ASSESSMENT OF RISK, LEGAL ISSUES, AND INSURANCE FOR GEOLOGIC CARBON SEQUESTRATION IN PENNSYLVANIA

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DEPARTMENT OF CONSERVATION AND NATURAL RESOURCES
Global warming is the most significant environmental problem facing the world today - one that threatens our environment, our economy, public health, and our way of life. The overwhelming scientific consensus is that the earth's climate is changing rapidly due to the atmospheric buildup of human-generated, heat-trapping emissions, primarily carbon dioxide pollution from power plants and automobiles.

Pennsylvania produces more greenhouse gas emissions than 105 developing countries combined. According to the National Environmental Trust, Pennsylvania emits 1 percent of the entire planet's human-caused global warming gases, and ranks third among all states in global warming emissions. The Commonwealth therefore has a special responsibility to take common sense, meaningful action to reduce global warming pollution.

Pennsylvania is also the 4th largest coal producing state in the United States. More than 40 percent of the state’s electricity is coal-fired, and 30 percent of the energy generated in Pennsylvania is exported to other states. If the Commonwealth is to reduce its global warming emissions, it must find ways to burn coal as cleanly as possible.

How will the state’s economy adapt under the imposition of federal carbon emission constraints? What steps does the Commonwealth need to take now to ensure environmental and economic sustainability as the world confronts the challenges of climate change?

There is certainly no single answer to those questions. Clearly, a portfolio of approaches, policies, and technologies will be required to confront the challenges of a carbon constrained world. Governor Rendell and the General Assembly have made Pennsylvania a national leader in renewable energy development and in energy conservation and energy efficiency. Those initiatives will significantly reduce the Commonwealth’s emissions of global warming gases. But there is more work to do.

One technology that offers great promise and that is particularly appropriate for consideration by the Commonwealth is carbon capture and sequestration (CCS) - a process of capturing carbon dioxide emissions from coal-fired electric power plants and other industrial facilities to prevent them from going into the atmosphere, and then storing them permanently underground in safe geological formations.
According to the Midwest Regional Carbon Sequestration Partnership (MRCSP), Pennsylvania has an estimated geologic capacity to store hundreds of years’ worth of carbon emissions at present rates. If that resource can be proven, and appropriately and safely developed along with all of the other technological requirements of CCS, the Commonwealth may be able to substantially reduce its global warming emissions and protect our environment, our economy, and public health - while preserving its position as a net energy exporter and creating jobs in the process.

The focus of this report, prepared by Tetra Tech under contract to the Department of Conservation and Natural Resources (DCNR) as the second of three reports required of DCNR by Act 129 of 2008, is an assessment of the risks associated with CCS in Pennsylvania and potential means to mitigate them. It follows a report issued by DCNR on May 1, 2009 on Geologic Carbon Sequestration Opportunities in Pennsylvania. A separate cost study of a state CCS network will complete DCNR’s work in complying with Act 129.

These reports, along with DCNR’s Report of the Carbon Management Advisory Group published in May, 2008, are a part of DCNR’s continuing contribution to the formation of Pennsylvania’s policy response to the challenges of reducing the Commonwealth’s global warming emissions and building a sustainable economy for our state.

There are many unanswered questions and concerns about an emerging technology like CCS. Given the magnitude of the challenge of reducing carbon dioxide emissions to avoid catastrophic impacts of climate change, it is essential that we explore the possibilities with the sense of urgency that the problem demands.

I would like to thank the team of professionals assembled by Tetra Tech for their thorough, comprehensive, and high quality work. Tetra Tech displayed a unique ability to tackle this multi-faceted task in a highly professional manner while meeting the ambitious schedule of Act 129.

I also want to acknowledge and thank the women and men of DCNR’s Bureau of Topographic and Geologic Survey for their continued excellence and professionalism in assisting in the preparation of this report.

John Quigley
Acting Secretary
Pennsylvania Department of Conservation and Natural Resources

