, causing gas to escape from the storage formation.[1470] As more natural gas

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[1457] *Id.*
[1458] *Id.*
[1459] *Id.*
[1460] *Id.*
[1461] *Id.* at 436.
[1462] *Id.*
[1463] *Id.*
[1464] *Id.*
[1465] *Id.*
[1466] *Id.*
[1467] *Id.*
[1468] *Id.*
[1469] *Id.*
[1470] *Id.* at 437.

was injected into the well on Sunday, Monday, Tuesday, and Wednesday, the fracture widened and caused more gas to escape.[1471] Once the gas reached Hutchinson, it escaped to the surface through high permeability conduits.[1472] The Kansas courts later found that the Yaggy controllers had not been trained to identify leakage problems and were not properly schooled on observing the MAOP.[1473] In particular, they were told that the MAOP was a goal to be reached and were never told that the MAOP should not be exceeded.[1474]

As might be expected, the Hutchinson explosions were the subject of significant liability litigation, and much has settled out of court. On October 21, 2002, ONEOK and Mid Continent Market Center entered into a settlement with State Farm Fire and Casualty Co. (on behalf of Décor).[1475] On January 31, 2003, ONEOK entered into a settlement with Hartford Insurance (on behalf of Woody's).[1476] As a result of the settlements, Décor was paid $576,405.50 and Woody's was paid $873,288.66.[1477]

ONEOK and MCMC also faced administrative liability, i.e. liability to the government. MCMC was fined $180,000 by the KDHE and reimbursed the agency $79,000 for administrative costs and expenses.[1478] MCMC also claimed that it spent thousands of dollars to remediate and prepare a geoengineering report of Yaggy.[1479] The total amount of MCMC's administrative liability is estimated to be $260,000.[1480] ONEOK settled with the City of Hutchinson on December 18, 2001 for $180,000.[1481] In addition, it agreed to continue monitoring the facility,

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1471 *Id.*
1472 *Id.*
1473 *Id.*
1474 *Id.*
1475 *Id.* at 438
1476 *Id.*
1477 *Id.*
1478 *Id.* at 449.
1479 *Id.*
1480 *Id.*
1481 *Id.* at 450.

close all exploratory wells, drill additional monitoring wells, submit a comprehensive geoengineering plan, and perform a soil cleanup of the brine around the geyser wells.[1482]

Finally, Woody's and Décor sued ONEOK and MCMC on negligence grounds.[1483] A jury found ONEOK and MCMC each 50% at fault.[1484] The jury awarded compensatory damages to Woody's of $955,636.76 and compensatory damages to Décor of $755,251.40.[1485] The jury also awarded punitive damages of $5,250,000 for both cases.[1486] In June 2006, the Kansas Supreme Court found that the compensatory damages should be reduced by the amount paid by the insurers (known as "subrogation").[1487] The new compensatory damages amount will be decided by the Kansas district court.[1488] (ONEOK and MCMC argue that the compensatory damages should reduce to $82,348.10 for Woody's and $178,845.90.[1489]) However, the Kansas Supreme Court refused to decrease the punitive damages of over $5 million and also awarded the attorney fees to the plaintiff.[1490]

There has been no reported liability litigation on the deaths of the two individuals killed in the mobile home park explosions and on reports of settlements paid. After the trial court's judgment in the Woody's and Décor negligence case, ONEOK issued a press release that the trial concluded all litigation related to the Yaggy incident, except for one case on appeal.[1491] It is unclear what the outstanding case was on appeal.

1482 *Id.*
1483 *Id.* at 444.
1484 *Id.*
1485 *Id.* at 438.
1486 *Id.*
1487 *Id.* at 439.
1488 *Id.*
1489 *Id.*
1490 *Id.* at 452, 457.
1491 Press Release, ONEOK, ONEOK Announces Verdict Reached in Trial Over Yaggy Storage Field (Sept. 23, 2004), *available at* http://www.prnewswire.com/cgi-bin/stories.pl?ACCT=109&STORY=/www/story/09-23-2004/0002257891&EDATE=

7.3.7. Implications for CO_2 Storage

Although both CO_2 storage and natural gas storage inject into similar types of geological formations, the risks and resulting liabilities of CO_2 storage and natural gas storage are very different. Natural gas is an explosive and flammable gas, while CO_2 is not. Natural gas storage poses a higher catastrophic risk; CO_2 storage would be catastrophic only in certain topographic situations which would likely be avoided during the site selection process. Thus in relation to CO_2 storage, the natural gas storage case study should be considered in the context of legal and regulatory mechanisms or as a conservative estimate of the upper-bound of CO_2 storage liability. The Hutchinson natural gas storage accident resulted in two deaths and structural damage to area businesses. Based on published reports and court documents, the total liability was at least $7-8 million. Payments to the deceased families have not been disclosed. Interestingly, liability litigation for the Hutchinson accident was made on negligence grounds and not strict liability. Strict liability is generally the preferred litigation option because reasonable care need not be proven, but because the plaintiffs prevailed in the case, this is a moot point.

Some scholars argue that the regulatory regimes of CO_2 storage and natural gas storage should be divergent because they pose different risks, i.e. CO_2 storage should not be exempted from UIC requirements. For example, CO_2 storage may pose a greater threat to groundwater than natural gas storage, which would undermine a basis for the statutory exemption from the SDWA and UIC. However, the analysis in this thesis suggests that natural gas storage has been regulated by state UIC-like programs even though there is no federal requirement to do so. Thus even though the IOGCC recommends that CO_2 storage be regulated like natural gas storage, it may still be that CO_2 storage is regulated in a UIC-like manner, albeit without having to comply with certain minimum federal requirements imposed by the UIC Program. With respect to CO_2

storage on federal lands, the precedent suggests that CO_2 is “natural gas” in the MLA context and that CO_2 storage is consistent with the subsurface storage provisions of the MLA.

The ownership issue for natural gas storage has received the most attention in the liability litigation context. At least for ownership of the geological formation, the property rights regime is independent of the fluid being injected into the subsurface. With respect to ownership of the injected natural gas, almost all states have held that the entity injecting the natural gas into the subsurface does not lose title to the natural gas. This case law is specific to natural gas storage, though sometimes the courts have been sloppy and used the terminology injected “gas” rather than injected “natural gas”. This makes the case law ambiguous with respect to its direct application to CO_2 storage, but at the very least, it will have value as precedent.

7.4. Liability of Secondary Recovery and EOR

This section examines secondary recovery and EOR liability and its implications for CO_2 storage. Oil production generally involves three stages: primary recovery, secondary recovery, and tertiary recovery. In primary recovery, the natural pressure of a reservoir is used to bring oil to the surface.[1492] Once oil can no longer be extracted by primary recovery, secondary recovery techniques are used. Secondary recovery typically involves injecting pressurized water into a reservoir to drive the oil to the surface or to maintain the reservoir pressure.[1493] This technique is also known as "water flooding". Tertiary recovery, also known as "enhanced oil recovery" or "EOR", is conducted after the end of secondary recovery. EOR refers to using sophisticated techniques for oil extraction, i.e. techniques more advanced than water flooding.[1494] One of the most common methods of EOR is to inject CO_2 into a reservoir to enhance the recovery of oil. The CO_2-EOR process for oil recovery is analogous to the CO_2 storage process for climate change mitigation, with the major difference being the length of time that the CO_2 is kept in the ground. In this section, the regulatory and liability treatment of EOR is stressed because, at least from an operational standpoint, EOR and CO_2 storage have comparable liability profiles where CO_2 is the injectate for EOR. However, some emphasis is also placed on secondary recovery, which confronts many of the same risks posed by EOR, but has a richer body of case law and literature with respect to liability. Even though secondary recovery does not entail CO_2 injection, it does involve subsurface fluid injection and could serve as precedent for future liability litigation of CO_2 storage.

[1492] Society of Petroleum Engineers, Reservoir Engineering: Primary Recovery, *at* http://www.spe.org/spe/jsp/basic/0,,1104_1714_1003990,00.html (last visited Nov. 23, 2006). *See also* SCHLUMBERGER, *supra* note 611 (s.v. "primary recovery").
[1493] Society of Petroleum Engineers, Reservoir Engineering: Augmented Recovery, *at* http://www.spe.org/spe/jsp/basic/0,,1104_1714_1155056,00.html (last visited Nov. 23, 2006). *See also* SCHLUMBERGER, *supra* note 611 (s.v. "secondary recovery").
[1494] SCHLUMBERGER, *supra* note 611 (s.v. "enhanced oil recovery").

7.4.1. Background

7.4.1.1. Secondary Recovery

Secondary recovery involves the injection of water or non-miscible fluids to repressurize the oil reservoir and to drive out remaining oil.[1495] The water or non-miscible fluid is injected through a series of injection wells and oil is produced from a series of production wells. Generally, the wells are configured such that one injection well is surrounded by four or more production wells.[1496] Water flooding, the most common form of secondary recovery, was first documented in 1880 and became standard industry practice by the 1940s.[1497] Lake et al describe the water flooding process:

> Because water is usually readily available and inexpensive, the oldest secondary recovery method is waterflooding, pumping water through injection wells into the reservoir. The water is forced from injection wells through the rock pores, sweeping the oil ahead of it toward production wells. This is practical for light to medium crudes. Over time, the percentage of water in produced fluids – the water cut – steadily increases. Some wells remain economical with a water cut as high as 99%. But at some point, the cost of removing and disposing of water exceeds the income from oil production, and secondary recovery is then halted.[1498]

The injection of natural gas into an oil reservoir is another method of secondary recovery, but the practice has become less prevalent as natural gas prices have increased.[1499] Primary recovery techniques recover about 10-25% of the original oil in place, while secondary recovery techniques will generally allow extraction of another 15% of the original oil in place.[1500]

[1495] U.S. OFFICE OF TECH. ASSESSMENT, ENHANCED OIL RECOVERY POTENTIAL IN THE UNITED STATES 24 (NTIS PB-276594, 1978) [hereinafter OTA EOR Report].
[1496] U.S. Envtl. Protection Agency, s*upra* note 386.
[1497] Society of Petroleum Engineers, *supra* note 1493.
[1498] Larry W. Lake et al, *A Niche for Enhanced Oil Recovery in the 1990s*, OILFIELD REV., Jan. 1992, at 56.
[1499] OTA EOR Report, *supra* note 1495, at 24.
[1500] Lake et al, *supra* note 1498, at 56.

7.4.1.2. EOR

EOR typically involves one of three methods: thermal EOR (heating oil to enhance its flow or to make its flow easier to drive with injected fluids),[1501] miscible EOR (injecting fluid that dissolves or interacts with the oil),[1502] and chemical EOR (injecting chemicals to modify the properties of the oil, affect interactions of the oil with the surrounding rock matrix, and/or increase the effectiveness of recovery using injected fluids).[1503] The analysis in this thesis focuses on one type of miscible EOR: EOR associated with CO_2 injection.[1504]

As shown in Figure 7.8, CO_2-EOR occurs by injecting CO_2 through one series of wells and producing oil from a second series of wells. When injected into an oil reservoir, the CO_2 increases the reservoir pressure and reduces the oil viscosity such that the injected CO_2 helps displace the native oil.[1505] CO_2 displaces oil efficiently at the minimum miscibility pressure ("MMP"), which is the pressure at which CO_2 readily dissolves in oil (becomes "miscible").[1506] The MMP for CO_2 in oil is between 10-15 megapascals (MPa) and is a function of the composition and temperature of the oil.[1507] Typically between 7-15% of the original oil in place can be recovered through the EOR process.[1508]

1501 OTA EOR Report, *supra* note 1495, at 27.
1502 *Id.* at 29.
1503 *Id.* at 31.
1504 Henceforth in this thesis, the term "EOR" will refer to EOR using CO_2 injection (CO_2-EOR) unless otherwise specified.
1505 Nat'l Energy Tech. Lab., Oil Exploration & Production Program: Enhanced Oil Recovery (June 2005), *at* http://www.netl.doe.gov/technologies/oil-gas/publications/prgmfactsheets/PrgmEOR.pdf.
1506 U.S. DEP'T OF ENERGY, *supra* note 55, at 11-12.
1507 *Id.*
1508 HEDDLE ET AL, *supra* note 36, at 29.

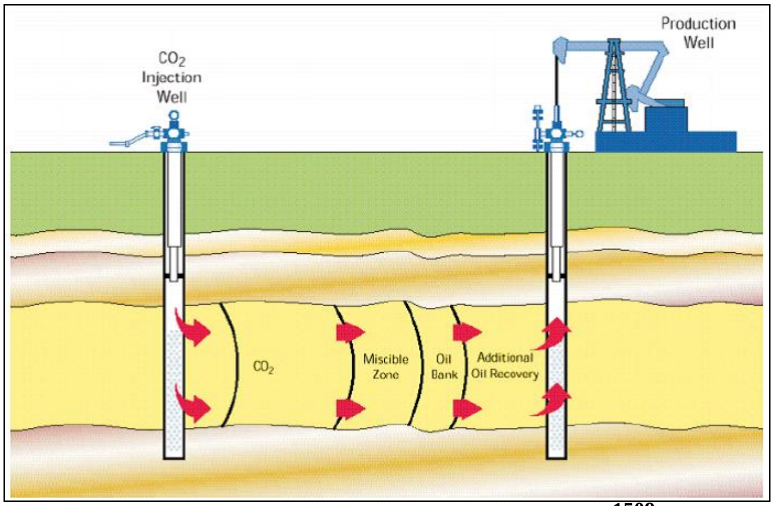

Figure 7.8 Schematic of EOR (IEA)[1509]

Standard EOR practice is to displace as much oil as possible while minimizing the amount of CO_2 that is injected.[1510] This is done to minimize the cost of the CO_2 used for injection. One way of minimizing cost is to alternate injecting CO_2 and injecting water, since water is cheaper than CO_2. This is known as the water-alternating-gas or "WAG" process. Cost is also minimized by re-injecting back into the reservoir any CO_2 that is produced with the oil. Over half of the CO_2 injected in an EOR operation returns with the produced oil.[1511] The recovered CO_2 is separated from the native oil and re-injected into the reservoir.[1512]

After the EOR operation is concluded, the oil reservoir is "blown down", meaning that any remaining CO_2 in the reservoir is vented to the atmosphere.[1513] If CO_2 storage became a secondary goal of an EOR project, the operational calculus regarding CO_2 injection might change because the net profit would derive not only from the production of oil, but also from

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[1509] INT'L ENERGY AGENCY, CO_2 CAPTURE AND STORAGE IN GEOLOGICAL FORMATIONS 10 (2003). © 2003 OECD/IEA. Reprinted with permission.
[1510] Kristian Jessen et al, *Increasing CO_2 Storage in Oil Recovery*, 46 ENERGY CONV. MGMT. 293, 295 (2005).
[1511] *Id.*
[1512] IPCC Special Report, *supra* note 11, at 215.
[1513] Herzog & Golomb, *supra* note 23.

CO_2 storage (e.g. carbon credits, tax breaks, or royalty incentives).[1514] The injection scheme would also depend on how the CO_2 used in EOR would be accounted for in GHG inventories.[1515] An important issue for inventory accounting is differentiating between captured CO_2 that is initially injected into the oil reservoir and CO_2 that is recovered and recycled during the EOR operation.

The commercial injection of CO_2 into oil reservoirs began in 1972 at the Scurry Area Canyon Reef Operators Committee ("SACROC") field in the Permian Basin of West Texas.[1516] To date, there are 84 EOR sites worldwide, 72 of which are located in the United States.[1517] Canada and Turkey are the only other countries with commercial-scale EOR,[1518] but other countries have EOR projects on a pilot scale.[1519] In 2000, the 72 EOR projects in the United States accounted for 192,209 barrels of oil per day (bbl/day), or about 5% of total U.S. oil production.[1520] Worldwide in 2000, EOR accounted for 200,772 bbl/day, or about 0.3% of total worldwide oil production.[1521] Thus the United States accounted for 95.7% of worldwide EOR activity in 2000.

The six largest EOR projects in the United States are described in Table 7.10. These six projects alone constitute about 50% of EOR in the United States, or about 2.5% of total U.S. oil production.[1522] Most large EOR projects in the United States are located in the Permian Basin. The next largest concentration of projects is located in the Rocky Mountain region.[1523] EOR

[1514] Orr, *supra* note 78, at 93.
[1515] See Section 6.4.
[1516] EPRI, ENHANCED OIL RECOVERY SCOPING STUDY 2-11 (TR-113836, 1999).
[1517] HEINRICH ET AL, *supra* note 749, at 18.
[1518] HEDDLE ET AL, *supra* note 36, at 27.
[1519] *Id.*
[1520] *Id.*
[1521] Based on a worldwide oil production estimate of of 67.2 million bbl /day. *Id.*
[1522] EOR projects in Table 7.10 produce 93,408 barrels of oil per day. Total EOR production in the United States was 192,209 barrels of oil per day in 2000. *Id*.
[1523] *Id.*

projects often use high-purity CO_2 found naturally in the subsurface, rather than CO_2 captured from power plants or other industrial sources. About 90% of the CO_2 used for EOR in the Permian Basin comes from three naturally occurring CO_2 reservoirs: McElmo Dome field in southwestern Colorado (owned by Shell and ExxonMobil); Bravo Dome field in the Permian Basin (owned by ARCO, ExxonMobil, and Amerada Hess), and Sheep Mountain field in southeastern Colorado (owned by ARCO and ExxonMobil).[1524] In comparison, CO_2 for EOR projects in the Rocky Mountain region is supplied not only from natural sources, but also from CO_2 captured from industrial processes such as natural gas processing or fertilizer production.[1525] Of the EOR projects noted in Table 7.10, captured CO_2 from natural gas processing has been used by the SACROC and Rangely projects.[1526] Although most EOR projects rely on natural sources of CO_2, reductions in the cost of CO_2 capture or government incentives to use captured CO_2 could make many oil reservoirs candidates for long-term CO_2 storage.[1527]

[1524] EPRI, *supra* note 1516, at 2-11; MARK H. HOLTZ ET AL, REDUCTION OF GREENHOUSE GAS EMISSIONS THROUGH UNDERGROUND CO_2 SEQUESTRATION IN TEXAS OIL AND GAS RESERVOIRS 2 (EPRI Technical Report, 1999).
[1525] EPRI, *supra* note 1516, at 2-11.
[1526] *Id.* at 2-7. From 1972 to 1995, SACROC used CO_2 from natural gas processing. In 1996, SACROC switched to naturally occurring CO_2.
[1527] Orr, *supra* note 78, at 92.