2 http://www.dcnr.state.pa.us/info/carbon/mastercstareport2.pdf
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<td>ac</td>
<td>acres</td>
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<tr>
<td>ACESA</td>
<td>American Clean Energy and Security Act of 2009</td>
</tr>
<tr>
<td>AEGL</td>
<td>acute exposure guideline</td>
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<td>AEGL</td>
<td>Alternative Energy Portfolio Standards Act</td>
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<td>ALOP</td>
<td>Advance Loss of Profits</td>
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<td>ANI</td>
<td>American Nuclear Insurers</td>
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<td>ANPR</td>
<td>Advance Notice of Proposed Rulemaking</td>
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<td>AoR</td>
<td>area of review</td>
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<tr>
<td>BACT</td>
<td>best available control technology</td>
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<tr>
<td>BAR</td>
<td>Builders’ All Risk</td>
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<tr>
<td>BI</td>
<td>Business Interruption</td>
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<tr>
<td>BLM</td>
<td>Bureau of Land Management</td>
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<tr>
<td>CAES</td>
<td>compressed air energy storage</td>
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<tr>
<td>CAR</td>
<td>Construction All Risk</td>
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<tr>
<td>CBM</td>
<td>coalbed methane</td>
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<td>CCS</td>
<td>CO₂ capture and sequestration</td>
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<tr>
<td>CERCLA</td>
<td>Comprehensive Environmental Response, Compensation, and Liability Act</td>
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<tr>
<td>CIAB</td>
<td>Coal Industry Advisory Board</td>
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<tr>
<td>CO₂</td>
<td>carbon dioxide</td>
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<td>CPM</td>
<td>computerized pipeline monitoring</td>
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<td>CSL</td>
<td>Clean Streams Law</td>
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<td>CSLF</td>
<td>Carbon Sequestration Leadership Forum</td>
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<tr>
<td>CSM</td>
<td>conceptual site model</td>
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<tr>
<td>CSN</td>
<td>carbon sequestration network</td>
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<td>CSP</td>
<td>carbon storage project</td>
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<tr>
<td>DCNR</td>
<td>Department of Conservation and Natural Resources</td>
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<tr>
<td>DECC</td>
<td>Department of Energy and Climate Change</td>
</tr>
<tr>
<td>DEP</td>
<td>Department of Environmental Protection</td>
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<tr>
<td>DEQ</td>
<td>Department of Environmental Quality</td>
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<tr>
<td>DNV</td>
<td>Det Norske Veritas</td>
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<tr>
<td>DOE</td>
<td>United States Department of Energy</td>
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<td>DOT</td>
<td>Department of Transportation</td>
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<tr>
<td>DSU</td>
<td>Delay in Start-Up</td>
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<tr>
<td>EAR</td>
<td>Engineering All Risk</td>
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<tr>
<td>EGU</td>
<td>electricity generating unit</td>
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<td>EIA</td>
<td>Energy Information Administration</td>
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<td>EOR</td>
<td>enhanced oil recovery</td>
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<tr>
<td>EPA</td>
<td>Environmental Protection Agency</td>
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<tr>
<td>EPC</td>
<td>engineering, procurement, and construction</td>
</tr>
<tr>
<td>EU</td>
<td>European Union</td>
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<tr>
<td>FEP</td>
<td>Features, Events, and Processes</td>
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<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<td>ft</td>
<td>feet</td>
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G8     Group of Eight
GCCSI  Global Carbon Capture and Storage Institute
GHG    greenhouse gas
GIS    Geographic Information System
gpm    gallons per minute
GS     geologic sequestration
GSFA   geologic sequestration financial assurance
GT     gigaton
H₂S    hydrogen sulfide
H/D    height and diameter
HSCA   Hazardous Sites Cleanup Act
ICA    Interstate Commerce Act
ICC    Interstate Commerce Commission
IDLH   immediately dangerous to life or health
IEA    International Energy Agency
IGCC   integrated gasification combined cycle
IOGCC  Interstate Oil and Gas Compact Commission
IPCC   Intergovernmental Panel on Climate Change
IRIS   Integrated Risk Information System
km     kilometer
km²    square kilometers
LPG    liquefied petroleum gas
m      meters
MAA    Municipal Authorities Act
MDSU   Marine Delay in Start-Up
MEA    monoethanolamine
mg/L   milligram per liter
MGSC   Midwest Geological Sequestration Consortium
mi     miles
mi²    square miles
MIT    Massachusetts Institute of Technology
MMBtu  million British Thermal Units
MMT    million metric tons
MMV    monitoring, measurement, and verification
MRCSP  Midwest Regional Carbon Sequestration Partnership
MT/yr  million tons per year
MVA    monitoring, verification, and accounting
MW     megawatt
NEPA   National Environmental Policy Act
NFR    naturally fractured reservoir
NGA    Natural Gas Act
NGO    nongovernmental organization
NIOSH  National Institute of Safety and Health
NODA   Notice of Data Availability
NPDES  National Pollution Discharge Elimination System
NPL    National Priority List
<table>
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<td>VEF</td>
<td>vulnerability evaluation framework</td>
</tr>
<tr>
<td>VHM</td>
<td>volcanic/hydrothermal/metamorphic</td>
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<tr>
<td>VSP</td>
<td>vertical seismic profiling</td>
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<tr>
<td>WCI</td>
<td>Western Climate Initiative</td>
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<tr>
<td>WIS</td>
<td>Well Information System</td>
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<tr>
<td>WPFF</td>
<td>Working Party for Fossil Fuels</td>
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<td>WRI</td>
<td>World Resources Institute</td>
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1.0 INTRODUCTION

Anthropogenic emissions of carbon dioxide (CO₂), a greenhouse gas (GHG), are considered to be a major contributor to global climate change. Approximately 41% of the GHG emissions in the U.S. are produced from electricity generation (EPA, 2009a). Worldwide energy demands are expected to increase by more than 60 percent by 2030 (Maddox, 2005). In the United States, a large portion of this demand may be met using coal, due to its abundance and low cost compared to other fuels. Unless preventive measures are taken to mitigate coal-fired power production emissions, it is predicted that anthropogenic CO₂ emissions will increase substantially.

Stabilization of atmospheric CO₂ levels is a global problem that will require global cooperation to solve. The following three options have been identified to achieve stabilization and are the focus of research and development (R&D) efforts worldwide:

- Improving efficiency of power generation and consumption.
- Utilizing alternative fuel sources that are less carbon-intensive than those currently in use.
- Capturing CO₂ from the atmosphere or its source and permanently sequestering it.

Geologic carbon capture and sequestration (CCS) involves the capture of CO₂ from a point source (such as a power plant), transporting it to a suitable reservoir, and permanently storing it. CCS is not presently practiced at a commercial scale in the United States; however, it is anticipated that future government regulations may limit CO₂ emissions, creating CCS project opportunities. In anticipation of these potential regulations, R&D is currently underway to find safe and efficient ways to capture and store CO₂ while minimizing the cost that would be passed to electricity rate payers.

This report provides an assessment of the risks, legal issues, and insurance issues associated with future statewide geologic sequestration of CO₂ in Pennsylvania. This assessment was performed as required by Pennsylvania Act 129 and is a follow-up to the Pennsylvania Department of Conservation and Natural Resources (DCNR) report “Geologic Carbon Sequestration Opportunities in Pennsylvania” (DCNR, 2009).

1.1 Act 129

Pennsylvania House Bill 2200, signed into law by Governor Rendell as Act 129 of 2008 on October 15, 2008, became effective on November 14, 2008 and addresses two primary areas: (1) adoption of energy efficiency and conservation measures; and (2) expanding the use of alternative energy. In addition, Act 129 contains several other provisions, including a requirement that DCNR undertake an assessment of carbon sequestration potential within the Commonwealth of Pennsylvania. Act 129 identified the following milestones for DCNR’s completion of this assessment:

- April 1, 2009 – Completion of a study identifying geological formations (including within, or proximate to, the Medina, Tuscarora, or Oriskany sandstone formations) suitable for a state sequestration network.
• May 1, 2009 – Submission of a report detailing the study identifying the geological formations suitable for a state sequestration network.
• June 1, 2009 – In consultation with the Public Utilities Commission (PUC), hiring of an independent consultant to assess capital requirements, safety considerations, and potential risks to individuals, property, and the environment associated with geologic CO₂ sequestration.
• October 1, 2009 – Completion of the assessment of capital requirements, safety considerations, and potential risks to individuals, property, and the environment associated with geologic CO₂ sequestration.
• November 1, 2009 – Submission of a report detailing the assessment of capital requirements, safety considerations, and potential risks to individuals, property, and the environment associated with geologic CO₂ sequestration.

Act 129 requires that reports be submitted to the Governor and the Chairmen and Minority Chairmen of the Environmental Resources and Energy Committee of both the Pennsylvania Senate and House of Representatives. Following the review of the independent consultant’s report, DCNR may undertake a pilot project to determine the viability of establishing a state network for CO₂ sequestration within Pennsylvania.

1.2 Summary of Previous Work

The U.S. Department of Energy (DOE) (DOE, 1999) identified four types of subsurface geologic sequestration targets: (1) deep saline formations; (2) oil and gas fields; (3) unmineable coal beds; and (4) carbonaceous shales. Regardless of the type of reservoir, several critical factors were used to determine the adequacy of a reservoir, including, but not limited to, the following:

- Depths greater than 2,500 feet (ft) (762 meters[m]) below ground surface.
- Adequate overlying confining units (also known as cap rock).
- Sufficient storage capacity (due to void space or porosity).
- Favorable structural or stratigraphic features (e.g., anticlinal folds)
- Extremely low fluid and gas flow velocities that limit mass transport
- Minimal intrusions (e.g., deep wells) to limit potential unwanted pathways (short circuiting) to the surface, which would compromise the CO₂ sequestration effort.

In accordance with the Section 2815 of Act 129 of 2008, DCNR prepared a report describing geologic carbon sequestration opportunities in the Commonwealth (DCNR, 2009). In this report, DCNR determined that, based on a preliminarily “desktop” assessment of available geographic and geologic data, the Commonwealth of Pennsylvania can support a subsurface carbon storage and sequestration network. The intent of this network would be to reduce the amount of GHGs, particularly CO₂, that are discharged into the atmosphere from point sources such as coal-fired power plants prevalent in Pennsylvania. To be effective, this storage network should be able to store large quantities (i.e., millions of tonnes annually) of CO₂ over a widespread area. The results of the DCNR report (2009) were consistent with previous reports such as the Midwest Regional Carbon Sequestration Partnership (MRCSP)’s Phase I evaluation.
indicating that Pennsylvania has a large potential capacity for CO\textsubscript{2} sequestration (DOE, 2004), which could accommodate Pennsylvania’s CO\textsubscript{2} emissions for approximately 300 years. The total amount of potential CO\textsubscript{2} sequestration capacity for Pennsylvania is estimated at 97.6 billion short tons (tons) [88.5 billion tonnes (t)]. This storage capacity is estimated to largely reside in deep saline formations (approximately 85 percent of the total), with smaller portions in carbonaceous shales (approximately 14 percent), oil and gas fields (less than 1 percent), and unmineable coal seams (less than 0.5 percent). The percentage of CO\textsubscript{2} sequestration capacity in salt beds was not specifically addressed in this particular research effort, however, the DCNR study (2009) did suggest that further evaluation of these formations are important and should be considered in future studies.