Table 7.10 Largest EOR Projects in the United States (adapted from Heddle et al)[1528]

OPERATOR	FIELD	REGION	AREA (KM^2)	NUMBER OF PRODUCTION WELLS	NUMBER OF INJECTION WELLS	PRODUCTION (BBL/DAY)
Occidental	Wasson (Denver)	Permian Basin	113	735	385	29,000
Amerada Hess	Seminole (Main)	Permian Basin	64	408	160	25,900
Chevron	Rangely Weber Sand	Rocky Mountain	61	341	209	11,208
ExxonMobil	Salt Creek	Permian Basin	49	137	100	9,300
Kinder Morgan	SACROC	Permian Basin	202	325	57	9,000
Occidental	Wasson (ODC)	Permian Basin	32	293	290	9,000

7.4.2. Sources of Secondary Recovery and EOR Liability

Ownership of oil is said to be governed by the "rule of capture": oil is a fugacious property and one does not come into ownership of the oil until it has been brought into personal possession.[1529] Where oil exists in a common pool, extraction by one person affects the volume and cost of production elsewhere within the reservoir because of interrelated pressure gradients and the resulting migration of the native oil.[1530] Thus the rule of capture creates incentives to extract as much oil as fast as possible from the common pool. The oil producer will behave so as to maximize its private profits, ignoring the externalities the producer imposes on other members of the common pool.[1531]

[1528] The six largest projects accounted for 47% of worldwide EOR production using in 2000. *See* HEDDLE ET AL, *supra* note 36, at 28.
[1529] Brown v. Spilman, 155 U.S. 665, 669 (1895).
[1530] Gary D. Libecap & James L. Smith, *The Self-Enforcing Provisions of Oil and Gas Unit Operating Agreements: Theory and Evidence*, 15 J.L. ECON. & ORG. 526, 531 (1999).
[1531] *Id.*

The oil industry has used unitization to overcome the inefficient outcome that would otherwise be created in a common pool. Unitization is the development and operation of the common oil pool as a unit.[1532] A unit operator is responsible for drilling wells and producing oil from the formation. The costs of production are allocated among the members of the unit, and members of the unit become residual claimants to the net economic profits from unit-wide production.[1533] Thus unitization avoids the economic waste of excess infrastructure and the physical waste of an oil field being abandoned too quickly because of private profitability concerns.[1534]

There are two ways that unitization may occur. The first approach is voluntary unitization, where the royalty interest owners and working interest owners voluntarily agree to create a unit. The parties enter into a unitization contract, where they agree to an allocation of revenues and costs. The voluntary unitization process may take many years for an agreement to be reached by all the interests in the common pool.[1535] Voluntary unitization usually fails because of asymmetric information regarding relative oil lease values.[1536] Libecap and Wiggins show that unitization is most likely to be opposed by lessees with high uncertainty regarding lease value and small firms with very productive leases.[1537] Larger firms with diversified property interests will be less likely to hold out because the gains of holding out at one lease will be offset by losses at another lease.[1538]

[1532] A. Allen King, *Pooling and Unitization of Oil and Gas Leases*, 46 MICH. L. REV. 311, 313 (1948).
[1533] Libecap & Smith, *supra* note 1530, at 532.
[1534] Jacqueline Lang Weaver & David F. Asmus, *Unitizing Oil and Gas fields Around the World: A Comparative Analysis of National Laws and Private Contracts*, 28 HOUS. J. INT'L L. 3, 12 (2006).
[1535] OTA EOR Report, *supra* note 1495, at 86. *See also* S.R. Wiggins & G.D. Libecap, *Oil Field Unitization: Contractual Failure in the Presence of Imperfect Information*, 75 AM. ECON. REV. 376 (1985).
[1536] Gary D. Libecap & Steven N. Wiggins, *The Influence of Private Contractual Failure on Regulation: The Case of Oil Field Unitization*, 93 J. POL. ECON. 690, 691 (1985).
[1537] *Id.* at 699.
[1538] *Id.* at 698.

Because of the difficulties in obtaining the voluntary consent of all members of the potential unit, many states provide for a second approach: compulsory unitization. Compulsory unitization means that once a certain percentage of owners in a common pool have voluntarily agreed to unitization, the remaining owners may be compelled by law to join the unit.[1539] The threshold necessary to achieve compulsory joinder varies by state, ranging from as low as 50% in Tennessee to as high as 85% in Mississippi.[1540] In a few states – Georgia, Indiana, and Washington – there is no minimum percentage of working interests required to achieve compulsory joinder.[1541]

Ironically, Texas, one of the largest oil producers in the United States, does not provide for compulsory unitization. Instead, all unitization must be agreed to voluntarily. The Texas position has historically been justified on the grounds that compulsory unitization is a "socialistic intrusion upon free enterprise".[1542] Although Texas does not have compulsory unitization, the Texas Railroad Commission (the state regulatory body with authority over oil production) often approves units that do not include all of the members of the common pool. About 48% of Texas oil production comes from voluntarily unitized fields, with much of the production from partially unitized fields rather than field-wide unitization.[1543]

Unitization in Texas typically occurs late in the life of the oil field.[1544] Texas law requires that units only be created for developed fields, meaning that there will be no units at the beginning of oil production, when primary recovery methods are initiated. Units in Texas tend

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[1539] *See, e.g.*, King, *supra* note 1532, at 335.
[1540] OTA EOR Report, *supra* note 1495, at 87.
[1541] *Id.*
[1542] Paula C. Murray & Frank B. Cross, *The Case for a Texas Compulsory Unitization Statute*, 23 ST. MARY'S L.J. 1099, 1153 (1992).
[1543] *Id.* at 1145.
[1544] Libecap & Wiggins, *supra* note 1536, at 701.

to be formed during the secondary and tertiary recovery phases of operation,[1545] which coincides with the point where oil production becomes significantly more expensive,[1546] given the necessity to inject fluids into the subsurface to increase oil production. Because unitization often occurs for secondary or tertiary recovery and the propensity for using partially unitized fields, one might expect that subsurface trespass causes of action would be especially prevalent in Texas. However, the Texas Supreme Court has developed a rule known as the "negative rule of capture" that secondary recovery by the partial unit operator does not cause liability.[1547]

A second potential area of risk is the potential of EOR to damage health or the environment. The U.S. Office of Technology Assessment ("OTA") conducted an assessment of the environmental and public health risks of EOR.[1548] The OTA found that EOR posed little risk to air and water quality.[1549] With respect to air quality, the OTA distinguished outcomes based on the purity of the CO_2 injectate. EOR was not found to pose a risk to air quality when the injectate was purely CO_2, but the risk increased if CO_2 was co-injected with H_2S and the CO_2/H_2S injectate leaked to the surface.[1550] With respect to water contamination, the OTA found little risk that CO_2-EOR activities might contaminate groundwater, but instead was concerned about increases in demand for water because of the WAG process.[1551] The OTA surmised that the risk of groundwater contamination would actually be less for EOR than for secondary recovery operations because of the incentive for EOR projects to minimize lost CO_2.[1552] The

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[1545] *Id.*.
[1546] *See* INT'L ENERGY AGENCY, ENERGY TECHNOLOGY ANALYSIS: PROSPECTS FOR CO_2 CAPTURE AND STORAGE 85-6 (2004).
[1547] Railroad Comm'n of Tex. v. Manziel, 361 S.W.2d 560, 562 (Tex. 1962) (noting that less valuable substances can migrate through the subsurface and replace more valuable substances without incurred liability). *See* Section 5.5.5.
[1548] OTA EOR Report, *supra* note 1495, at 93.
[1549] *Id.* at 94-98.
[1550] *Id.* at 97. *See supra* Section 7.2.2.
[1551] OTA EOR Report, *supra* note 1495, at 98-100.
[1552] *Id.*

OTA also noted that increased water usage could have an effect on the viability of aquatic flora and fauna living in the area of the water being drawn by the EOR operation.[1553]

A third set of risks deal with induced seismicity and subsidence – what the OTA termed "geologic hazards".[1554] The OTA found that the risk of subsidence would be lower for EOR than in the classical oil extraction context because fluids would remain in the subsurface after EOR operations are complete.[1555] This is a bit misleading since some of the injected fluids will be extracted with the oil and the CO_2 will no longer be stored in the reservoir after the reservoir is blown down. Interestingly, the OTA found that "seismic activity will not be increased by EOR methods".[1556] The OTA brushed aside the case of the Denver earthquakes that resulted from fluid injection at the Rocky Mountain Arsenal,[1557] arguing that the Denver earthquakes resulted from fluid injection into a geological formation that did not ordinarily contain fluids and that EOR would involve injection into a geological formation that contained native oil.[1558] The induced seismicity experiment at Rangely, which was not cited in the OTA report, would appear to counter the OTA's conclusion.[1559] Recall that Rangely involved the controlled injection of water resulting in induced seismic activity.[1560] Nonetheless, experience has shown that given proper site selection and monitoring, induced seismic activity can be minimized.[1561] Another example of injection-induced seismicity in the context of secondary recovery is the Romashkino

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[1553] *Id.* at 101-05 ("while the potential for such an occurrence is extremely small, the impact, if it occurred, could be locally significant").
[1554] *Id.* at 100.
[1555] *Id.* But recall that it is standard practice to blow the CO_2 out of the oil reservoir at the end of the EOR operation's life, which would decrease the amount of injected CO_2 in the reservoir.
[1556] *Id.* at 101.
[1557] Healy et al, *supra* note 579, at 1301.
[1558] OTA EOR Report, *supra* note 1495, at 101.
[1559] Raleigh et al, *supra* note 590, at 1230.
[1560] *See supra* Section 5.2.1.
[1561] *Id.*

oil field located in Tatarstan, Russia.[1562] Although Tatarstan had not experienced any seismic activity historically, residents in the area began experiencing earthquakes in 1982.[1563] By 1987, 100-150 earthquakes of magnitude $M_L = 0.5\text{-}4$ were being recorded annually, and more than 700 earthquakes had been recorded by 1998.[1564] Water injection at Romashkino, the largest oil field in Russia, was found to be the source of the induced seismicity.[1565] In 1998, water injection was controlled to keep volume below a specified level and seismic activity dropped to no more than 15 events per year by 2002.[1566]

7.4.3. Regulation of Secondary Recovery and EOR

7.4.3.1. Federal Regulation

7.4.3.1.1. UIC

The EPA regulates secondary recovery and EOR injection wells under the Class II category of the UIC Program. A detailed analysis of the Class II regime is found in Section 3.2.3 of this thesis. According to UIC regulations, Class II wells include "wells which inject fluids … in connection with … conventional oil or natural gas production" and "wells which inject fluids for enhanced recovery of oil or natural gas".[1567] Of the approximately 167,000 Class II wells, most are used for secondary recovery.[1568] The EPA has developed design specifications for Class II injection wells, but states are free to assume primacy and diverge from the EPA

[1562] Adushkin et al, *supra* note 578, at 7.
[1563] *Id.* at 8.
[1564] R.N. Gatiatullin et al, *Seismicity, Man-Caused Accidents in South-Eatern Tatarstan and Karst Hazard in the Town of Kazan (Tatarstan, Russia)*, *in* PROC. FOURTH EUROPEAN CONGRESS ON REGIONAL GEOSCIENTIFIC CARTOGRAPHY AND INFORMATION SYSTEMS: GEOSCIENTIFIC INFORMATION FOR SPATIAL PLANNING 357 (2003).
[1565] *Id.*
[1566] *Id.*
[1567] 40 C.F.R. § 144.6.
[1568] U.S. Envtl. Protection Agency, s*upra* note 386.

recommendations as long as the state requirements are effective to preventing the endangerment of underground sources of drinking water.[1569]

7.4.3.1.2. CO_2 Storage and EOR on Federal Lands

In Section 354 of the Energy Policy Act of 2005 ("EPAct"), Congress created a set of incentives for enhanced oil and natural gas production through CO_2 injection. Congress found that "approximately two-thirds of the original oil in place in the United States remains unproduced"[1570] and that enhanced oil and gas recovery "has the potential to increase oil and natural gas production".[1571] Congress also noted that CCS could "reduce the carbon intensity of the economy".[1572] Congress had two purposes in its enactment of the statutory provision: to promote CCS in oil and gas fields[1573] and to promote enhanced oil and natural gas production using CO_2 injection.[1574]

The cornerstone of the proposed EPAct incentive program is the suspension of royalties where oil or gas is produced in conjunction with EOR. The EPAct authorizes the Secretary of Interior to suspend these royalties by up to 5,000,000 barrels of oil equivalent produced,[1575] but the Secretary may limit the royalty reduction based on market price.[1576] To be eligible for a royalty suspension, the oil or gas production must take place on a federal lease,[1577] enhanced recovery techniques must be used,[1578] and the Secretary must determine that the lease contains

[1569] *Id.*
[1570] EPAct, *supra* note 115, at § 354(a)(1)(A).
[1571] *Id.* at § 354(a)(1)(B).
[1572] *Id.* at § 354(a)(1)(C).
[1573] *Id.* at § 354(a)(2)(A).
[1574] *Id.* at § 354(a)(2)(B).
[1575] *Id.* at § 354(b)(4).
[1576] *Id.* at § 354(b)(5).
[1577] *Id.* at § 354(b)(3)(A).
[1578] *Id.* at § 354(b)(3)(B).

oil or gas that would not likely have been produced without the royalty incentives.[1579] The royalty suspension applies not only where CO_2 captured from stationary sources is injected for enhanced oil or gas recovery, but also where "natural CO_2" or "other appropriate gases" are used.[1580]

Section 354 also establishes a demonstration program for enhanced oil and gas recovery. The Secretary of Energy is to establish a competitive grant program for this purpose for up to ten projects in the Williston Basin of North Dakota and Montana, and for one project in the Cook Inlet Basin of Alaska.[1581] The programs, which may receive up to $3 million in federal assistance for up to five years,[1582] will be selected based on their ability to maximize oil and gas production in a cost-effective manner, store significant quantities of CO_2, demonstrate that the project may continue after federal assistance is completed, minimize adverse environmental effects,[1583] and the applicants' previous experience with similar projects.[1584]

On March 8, 2006, the BLM and MMS issued an advance notice of proposed rulemaking ("ANPR") seeking comments and suggestions to assist them in implementing the EPAct enhanced oil and gas recovery provisions.[1585] The notice provided a review of the EPAct provisions, as well as a technical review of EOR.[1586] The BLM and MMS suggested that because enhanced recovery could use a number of different techniques, "a rule providing for a

[1579] *Id.* at § 354(b)(3)(C).
[1580] *Id.* at § 354(a)(2)(A).
[1581] *Id.* at § 354(c)(B).
[1582] *Id.* at § 354(c)(5).
[1583] *Id.* at § 354(c)(4)(B).
[1584] *Id.* at § 354(c)(4)(A).
[1585] Enhanced Oil and Natural Gas Production through Carbon Dioxide Injection, 71 Fed. Reg. 11557 (Mar. 8, 2006).
[1586] *Id.* at 11558.

flexible, case-by-case assessment of each [enhanced recovery] application for royalty relief would be the most logical approach to take".[1587]

The ANPR set forth sixteen topics on which the BLM and MMS sought specific guidance. One set of questions asked whether the federal government should even be providing incentives for enhanced oil and gas recovery projects.[1588] A second set of questions asked how the royalty relief mechanism should be implemented, such as whether a case-by-case assessment approach would be appropriate, criteria to be used in the assessment, and potential limitations.[1589] A final set of questions dealt with CO_2 storage in particular, such as how CO_2 storage could best be encouraged by the federal government, how CO_2 should be treated with respect to other gases for enhanced recovery, and whether relief could be structured to focus on CO_2 that would otherwise be emitted to the atmosphere.[1590]

The EPAct allows royalty reductions for any type of enhanced recovery injectate, which would be acceptable if the goal of the program was merely the enhanced recovery of oil, but with a dual goal of promoting carbon capture and storage, the program would want to provide an additional incentive for using captured CO_2 rather than naturally-occurring CO_2. If operators were conducting operations merely for enhanced recovery, they would try to minimize the amount of CO_2 being injected in order to minimize the cost of the process. With a dual incentive for enhanced recovery and CO_2 storage, there would be a financial incentive to store more CO_2. The use of a case-by-case assessment approach, as suggested by the BLM and MMS, would be consistent with maximizing the objectives of promoting enhanced recovery and CO_2 storage.

[1587] *Id.*
[1588] *Id.* at 11558-9.
[1589] *Id.* at 11559.
[1590] *Id.*

Interestingly, the ANPR seems to assume that the long-term storage of CO_2 on federal lands would be legally permissible. No statements or inquiries are made as to whether CO_2 storage would be consistent with the Mineral Leasing Act ("MLA") or other statutes governing BLM and MMS activities. In addition, the ANPR does not address the liability and ownership repercussions of storing CO_2 on federal lands. The ANPR clearly contemplates that CO_2 would remain in the subsurface for a long period of time. Although ANPR and the EPAct do not mention the climate change mitigation aspect *per se*, they contemplate that CO_2 storage could serve "other public interests in addition to EOR".[1591]

On August 23, 2006, an article in E&E News PM reported that the Department of Interior ("DOI") had decided to defer rulemaking providing federal incentives for enhanced oil and gas recovery on federal lands.[1592] According to the article, the BLM determined that tax incentives and DOE R&D grants would be more effective than royalty incentives for increasing the use of enhanced recovery.[1593] The article cited a memo by BLM Director Kathleen Clarke, who made several justifications for deferring the rulemaking.[1594] First, most enhanced recovery occurs on private lands due to the availability and cost of CO_2. Second, royalty incentives would be unlikely to promote CO_2 storage because an enhanced recovery project with CO_2 storage would lead to less oil or gas being recovered compared with a non-CO_2 storage project.[1595] Third, high oil and gas prices will continue to stimulate enhanced recovery development without additional incentives.[1596] A memo from the MMS cited the need to gain additional operating experience for EOR on the outer continental shelf, and the problem of finding sufficient low-cost CO_2 for

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[1591] *Id.* at 11559.
[1592] Ben Geman, *Interior Shelves Rulemaking on CO_2 Sequestration Incentives*, 10 E&E NEWS PM (Energy & Environment Publishing LLC) (Aug. 23, 2006).
[1593] *Id.*
[1594] *Id.*
[1595] *Id.*
[1596] *Id.*

offshore storage.[1597] Thus the DOI concluded that implementing royalty incentives would be "premature".[1598]

7.4.3.2. State Regulation

Because many states have primacy over their Class II injection wells and are not required to follow EPA's Class II recommendations, treatment of risk and liability for Class II wells for secondary recovery and EOR is generally a matter of state law. I review the regulations of the two states that have the most number of Class II wells: Texas and California, with 53,000 and 25,000 Class II wells respectively.[1599] Their regulatory schemes are representative of frameworks in other states.

7.4.3.2.1. Texas

Secondary recovery and EOR in Texas are governed by Title 16, Section 3.46 of the Texas Administrative Code, commonly known as "Rule 46". Rule 46 regulates fluid injection into productive oil, gas, or geothermal reservoirs. The Rule 46 regulatory framework is structurally and substantively similar to the Rule 36 framework governing acid gas injection and discussed in Section 7.2.4.3.1.