Deep saline formations are promising geologic sequestration targets because they are generally widespread, thought to have relatively large pore volumes, and are believed to be moderately thick across Pennsylvania. These formations are favorable for injection and sequestration of CO\textsubscript{2} because of the ability to inject gases and/or fluids into the formations, anticipated reservoir integrity, and adequate geochemical conditions for sequestration. Salt caverns (voids) derived from solution mining may also provide significantly more storage capacity than porous saline formations with similar integrity; however, there are no cavern networks currently developed in Pennsylvania that can be used for geologic sequestration. Conversely, despite the significantly lower percentage in storage capacity of carbonaceous shale formations and oil and gas fields, these units are plentiful and the incentive to utilize these formations as sinks may be driven by enhanced natural gas and oil production using CO\textsubscript{2}. In carbonaceous shale and oil and gas fields, the injected CO\textsubscript{2} is used to displace the gas or oil that has reached asymptotic extraction performance using conventional drilling approaches. Enhanced oil recovery (EOR) techniques using CO\textsubscript{2} as a recovery agent have been used successfully since the 1980s. Using CO\textsubscript{2} as an agent is ideal because its density is similar to that of oil but its viscosity is lower, allowing CO\textsubscript{2} to flow through the reservoir rock and displace the oil to recovery wells. After the oil is displaced, the CO\textsubscript{2} remains in pore spaces under the same cap rock that retained the natural oil or gas. Carter et al, (2009) reported that while Act 129 of 2008 strictly prohibits the inclusion of EOR as a valid sequestration technique, it is an approach that has been adopted in numerous parts of the world to not only sequester the carbon but also enhance the recovery of hydrocarbons such as oil and gas.

Based on current data available across Pennsylvania, the following four potential sequestration reservoirs were selected for further evaluation (from oldest to youngest): (1) the Lower Silurian Medina Group/Tuscarora Sandstone; (2) the Upper Silurian Salina Group; (3) the Lower Devonian Oriskany Sandstone; and (4) Upper Devonian sandstone reservoirs. These formations are described by DCNR (2009) and are described in greater detail in Section 2.

DCNR (2009) noted that these four potential sequestration reservoirs were not inclusive of all potential sequestration reservoirs in Pennsylvania and that further evaluation should be conducted to identify others. The report findings, along with data obtained from DCNR’s Wells Information System (WIS) database, indicate that there is a limited amount of deep geologic information available in the Commonwealth. For example,
there is a bias in the quality and amount of data in the western and north-central sections of Pennsylvania due to previous coal, oil, and gas exploration. Other areas of the commonwealth lack the data needed to determine possible reservoirs. In particular, additional data collection is needed (and is currently underway) to improve the understanding of potential CO₂-storage reservoirs in the central and eastern portions of Pennsylvania.

The report concluded that additional work is needed to better understand a number of other important factors beyond geologic assessments and site characterization required to support a CO₂ sequestration project and network, including the following:

- An economic analysis.
- A risk assessment evaluation to identify both perceived and real risk factors regarding exposure pathways for environmental and human health.
- Quantification of identified risks that would require insurance for potential restoration.
- Monitoring, measurement, and verification (MMV) requirements to determine the performance of a sequestration project.
- Community interaction and outreach required to convey the operation of a CO₂ sequestration network to the community.

1.3 Scope of Report

The recommendations made in the DCNR (2009) report are being addressed in this report. As described in the following sections a detailed risk assessment of geologic carbon sequestration in Pennsylvania is included in this report. A discussion of potential salt caverns storage capacity and the feasibility review of saline aquifer storage are included as well. The report also evaluates legal liabilities and ownership issues related to geologic sequestration. The risk assessment identifies and evaluates potential risks, including their probability of occurring and the environmental and economic consequences, should they occur.
2.0 CARBON DIOXIDE STORAGE SITE ASSESSMENT

2.1 Introduction

2.1.1 Background

DCNR produced a report titled “Geologic Carbon Sequestration Opportunities in Pennsylvania,” which was finalized in August 2009 in accordance with the Section 2815 of Act 129 of 2008. In this report, DCNR determined that, based upon a desktop assessment of available geographic and geologic data, the Commonwealth can support a subsurface carbon storage and sequestration network. The intent of this storage network is to reduce the amount of GHGs, particularly CO$_2$, that are discharged into the atmosphere from point sources such as coal-fired power plants, which are very common in Pennsylvania. In order to be effective, this storage network should be able to store large quantities (i.e., millions of tons annually) of CO$_2$ over a widespread area. Specifically, this report identified four potential reservoirs and listed recommendations for additional characterization of these reservoirs as well as others that may exist in the Commonwealth.

2.1.2 Purpose

The purpose of this document is to identify potential risks that may be associated with subsurface storage of CO$_2$. In order to properly evaluate potential risks, however, a clear understanding of the geology is paramount. The purpose of this particular section is twofold. First, to present results of Tetra Tech’s review of DCNR’s August 2009 report. Secondly, to summarize Tetra Tech’s further evaluation of the potential storage reservoirs identified by the DCNR and to present findings of research into other potential storage reservoirs.

2.1.3 Format

The evaluation of the potential reservoirs has been separated into two sections, Salt Cavern Analysis and Saline Formation Analysis. In general, each of these sections presents existing information, conceptual site models, applicability for use and data gaps. In addition, this section discusses estimating capacity for carbon sequestration as well as potential impact of carbon sequestration on oil and gas exploration and development. Recommendations for further data collection and evaluation are presented at the end of this section. Prior to discussing in detail the potential for salt cavern and saline formations for CO$_2$ storage, the following is an overview of the geology of Pennsylvania and findings of the DCNR report.

2.2 Geology of Pennsylvania

The evaluation of potential storage units includes several units of various depths and various geologic ages. This section summarizes the general geology of the Pennsylvania and provides a stratigraphic column to assist the reader with the relative position of the identified units presented below.
2.2.1 Summary of Geologic Provinces

The geology of Pennsylvania is relatively complex and is significantly different across the Commonwealth. Pennsylvania has been divided into five geologic provinces which are illustrated in Figure 2-1. The Appalachian Plateau Province is the largest and includes nearly 50 percent of the Commonwealth. This province includes the western and northern portion of the Commonwealth. The Ridge and Valley Province is the second largest province and extends from the south-central portion of the Commonwealth to the east-central portion. The Reading Prong Province, the smallest province, is located in the eastern portion of the Ridge and Valley Province and is somewhat discontinuous. The Piedmont Province is located in the south-east corner of the Commonwealth and is the third largest province. The Gettysburg-Newark Basin Province is located between the Piedmont and Ridge and Valley provinces in the south-eastern portion of the Commonwealth. The DCNR presented a good summary of the five geologic provinces in its August 2009 report which is excerpted below:

Appalachian Plateau Geologic Province

“The Appalachian Plateau Province is an area of broad undulatory uplands, rounded hills, and narrow steep-sided valleys across western and northern Pennsylvania (DCNR, 2009).”
“The sedimentary bedrock underlying this region is about 5,000 ft (1,524 m) thick near Lake Erie, and increases steadily to 25,000-30,000 ft (7,620-9,144 m) thick at the boundary with the Ridge and Valley Geologic Province to the south and east…. The rock layers beneath the Appalachian Plateau are relatively flat-lying with only broad, gentle folds. There are some faults several thousand feet below the surface; however, these only locally disturb the rocks at depth (DCNR, 2009).”

**Ridge and Valley Geologic Province**

“This region forms a curving band through the central part of Pennsylvania from the Maryland border to the Delaware River. It is underlain by a variety of sandstone, shale, and limestone layers reaching a total thickness of 35,000 ft (10,668 m) or more. The sedimentary bedrock is complexly folded and faulted. The long, sinuous ridges that characterize the topography of this region are held up by resistant sandstone layers that trace the complex outlines of the folds. The ridges are separated by broad valleys underlain by limestone. The same Cambrian to Devonian-age layers that are buried thousands of feet deep under the Plateau are exposed at the surface in the Ridge and Valley…. As this region was squeezed from the southeast during mountain-building events, rock layers deep in the stratigraphic section broke along faults, which carried stacks of rock toward the northwest and placed them above adjacent stacks of the same rock layers. Consequently, the older rock layers that were originally deep in the section are repeated vertically several times, creating great thicknesses of sedimentary rock even though the upper parts of the section have been removed (DCNR, 2009).”

**Reading Prong**

“This small geologic province in eastern Pennsylvania consists of a series of fault slices of metamorphic rock that is primarily granite-like in composition, probably several thousand feet thick. Although they are older than the sedimentary rocks of the Ridge and Valley Province, these rocks have been raised up and moved along thrust faults so that they now lie on top of the sedimentary rocks (DCNR, 2009).”

**Gettysburg-Newark Basin**

“This province is a relatively narrow band that extends from Adams County in the southwest to Bucks County in the northeast. It is an asymmetric basin with its deepest part (about 15,000 ft [4,572 m]) towards the north side. The basin formed as the continent of Africa pulled away from North America, stretching the Earth’s crust and causing a series of blocks to drop along large faults. River systems developed in the lowlands formed by the downdropped blocks. Sediments from these rivers and lakes filled the basin, and became the sandstones, shales, and conglomerates that we find in the area today. Dikes (cutting across the...
sedimentary layers) and sills (parallel to the sedimentary layers) of diabase are irregularly interspersed with the sedimentary rocks. Diabase is an igneous rock similar to the basalt that is erupted out of volcanoes like those in Hawaii today. The dikes may only be a few feet across, but the sills are up to 2,000 ft (610 m) thick. All the rocks in this basin are of Jurassic and Triassic age (much younger than the other sedimentary rocks in Pennsylvania). There were probably volcanoes in Pennsylvania in the Jurassic, but they have been eroded away and the rocks that cooled underground are all we see now (DCNR, 2009).”

Piedmont Geologic Province

“The Piedmont occupies the southeastern corner of Pennsylvania. This subdued landscape of rolling hills and shallow valleys is underlain by a variety of metamorphic rocks – schist, gneiss, quartzite, marble, and serpentinite. These rocks are complexly folded and faulted. The distribution of rock types has been mapped at the surface. Little subsurface exploration has been done in this province, however, and geologic structures are poorly understood at depths beyond about 1,000 ft (305 m) (DCNR, 2009).”

2.2.2 Summary of Subsurface Geology

Figure 2-2 presents a subsurface rock correlation diagram for western and central Pennsylvania (Carter et al, 2007). Several geologic units are highlighted in the diagram as potential targets for CO₂ storage. They include the following listed chronologically from oldest to youngest:

- Basal sandstones including the Potsdam Sandstone – Cambrian System
- Upper Sandy member of the Gatesburg Formation – Upper Cambrian Series
- Medina Group (Whirlpool and Grimsby formations) and Tuscarora Sandstone – Lower Silurian
- Salina Group (Units A1, A2, B, D, E, F, and G) – Upper Silurian
- Bass Islands Group – Upper Silurian
- Oriskany Sandstone – Lower Devonian
- Upper Devonian Sandstones