Under Rule 46, all prospective secondary recovery and EOR operators must file an application with the Railroad Commission of Texas ("RRC") for an area permit, which, upon approval, authorizes subsurface injection within the area specified in the area permit.[1600] The application provides information about the subsurface geology (such as the location of adjacent potable water aquifers), the proposed injection operation (such as the depth of injection, the

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1597 *Id*.
1598 *Id*.
1599 U.S. Envtl. Protection Agency, s*upra* note 386.
1600 Tex. Admin. Code § 3.46(b)(1) (2006).

maximum number of injection wells that will be operated, and the maximum injection), information about the injectate (such as the type of fluid to be injected, the injection rate, and the maximum amount of fluid to be injected), and the presence of any unplugged or improperly plugged wells within a one-quarter mile radius area of review.[1601] If the area permit is approved, the operator still needs to obtain an individual well permit for any injection well to be constructed.[1602]

All secondary recovery and EOR injection wells must comply with periodic monitoring and testing requirements. Injection rates are to be monitored at least monthly and reported to the RRC annually.[1603] Pressure testing of the well tubing, packer and casing must be conducted prior to injection and at least every 5 years.[1604] Injection wells must be able to withstand a pressure of at least 200 pounds per square inch gauge (psig) up to the maximum pressure specified in the area permit (or 500 psig, whichever is less).[1605]

If a secondary recovery or EOR permit is violated, the RRC may issue an administrative penalty of up to $10,000 per day for each violation.[1606] As in the case of *Jolly*,[1607] which discussed Congressionally-established guidelines for determining administrative penalties, the Texas legislature has provided several factors that the RRC should consider in setting penalties: the permitee's history of previous violations, the seriousness of the violation, any hazard to the health or safety of the public, and the demonstrated good faith of the person charged.[1608] The

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1601 *Id.* at § 3.46(e), (k). *See also* Railroad Comm'n of Tex., Form W-1: Application for Permit to Drill, Recomplete or Re-Enter (Oct. 2004), *available at* http://www.rrc.state.tx.us/divisions/og/form-library/finalw-1-92104.pdf; Railroad Comm'n of Tex., Form H-12: New or Expanded Enhanced Oil Recovery Project and Area Designation Approval Application (Oct. 2003), *available at* http://www.rrc.state.tx.us/divisions/og/form-library/h-12p.pdf.
1602 *Id.* at § 3.46(k).
1603 *Id.* at § 3.46(i)(1)-(2).
1604 *Id.* at § 3.46(i)(3). For definitions of terminology, see *supra* Section 2.2.3 of this thesis.
1605 *Id.* at § 3.46(j)(4)(A)(i).
1606 Tex. Nat. Res. Code § 81.0531.
1607 *See supra* Section 5.3.5.
1608 Tex. Nat. Res. Code § 81.0531.

administrative penalty provisions are generally invoked to enforce the plugging of orphan wells.[1609]

There are a number of aspects of the secondary recovery and EOR rule which are identical to acid gas injection in Texas. Well plugging and abandonment procedures follow Rule 14 of the Texas Administrative Code, as outlined in Section 7.2.4.3.2 of this thesis for acid gas injection.[1610] Financial assurance requirements are also identical: under Rule 78, operators must provide a performance bond, letter of credit, or cash deposit in an amount set forth by the RRC (at least $25,000).[1611] Finally, secondary recovery and EOR use the same Oil Field Cleanup Fund and Orphaned Well Reduction Program as acid gas injection.[1612] These programs are used for plugging and remediating orphan wells.

7.4.3.2.2. California

As shown in Table 3.2, California has partial primacy over its UIC program, meaning that the state only has primacy over Class II wells in the state. Secondary recovery and EOR is regulated by Article 1724.6 of the California Code of Regulations, which requires the approval of the California Department of Conservation ("CDOC") before any subsurface injection or disposal project can proceed, including all Class II injection wells.[1613] Applications for Class II wells must be accompanied by an engineering study (which describes reservoir characteristics and outlines the well plugging and abandonment plan), a geological study (which provides structural contour maps and cross-sectional diagrams of the injection zone area), and an injection

[1609] *See, e.g.*, State v. Leutwyler, 979 S.W.2d 81 (Tex. 1998).
[1610] Tex. Admin. Code § 3.14.
[1611] Tex. Admin. Code § 3.78.
[1612] Tex. Nat. Res. Code §§ 89.047, 91.111. *See also* Section 7.2.4.3.3 of this thesis.
[1613] Cal. Code of Regs. tit. 14, § 1724.6.

plan (which describes the fluids to be injected, source of the injectate, rates of injection, injection pressures, and subsurface monitoring systems).[1614]

California's regulatory requirements are structurally similar to the Texas secondary recovery and EOR requirements. Like Texas, the mechanical integrity of the injection wells must be tested immediately prior to injection and every 5 years subsequent.[1615] Additionally, after 3 months of injection, operators must show that there is no fluid migration behind the casing, tubing, or packer of the injection well.[1616] The monitoring of injection pressures is to be recorded monthly.[1617] Also like Texas, the plugging and abandonment of any injection well must be preceded by a notice of intent and must be conducted using cement plugs to prevent degradation of drinking water.[1618]

All injection well operators are required to obtain financial assurance in the form of an indemnity bond.[1619] Bonds may be posted either on an individual well basis or as blanket coverage. For individual well bonds, the amount is a function of the depth of the well: $15,000 if the well is less than 5,000 feet deep, $20,000 for wells between 5,000 and 10,000 feet deep, and $30,000 for wells more than 10,000 feet deep.[1620] A blanket bond may be used to cover several injection wells at a time: $100,000 for 50 wells or fewer and excluding idle wells, $250,000 for more than 50 wells and excluding idle wells, or $1 million for all wells including idle wells.[1621] Once a well has been properly completed and abandoned, or substituted by another bond (e.g., if the well is transferred to a new owner), then the indemnity bond may be

[1614] *Id.* at § 1724.7.
[1615] *Id.* at § 1724.10(j)(1).
[1616] *Id.* at § 1724.10(j)(3).
[1617] *Id.* at § 1748.3.
[1618] *Id.* at § 1723.
[1619] Cal. Pub. Res. Code § 3202(e) (2006).
[1620] *Id.* at § 3204.
[1621] *Id.* at § 3205.

released.[1622] If the CDOC deems a well to be idle, the owner must either pay an annual fee, establish an escrow account of $5,000 per idle well, file a bond of $5,000 per idle well, or commit to plugging the idle well.[1623]

Reminiscent of the Alberta continuing liability provisions in Section 7.2.3.6 of this thesis, the CDOC may order that a previously abandoned well be "reabandoned". There are three situations where reabandonment is required. The first is where the operator plugged and abandoned the wells in compliance with regulations, but future construction on the site would impede access to the abandoned well.[1624] The property owner would be required to reabandon the well.[1625] The second situation is where construction was undertaken that would impede access to the well and no opinion was obtained regarding whether the well would need to be reabandoned.[1626] Again, the property owner would be responsible for reabandoning the well.[1627] The third situation is where the integrity of the abandoned well was disturbed, in which case the party responsible for disturbing the integrity of the abandoned well would be responsible for reabandonment.[1628]

7.4.4. Cases of Secondary Recovery

Although searches of relevant case law in Westlaw and LexisNexis revealed zero cases of health, safety, and environmental damage related to EOR, there has been tortious liability litigation related to secondary recovery. Secondary recovery liability has been seen in two major areas: groundwater contamination and geophysical subsurface trespass. Although the factual

[1622] *Id.* at § 3207.
[1623] *Id.* at § 3206.
[1624] *Id.* at § 3208.1.
[1625] *Id.*
[1626] *Id.*
[1627] *Id.*
[1628] *Id.*

backgrounds may not exactly mirror those of CO_2 storage, the holdings in these cases may provide value as precedent.

7.4.4.1. Liability for Groundwater Contamination

In this section, I examine groundwater contamination as a source of secondary recovery liability. The first case presented, *Mowrer v. Ashland Oil & Refining Co.*, provides an example of a case where the defendant oil company engaged in activities authorized by statute and approved by the state regulatory agency, yet still was found liable for contamination of a neighboring drinking water aquifer.[1629] In the second case, *Gulf Oil Corp. v. A.L. Hughes*, the Supreme Court of Oklahoma examined the various grounds under which an oil company may be liable for groundwater contamination from secondary recovery.[1630]

7.4.4.1.1. Mowrer v. Ashland Oil & Refining Co.

In *Mowrer*, the plaintiff leased 135 acres in Gibson County, Indiana in 1952 for oil and gas exploration.[1631] As part of the activities, three wells were drilled on the plaintiff's property, which were abandoned by 1956.[1632] In 1955, i.e. prior to the well abandonment, the defendant oil company, Ashland Oil & Refining, began a secondary recovery project on property adjacent to the plaintiff's wells.[1633] The secondary project had been authorized and approved by the Oil and Gas Division of the Indiana Department of Conservation.[1634] On several occasions between 1958 and 1960, the plaintiff found crude oil seeping out from one of the plaintiff's abandoned

[1629] 518 F.2d 659 (7th Cir. 1975).
[1630] 371 P.2d 81 (Okla. 1962).
[1631] 518 F.2d at 660.
[1632] *Id.*
[1633] *Id.*
[1634] *Id.* at 661.

wells.[1635] By 1963, it was found that Ashland's crude oil had leaked into the plaintiff's drinking water well in 1963.[1636]

The plaintiff brought suit against Ashland claiming that Ashland's activities had created a private nuisance.[1637] Under Indiana law, a private nuisance is defined as "whatever is injurious to health, or … an obstruction to the free use of property, so as essentially to interfere with the comfortable enjoyment of life or property, is a nuisance, and the subject of an action".[1638] Ashland did not dispute that its water flood caused salt water and oil to migrate onto the plaintiff's property, but instead argued that its secondary recovery operation was authorized by the Indiana Department of Conservation and therefore Ashland could not be liable for the groundwater contamination.[1639] The Seventh Circuit affirmed the trial court's finding for the plaintiff.[1640] Because the plaintiff had claimed the groundwater contamination was a nuisance, the lawfulness of the business and the absence of negligence were not defenses to liability.[1641]

7.4.4.1.2. Gulf Oil Corp. v. A.L. Hughes

In *Gulf Oil*, the defendant Gulf Oil Corp. operated a secondary recovery operation in Creek County, Oklahoma.[1642] Some of the salt water injected as part of its water flood migrated onto the property of the plaintiff Hughes and contaminated the Hughes water supply.[1643] The plaintiffs sought compensation for the reduced value of their land now that the groundwater supply was contaminated.[1644] The jury awarded $6,000 in damages to Hughes. Gulf Oil

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[1635] *Id.*
[1636] *Id.*
[1637] *Id.*
[1638] Ind. Code § 34-1-52-1 (2006).
[1639] 518 F.2d at 661.
[1640] *Id.* at 662.
[1641] *Id.*
[1642] 371 P.2d at 81.
[1643] *Id.*
[1644] *Id.*

appealed alleging that the jury's decision was based on strict liability grounds rather than grounds of negligence or nuisance.[1645] The jury had been instructed that:

> [I]f you should find that the Gulf Oil Corporation conducted water flooding operations for the recovery of oil in the vicinity of the land of Mr. and Mrs. Hughes, and if you should further find that such water flooding operations caused the water supply of the Hughes' to become unfit for drinking or other household uses, and that such water flooding operations were the direct, natural and proximate cause of the damage and injury to the water supply of the Hughes, then you are instructed that the Hughes should recover damages from the Gulf Oil Corporation . . . [1646]

Gulf Oil claimed that liability for contamination of groundwater due to secondary recovery could only occur under theories of negligence or nuisance. In response to Gulf Oil's contentions, the Supreme Court of Oklahoma examined a number of past Oklahoma cases involving groundwater contamination from secondary recovery. In one case, *Fairfax Oil Co. v. Bolinger*, a landowner's property was damaged due to vibrations from an adjacent well.[1647] The *Fairfax Oil* court concluded that a lawful business could still constitute a nuisance if property was substantially damaged as a result of the activity.[1648] In another case, *British-American Oil Producing Co. v. McClain*, the court found that a secondary recovery operation "need not be of a careless or negligent nature, or unreasonable or unwarrantable to entitle the injured party to recover".[1649] The *Mowrer* court concluded that these past cases fairly stated the applicable law and that the trial court's instruction to the jury was correct.[1650] Thus Gulf Oil was held liable for contaminating the Hughes water supply.

1645 *Id.*
1646 *Id.* at 84.
1647 97 P.2d 574 (Okla. 1939).
1648 *Id.*
1649 126 P.2d 530, 532 (Okla. 1942).
1650 371 P.2d at 81.

7.4.4.2. Liability for Subsurface Trespass or Migration

In Section 5.5.3 of this thesis, the issue of liability for subsurface trespass was introduced in the context of *Railroad Commission of Texas v. Manziel*.[1651] This section analyzes three exemplary cases of liability for subsurface trespass or migration. In the first case, *Carter Oil Co. v. Dees*, the Appellate Court of Illinois analyzed the issue of secondary recovery causing oil beneath a neighboring property to migrate.[1652] In the second case, *Greyhound Leasing & Financial Corp. v. Joiner City Unit*, the Tenth Circuit Court of Appeals examined subsurface migration from secondary recovery as a nuisance.[1653] In the third case, *Morsey v. Chevron USA*, the court examined the effect of temporal limitations on liability.[1654]

7.4.4.2.1. Carter Oil Co. v. Dees

In *Carter Oil*, the Appellate Court of Illinois analyzed the issue of whether the plaintiff Cater Oil could commence a secondary recovery operation on a leased field owned by the defendant Mr. Dees and despite Mr. Dees's objections.[1655] Carter Oil operated four wells on its 40-acre site under an oil and gas mining lease with Mr. Dees.[1656] Over the project life, production at the site had declined from 100-200 barrels per day to 6-11 barrels per day.[1657] Carter Oil noted that the decline in production was due to the exhaustion of gas pressure rather than the depletion of oil reserves.[1658] Carter Oil sought to inject dry gas to prolong the productive life of the reservoir and increase the amount of recoverable oil.[1659] If the site was converted to a secondary recovery operation, all of the oil under 5 of the 40 acres owned by Mr.

[1651] 361 S.W.2d 560 (Tex. 1962).
[1652] 92 N.E.2d 519 (Ill. 1950).
[1653] 444 F.2d 439 (10th Cir. 1971).
[1654] 94 F.3d 1470 (10th Cir. 1995).
[1655] 92 N.E.2d at 521.
[1656] *Id.* at 520.
[1657] *Id.*
[1658] *Id.*
[1659] *Id.*

Dees would migrate onto adjoining lands that Mr. Dees did not own.[1660] However, Carter Oil operated a secondary recovery operation on a site adjoining the Dees property and some of the oil would migrate from Carter Oil's property onto Mr. Dees's lands.[1661] The trial court found for the defendant, holding that the plaintiff Carter Oil could not convert its wells into a secondary recovery operation because some of Mr. Dees's oil would be irretrievably lost.[1662]

On appeal, Carter Oil argued that substantially the same amount of oil would migrate onto the Dees property as would migrate from the Dees property.[1663] Carter Oil also contended that the secondary recovery operation would be consistent with its requirement under the leasehold arrangement to manage the premises as a prudent, competent and experienced operator.[1664] Mr. Dees countered that he had title to the oil under the land and that Carter Oil had an implied duty to prevent drainage of this oil onto adjoining lands.[1665]

The appellate court reversed the trial court's decision and found for the plaintiff Carter Oil.[1666] The court noted that the lease was a commonly used form where the lessor gave the lessee the right to mine for oil and gas in exchange for a 1/8 share of the proceeds and royalties. Reviewing past cases involving oil migration, the court noted that the cases turned on whether the intent of the parties defeated the prime purpose of the lease, i.e. whether the royalties reserved to the lessors were diminished. In this case, the lease was silent as to the oil recovery methods that could be used and thus the presumption was made that any method reasonably designed to accomplish the purpose of the lease could be used.[1667] Although one of the wells to

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[1660] *Id.*
[1661] *Id.*
[1662] *Id.*
[1663] *Id.* at 521.
[1664] *Id.*
[1665] *Id.*
[1666] *Id.* at 524.
[1667] *Id.*

be converted was an offset well,[1668] which are used to reduce the possibility of drainage, there was no obligation in the lease to establish an offset well.[1669] Because Dees would not suffer from detriment, deprivation, or pecuniary loss, the appellate court found that the secondary recovery operation would be consistent with the actions of a prudent operator.[1670]

7.4.4.2.2. Greyhound Leasing & Financial Corp. v. Joiner City Unit

In *Greyhound*, the Tenth Circuit Court of Appeals analyzed several past cases in finding damages from a subsurface trespass by a secondary recovery operation in Oklahoma.[1671] The defendant, Joiner City Unit, was unitized in 1965.[1672] During the unitization hearing, the plaintiff, Greyhound Leasing & Financial, insisted that its two oil and gas leases not be included within the Joiner City Unit boundaries.[1673] The boundaries were thus redrawn and the Greyhound Leasing & Financial leases were excluded from the unit.[1674] In September 1965, the Joiner City Unit began injecting salt water for secondary recovery and the injected water reached the Greyhound Leasing & Financial wells by August 1966.[1675]

Greyhound Leasing & Financial brought suit against the Joiner City Unit on the grounds that its oil and gas leases and wells were permanently damaged by the injected salt water.[1676] At the trial level, the jury was instructed that the secondary recovery operation was lawfully conducted, that the evidence showed no negligence on the part of the Joiner City Unit, and that the facts did not prevent the Joiner City Unit from being liable for Greyhound Leasing &

[1668] An offset well is an existing wellbore used to provide information for planning a proposed well. SCHLUMBERGER, *supra* note 611 (s.v. "offset well").
[1669] 92 N.E.2d at 525.
[1670] *Id.*
[1671] 444 F.2d 439, 440 (10th Cir. 1971).
[1672] *Id.*
[1673] *Id.*
[1674] *Id.*
[1675] *Id.*
[1676] *Id.* at 441.