Figure 2-3 presents a generalized geologic cross section from east-west through the southern portion of Pennsylvania. The cross section passes through all of the geologic provinces of the state except for the Reading Prong and identifies the age of the rocks which are present across the state in these provinces. Also shown are general characteristics of the rocks by age (e.g., whether they contain coal, saline formations and/or salt). The western portion of the Commonwealth is located in the Appalachian Plateau geologic province. As indicated, rock at the surface is mostly of Pennsylvanian and Mississippian age, with some limited outcrops of Devonian-age rocks. The subsurface geology in this province is defined by relatively horizontal beds with no significant surface geologic structure. Faults in this area are relatively deep and do not
extend to the ground surface. This is contrary to the subsurface geology observed in the Ridge and Valley Province. The rock in this province is highly folded and faulted, and outcrops of various aged rock, from Cambrian to Devonian, are present. Geologic units in this province can be encountered vertically multiple times due to thrust faulting. As shown on the cross section, the faults in this province extend to the ground surface. The Gettysburg-Newark Lowland does not show any significant folding or faulting, mostly due to the fact that the rocks are much younger than others in the Commonwealth. The eastern portion of the cross section ends in the Piedmont Province, which is characterized by Precambrian aged metamorphic rocks that crop out in complex patterns.

2.3 DCNR August 2009 Report

2.3.1 Report Summary

DCNR identified, up to five types of subsurface geologic reservoirs or “sinks” as present in Pennsylvania and that may store sufficient quantities of CO$_2$. These include: (1) deep saline formations; (2) oil and gas reservoirs; (3) unmineable coal beds; (4) carbonaceous shales; and (5) thick salt-beds. Regardless of the type of reservoir, several critical factors were evaluated to determine its adequacy. These factors included, but were not limited to, formations present at depths greater than 2,500 ft (762 m) below ground surface (in accordance with DOE guidance); formations with adequate overlying confining units (cap rock); formations with sufficient storage capacity (due to void space or porosity); formations with favorable structural or stratigraphic features (e.g., anticlinal folds); formations with extremely low fluid and gas flow velocities that limit mass transport; and formations with minimal intrusions (e.g., deep wells) that will minimize potential unwanted pathways (short circuiting) to the surface, thereby compromising the natural integrity to sequester CO$_2$.  

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Figure 2-2. General Western Pennsylvania stratigraphy showing potential sequestration reservoirs (Adapted from Carter, 2007)
Figure 2-3. Generalized geologic cross section
The results of MRCSP Phase I evaluation indicated that Pennsylvania has a large potential capacity for CO$_2$ sequestration. The total storage option alone could accommodate Pennsylvania’s CO$_2$ emissions for roughly three hundred years. The total amount of potential CO$_2$ sequestration capacity for Pennsylvania is estimated at 97.6 billion short tons (T). This storage capacity is estimated to largely reside in the deep saline formations (approximately 85 percent of the total), with smaller portions in carbonaceous shales (approximately 14 percent), oil and gas fields (less than 1 percent), and unminable coal seams (less than 0.5 percent).

Saline formations provide large storage capacities because they are widespread, thought to have large pore volumes, and are believed to be moderately thick across Pennsylvania. These formations are attractive because of injectivity, reservoir integrity, and they provide adequate geochemical sequestration. Salt caverns (voids) derived from solution mining can provide significantly more storage capacity per square mile over porous saline formations while having similar integrity. However, there are no cavern networks currently developed in Pennsylvania that can be used for geologic sequestration.

Despite the significantly lower percentage in storage capacity of carbonaceous shale formations and oil-and-gas fields, these units are plentiful and the incentive to utilize these formations as sinks is driven by enhanced natural gas and oil production using CO$_2$ recovery techniques. In carbonaceous shale and oil-and-gas fields, the injected CO$_2$ is used to displace the gas and/or oil that have reached asymptotic extraction performance using conventional drilling approaches. EOR techniques using CO$_2$ as a recovery agent have been used successfully since the late 1960’s. Using CO$_2$ as an agent is ideal because its density is similar to that of oil, but its viscosity is lower, allowing flow of CO$_2$ through the reservoir rock and displacing the oil to recovery wells. Once the oil is displaced the CO$_2$ remains in the pore space under the same cap rock that retained the natural oil or gas.

Based upon current data available across Pennsylvania, the report identified four potential sequestration reservoirs for further evaluation. These formations include (from oldest to youngest) (1) the Lower Silurian Medina Group/Tuscarora Sandstone; (2) the Upper Silurian Salina Group; (3) the Lower Devonian Oriskany Sandstone; and, (4) Upper Devonian, Venango Group sandstone. Each of these are described in greater detail in Section 2.5.

The report noted that these four potential sequestration reservoirs were not inclusive of all potential reservoirs in Pennsylvania and that further evaluation was recommended to identify others. One limitation of the evaluation is that there is a limited amount of deep geology data available across the Commonwealth. For example, there is a bias in quality and amount of data in the western and north-central sections of Pennsylvania due to coal, oil, and gas exploration, whereas other areas lack the data needed to determine other possible reservoirs. In particular, additional data collection is needed (and is currently underway) to better understand potential CO$_2$ storage reservoirs in the central and eastern part of Pennsylvania.
2.4 Salt Cavern Evaluation

2.4.1 Historical Use

Salt cavern storage of both liquid and gases was reportedly first used in Canada in the early 1940s. Storage of Liquefied Petroleum Gas (LPG) and other light hydrocarbons (e.g., ethane, propane, butane) in salt caverns spread rapidly in the early 1950s in North America and Europe. Currently, salt caverns in Texas provide 58 percent of the total storage of light hydrocarbons in the United States and Canada, forming a "market hub" for LPG in North America. Storage of crude oil or unrefined petroleum was first reported in the early 1950s in England. The United States began to store its Strategic Petroleum Reserve (SPR) in 1978 and now has approximately 563 million barrels of crude oil stored in five salt caverns in Texas and Louisiana. Salt cavern storage for natural gas started in the 1970s when two gas caverns were constructed in Mississippi. According to the Energy Information Administration (EIA), as of July 2009, 299.945 million cubic feet of natural gas is stored in salt caverns, which consists of 4 percent of the total natural gas in storage in the United States (2009). Salt caverns have also been used for Compressed Air Energy Storage (CAES), first implemented in Germany in 1978. In the United States, a CAES plant was constructed in 1991 near Mobile, Alabama.

Using salt caverns for waste disposal began in 1959 when alkali wastes from local “soda ash” production were deposited in “worked out” caverns in England. In the United States, nine salt cavern facilities have been permitted to dispose of non-hazardous oil field wastes in the past few years. Two of these facilities are also permitted to dispose of hazardous oil field wastes. However, such use of salt caverns is still subject to significant public objections and lengthy examination processes in the United States (Thoms and Gehle, 2000). The potential to store CO$_2$ in salt caverns has been investigated by many researchers (e.g., Dusseault et al., 2001; IPCC, 2005); however, there are currently no pilot-scale or demonstration projects for this type of storage.

2.4.2 Considerations in Utilizing Salt Caverns for CO$_2$ Storage

Salt caverns are formed through solution mining process in which fresh water is injected into salt deposits to dissolve salt, and the resulting brine solution is removed leaving a void space (i.e., salt caverns). Depending on the size and thickness of salt deposits, salt caverns can be formed in either salt domes (i.e., large nearly homogeneous formations of salt) or bedded salts (i.e., interbedded salt layers and other materials such as anhydrite, shale, and dolomite). Salt caverns are widely used for storage purposes because (1) pure salt is essentially impermeable and (2) the walls of a salt cavern have the structural strength of steel, making them very resistant to reservoir degradation.

Of the materials currently stored in salt caverns, natural gas is the closest to CO$_2$ in physical properties. For natural gas, the types of underground storage include depleted gas reservoirs, saline formations, and salt caverns. Among these, salt caverns provide the least storage capacity nationwide. As stated previously, natural gas stored in salt caverns consists of only 4 percent of the total natural gas storage in the United States (EIA, 2009). There are two main reasons for this for this low percentage. First, salt caverns are typically much smaller than depleted gas reservoirs and aquifers. In fact, underground
salt caverns usually take up only 1/100 of the acreage taken up by a depleted gas reservoir. Although the unit storage volume of an individual salt cavern is high (i.e., the volume is not subject to the porosity of underground formations), the total volume of an individual salt cavern is much lower than the other storage formations because of the size differences. Although multiple salt caverns can be developed, suitable salt deposits may not be readily available. In fact, existing salt cavern storage facilities are primarily located along the Gulf Coast (salt domes) and in some northern states (bedded salts) (Figure 2-4). As indicated, much of Pennsylvania is shown as having significant bedded salt deposits.

![Figure 2-4. Major U.S. subsurface salt deposits (Veil et al., 1996, data from Johnson and Gonzales, 1978)](image)

Secondly, the construction costs for salt caverns are high in comparison to other storage options. The high construction costs are primarily due to the disposal of enormous amount of brine (e.g., millions of tons) during the construction period, which typically lasts 1 to 2 years. Unless there is a market for the brine, the startup costs for salt caverns could be very expensive. Disposal of brine can also be environmentally problematic.

Another consideration for CO$_2$ storage in salt caverns is the time scale. CO$_2$ storage must be effective on a centuries-to-millenia time scale. This length of time impacts the risk evaluation for the structural and permeability integrity of salt caverns for CO$_2$ storage due to the potential movement that can occur in salt units.

Accidents at natural gas salt cavern storage facilities are reported at a frequency of one in several years. These accidents are typically due to the high demand use (i.e. injection and removal cycles) associated with salt caverns. However, these conditions would not be applicable to CO$_2$ storage because (1) CO$_2$ is inflammable and (2) the design features of CO$_2$ storage would be different than natural gas because gas cycling is not required.
Design considerations taking into account the long-term salt cavern behavior for CO\textsubscript{2} storage will require an optimal strategy including not only the design of an appropriate geometric shape for the caverns but also a filling (pressurization) strategy that achieves the goals of minimal distortion of the overlying strata, maximum storage, and maintenance of structural integrity of the cavern walls (Dusseault et al., 2001). The weakest points in cave
tin integrity are the borehole and surrounding casing. However, a
monitoring plan can be implemented and mitigation measures taken if CO\textsubscript{2} leakage is
detected. The presence of stratigraphic traps and low vertical permeability units on top of
the caverns can help reduce the potential for CO\textsubscript{2} leakage.

In summary, CO\textsubscript{2} storage in salt caverns is technically achievable, but the expensive
construction costs and small overall capacity may prevent this technology from playing a
major role in CO\textsubscript{2} sequestration. Salt caverns may be a potential sequestration option in
areas that lack other storage options or already have such caverns developed. In addition,
using salt caverns as “buffer” capacity for other storage options with slower injection
rates to buffer peak CO\textsubscript{2} emissions from large producers may be another cost-effective
consideration. The following section evaluates the geology of salt deposits in
Pennsylvania as it relates to potential for CO\textsubscript{2} storage.