Financial's damages.[1677] In other words, although the Joiner City Unit was not liable on negligence grounds, the trial judge instructed the jury that the Joiner City Unit could still be liable because it caused a private nuisance. The jury found in favor of Greyhound Leasing & Financial, awarding it $142,404.41 for damage to one lease and $387,440.11 for damage to its other lease.[1678] Joiner City Unit appealed arguing that the doctrine of private nuisance did not apply to the facts at issue in the case.[1679]

Relying on several past cases in the Oklahoma judiciary, including *Gulf Oil Corp. v. A.L. Hughes*,[1680] the Tenth Circuit found that the private nuisance doctrine had been properly applied to the secondary recovery operation at issue.[1681] Prior cases held that recovery of damages was not dependent on proving negligence.[1682] Even though Greyhound Leasing & Financial participated in the unitization hearings, the court noted that Greyhound Leasing & Financial's wells were in existence prior to the unitization and would have been damaged regardless.[1683]

7.4.4.2.3. Morsey v. Chevron USA

In *Morsey*, the Tenth Circuit Court of Appeals analyzed a case of subsurface trespass from a secondary recovery operation at the Rhodes Field in Kansas, a source of oil supply for a number of leases.[1684] The plaintiff Morsey owned a lease for Section 20 of the field.[1685] Before Morsey acquired the lease, Section 20 had been used for primary and secondary recovery for over 30 years.[1686] Secondary recovery was conducted through a cooperative water injection

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[1677] *Id.*
[1678] *Id.* at 440.
[1679] *Id.* at 441.
[1680] *See* Section 7.4.4.1.2.
[1681] 444 F.2d at 444.
[1682] *Id.*
[1683] *Id.* at 445.
[1684] 94 F.3d 1470, 1473 (10th Cir. 1995).
[1685] *Id.*
[1686] *Id.*

agreement among the operators at the Rhodes Field with the approval of the Kansas Corporation Commission.[1687] By the time Morsey acquired Section 20, secondary recovery had been halted. The defendant Chevron conducted secondary recovery on leases surrounding Section 20.[1688] The Chevron leases had previously been operated by Gulf Oil, but were acquired by Chevron after the companies merged.[1689] Morsey brought an action against Chevron alleging that the Chevron waterflood was interfering with the oil production activities of his property.[1690]

Both the trial court and the Tenth Circuit found in favor of Chevron.[1691] The reasoning of the courts centered on the Kansas statute of limitations and the failure of Morsey to prove damages.[1692] Kansas bars any claim for damages inflicted more than two years before the filing of the complaint.[1693] Morsey's claims for permanent damages would be barred by the statute of limitations, but claims for temporary damages within the previous two years would be permitted.[1694] However, both the trial court and Tenth Circuit found that Morsey did not provide sufficient evidence to show temporary damages to Section 20 after he acquired the property.[1695] He needed to show that "the water interfering with the recovery of oil on Section 20 could be remedied, removed, or abated within a reasonable time and at reasonable expense", but did

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[1687] *Id.*
[1688] *Id.* at 1474.
[1689] *Id.*
[1690] *Id.*
[1691] *Id.*
[1692] *Id.* at 1474-75. The Kansas court refers to the temporal limitation as a "statute of repose", but it is actually a "statute of limitations" since the temporal limit is not keyed off of the date of the activity.
[1693] *Id.*
[1694] *Id.* at 1475. Regarding the distinction between temporary and permanent damages, see McAlister v. Atlantic Richfield, 662 P.2d 1203, 1211 (Kan. 1983) ("Temporary damages or continuing damages limit recovery for injury that is intermittent and occasional and the cause of the damages remediable, removable, or abatable. Damages are awarded on the theory that cause of the injury may and will be terminated. Temporary damages are defined as damages to real estate which are recoverable from time to time as they occur from injury. Permanent damages are given on the theory that the cause of injury is fixed and that the property will always remain subject to that injury. Permanent damages are damages for the entire injury done – past, present, and prospective – and generally speaking those which are practically irremediable. If an injury is permanent in character, all the damages caused thereby, whether past, present, or prospective must be recovered in a single action.").
[1695] 94 F.3d at 1475-76.

nothing to distinguish the temporary damages claim from the permanent damages claim that had been barred by the statute of limitations.[1696]

7.4.5. EOR with CO_2 Storage: EnCana's Weyburn Project

On September 15, 2000, the Canadian energy company EnCana began an EOR project at its Weyburn oil field in Alberta, Canada.[1697] The Weyburn field contains about 1.4 billion barrels of oil, and only about 24% of the original oil in place had been recovered by 2000.[1698] It was expected that EOR would allow EnCana to recover an additional 130 million barrels of oil and extend the life of the field by twenty-five years.[1699]

The Weyburn project is unique because it has a secondary goal of CO_2 storage. Instead of blowing down the reservoir, as is generally done at the end of an EOR project's life, the CO_2 injected at Weyburn will be stored in the oil field.[1700] About 5,500 tonnes of CO_2 per day are injected at Weyburn.[1701] The CO_2 injected into the oil field is purchased from the Dakota Gasification Company synthetic fuel plant in Beulah, North Dakota, and transported by pipeline 320 km away to Weyburn.[1702] The CO_2 injection has increased production by 9,000 bbl/day, an production at Weyburn is currently 22,400 bbl/day.[1703] The IEA, in conjunction with fifteen governmental[1704] and industrial sponsors,[1705] is conducting a monitoring project at Weyburn to

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[1696] *Id.* at 1476.
[1697] PETROLEUM TECHNOLOGY RESEARCH CENTRE, THE IEA WEYBURN CO_2 MONITORING AND STORAGE PROJECT 2 (Sept. 2002), *at* http://www.nrcan.gc.ca/es/etb/cetc/combustion/co2network/pdfs/ptrc_weyburn_2002.pdf.
[1698] White, *supra* note 134, at 75.
[1699] M. Wilson et al, Introduction, *in* Weyburn Phase I Report, *supra* note 134, at 9.
[1700] *Id.* at 1.
[1701] Steve Whittaker, *Geological Characterization of the Weyburn Field for Geological Storage of CO_2: Summary of Phase I Results of the IEA GHG Weyburn CO_2 Monitoring and Storage Project*, *in* 1 SASKATCHEWAN GEOLOGICAL SURVEY SUMMARY OF INVESTIGATIONS 2005 1 (2005).
[1702] *Id.*
[1703] Wilson et al, *supra* note 1699, at 1.
[1704] The governmental sponsors are: Alberta Energy Research Institute, European Community, Natural Resources Canada, Petroleum Technology Research Centre, Saskatchewan Industry and Resources, and U.S. Department of Energy. *Id. at* 2.

analyze the fate of the injected CO_2.[1706] The goals of the project are to enhance the effectiveness of the CO_2 flood, determine the potential of the Weyburn field for long-term CO_2 storage, and determine the economic feasibility of long-term CO_2 storage.[1707]

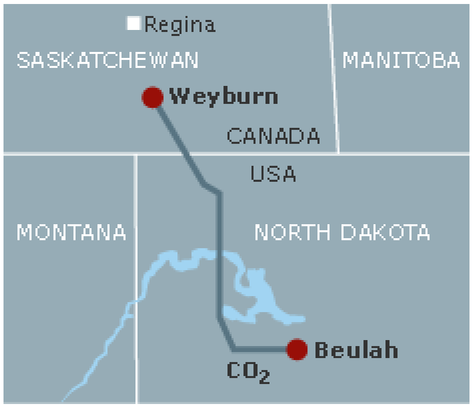

Figure 7.9 Weyburn CO_2-EOR Project (EnCana)[1708]

Before the Weyburn EOR project commenced, a geological characterization study was conducted by the IEA GHG Weyburn CO_2 Monitoring and Storage Project to ensure that the field was suitable for long-term CO_2 storage.[1709] The Weyburn field is located in the Williston Basin, an elliptical depression centered in North Dakota.[1710] Using a system model of the geological, hydrogeological and geophysical characteristics of the Basin, the project team found the project area to be conducive to CO_2 storage.[1711]

[1705] The industrial sponsors are: BP, ChevronTexaco, Dakota Gasification, Engineering Advancement Association of Japan, EnCana, Nexen, SaskPower, Total, and Trans Alta Utilities. *Id.*
[1706] *Id.*
[1707] *Id.*
[1708] EnCana, Scope of Weyburn CO_2 Flood Project, *at* http://www.encana.com/operations/upstream/weyburn_scope_co2.html (last visited Nov. 24, 2006). Reprinted with permission.
[1709] *See generally* Steve Whittaker, Theme 1: Geological Characterization *in* Weyburn Phase I Report, *supra* note 134, at 9.
[1710] John Lake & Steve Whittaker, *Occurrences of CO_2 within Southwest Saskatchewan: Natural Analogues to the Weyburn CO_2 Injection Site*, *in* 1 SASKATCHEWAN GEOLOGICAL SURVEY SUMMARY OF INVESTIGATIONS 2005 2 (2006).
[1711] Whittaker, *supra* note 1709, at 18.

The project team also conducted an assessment of the local and global environmental risks of CO_2 leakage from the Weyburn field. The team developed a model of the Weyburn system comprised of the surface ("biosphere"), geological subsurface between the Weyburn field and the surface ("upper geosphere"), the wellbore, and the geological subsurface including and below the Weyburn field ("lower geosphere").[1712] Many of the parameters of the model were incorporated from the geological characterization portion of the project. Migration of CO_2 within the subsurface was modeled dynamically, and although some migration was predicted, the injected CO_2 was not predicted to enter a drinking water aquifer.[1713] CO_2 leakage via abandoned wells, which was modeled stochastically, was found to be less than 0.001% at the end of the injection phase of operations and about 0.14% after 5,000 years.[1714] The risk assessment did not analyze the effect of CO_2 migration on health, safety and the environment, except for an analysis on the effect of CO_2 leakage on indoor CO_2 concentrations, which found that it unlikely that leakage would cause indoor CO_2 concentrations to exceed acceptable levels.[1715]

The focus of the Weyburn project has now shifted to MMV of the injected CO_2.[1716] One aspect of the MMV project is tracing the fate of the injected CO_2. As mentioned in Section 2.2.4.1, the injected CO_2 at Weyburn uses a different carbon isotope (^{13}C) from naturally occurring CO_2 (^{12}C), allowing the path of the injected CO_2 to be traced. Following the path of the isotopic carbon, the project team reported that the injected CO_2 interacted with the *in situ* formation waters within six months of injection and began to dissolve in the waters within ten

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[1712] *Id.*
[1713] Whittaker, *supra* note 1701, at 4.
[1714] Rick Chalaturnyk, Theme 4: Long-Term Risk Assessment of the Storage Site, *in* Weyburn Phase I Report, *supra* note 1698, at 212.
[1715] *Id.* at 238.
[1716] Petroleum Technology Research Centre, Phase II: Mission Statement, *at* http://www.ptrc.ca/access/DesktopDefault.aspx?tabindex=0&tabid=259 (last visited Nov. 23, 2006).

months of injection.[1717] The path of the carbon tracer is shown in Figure 2.10. A second aspect of monitoring at Weyburn has been seismic imaging of the subsurface, including vertical, cross-well, and 3D seismic.[1718] Seismic surveys were conducted prior to CO_2 injection and have been conducted at regular intervals during the EOR process.[1719] Any seismic anomalies have been consistent with the presence of injected CO_2 in the subsurface and the seismic results suggest that the injected CO_2 has been effectively contained.[1720] A third MMV aspect has been the sampling of gas from the surface soil, which is tested for the presence of carbon tracers.[1721] The soil gas sampling has not detected the presence of any injected CO_2.[1722]

Phase I of the Weyburn project ended in June 2004 and Phase II began in May 2005.[1723] The MMV portion of the project will be continued in Phase II and a long-term risk assessment will be conducted.[1724] The eventual output of Phase II will be a Best Practices Manual for the design, development, and operation of CO_2 storage projects.[1725]

7.4.6. Implications for CO_2 Storage

The liability of EOR has been successfully managed since its inception nearly three decades ago. EOR provides one of the closest subsurface injection analogs to CO_2 storage, and many studies argue that the first instances of CO_2 storage in the United States may be in conjunction with EOR activities because of existing experience and infrastructure.[1726] Based on an examination of the case law, I found no reported cases of EOR tortious liability for health,

[1717] White, *supra* note 134, at 85.
[1718] *Id.*
[1719] *Id.* at 89-92.
[1720] *Id.*
[1721] *Id.* at 88.
[1722] *Id.* at 96.
[1723] Petroleum Technology Research Centre, *supra* note 1716.
[1724] *Id.*
[1725] *Id.*
[1726] *See, e.g.*, IPCC Special Report, *supra* note 11, at 203.

safety and environmental damage. One explanation is that cases were settled out of court, meaning that there could be instances of liability but the damage payments and circumstances surrounding the liabilities are confidential. Nonetheless, it would be unusual for there to be extensive liability payouts given zero case law. The findings are also consistent with historical risk assessments of EOR, which have also found the risk of damage to be low. Another possible explanation is that because EOR follows secondary recovery, one would expect liability to occur at the secondary recovery stage. In other words, any groundwater contamination or subsurface trespass that might be expected from EOR probably would have occurred earlier during the water flood. If there is no groundwater contamination or subsurface trespass during the secondary recovery stage, there probably would not be any groundwater contamination or subsurface trespass during the EOR stage either. Thus an additional reason why depleted oil and gas fields may be especially appropriate for CO_2 storage is there proven integrity for containing fluids that have been injected into the subsurface (i.e., water during secondary recovery).

The analysis of secondary recovery and EOR regulatory regimes suggests that even though there is no requirement to follow EPA requirements for Class II injection wells, state regulations for underground injection may be remarkably similar. Recall that the SDWA provides state with the most leeway for regulating their Class II wells.[1727] Both Texas and California require operators to submit data on the characteristics of the reservoir, the nature of the injection project, and plans for monitoring and verification. Although specifics of their regulations might differ, such as how often data must be reported to the administrative agency or the level and type of requisite financial assurance, the regulatory regimes are structurally comparable.

[1727] *See* Section 3.2.3.

Finally, the analysis of secondary recovery case law provides a number of lessons for CO_2 storage. First, liability may go beyond traditional negligence causes of action. For example, because groundwater contamination interferes with the use of landowner's property, there is a potential nuisance cause of action. Under nuisance law, the operator's level of reasonable care and the legality of the activity are irrelevant. There may be liability as long as substantial damage is caused. This liability might exist despite compliance with all applicable regulations. Second, statutes of limitations and repose are critical. In *Morsey*, it was irrelevant that the plaintiff's reservoir may have been damaged historically because the plaintiff did not bring a case within the requisite two-year window. Even for those damages that were within the proper time period, the plaintiff still was not able to show the kinds of permanent damages that would be required for recovery. Finally, subsurface trespass could be a key area affecting CO_2 storage liability and one where there is substantial precedent. Mandatory unitization provides a paradigm that is similar to eminent domain in the natural gas storage context. In both, the land owner is required by law to agree to the use of its subsurface property for oil recovery in the case of unitization or natural gas storage in the case of eminent domain. Where rights to use of the property have not been acquired, any liability will be premised on the showing of damages. Also of note, there will be jurisdictional differences across states; what constitutes subsurface trespass in one state might not constitute subsurface trespass in another state. For example, although the plaintiff in *Carter Oil* was unsuccessful in his subsurface trespass case, the court suggests that it would be willing to find liability where the landowner can show "detriment, deprivation, or pecuniary loss".[1728] This situation in Illinois can be contrasted with the Texas case of *Manziel*, where there would be no liability in a secondary recovery case, despite the fact that subsurface migration of oil could be shown.

[1728] 92 N.E.2d 519, 524. (Ill. 1950)

7.5. Conclusion

This chapter considered the liability treatment for several subsurface injection cases: acid gas injection, natural gas storage, secondary recovery, and enhanced oil recovery. Acid gas injection is a very young field and the issues confronted thus far have been regulatory in nature. The approaches of Alberta, Texas, and Wyoming could be thought of along a spectrum from most defined to most *ad hoc*. Alberta has developed a significant regulatory regime governing acid gas injection. The Texas and Wyoming are keyed off of state UIC program requirements and provide more flexible ways of addressing the issues of concern. Texas does have some acid gas injection-specific regulations in place, while Wyoming's acid gas regulatory regime is more informal and essentially treated as a UIC Class II operation. The assertion of the varying regulatory approaches is not meant to imply that one regime is any better at managing liability than another, or that one regulatory regime sees risks inherent in acid gas injection that others do not. Instead, the development of the regulatory regime appears to be a function of the emergence of the sector. Alberta has by far the most acid gas injection projects in the world. Texas has some acid gas injection operations, but far fewer than Alberta, and Wyoming has only a handful of projects. Wyoming is able to examine acid gas injection on a case-by-case basis, while Alberta has necessarily developed a regulatory regime that is able to accommodate the size of its acid gas injection industry. Texas has split the difference by creating special rules for acid gas injection under its state UIC program, but many requirements are similar to the traditional Class II context.

Liability related to natural gas storage has a long history, with emphasis placed on common law ownership issues. The judicial findings of ownership of the geological storage reservoir and ownership of injected gas provide critical precedent for CO_2 storage. The natural gas storage experience also shows the evolution of a regulatory regime. For example, ownership of injected gas has evolved from a regime where title to injected gas was lost (based on an analogy to the capture and release of wild animals) to an exact opposite rule where title to injected gas is retained by the injector. The change in liability rules was motivated by concerns about the development of the natural gas storage industry. Outside of the geophysical trespass context, liability litigation for natural gas storage has been limited. The Hutchinson case provides a recent example of a court examining a subsurface injection tortious liability case. Because the actions of the operators were clearly negligent, there was no need to resort to other tortious liability theories, such as strict liability, that might otherwise be invoked in other natural gas storage cases. However, given the few liability cases outside of the trespass context, the thesis analysis reveals the regulatory regime has been quite effective in containing the risk, absent gross negligence.

The experience of EOR shows the effective containment of the liability. This could be because EOR is preceded by secondary recovery and any risks and associated liabilities would be revealed during the secondary recovery phase of operations. Nonetheless, despite an exhaustive search of the case law, there have been no examples of tortious liability related to CO_2 injection for EOR. There have been cases of secondary recovery, primarily on the issues of subsurface trespass and nuisance and negligence related to groundwater contamination. The liability experience has revealed that both nuisance and negligence are equally applicable liability rules and the absence of one does not necessarily negate liability for the other. For example, an operator could be found liable for groundwater contamination on the basis of nuisance, despite having conducted its secondary recovery operation in a reasonable and non-negligent manner.

8. Discussion

8.1. Introduction

The preceding chapters examined the risks posed by CO_2 storage, the regulatory regimes governing these risks, and liability arrangements in other sectors where analogous risks have been confronted. The risks of CO_2 storage were found to fall into six categories: induced seismicity, groundwater contamination, human health, environmental degradation, property damage, and contributions to climate change. While the risks associated with CO_2 storage are non-trivial, analogous risks have been effectively managed in a number of historical cases including acid gas injection, natural gas storage, secondary recovery, and EOR. However, the implication in the previous chapters is that the current private and public liability frameworks do not adequately address the CO_2 storage liability issue.

This chapter provides an integrated discussion of CO_2 storage risks and liability frameworks. In the first half of the chapter, I consider six lessons learned from the historical treatment of analogous risks and liability in other sectors. In the second half of the chapter, I put forward a proposal for addressing the CO_2 storage liability issue. In place of the current mechanisms that would govern CO_2 storage liability, I advocate an arrangement where the UIC permitting regime is amended, long-term liability is managed by a governmental CO_2 Storage Corporation with backing from an industry-financed CO_2 Storage Fund, tortious liability compensation occurs exclusively through an Office of Special Masters for CO_2 Storage in the U.S. Federal Court of Claims, and liability for non-performance of CO_2 storage contracts is addressed on an annual *ex post* basis during the injection phase of CO_2 storage operations and on an *ex ante* basis when sites are transferred to the CO_2 Storage Corporation.

Some of the liability issues presented in this chapter assume the existence of future carbon-constraining regulations, while other liability issues would need to be addressed regardless of the regulatory regime. In the absence of a climate regime, one would still expect tortious liability for damage to health, safety, and the environment. For example, the subsurface trespass cause of action has been well established for all subsurface injection activities. There would also need to be a regulatory regime governing the control of CO_2 underground injection, regardless of future carbon policies. On the other hand, the liability associated with covering CO_2 storage contracts assumes that operators receive credit for storing CO_2 and that the credit regime would be undermined where the quantity of CO_2 credits given does not match the quantity of CO_2 stored. In addition, the context of the CO_2 underground injection regulations could be affected by liability for CO_2 emissions to the atmosphere.

8.2. Lessons Learned

8.2.1. The CO_2 liability issue can be successfully resolved by combining our understanding of physical and regulatory analogs.

This thesis has analyzed the CO_2 storage liability issue by means of analogy. There are two types of analogs that are relevant to the analysis. The first type involves cases that are analogous in a physical sense to CO_2 storage, i.e. cases of subsurface injection. Physical analogs are useful in speaking to the properties of the geophysical system and the risks of leakage. Because they provide some precedent in areas such as permitting and risk management, physical analogs may have a policy component as well. The physical analogs analyzed in this thesis included acid gas injection, natural gas storage, secondary recovery of oil, and EOR. The thesis also documented the experiences of current and prospective large-scale CO_2 storage projects, including Sleipner and Weyburn. In many cases, the physical analogs involved not only subsurface injection generally, but in particular the subsurface injection of CO_2. A comparison of the scale of the CO_2 injection operations is shown in Figure 8.1.

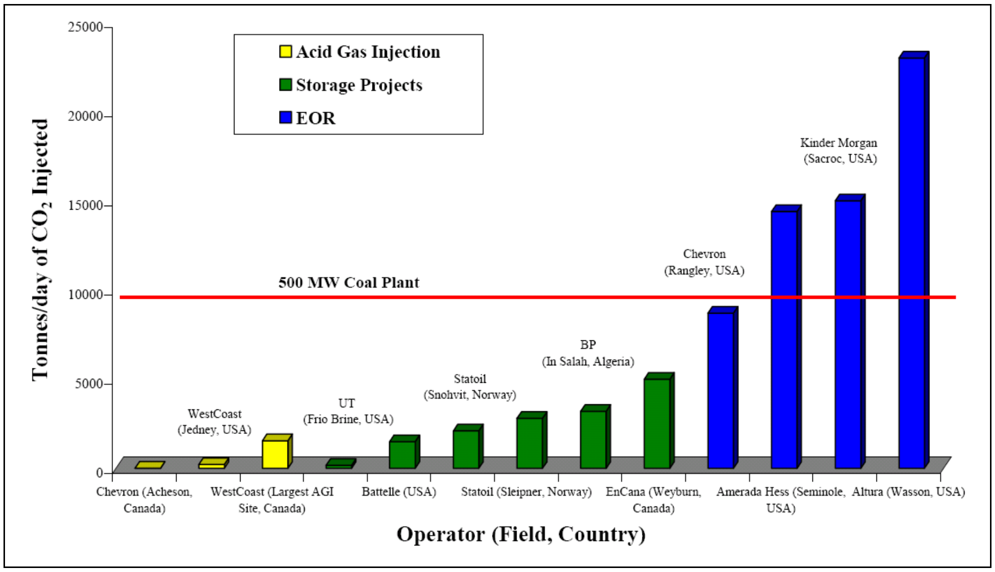

Figure 8.1 Comparison of CO_2 Injection Activities (Heinrich et al/IPCC)[1729]

No one physical analog encompasses every geophysical, toxicological, and environmental risk faced by CO_2 storage. Even where the physical analog faces the same type of risk, it is unlikely to be with the same probability or magnitude. However, as an aggregate, the physical analogs have revealed all of the currently identifiable risks relevant to CO_2 storage, and in some cases, with greater probability or magnitude. For example, the magnitude of toxicological risk associated with acid gas injection is much greater than that of CO_2 storage. The cases analyzed suggest that the *de jure* and *de facto* liability arrangements adopted have been effective in containing the risks. While a hybrid of preventative strategies will need to be used, the adequacy of site characterization appears to be a critical determinant of future risk.

[1729] HEINRICH ET AL, *supra* note 749, at 11; IPCC Special Report, *supra* note 11, at 223.

The second type of analogous activity relevant to the CO_2 storage liability analysis is the regulatory analog. Regulatory analogs may not necessarily address the same physical risks as CO_2 storage, but provide insight into the variety of policy templates that could be applied and the range of associated responses.[1730] Thus regulatory analogs help us understand what might be appropriate for future CO_2 storage liability policy. The discussion of liability in Chapter 2 reviewed several private and public mechanisms that have been used for managing large-scale long-term liabilities. Although the physical analogs contain some policy mechanisms for addressing liability (such as command-and-control regulations that have the effect of reducing liability), the legal and regulatory analysis in Section 2.3.3 outlined several mechanisms from beyond the subsurface injection context. These included insurance and private mechanisms; government as insurer and risk manager; immunity caps, floors, and exemptions; and compensation funds. Thus, as in the case of the physical analogs, there is no single regulatory analog that addresses the liability issues in question with CO_2 storage, but regulatory analogs provide the range of the types of legal and regulatory mechanisms that might be used.

Ultimately, the successful resolution of CO_2 storage liability will require combining our understanding of physical and regulatory analogs. Although physical analogs can assist in framing the risks of subsurface injection, their regulatory and liability framework may not necessarily be appropriate for CO_2 storage, whether for jurisdictional reasons (in the case of Alberta acid gas injection), statutory restrictions (in the case of natural gas storage), or the purpose for injection (in the case of secondary recovery and EOR). In fact, our understanding of the physical properties of the system is a result of a combination of multiple physical analogs. Regulatory analogs, on the other hand, allow us to understand the suitability of various liability policy strategies, but may not necessarily accurately reflect the risks inherent to CO_2 storage. A

[1730] *See generally* Reiner & Herzog, *supra* note 220.

CO_2 storage liability strategy must consider both the physical and regulatory constraints of the system.

8.2.2. The prospect of CO_2 storage liability will affect the implementation of predictive models and incentives to monitor leakage

The primary source of CO_2 storage liability is CO_2 leakage from the geological formation, such as through improperly abandoned wells, human-induced pathways, and natural variation in the subsurface. Leakage may lead to two types of liability: tortious liability due to health, safety, or environmental damage, and contractual liability where leakage undermines any carbon-constraining regime and contributes to climate change. Tortious liability would require attributing the cause of leakage to a culpable operator. One way to attribute liability is through direct evidence, such as testimony by a witness who observed the operator acting in an unreasonable manner. Where direct evidence is unavailable, liability actions may rely upon indirect evidence, such as models or data that would lead to a reasonable inference and conclusion of liability. In many cases, both direct and indirect evidence are relied upon. For example, in the *ONEOK* Hutchinson natural gas storage case,[1731] the liability finding was based both on direct evidence and predictive models and monitoring by the Kansas Geological Survey. Even if there is direct evidence, the cases analyzed in this thesis show that scientific evidence will need to be produced to confirm that CO_2 caused the harm in question. In addition, in areas of technical complexity or where reasonable conduct is not directly observable, expert testimony – particularly the use of predictive models – will play a crucial role. Thus in the *Anthony* case, which involved alleged groundwater contamination from an adjacent secondary recovery operation, flaws in the injection and groundwater models of the plaintiff led to Judge Garza

[1731] *See supra* Section 7.3.6.

finding the defendant not liable for the alleged contamination.[1732] However, as shown by the lack of induced seismicity cases, predictive models and a sound scientific understanding of the risk does not automatically lead to liability litigation.

If the climate liability regime for CO_2 storage follows the current IPCC Inventory Guidelines,[1733] the framework may be especially vulnerable to the gaming of predictive models and could create perverse monitoring incentives. The IPCC Inventory Guidelines use a so-called "tier 3" methodology for reporting leakage. As shown in Figure 8.2, the IPCC has created a four-step inventory accounting process involving the geological characterization of the storage site, modeling the system to determine the fate of the injected CO_2, conducting post-injection monitoring of the system, and using monitoring to validate and/or update the model.

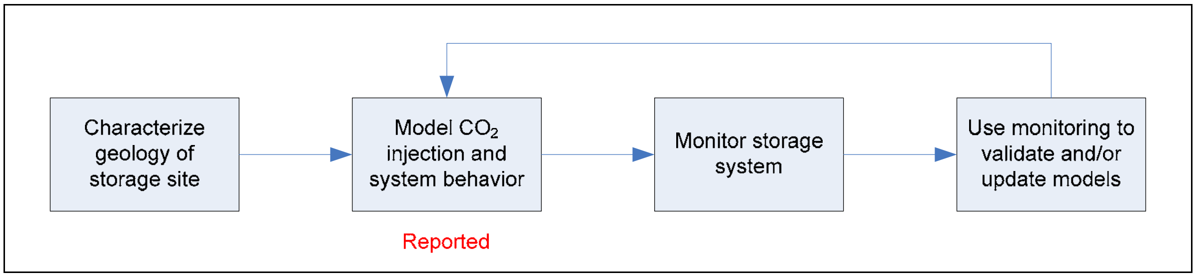

Figure 8.2 IPCC GHG Inventory Accounting Procedures for CO_2 Storage

The CO_2 storage models are used to report leakage at an individual CO_2 storage site ("CO_2 storage site emissions"). The reported leakage at each individual site in a country is summed to determine total leakage from all CO_2 storage sites in the country, which is then reported in the national greenhouse gas inventories. A government compiler serves to maintain the reported data and verify inventory procedures. The IPCC Inventory Guidelines describe the leakage reporting procedure as follows:

[1732] *See supra* Section 5.3.4.
[1733] *See supra* Section 6.4.

> The emissions recorded from the site and any leaks that may occur inside or outside the site in any year will be the emissions *as estimated from the modeling* (which may be zero), adjusted if needed to take account of the annual monitoring results.[1734] [emphasis added]

Although countries have not asserted that the IPCC Inventory Guidelines will be the basis for future climate liability regulation, the Guidelines are currently the only internationally recognized method for CO_2 storage inventory accounting method.

If the IPCC framework is applied to the climate liability context, liability would not be based on actual leakage. Instead, any liability would be based on the predicted leakage from the CO_2 storage models, as augmented by post-injection monitoring, and the models could very well predict zero leakage. The IPCC provides no guidelines for what constitutes an acceptable model, other than the model should make short-term and long-term simulations of the fate of the injected CO_2. Given the potential of there being several types of models with different assumptions and capabilities for estimating potential leakage, operators will have an incentive to lobby for the model that most greatly underestimates leakage (preferably the model likely to find leakage to be zero) because liability will depend on the leakage estimates of the model. Alternatively, operators with actual leakage lower than that estimated by the predictive model would potentially face liability even though it may be unjust.

Although the model predictions are to be adjusted in light of annual monitoring results, there are incentives to conduct inadequate monitoring. The Guidelines note:

> Once the CO_2 approaches its predicted long-term distribution within the reservoir and there is agreement between models and measurements made in accordance with the monitoring plan, it may be appropriate to decrease the frequency of (or discontinue) monitoring.[1735]

[1734] IPCC Inventory Guidelines, *supra* note 847, at 5.16.
[1735] *Id.*

The Guidelines create an incentive to pick the post-injection monitoring technology that underestimates leakage the most. In fact, if the predictive model estimates no leakage and monitoring shows no leakage (placing the model and monitoring measurements in "agreement"), the Guidelines suggest that it may be appropriate to decrease or discontinue monitoring. Without monitoring, liability would be premised solely on the predictions of the model, where the operator would ideally hope to find zero leakage and there would be no verification of the model. The adequacy of the predictive model and monitoring is to be validated by the national compiler, but without specific guidelines on the characteristics of suitable models and monitoring, it is unclear what validating role the compiler actually plays. In addition, because of the economic consequences to a country for finding leakage and the lack of oversight over the compiler, the compiler may not have any incentive to find leakage.

8.2.3. Jurisdictional differences in liability exposure could affect where CO_2 storage projects are eventually sited

The siting of a CO_2 storage operation will be a function of a number of factors, including the technical suitability of long-term CO_2 storage at a given site, the receptiveness of the public to the storage of CO_2, and the cost of CCS. Historically, it has been difficult to site facilities that serve a public need but pose health, safety, or environmental risks.[1736] The analysis in this thesis suggests that liability exposure for CO_2 storage is jurisdictionally dependent. Because liability exposure is one factor in determining whether CO_2 storage is economical, jurisdictional differences in liability exposure could affect where CO_2 storage projects are eventually sited.

[1736] GEMMA A. HEDDLE, SOCIOPOLITICAL CHALLENGES TO SITING FACILITIES WITH PERCEIVED ENVIRONMENTAL RISKS (S.M. thesis, MIT, 2003).

An obvious example is that liability exposure depends on the number of people potentially affected by a leakage incident. Siting a CO_2 storage facility beneath a highly populated area such as Berlin will create higher liability exposure than a CO_2 storage facility beneath an unpopulated area such as the Sahara desert, *ceteris paribus*. Compared with onshore storage, sub-seabed storage may be appealing from a liability standpoint because it essentially eliminates the potential for property damage and toxicological risks. Although sub-seabed storage might be more expensive than onshore storage from the perspective of transporting CO_2 to the storage site,[1737] this may be hedged by liability exposure being relatively cheaper.

The historical cases show that states may regulate a given risk very differently. In some areas, such as ownership of natural gas after it has been injected into a subsurface formation, state jurisprudence is remarkably consistent. However, in other areas, such as liability for groundwater contamination, liability is jurisdictionally dependent: liability will depend on the property doctrine used to determine who owns subsurface water. There may be cases where an almost identical fact pattern, leads to different outcomes: for example, ownership of the subsurface mineral formation lies with the surface estate owner in some states and with the mineral estate owner in other states. Even if state regulations appear to be substantively the same, for example all states having financial assurance requirements for underground injection, there may be differences in the way the regulations are implemented, for example what constitutes an acceptable form or level of financial assurance. One way to encourage regulatory consistency is through the use of model regulations or interstate compacts, as the IOGCC has done in its natural gas storage model statute and its proposals for future regulation of CO_2

[1737] IPCC Special Report, *supra* note 11, at 190.

storage.[1738] Alternatively, one might establish federal standards as part of broader climate legislation or narrower efforts to regulate CO_2.

Without regulatory consistency, there could be fights among states in how they treat liability in order to attract future CO_2 storage projects. For example, in order to attract FutureGen, the Texas legislature passed a bill that would place title to CO_2 injected by a FutureGen project with the Texas Railroad Commission, the state regulatory body responsible for oil and gas regulation.[1739] If there is competition among states in relieving potential CO_2 storage operators of liability, there could be race to the bottom concerns where operators take relatively fewer precautions because future costs of liability are not internalized. This can be mitigated through regulations that contain the probability of future risk, such as the procedures in Alberta for acid gas injection permitting, suspension, and abandonment.

8.2.4. The development of liability rules is a function of an industry's emergence, but an industry's emergence, in turn, may affect the content of the liability rules.

Liability rules derive from three major sources: legislation, regulation, and judge-made law. Legislation may set forth liability requirements explicitly, such as by setting the standard by which liable conduct should be judged and penalties for non-conformance with laws, or may address liability indirectly, such as by legislating conduct that would contain future risk. Regulation serves a similar function since the administrative agency is implementing a mandate provided by the legislature. Liability defined by judge-made law may derive from judicial interpretation of legislative or regulatory language, or may draw upon analogs which provide historical precedent.

[1738] *See supra* Section 5.5.5.
[1739] *See supra* note 1.

The development of liability rules will be a function of the industry's emergence. This is due to a couple factors. First, liability rules established by legislators and regulators represent current interests, possibly to the exclusion of future interests. In other words, this is a situation where current interests are over-concentrated and future interests are under-concentrated. The resulting liability rules will tend to favor current interests. Second, initial liability rules established by the judiciary will depend on the fact patterns in liability actions brought before the court. For nascent technologies, liability rules from judge-made law may involve conduct where judges have had no previous experience. Even with expert testimony, there is the potential for courts to "get it wrong" in hindsight.

For example, when natural gas storage first emerged, there were questions regarding ownership of the natural gas after it had been injected into the subsurface. Although there was precedent from the hydrocarbon extraction industries regarding ownership of surface and mineral estates, there was no precedent in subsurface injection operations. The issue first came before the Kentucky Supreme Court, which analogized natural gas storage to the capture and release of wild animals and created a rule that ownership of natural gas was lost after being injected into a subsurface formation. The resulting decision was widely criticized by industry and even later courts because of the legal uncertainty that it placed on natural gas storage operations; operators would always be vulnerable to competing claims on the stored natural gas.[1740]

However, as an industry or issue emerges, the content of liability rules may be affected. For legislation and regulation, this is because the relevant interests may change and/or gain political power. For example, the natural gas storage industry successfully argued that its activities posed little harm of groundwater contamination after evidence of safe operation. The Safe Drinking Water Act was amended to exempt natural gas storage from federal underground

[1740] *See supra* Section 7.3.2.2.

injection regulation. For judge-made law, courts will have more experience in addressing the once novel liability issues and the technology will be better refined by industry. The natural gas storage property liability regime has evolved, moving from the original *Hammonds* standard of Kentucky to one where title to injected natural gas is not lost upon ownership. The property regime adapted to criticism that the analogy of natural gas storage to wild animals was illogical. Liability rules may also be affected as the technology or issues become better refined or as new developments emerge. Thus as the oil and gas sector has matured, liability litigation has shifted from a strict liability regime for abnormally dangerous activities to a negligence regime where conduct need only be shown to be reasonable, but obviously this has taken a period of years. Whether the content of liability rules is likely to be modified will depend on the adequacy of current liability rules, the ability to adopt alternative liability approaches, the willingness of stakeholders to demand changes in the liability regime, and the institutional and political capacity for change.[1741]

Any CO_2 storage liability policies implemented today should take into account the ability to adapt liability rules as new information about CCS risks emerges. Alternatively, existing stakeholders should realize that liability rules are not static and the CO_2 storage liability regime may change over time as the CCS sector matures.

8.2.5. Conventional wisdom: By complying with all applicable regulations, operators are saved from liability. Refutation: Regulatory compliance is not always a safe harbor for liability.

Regulatory compliance is often invoked as a defense in liability litigation. It is black letter law that regulatory compliance provides evidence of reasonable care, but does not

[1741] *See generally* JAMES L. FOSTER, THE DEAD HAND OF ENVIRONMENTAL REGULATION (The Center for Environmental Initiatives and the MIT Consortium on Environmental Challenges, 1999).

constitute an affirmative defense that would absolve an operator of liability.[1742] However, some state legislatures have passed legislation that regulatory compliance *per se* is sufficient to show due care and prevent liability on a negligence cause of action.[1743] Non-compliance with regulation, on the other hand, is considered negligence *per se* and creates liability. In states without a regulatory compliance defense, compliance with regulation does not necessarily preclude liability. For a given CO_2 storage risk, regulatory compliance could take one of three forms: (1) the risk is regulated and the operator has complied with the regulation; (2) the risk is regulated but the operator has not complied with the regulation; or (3) the risk is not regulated.

The most straightforward category of cases is where non-compliance with regulation leads to liability. Where the non-compliance results in the same kind of harm that the regulation was meant to protect, the unexcused violation of the law is negligence *per se*. For example, the UIC Program establishes injection well requirements that all operators must meet. The *Jolly* case showed that the unexcused violation of a UIC permit could lead to penalties of up to $25,000 per day for each violation.[1744] Similar arguments can be made for the unexcused release of chemicals into the air, as in the case of hydrogen sulfide and acid gas injection, or in the violation of laws maintaining the structural integrity of the subsurface, as in the case of state subsidence laws.

Another category of cases is where an operator does not comply with a regulation, but is still not liable. In this context, one needs to be attentive in defining "liability". Liability could derive either from the enforcement of regulatory violations or from harm to the public,

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[1742] *See, e.g.*, Rest. 3d. Torts: Products Liability § 4(b) ("A product's compliance with an applicable product safety statute or administrative regulation is properly considered in determining whether the product is defective with respect to the risks sought to be reduced by the statute or regulation, but such compliance does not preclude as a matter of law a finding of product defect."). Although the Restatement definition governs product liability (where the defense is often raised), the rationale is broadly applicable to other areas of tortious liability.
[1743] Ashley W. Warren, *Compliance with Governmental Regulatory Standards: Is It Enough to Immunize a Defendant from Tort Liability?* 49 BAYLOR L. REV. 763, 781 (1997).
[1744] *See supra* Section 5.3.5.

environment, or property due to the non-complying conduct. An example of a regulatory violation would be exceeding a maximum contaminant level standard for underground drinking water. The non-compliance, for example, could harm public health and lead to private tortious liability for personal injuries or future medical monitoring. Thus non-compliance with regulation that does not lead to liability means there has been a decision by the regulatory agency not to enforce the alleged violation, similar to a district attorney's decision not to prosecute a crime. This option would not be available to an agency if Congress statutorily limited the enforcement discretion of the agency.[1745] Cases falling in the non-compliance with regulation / no liability category would also include cases where a private cause of action was not brought for private harm resulting from the violation, or where a liability action was brought and dismissed. This could be because regulatory non-compliance did not lead to the harm in question, or because the operator had an affirmative defense. An affirmative defense means that the operator acknowledges fault but has a defense that releases the operator from liability. For example, the victim might have seen the risk and unreasonably proceeded in the face of it (known as "contributory negligence"), or the victim might have known of and voluntarily assumed the risk (known as "implied assumption of risk").

Another set of historical cases are those where there is no regulation of the risk whatsoever. In some cases, non-regulation is associated with no liability, while in other cases there may be no risk regulation yet liability is imposed. This raises two issues: (1) under what conditions are known risks not regulated; and (2) under what conditions does the lack of risk regulation lead to liability? There are several possible explanations for the lack of regulation of a known risk. First, the risk in question could be subject to a poorly understood causal mechanism. While this is certainly seen in epidemiological settings, this explanation is less

[1745] *See, e.g.*, Heckler v. Chaney, 470 U.S. 821, 832 (1985).

likely for CO_2 storage because CO_2 storage risks are largely well understood. A second and more likely explanation is that although the causal mechanism is understood, manifestation of the risks is hard to predict *ex ante*. For example, it is well known that induced seismicity is a function of fluid pressure and the geophysical system's principal stresses, but it is virtually impossible to predict the frequency and magnitude of seismic activity from a given subsurface injection before injection has taken place. Third, a risk may remain unregulated because the nature of the risk may not lend itself to a regulatory regime. An example here would be the risk of contractual breach if an operator does not fulfill its duties in a given CO_2 storage contract. States provide general standards governing contract formation, breach of contract, and remedies for breach, but liability will be a function of the terms of the individual contract. Any default rules provided by regulation could be bargained around in the contract. The *ex post* interpretation of contractual terms is better suited for the judiciary than a regulatory regime.

With respect to accounting for variation in liability outcomes of non-regulated cases, again there are several explanations. First, liability outcomes will depend on the availability and suitability of evidence. For example, in induced seismicity cases, it may be difficult to show on the preponderance of the evidence that an operator caused the seismic activity in question. This is because of the time lag between injection and seismic activity, the possibility that multiple operators may be injecting in the general vicinity, and the susceptibility of a seismically active area to injection-induced seismicity. Even if the case is brought to court, it may be difficult to comply with standards concerning the admissibility of evidence. This could also explain why the risk in question is not regulated. Evidence supporting regulation must comply with federal Data Quality Act requirements, and evidence underlying liability litigation must meet the Federal

Rules of Evidence and/or requirements stemming from the *Daubert* and *Frye* line of cases.[1746] For example, the results of novel monitoring methods that have are not generally accepted by the scientific community may not be admissible in court. Finally, it could just be that the results are not generalizable. For contractual liability cases, sometimes the actions of the operator will cause the operator to be in breach of the contract and in other times those same actions will not cause breach. Liability is merely a function of the terms of the contract. Variation in liability outcomes can be case-dependent.

Finally, there is the issue of cases where regulations have been complied with, but the operator still faces liability. Compliance with regulation – or even industry custom – may show that an operator acted reasonably. Because reasonableness is an essential element in determining negligence, regulatory compliance provides evidence that would shield an operator from liability. On the other hand, there are a number of cases where an operator has been found liable, despite regulatory compliance. For example, regulatory compliance would not shield an operator from strict liability. For abnormally dangerous activities, strict liability occurs where it can be shown that the operator engaged in the activity in question and harm resulted. The amount of care taken by the operator is irrelevant. Although the *ONEOK* case of the natural gas storage accident in Hutchinson, Kansas was brought on negligence grounds, natural gas storage has been deemed an abnormally dangerous activity by legal commentators.[1747] If a liability litigation case was brought on strict liability grounds, a natural gas storage accident could theoretically result in liability even if the operator complied with all applicable regulations.

[1746] *See* Daubert v. Merrell Dow Pharmaceuticals, Inc., 509 U.S. 579 (1993); General Electric Co. v. Joiner, 522 U.S. 136 (1997); Kumho Tire Co. v. Carmichael, 527 U.S. 137 (1999); Frye v. U.S., 293 F. 1013 (D.C. Cir. 1923).

[1747] *See supra* Section 7.3.6. This is distinct from local natural gas pipelines which are not considered to be abnormally dangerous. *See, e.g.*, New Meadows Holding Co. v. Wash. Water Power Co., 687 P.2d 212 (Wash. 1984).

A second area where regulatory compliance does not shield an operator from liability is when the operator is subject to multiple regulations. If the operator complies with one regulation, it could still face liability on negligence *per se* grounds if it is non-compliant with other regulations.

A third set of regulatory compliance/liability cases is activities giving rise to a private nuisance. This was seen in the secondary recovery line of cases. For example, *Mowrer* involved a secondary recovery operation where a neighboring drinking water aquifer was contaminated by saltwater.[1748] The operator had procured all the necessary regulatory permits and appeared to be fully compliant with the law. However, the court found that its regulatory approval and compliance were not defenses to nuisance liability. In another case, *Gulf Oil*, the Supreme Court of Oklahoma articulated a similar rationale: a secondary recovery operation need not be of a negligent or unreasonable nature to entitle the injured party to recover.[1749] Thus, regulatory compliance does not always shield an operator from liability.

8.2.6. Conventional wisdom: Private liability of CO_2 storage operators lasts indefinitely. Refutation: Statutes of limitations and repose mean that private liability is not necessarily "forever"

Several commentaries on CO_2 storage liability assume that the starting point for discussion is that CO_2 storage operators face an open-ended liability for indefinite time.[1750] Thus it has been argued that government must enact policies to contain this potentially limitless liability. However, the analysis in this thesis suggests that liability is not "forever" because of temporal limits on liability established by state legislatures.

[1748] *See supra* Section 7.4.4.1.1.
[1749] *See supra* Section 7.4.4.1.2.
[1750] *See, e.g.*, INT'L ENERGY AGENCY/CARBON SEQUESTRATION LEADERSHIP FORUM, DISCUSSION PAPER FOR SECOND IEA/CSLF WORKSHOP ON LEGAL ASPECTS OF CARBON CAPTURE AND STORAGE 37 (2006).

As discussed in detail in Section 2.3.1.1, there are two types of temporal limitations relevant to CO_2 storage liability. The first is the statute of limitations, which places a time limit on bringing a liability action based on the time *when the injury occurred*.[1751] Although the length of a statute of limitations varies depending on the state, all states have some form of a statute of limitations. The second is a statute of repose, where the time limit on bringing a liability cause of action is based on *when the defendant acted*, even if the period ends before the plaintiff has sustained a resulting injury.[1752] A graphical representation of statutes of limitations and repose is shown in Figure 8.3.

In order for the CO_2 storage operator to be found liable, any liability actions for purported injuries must be brought within the time limit of the statute of limitations and the statute of repose. There are three potential scenarios for liability actions. In the first scenario, shown in Figure 8.3(a), the time limit on the statute of repose exceeds the time limit on the statute of limitations. The victim will be permitted to bring its claim so long as it is brought within the time period designated by the statute of limitations. In the second scenario, shown in Figure 8.3(b), there is an overlap between the statute of limitations and the statute of repose. Because of the statute of repose, the victim does not have the full time provided in the statute of limitations in which it may bring its liability action. The victim may only bring an action between the time of the injury and the time that the statute of repose ends, otherwise its liability action will be temporally barred. In the third scenario, shown in Figure 8.3(c), the injury occurs after the statute of repose has ended. The victim will be temporally barred from bringing its claim. Although this is seemingly unfair to the victim, who is not given a chance to be compensated for its injuries through no fault of the victim's own, the statute of repose is a legislative

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[1751] BLACK'S LAW DICTIONARY (8th ed. 2004) (s.v. "statute of limitations").
[1752] *Id.*

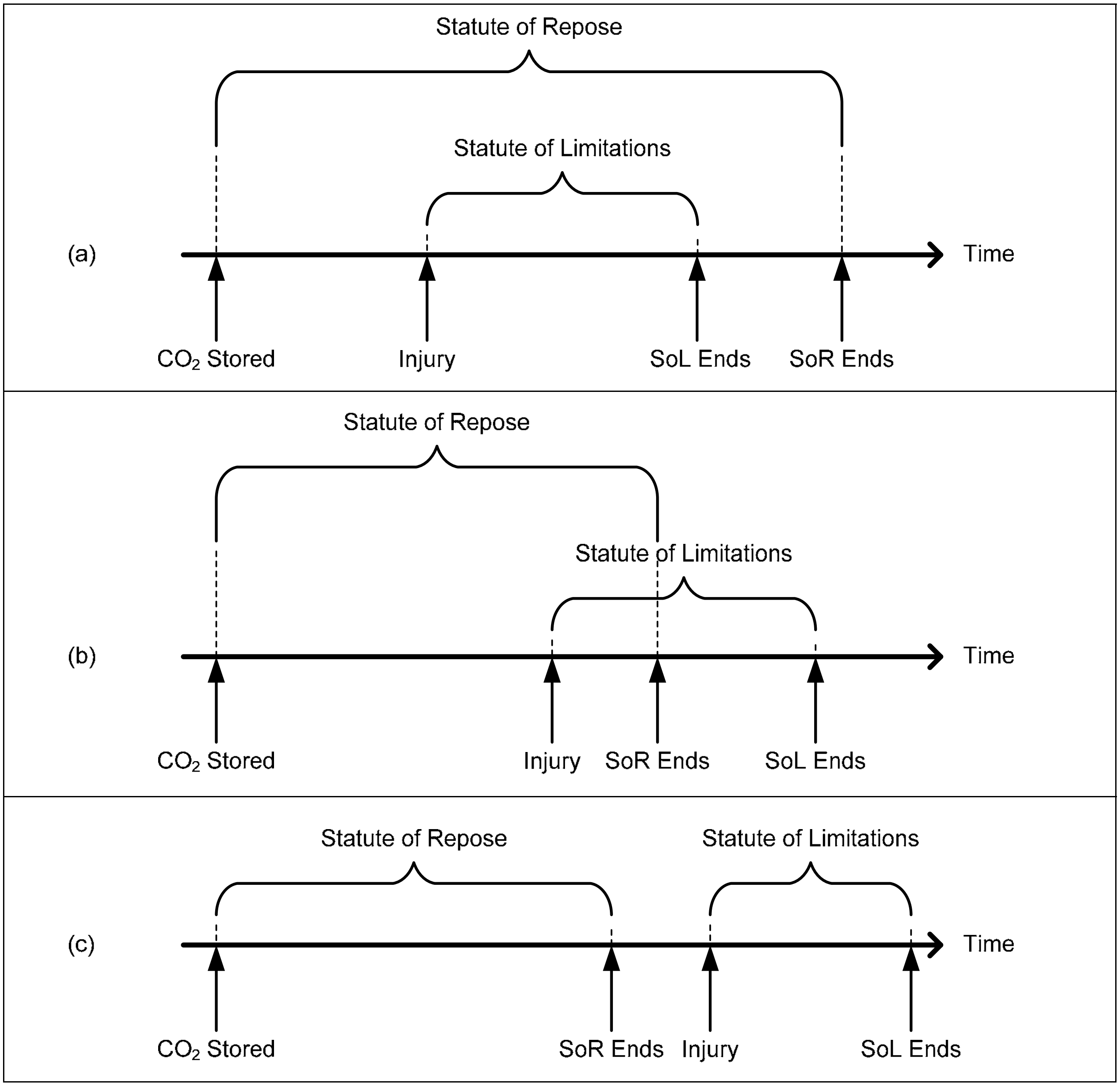

Figure 8.3 Temporal Limit Scenarios for CO_2 Storage Liability where SoL means Statute of Limitations and SoR means Statute of Repose

determination that the broader interest in temporally baring the victim's claims outweighs the private interests of allowing the action to go forward.

In Sections 5.3.1 and 7.4.4, the issue of temporal limitations on liability was seen in the context of groundwater contamination from oil recovery. In the *Matysek* case, a family's private groundwater aquifer was contaminated with salt water from an adjacent oil recovery operation.[1753] However, because the liability action was brought after the Texas two-year statute of limitations, their cause of action was barred. Similarly, in the *Morsey* case, an oil lease owner was temporally barred from bringing a liability action alleging subsurface trespass by a neighboring water flood because it exceeded the Kansas statutes of limitations and repose.[1754] Kansas provided a 10-year statute of repose and 2-year statute of limitations for the trespass and damage claims in question.

In summary, statutes of limitations and repose will play a key role in any CO_2 storage liability policy. Generally applicable statutes of repose may already exist (as was seen in *Morsey*), but some states might require the state legislature to enact a statute of repose that is specific to CO_2 storage. In either case, the analysis in this thesis shows that, depending on the state, liability for CO_2 storage might not be forever. The terms of the CO_2 storage liability debate should shift from asking how we might limit an indefinite liability to asking under what conditions we should consider extending a finite liability, in keeping with the long-term nature of CO_2 storage.

[1753] *See supra* Section 5.3.1.
[1754] *See supra* Section 7.4.4.2.

8.3. A Proposal for Addressing the Liability of CO_2 Storage

Any effective CO_2 storage liability policy should address both the tortious liability related to health, safety, and environmental damage, and the contractual liability associated with non-performance under the CO_2 storage contract. There are three potential paths that CO_2 storage liability policy could follow. One option would be to maintain the current liability and regulatory regime, as outlined in Chapter 3. However, the analysis in this thesis suggests that the current private and public liability frameworks governing CO_2 storage are not adequate given the nature of the risks, the expectation that the injected CO_2 will be stored in the subsurface for hundreds of years, and difficulties in attributing causation. A second option would be to do away with the current liability and regulatory framework and create an entirely new arrangement for CO_2 storage. However, because there is already extensive experience and precedent related to CO_2 injection for EOR, it would be impractical – if not politically infeasible – to carve out CO_2 storage from the existing regime and start anew.

The final option, and my recommended strategy, is to pursue a hybrid approach with aspects of both the current regime and a novel liability mechanism. There are a number of ways this could be pursued. My proposal has three components: (1) amending the UIC regime to account for the novel issues of CO_2 storage; (2) establishing a CO_2 storage trust fund, long-term management regime, and compensation mechanism for tortious damages; and (3) creating a mechanism to contain the risk of permanence. I address each component in turn.

8.3.1. Amending the UIC Regime

My suggestion for adapting the UIC regime has three parts. First, I recommend that the current regulations be maintained for CO_2 that is injected for enhanced recovery of oil and gas.

There is extensive experience on the state and federal level in permitting CO_2-EOR injection wells. These wells are currently permitted under the Class II status, often by state agencies that have acquired primacy over Class II permitting. In order to receive a permit, a Class II well must be shown not to endanger underground sources of drinking water. Class II injection wells have additional flexibility in achieving the non-endangerment criterion as compared with other injection well classes. This thesis has shown that secondary recovery and EOR injection wells have historically posed a minimal risk of long-term liability.

Second, I recommend that "experimental" CO_2 storage projects be permitted under the Class V status. This is consistent with draft guidance proposed by the EPA in October 2006.[1755] There is precedent in using the Class V status for underground injection experiments generally[1756] and for CO_2 storage projects in particular.[1757] The advantage of Class V status is that it relieves the operator from the requirements of the class into which the injection well would ordinarily fall,[1758] while assuring the protection of underground sources of drinking water. Obviously, there will be a debate as to whether a given project is "experimental" versus "commercial". The burden of proof should lie with the operator in advancing a credible argument to the permitting agency that the project is indeed experimental. Certainly, the definition of "commercial" may also depend on the existence of a CO_2 market.

Third, a new Class VI category should be created for commercial CO_2 storage projects unrelated to EOR. Although the Class V category is useful in allowing experimental projects to proceed, the permitting of commercial CO_2 storage projects on an *ad hoc* basis is not advisable.

[1755] *See generally* U.S. Envtl. Protection Agency, Underground Injection Control Program, Geologic Sequestration of Carbon Dioxide, *at* http://www.epa.gov/safewater/uic/wells_sequestration.html (last updated Nov. 17, 2006).
[1756] Memorandum from Victor J. Kimm, Director, Office of Drinking Water, U.S. Environmental Protection Agency to Water Division Directors, Regions I-X, Water Supply Branch Chiefs, and UIC Representatives regarding the Appropriate Classification and Regulatory Treatment of Experimental Technologies (Ground-Water Program Guidance No. 28, May 31, 1983).
[1757] HAVORKA ET AL, *supra* note 316.
[1758] Kimm, *supra* note 1756.

My recommendation for a non-EOR CO_2 storage category maintains consistency by ensuring that EOR CO_2 storage continue to be permitted as Class II wells. However, this is a dramatic change for non-EOR CO_2 storage wells, which based on the analysis in Section 3.2.4 of this thesis, would likely otherwise be permitted as a non-hazardous Class I well used for non-hazardous fluid injection below the lowermost underground source of drinking water. Also, any Class II EOR injection well would eventually need to be re-classified as a Class VI well if the EOR operator seeks to keep the CO_2 stored in the subsurface once oil recovery operations are complete.

Table 8.1 Summary of Proposal for Amending the UIC Regime for CO_2 Storage

CLASS	DESCRIPTION
Class II	Wells which inject CO_2 for enhanced recovery of oil or natural gas
Class V	Wells which inject CO_2 for scientific experiments
Class VI	Wells for all other CO_2 injection and storage

Although there is no precedent in creating a new UIC class, which would need to occur for a new Class VI status, there is nothing in the SDWA that prevents the EPA from doing so. The SDWA only requires that the EPA establish regulations for preventing underground injection from endangering drinking water sources. Certainly, Congress could provide direct guidance to the EPA on establishing a separate classification for CO_2 storage injection wells, which would avoid the inevitable strategic maneuvering that would take place during the rulemaking process. The administration could seek recourse through regulation if it was dissatisfied with the legislative option.

The primary justification for a new injection well category is that current UIC regulations do not adequately address the risks inherent to CO_2 storage. I anticipate similarities to the current UIC regime, such as in the use of well design specifications and financial assurance requirements. However, the new Class VI well category would have several differences from the current Class I regulations. The new category would enable specification of CO_2 storage site characterization, the primary approach to reducing liability exposure. The area of review would be expanded from the current one-quarter mile radius standard because of the risk of the CO_2 plume migrating over a larger distance. The Class VI standard would prescribe injection design standards that would minimize degradation of the well from the acidic CO_2 injectate. Post-injection monitoring, which is not required for non-hazardous injection wells, would be mandated for Class VI wells. Procedures would be established to address the situation where unintended subsurface CO_2 migration or leakage has the potential to cause harm to health, safety, or the environment, including measures for halting CO_2 injection and remediation of the storage site.[1759] Finally, injection well operators would be allowed to abandon their wells after 10 years from the end of CO_2 injection, with long-term responsibility placed in the hands of a governmental corporation described below. This is consistent with previous statutes of repose.[1760] Abandonment would be contingent on showing containment of the stored CO_2. Obviously, the new Class VI regime would be subject to notice-and-comment rulemaking, and any state wishing to have primacy over its Class VI wells would need to submit the program to the EPA for review, also subject to notice-and-comment.

The regulatory regime for CO_2 storage was chosen from three alternatives: (1) the do-nothing option, (2) creating a Class I sub-classification, and (3) my eventual proposal for a hybrid regime with new classification. My proposal keeps the permitting regime for EOR wells at the status quo to avoid moving certain wells currently regulated as Class II into an uncertain and potentially more burdensome regulatory category. Because of the constraints of the current

[1759] *See, e.g.*, David W. Keith et al, *Regulating the Underground Injection of CO_2*, 39 ENVTL. SCI. & TECH. 499A, 504A (2005).
[1760] *See* Sections 2.3.1.1 and 8.2.6.

regime, including the lack of post-injection monitoring, a relatively small area of review compared to the size of the CO_2 plume footprint, and zero tolerance for leakage, the creation of a new classification is the cleanest way of establishing a new regulatory regime. Its strength lies in not being constrained by the traditional UIC regulatory apparatus. One might question the political feasibility of creating a new UIC classification. In the history of the UIC program, a new injection well classification has never been established, but neither has it been attempted. In the event of a new well class, states seeking to regulate their own CO_2 storage wells would need to seek approval from the EPA for Class VI primacy. Primacy over other injection well classes would not change. If a state received primacy over its Class VI wells, the result in my proposal would be a mix of state law for permitting and federal law for the liability management mechanism. A solution could be to allow states to manage their own state CO_2 storage funds, but this would eliminate the regulatory consistency, economies of scale, and cross-subsidization provided by a single federal fund.

8.3.2. Establishing a Liability Fund, Long-Term Management Regime, and Compensation Mechanism

Regarding the treatment of long-term CO_2 storage liability, there are two fundamental issues: (1) who is responsible for the long-term *management* of the CO_2 storage site in, and (2) who *pays* if damages are incurred in the long-term. It does not necessarily follow that the entity responsible for managing the site will also be financially responsible for damages. Thus, the second component and cornerstone of my liability strategy is the establishment of a liability fund, long-term CO_2 storage management regime, and compensation mechanism for potential tortious liability victims. This prong of the proposal would require Congressional action, and could be presented as a package for Congressional approval in conjunction with the permitting prong of the proposal. The proposal would also likely be better received by Congress it felt that it was being consulted on the whole question of CO_2 storage liability, rather than on a piecemeal basis.

The liability fund, which I call the CO_2 Storage Fund, would have four purposes: (1) to finance long-term monitoring and management of CO_2 storage sites; (2) to finance the abandonment of orphaned CO_2 storage injection wells; (3) to compensate tortious liability victims who receive injuries or damages from health, safety, or environmental risks from a CO_2 storage operation; and (4) to finance the remediation of damaged sites. The CO_2 Storage Fund would have three sources of income. The first would be a levy on CO_2 storage activities. The levy would be a function of the amount of CO_2 injected in the subsurface, i.e. those operators injecting more CO_2 into the subsurface would pay more into the fund. The levy would be set by the fund manager as described below. Second, the fund manager would be authorized to invest non-working funds in interest-bearing obligations of the United States, i.e. treasury notes. Third, under certain circumstances outlined below, the fund manager could seek reimbursement from a CO_2 storage operator for amounts paid out of the fund.

A number of other financing options were considered, including insurance. The analysis of regulatory mechanisms suggested that insurance or pools of funds are a common way of financing analogous long-term responsibilities. I chose a fund approach because it would allow not only for compensation of victims, but could also finance other necessary activities, such as long-term monitoring, remediation of storage sites, and the abandonment of orphaned sites. The industry-fund approach also minimizes the subsidization of liability by the taxpayer. A fund is susceptible to the criticism that questions the need to set aside large amounts of money. However, this could be countered by arguments that a fund is necessary because of the public interest of the CO_2 storage activity, the magnitude of the risks in question, and the long-term nature of the problem. Although insurance is well suited for compensating victims if the magnitude and probability of risk could be assessed, it would not provide the access to working capital necessary for a third party to conduct long-term monitoring and management of the site. Insurance is also limited temporally – the injected CO_2 is expected to remain in the ground for hundreds, if not thousands, of years, which far exceeds the longest insurance policies written. However, the choice of insurance versus fund does not allow one to escape conducting an analysis of the probability and magnitude of future risk. In the case of insurance, actuarial assessments are needed to determine the premium that should be charged to CO_2 storage operators. In the case of a fund, the same figures are needed to determine the necessary level of industry contributions into the fund.

There are a number of ways in which the CO_2 Storage Fund could be managed. My preferred approach would see the creation a governmental corporation,[1761] which might be called the CO_2 Storage Corporation. The CO_2 Storage Corporation would be responsible for managing the CO_2 Storage Fund and would have long-term responsibility for abandoned CO_2 storage sites. (As described in the first prong of my liability proposal, CO_2 storage operators would be allowed to abandon their wells after 10 years from the end of injection using procedures outlined in the proposed Class VI program.) Congress would charter the corporation and the federal government would hold 100% of the corporation's equity. The Chairman of the CO_2 Storage Corporation would be the EPA Administrator. Because the EPA is the lead agency for underground injection control regulations governing CO_2 storage, it would be appropriate for it

[1761] Federal authority to charter corporations is derived from the Necessary and Proper Clause. U.S. CONST. art. I, § 8, cl. 18. *See also* McCulloch v. Maryland, 17 U.S. (4 Wheat.) 316, 409-12 (1819); Osborn v. Bank of the United States, 22 U.S. (9 Wheat.) 738, 859-60 (1824); A. Michael Froomkin, *Reinventing the Government Corporation*, 1995 U. ILL. L. REV. 543, 551 (1995).

also to oversee the management of CO_2 storage sites. Members of the board of directors would be appointed by the President and subject to Senate confirmation. The board would include representatives of the DOE, state agencies responsible for CO_2 storage, industry, NGOs, citizens, and the scientific community. The directors would appoint a Chief Operating Officer responsible for the day-to-day operations of the CO_2 Storage Corporation. The operating expenses of the CO_2 Storage Corporation would come out of the CO_2 Storage Fund. The board of directors would be required to provide an annual report to Congress and the corporation would be subject to Congressional oversight.

There will obviously be institutional implications if an operator is expected to have long-term responsibility over a storage site since the CO_2 would remain in the subsurface much longer than the expected lifetime of the operator. On the other hand, one might expect inflated costs and/or unrealistic standards if the government manages liability.[1762] The governmental corporation provides greater stability since it is not beholden to any single CO_2 storage operator for its management, yet provides greater flexibility than if the storage site was maintained by a purely governmental agency. An alternative fund management option would have the U.S. Department of Treasury would serve as trustee for the CO_2 Storage Fund, but this approach presents potential problems because the federal government does not have a fiduciary responsibility to the beneficiaries and could unilaterally decide to change the purpose for using the fund and the amounts collected.[1763]

[1762] WORLD RESOURCES INSTITUTE, SUMMARY OF WRI WORKSHOP ON CARBON CAPTURE AND STORAGE LIABILITY (Sept. 29, 2006).

[1763] U.S. GOV'T ACCOUNTABILITY OFFICE, FEDERAL TRUST AND OTHER EARMARKED FUNDS: ANSWERS TO FREQUENTLY ASKED QUESTIONS 7 (GAO-01-199SP, Jan. 2001).

Compensation would occur as follows. An Office of Special Masters for CO_2 Storage would be established in the U.S. Federal Court of Claims.[1764] The special master mechanism was seen in Section 2.3.3.4 in the context of compensation for childhood vaccine injuries. All claims for compensation would be required to be brought exclusively before the Special Master. The Special Master would be responsible for evaluating the merits of the claim and deciding what, if any, compensation should be provided. All compensation would come out of the CO_2 Storage Trust Fund. Compensation to victims would be on a no-fault basis, meaning that victims would need only show that the injuries incurred were the result of a CO_2 storage operation. They would not need to show that the injuries resulted from a lack of reasonable care.

I suggest three carve-outs from the compensation mechanism, i.e. three situations where compensation would be sought through traditional liability litigation mechanisms. First, liability related to CO_2 injection from EOR activities would be excluded from the special master compensation mechanism as long as the injection well remained under the Class II category of the UIC program. Thus EOR liability would remain status quo. However, if the CO_2 storage operator seeks to reclassify the EOR well as a Class VI CO_2 storage well, the well would be brought under the CO_2 Storage Fund mechanism and contributions to the fund would need to be made according to the amount of CO_2 stored. Second, liability for subsurface trespass and contamination of native minerals would be excluded from trust fund compensation. Given the substantial precedent in subsurface trespass case law, there is no need to resort to the proposed compensation mechanism for damages. Third, I would exclude routine operational liabilities of the sort already successfully managed in day-to-day subsurface injection operations.

[1764] "The Court of Federal Claims is authorized to hear primarily money claims founded upon the Constitution, federal statutes, executive regulations, or contracts, express or implied-in-fact, with the United States." U.S. Court of Federal Claims, *History*, *at* http://www.uscfc.uscourts.gov/USCFChistory.htm (last updated June 4, 2001).

The CO_2 Storage Corporation would be permitted to seek reimbursement from the operator of a CO_2 storage well for which tortious liability compensation was necessary if compensation occurred within 10 years of the end of CO_2 injection. If compensation was sought after 10 years from the end of CO_2 injection, the operator would not be required to reimburse the CO_2 Storage Fund. In other words, I propose a *de facto* 10-year statute of repose from the standpoint of the operator, which is consistent with other statute of repose legislation.[1765] However, there is no time limit for the victim bringing a claim for compensation from the CO_2 Storage Fund. However, I propose a 5-year statute of limitations, where a claim for compensation must be brought within 5 years of injury. Reimbursement could also be sought from operators who were grossly negligent in their duties. For due process reasons, the CO_2 storage operator whose injection wells caused the injuries in question would be permitted to intercede in both the compensation and reimbursement hearings. The judgments of the Special Master could be appealed to the U.S. Court of Federal Claims, the U.S. Court of Appeals for the Federal Circuit, and ultimately, the U.S. Supreme Court.

Even if long-term management and financing mechanisms are established, they do not address the issue of how victims are compensated. Assuming *arguendo* that a fund would be used to finance long-term liability, the alternative to the special master mechanism that I suggest would have been to use a hybrid approach where victims sought compensation by bringing a cause of action against the CO_2 storage operator in the short-term, but would seek compensation from the CO_2 Storage Fund if injuries were incurred in the long-term. The advantage of my approach is that it provides a straightforward means of compensating victims of CO_2 storage accidents, instead of the confusion that would likely ensue if the choice of forum was a function of the length of time after CO_2 was injected into the geological formation. There is no confusion

[1765] *See* Sections 2.3.1.1 and 8.2.6.

because victims would always seek compensation from the Special Master and compensation would always come from the CO_2 Storage Fund. Steps are taken to minimize depletion of the fund through the reimbursement mechanism. My approach also prevents the gaming of the system due to forum shopping. Forum shopping might occur in the hybrid regime if victims thought higher compensation was more likely in post statute of repose compensation than liability litigation or vice versa. A possible solution would be mandatory arbitration, which one might argue is in the spirit of the special master approach. Finally, the use of a special master provides an arbiter of disputes that would develop experience and specialized knowledge in addressing compensation from CO_2 storage operations.

A weakness of the liability compensation mechanism being advanced is that it mandates resolution of disputes in federal courts on issues which some might argue are fundamentally state law if states have primacy over CO_2 storage sites. However, when compensation is on a no fault basis, the reasonableness of the CO_2 storage operations *vis a vis* state law is not an issue. Instead, the question is whether the injuries sustained by the victim were the result of the CO_2 storage activity. Another issue is what should happen if the CO_2 storage fund is prematurely depleted, or alternatively, if it is never used. I address the overuse issue by allowing the CO_2 storage levy to be adjusted by the board of the CO_2 Storage Corporation. Alternatively, the levy could be predetermined in legislation establishing the CO_2 Storage Fund, but this could lead opponents of the fund to repeal the levy, which would remove the funding mechanism for future management of the site and compensation of victims. By providing that the fund is used to finance long-term monitoring, I assure that the fund will not simply grow and serve as a potential target for raiding. Finally, one might question why CO_2 storage should receive this extraordinary special master liability treatment, while other activities involving large-scale, long-term liabilities do not. However, even compared to the physical and regulatory analogs, by all accounts, the combination of risks, time frames, and the scale of operations make the CO_2 storage liability issue unique.

As an incentive for the development of CO_2 storage projects in the near-term, I propose that the federal government subsidize the payments into the CO_2 Storage Fund for CO_2 storage projects that are operational by the year 2020. I also propose that these projects not be required to reimburse the CO_2 Storage Fund for liability payments made out of the fund. There have been two large-scale CO_2 storage projects proposed in the United States, FutureGen and the BP Carson Project, both of which are expected to be operational by the year 2013. The fund subsidy and removal of reimbursement is intended to provide financial incentives to other early movers.

8.3.3. Containing the Permanence Risk

The final prong of the liability proposal is to create a mechanism for containing the risk of permanence, assuming a regulatory regime where credits are received for storing CO_2. While measuring the amount of CO_2 injected into a storage formation does not necessarily pose technical difficulties, a climate liability regime must also account for leakage of CO_2 from the storage formation. In a liability regime, if the amount of CO_2 that is stored does not match the amount of CO_2 for which credit is given, the policy regime will be undermined unless there is liability associated with the leakage. I propose that the permanence issue be addressed on an annual *ex post* basis during the injection phase of CO_2 storage operations and on an *ex ante* basis when sites are transferred to the CO_2 Storage Corporation.

As in my recommendation for long-term governance, the permanence issue for CO_2 storage can also be broken into short-term and long-term components, i.e. before hand-off of the storage site to the CO_2 Storage Corporation and after hand-off. Before hand-off, CO_2 storage operators would be receiving credits associated with their storage activities and would be required to comply with a monitoring protocol. As long as the storage operator maintained ownership over the storage site, leakage from the site would be determined on an annual basis from the reported monitoring results, subject to third party audits. Leakage could be zero if no leakage was found from the storage site, in which case there would be no liability. If positive leakage was found, the operator would be required to purchase an equivalent amount of credits on the market to cover the leakage. If monitoring technologies are incapable of effectively determining leakage at a resolution necessary to ensure the integrity of the climate regime, leakage would need to be modeled and the quantity of credits purchased to cover leakage would be on the basis of the model results. Although this presents potential perverse incentives for model gaming, this could be minimized through the standardization of assumptions.

When the storage operator was ready to hand-off ownership of the site to the CO_2 Storage Corporation, leakage would be determined on a future basis until a time in the future deemed to constitute permanent storage. Future expected leakage from the geologic formation would be modeled over time. Again, leakage could very well be zero. However, if future leakage is predicted by the model, the operator would be required to purchase credits on the market to cover the expected leakage. This approach provides an incentive for CO_2 storage operators to choose less risky sites. If the operator chooses sites that have a higher probability of leakage, then the operator must cover the expected leakage accordingly.

The liability approach presented is one of "seller beware", where there are standards of performance associated with CO_2 storage and the CO_2 storage operator is liable for the non-performance risk of leakage from the geological formation.[1766] This strategy is chosen because the CO_2 storage operator is the least cost avoider for the risk of leakage. In other words, of the

[1766] *See* Section 6.3.

parties that would enter into a CO_2 storage agreement, the CO_2 storage operator is in the position to most efficiently minimize future leakage. This also minimizes the moral hazard that could result from the CO_2 storage operator not being liable for the consequences of its actions.

Although my proposal does not forestall actions for fraud where the CO_2 storage operator does not store the quantity of CO_2 that was promised in the storage contract, it renders moot the issue of contractual non-performance due to leakage. The effectiveness of my proposal will ultimately depend on monitoring and modeling capabilities. If monitoring technologies are able to detect CO_2 fluxes from a geological formation at a resolution consistent with assuring the performance of the climate regime governing CO_2 storage, the *ex post* component of managing the permanence issue could be based on the direct monitoring of leakage. Research on the suitability of various monitoring technologies is ongoing,[1767] and the IPCC Inventory Accounting Framework concluded that an accounting regime based on *per se* monitoring would not be sufficient.[1768] However, liability that is based solely on model outputs, as might be the case if liability rules were governed using an IPCC Inventory Accounting framework, would be susceptible to gaming and could undermine confidence in the climate regime. The architects of the liability regime will need to be cognizant of the perverse incentives that could arise. If *ex post* management of the permanence issue cannot be based on actual monitoring at the present time, as monitoring technologies are refined, I would anticipate that policy would move from a liability regime based on modeling to one where liability depends on monitoring actual CO_2 fluxes from the storage formation. Nonetheless, the use of models will be necessary for managing the permanence issue *ex ante* when storage sites are transferred from the operator to the CO_2 Storage Corporation.

[1767] *See* Section 2.2.4.
[1768] *See* Section 6.4.

9. Appendix

9.1. Stakeholder Questionnaire on Carbon Capture and Storage[1769]

ALLIANCE FOR GLOBAL SUSTAINABILITY
An International Partnership

Stakeholder Questionnaire on Carbon Capture and Storage

This questionnaire is part of a project on social and political aspects of Carbon Capture and Storage (CCS). The aim of the project is to identify, study, and address non-technical issues associated with CCS from fossil-fuelled energy production, and to provide guidance to decision makers. The project will help to evaluate the attitudes of both the public and of key stakeholders to see what role, if any, that CCS might play in a more sustainable energy system. The project is a co-operative effort between MIT (USA), Chalmers University of Technology (Sweden), University of Cambridge (UK), and the University of Tokyo (Japan) and is financed by the Alliance for Global Sustainability (described here) with the active support and involvement of both industry and environmental groups.

The questions are grouped into two sections:

1. General Background on Climate Change
2. Carbon Capture and Storage
    - General Questions
    - Future of CCS - Public Attitudes towards CCS
    - Your Organization's Approach

Your participation in this study is voluntary, and your opinions and any information you provide will be kept confidential. You are free to leave unanswered any questions that you wish. All surveys will be coded and data will be reported in summary form so it will not be possible to link information to any individual. The survey should take about 15-20 minutes to complete. We also hope to follow up on this questionnaire to allow you to clarify or expand on your views. All survey data will be kept in a secure location and will be available only to members of the research team.

If you encounter any problems during the course of the survey, please start again from the beginning by coming back to this page. Please do not hit the "back" button on your browser. In the unlikely event that any technical problems persist and you are unable to complete the survey, please let us know by emailing Linda Ye at surveyccs@mit.edu.

Finally, we thank you in advance for answering the questionnaire and thereby making a valuable contribution to our research project!

~The Project Team

ENTER the Questionnaire

[1769] Available online at http://sequestration.mit.edu/temp/survey/

1. How serious do you consider the threat of climate change to be relative to other problems facing society?

Please mark the statement that comes closest to **your opinion**. (Only one alternative should be marked)

☐ Much more serious than other problems
☐ More serious than other problems
☐ Similar to other problems
☐ Less serious than other problems
☐ Much less serious than other problems
☐ Unsure

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2. What impact do you think national and international regulation related to climate change will have on emissions of carbon dioxide and other greenhouse gases over the next 20 years?

Please mark the statement that comes closest to **your opinion**. (Only one alternative should be marked)

☐ Regulation will lead to very large reductions in emissions
☐ Regulation will lead to large reductions
☐ Regulation will lead to moderate reductions
☐ Regulation will lead to small reductions
☐ Regulation will lead to very small reductions
☐ There will be no effective regulation of greenhouse gases
☐ Unsure

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3. How much of a burden do you expect climate change policies to impose on businesses over the next decade?

Please mark the alternative that comes closest to **your opinion**. (Only one alternative should be marked)

☐ Very heavy burden
☐ Heavy burden
☐ Moderate burden
☐ Light burden
☐ Very light burden
☐ Unsure

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4. If emissions are reduced, which do you think will be the major driver in reducing emissions – advances in technology or changing individual behavior?

Please mark the answer that comes closest to **your opinion**. (Only one alternative should be marked)

- ☐ Definitely technology
- ☐ Primarily technology
- ☐ Combination/both will be major drivers
- ☐ Primarily behavior
- ☐ Definitely behavior
- ☐ Neither will be a major driver
- ☐ Unsure

----

5. How difficult do you think it will be to significantly reduce global CO 2 emissions over the coming century using ALL current best available and appropriate approaches you consider (including conservation, efficiency, wide-scale deployment of renewables, fuel switching to less carbon-intensive fuels, and / or increased use of nuclear power)?

Please mark the statement that comes closest to **your opinion**. (Only one alternative should be marked)

- ☐ Very difficult
- ☐ Difficult
- ☐ Moderate
- ☐ Easy
- ☐ Very easy
- ☐ Unsure

----

6. How do you consider climate change to fit within your organization's overall portfolio of environmental concerns?

Please mark the answer that comes closest to **your opinion**. (Only one alternative should be marked)

- ☐ Top priority
- ☐ High priority
- ☐ One of many priorities
- ☐ Low priority
- ☐ Negligible
- ☐ Unsure

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7. Does your organization currently have a clear position on climate change (e.g., in the political debate over regulating emissions or in your organization's Environmental Management System)?

Please mark the answer that comes closest to **your opinion**. (Only one alternative should be marked)

☐ Yes, clearly formulated and publicly available
☐ Yes, clearly formulated but not publicly available
☐ Yes, but under review
☐ Discussions underway
☐ No, but intend to in near future
☐ No, no intention in near future
☐ Unsure

Carbon Capture and Storage (CCS)

General Questions

8. What term do you think is most appropriate for describing the technology for reducing CO2 emissions into the atmosphere by capturing CO2 from flue gas and injecting into the ocean or a geological reservoir?

Please mark **all** terms that you consider applicable, i.e. more than one term may be marked .

☐ Carbon sequestration

Carbon / Carbon dioxide capture and …

☐ sequestration
☐ storage
☐ disposal
☐ dumping

☐ Unsure

☐ Other, namely: _______________

9a. Are you familiar with the concept of Enhanced Oil Recovery (EOR)?

☐ Yes =>Go to Question 9b
☐ No =>Go to Question 10a

9b. If yes, how does this affect **your opinion** on CCS?

Please mark the alternative that best describe your opinion. (Only one alternative should be marked)

☐ Knowing of EOR gives a more favorable impression of CCS
☐ EOR does not affect view of CCS
☐ Knowing of EOR gives a more negative view of CCS

10a. Are you familiar with ongoing projects that inject carbon dioxide into reservoirs (e.g., Sleipner project in the North Sea, In Salah project in Algeria)?

☐ Yes =>Go to 10b
☐ No =>Go to 11a

10b. If yes, how does this affect **your opinion** on CCS?

Please mark the alternative that best describe your opinion. (Only one alternative should be marked)

☐ Knowing of these projects gives a more favorable impression of CCS
☐ These projects do not affect view of CCS
☐ Knowing of these projects gives a more negative view of CCS

11a. Do you think that large-scale adoption of CCS will increase the cost of electricity generated from fossil fuels?

☐ Yes, I think it will increase the cost significantly
☐ Yes, I think it will increase the cost a little
☐ No
☐ Unsure

11b. Which of the following options gives the best description of the relationship between the effect of CCS on electricity prices faced by consumers and penetration of other low-carbon alternative sources of energy such as renewables or nuclear?

Please mark the alternative that best describes **your opinion**.

Choose one answer in each column

	Renewables	Nuclear Energy
Increased adoption of CCS will encourage renewables / nuclear energy	☐	☐
Introduction of CCS will not influence the role of renewables / nuclear energy	☐	☐
Increased adoption of CCS will discourage renewables / nuclear energy	☐	☐
Unsure	☐	☐

Future of Carbon Capture and Storage

12. Which of the following statements coincides best with your view of the relationship between development of CCS and regulation of carbon dioxide and other greenhouse gases?

Please mark the statement that comes closest to **your opinion**. (Only one alternative should be marked)

☐ Advances in CCS will lead to more stringent regulation of greenhouse gases.
☐ More stringent regulation will lead to advances in CCS
☐ Advances in CCS will weaken efforts to introduce more stringent regulation of greenhouse gases
☐ Advances in CCS will have no relation with regulation of greenhouse gases
☐ Unsure

13a. How would you characterize the role that CCS plays in the current **national** climate change debate in **your country**?

Please mark the answer that comes closest to **your opinion**. (Only one alternative should be marked)

☐ Very large
☐ Large
☐ Moderate
☐ Small

☐ Very small
☐ Unsure

13b. Do you believe that the role of CCS is increasing or decreasing in the **national** climate change debate in **your country**?

Please mark the answer that comes closest to **your opinion**. (Only one alternative should be marked)

☐ Increasing substantially
☐ Increasing slightly
☐ Staying the same
☐ Decreasing slightly
☐ Decreasing substantially
☐ Unsure

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14. When do you think that it will be possible to receive credits for CCS in national accounting systems and/or emissions trading systems?

Please mark the answer that comes closest to **your opinion**. (Only one alternative should be marked)

☐ During the first commitment period of the Kyoto Protocol (2008-2012)
☐ In the second commitment period (2013-2016)
☐ Sometime between 12 and 20 years from now
☐ More than 20 years from now
☐ Will never receive credit for CCS
☐ Unsure

---

15. When do you think that large-scale entry of the following technologies in the electric power sector is likely?

Please mark for each technology the time frame that comes closest to your **belief**. Fill in one answer for each row.

	Within the next 10 years	In 20 years	In 50 years	Never
Carbon Capture and Storage	☐	☐	☐	☐
Solar energy	☐	☐	☐	☐

Fuel cells	☐	☐	☐	☐
Hydrogen power	☐	☐	☐	☐
Nuclear fusion	☐	☐	☐	☐
Tidal power	☐	☐	☐	☐

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16. How would you rate the social acceptability of different forms of CCS?

Please mark for each form of CCS the alternative that comes closest to **your opinion. Fill in one answer for each row**. (Please mark one alternative per row)

	Highly Unacceptable	Probably Unacceptable	Possibly Acceptable	Probably Acceptable	Highly Acceptable	Unsure
CCS in general	☐	☐	☐	☐	☐	☐
Onshore geological storage	☐	☐	☐	☐	☐	☐
Storage in geological reservoirs beneath the seabed	☐	☐	☐	☐	☐	☐
Dilution-type ocean storage*	☐	☐	☐	☐	☐	☐
Lake-type ocean storage**	☐	☐	☐	☐	☐	☐

* Storage of CO2 in the ocean by dispersion of CO2 to minimize degree of impact
** Storage in the ocean as liquid CO2 to isolate CO2 and minimize spatial extent of impact

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17. Which form of CCS did you consider to be most desirable or the least undesirable?

Please mark the answer that comes closest to **your opinion**. (Only one alternative should be marked)

☐ Onshore geological storage
☐ Offshore geological storage
☐ Geological storage in general (I do not prefer any particular type of geological storage)
☐ Dilution-type ocean storage
☐ Lake-type ocean storage
☐ Ocean storage in general (I do not prefer any particular type of ocean storage)
☐ CCS in general (I do not prefer any particular type of CCS)

----

18. Thinking of the form of CCS you chose in Q17, how would you compare the following electric power sector technologies to fossil-fired plants with carbon capture and storage for generating about the same amount of electricity? Please fill in one answer for each row.

	Much more preferable than CCS	More preferable than CCS	Similar to CCS	Less preferable than CCS	Much less preferable than CCS	Unsure
Natural gas turbines (without CCS)	☐	☐	☐	☐	☐	☐
Conventional coal power (without CCS)	☐	☐	☐	☐	☐	☐
Hydropower	☐	☐	☐	☐	☐	☐
Wind turbines	☐	☐	☐	☐	☐	☐
Nuclear power	☐	☐	☐	☐	☐	☐
Biomass/bioenergy	☐	☐	☐	☐	☐	☐
Solar power	☐	☐	☐	☐	☐	☐
Nuclear fission	☐	☐	☐	☐	☐	☐

19a. Still thinking of the form of CCS you chose in Q17, how serious do you consider the following risks to be for CCS?

Please mark for each risk the answer that comes closest to **your opinion. Fill in one answer for each row.**

	Very High risk	High risk	Medium risk	Low Risk	Negligible risk	Unsure	Insufficient Information
Water contamination	☐	☐	☐	☐	☐	☐	☐
Land/soil degradation	☐	☐	☐	☐	☐	☐	☐
Ecosystem impacts	☐	☐	☐	☐	☐	☐	☐
Human health impacts	☐	☐	☐	☐	☐	☐	☐
Sudden large scale release	☐	☐	☐	☐	☐	☐	☐
Other, namely	☐ ____	☐ ____	☐ ____	☐ ____	☐ ____	☐ ____	☐ ____

19b. Which do you believe to be the major sources of risk for CCS?

Please mark **all** concerns that you consider applicable, i.e. more than one term may be marked.

☐ Accidents in transport and handling
☐ Injection at storage sites
☐ Leakage from reservoirs

☐ Seismic activity
☐ Other: __________
☐ None of the above
☐ Unsure

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20. Thinking again of the form of CCS you chose in Q17, which of the following would you consider to be to be most significant concerns that would discourage wide-scale penetration of CCS?

Please mark **all** concerns that you consider applicable, i.e. more than one term may be marked.

Social Acceptability
☐ Acceptability to the wider public
☐ Acceptability to local publics
☐Acceptability to NGOs
☐Acceptability to the business community

Siting
☐ Equity or fairness in siting
☐ Finding suitable storage sites

Economics
☐ Economic viability (cost per ton of carbon dioxide abated)
☐ Capital costs (e.g., coal gasification plants or IGCC)

Technical and Institutional design
☐ Monitoring
☐ Accounting and securing credit for activities
☐ Emissions regulation and carbon pricing system (e.g., emissions cap and trading system)

Other
☐ Concerns over effects on other mitigation technologies (e.g., renewables)
☐ Concerns that will discourage efficiency & conservation
☐ Other: ________________
☐ None of the above
☐ Unsure

----

21. Which of the following would you consider to be to be most compelling persuasive reasons why if you would support wide-scale penetration of CCS in the future ?

Please mark all concerns that you consider applicable, i.e. more than one term may be marked.

Social Acceptability
- ☐ Acceptability to NGOs
- ☐ Acceptability to the business community

Political and geopolitical reasons
- ☐ Continued generation from fossil fuel
- ☐ Rapid growth in generation from fossil fuels in developing countries
- ☐ Energy security

Economics
- ☐ Economic viability (cost per ton of carbon dioxide abated)
- ☐ Maintains flexibility and options
- ☐ Allows for significant reductions relatively quickly

Technical and Institutional design
- ☐ Can be accomplished incrementally (i.e., can use existing infrastructure)
- ☐ Can build on existing activities (such as EOR)
- ☐ Preferable to competing technologies
- ☐ Technology is well-established

Other
- ☐ Other: ______________________
- ☐ Unsure
- ☐ No reason
- ☐ No persuasive reason to support CCS

Public Attitudes towards CCS

22. What would you think is the current attitude among the public toward CCS?

Please mark the statement that comes closest to **what you believe to be the public attitude**.
(Only one alternative should be marked)

- ☐ Very positive
- ☐ Moderately positive
- ☐ Ambivalent
- ☐ Moderately negative
- ☐ Very negative
- ☐ Largely ignorant
- ☐ Unsure

----

23. When would you expect that the public would begin to understand the issues associated with CCS?

Please mark the alternative that comes closest to **your opinion on public understanding**. (Only one alternative should be marked)

☐ Next few years
☐ Next few decades
☐ Only if CCS becomes controversial in the public arena
☐ Only when confronted with a local siting question
☐ Never
☐ Unsure

---

24. Would you expect that CCS would be more of a national policy question or more of a local siting question?

Please mark the statement that comes closest to **your opinion**. (Only one alternative should be marked)

☐ Primarily national
☐ Mostly national
☐ Mix/Both
☐ Mostly local
☐ Primarily local
☐ Unsure

---

25. To what extent do you believe that more information and public consultations would help ease potential public concerns over CCS?

Please mark the alternative that comes closest to **your opinion**. (Only one alternative should be marked)

☐ Public consultations and more information are likely to be very helpful
☐ Public consultations and more information are likely to be helpful
☐ Public consultations and more information may or may not be helpful
☐ Public consultations and more information are unlikely to be helpful
☐ Public consultations and more information are very unlikely to be helpful
☐ Not relevant since CCS should not be undertaken
☐ Unsure

Your Organization's Approach on CCS

26a. Does your organization currently have a clear position on CCS?

Please mark the alternative that comes closest to **your opinion**. (Only one alternative should be marked)

- ☐ Yes, it is positive toward CCS
- ☐ Yes, it is neutral toward CCS
- ☐ Yes, it is negative toward CCS
- ☐ No
- ☐ Discussions underway
- ☐ Unsure

26b. If "No" or "Discussions underway", what do you expect the future position of your organization is likely to be regarding CCS?

Please mark the alternative that comes closest to **your opinion**. (Only one alternative should be marked)

- ☐ Positive toward CCS
- ☐ Neutral toward CCS
- ☐ Negative toward CCS
- ☐ No position toward CCS likely to be taken
- ☐ Unsure

26c. Which of the following do you consider to be the major reason(s) for your organization's position on CCS?

Please mark all concerns that you consider applicable, i.e. more than one term may be marked.

Economic Considerations

- ☐ Cost-effectiveness of CCS as a climate change mitigation measure
- ☐ Costliness of CCS as a climate change mitigation measure
- ☐ Business opportunity
- ☐ Business risk
- ☐ Uncertainty
- ☐ Regulatory risk

Social and Environmental Considerations

- ☐ Other available measures for mitigating climate change are less effective

- [ ] Other available measures for mitigating climate change are more effective
- [ ] CCS would allow society to continue using fossil fuels
- [ ] Potential magnitude of CO_2 emission reductions from CCS
- [ ] CCS would discourage other climate change mitigation measures such as renewables
- [ ] Risk to the environment
- [ ] Risk to human health

Other
- [ ] Other: ________________
- [ ] Unsure

----

27. How do you assess current attitudes toward CCS among colleagues within your organization?

Please mark the alternative closest to **your opinion**. (Only one alternative should be marked)
- [ ] Very positive
- [ ] Moderately positive
- [ ] Ambivalent
- [ ] Moderately negative
- [ ] Very negative
- [ ] Largely ignorant
- [ ] Unsure

28a. Do you think there is any new information or event that might change your organization's current attitude towards CCS?

Please mark the statement that comes closest to **your opinion**. (Only one alternative should be marked)

- [ ] Very unlikely
- [ ] Unlikely
- [ ] Ambivalent
- [ ] Quite possible
- [ ] Very possible
- [ ] Unsure

28b. If so, what sort of information or event might change those attitudes?

____

____

Demographics

29. What is your organization's primary function?

☐ Chemical
☐ Electricity
☐ Oil & Gas
☐ Steel
☐ Automotive
☐ Other Manufacturing
☐ Media
☐ NGO
☐ Research
☐ Other: ______________________

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30. What country are you located in?

☐ Austria
☐ Belgium
☐ Canada
☐ Denmark
☐ Finland
☐ France
☐ Germany
☐ Italy
☐ Netherlands
☐ Norway
☐ Poland
☐ Portugal
☐ Spain
☐ Sweden
☐ Switzerland
☐ United Kingdom
☐ United States
☐ Other: ______________________

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31. Please indicate whether you would be willing to participate in a short followup to discuss matters arising out of the questionnaire and to allow you to elaborate on your answers?

☐ Yes
☐ No

Preferred form of contact:

Tel: ______________________________
Email: ______________________________
Fax: ______________________________

SUBMIT Answers　　　　See Summary

Thank you for your time and participation!