2.4.3 Geology

The Salina Group consists of seven units are designated Units A through G (DCNR,
2009). The following descriptions of characteristics of these seven units, from oldest to
youngest, were excerpted from the PADCNR August 2009 report:

- “Unit A consists of dolostone, anhydrite, and some light gray sandy shale
  in the upper part. It ranges in thickness from 50 feet (15.2 m) in the
  western part of Pennsylvania to over 500 feet (152 m) in Bradford
  County.”

- “Unit B contains the first salt beds deposited in the Salina Group but does
  not contain salt in all areas across the extent of the unit in Pennsylvania.
  The salt typically occurs in two beds separated by 10 to 50 feet (3.1 to
  15.2 m) of shale, anhydrite, and dolostone. The salt beds are thin and
  form a sinuous ribbon-like pattern across northwestern Pennsylvania
  before connecting with thicker basin deposits in the north-central area.
  Unit B ranges in thickness from a little over 100 feet (30 m) in Erie
  County to well over 700 feet (213 m) in Tioga County. It becomes thinner
  to the southwest but increases in thickness to the east in Bedford and
  Somerset Counties where it grades into the Wills Creek Formation.”

- “Unit C consists primarily (from 35 to 75 percent) of gray to green shale
  with some shaly dolostone and anhydrite, but in some areas, the entire unit
  is composed of shaly dolostone. Unit C contains a few thin salt beds in
  some wells, but salt is largely absent. In northeastern Pennsylvania, Unit
  C contains more dolostone and less shale than it does to the west.”
• “Unit D contains salt, often greater than 200 feet (61 m) thick in north-central Pennsylvania, but can also consist only of dolostone and anhydrite. It is typically thinner in the southwest.”

• “Unit E varies in composition, but the top is always marked by a sequence of shale that ranges from a few tens to almost 100 feet (30 m) thick. The remainder of the unit consists of interbedded dolostone, anhydrite, and sporadic salt. The salt beds typically are thin, rarely attaining thicknesses greater than 30 feet (9 m), but thick sequences also exist.”

• “Unit F is the thickest Salina unit, ranging from 64 feet (20 m) in Erie County to more than 1,300 feet (396 m) in Fayette County. It consists of thick salt beds separated by beds of dolostone, shaly dolostone, and dolomitic shale. Six distinct salt-bearing sections occur within Unit F in the Michigan Basin, but typically only the lower two or three of these occur in Pennsylvania. The upper three salt beds of Michigan are represented by anhydrite or are missing in Pennsylvania.”

• “Unit G consists of a lower relatively thick shale sequence (the Camillus Shale of New York State) and an upper sequence of dolostone and anhydrite. This unit does not contain salt. The anhydrite beds occur at the top of the unit and mark the uppermost boundary of the Salina Group. Unit G ranges in thickness from approximately 100 feet in northeastern Pennsylvania to over 200 feet in north central Pennsylvania. Due to the relatively impervious nature of this upper unit in the Salina Group, it could serve as an upper confining unit.”

Based on the available information from the DCNR and the MSRCR, the interbedded units of the Salina Group consist of shales, dolostones, and anhydrites. These lithologies typically exhibit relatively low porosities and low permeabilities. However, depending on the nature of the deposition of the units, horizontal bedding planes could act as potential conduits for horizontal movement of CO₂. Due to the relatively impervious nature of the upper Unit G in the Salina Group, it could serve as an upper confining unit.

The DCNR report indicates that a zone of complex faulting that generally begins in the Salina and ends in the Marcellus Shale is present in north-central Pennsylvania. Further evaluation of this zone should be conducted to determine the potential for CO₂ to migrate along the faults to the Marcellus Shale. The Marcellus Shale would likely be an appropriate cap rock, but continued exploration and potential development in this unit for natural gas production could potentially compromise the integrity of this formation as a viable cap rock in areas of natural gas production. Further evaluation of the structural geology of the Salina Group will be required to evaluate the potential for vertical migration of CO₂.
Stratigraphically, the Salina Group lies below the Oriskany Formation, which is also being evaluated as a potential CO\(_2\) reservoir. If the Oriskany is found to be a suitable unit for CO\(_2\) sequestration, potential hydraulic interaction between the two units would not be an issue because any leakage that would migrate upward should be captured in the overlying Oriskany.

2.4.4 Regional Conceptual Model

The gross thickness of the Salina Group is presented in Figure 2-5 and shows the distribution of this group in Pennsylvania. Figure 2-6 illustrates the net thicknesses of the salt units within the Salina Group. The most effective areas for further evaluation would be in the north-central and southwestern portions of the Commonwealth. The net salt thicknesses in these two areas would be adequate for development of sufficiently sized storage caverns. It is noted that the thick net salt deposits in southwest Pennsylvania are located in the area where many of the larger sources of CO\(_2\) are also located. The DCNR also constructed several cross sections that focused on the Salina Group. The cross sections consist of several north-south and east-west transects (Figure 2-7), three of which are presented in herein (Figures 2-8 through 2-10). These cross-sections demonstrate the interbedded nature of the Salina Group and the variability in unit thicknesses.

![Figure 2-5. Gross thickness isopach of the Salina Group (DCNR, 2009)](image)
To achieve proper roof and cap rock thicknesses between a salt cavern and overlying Bass Islands Dolomite and to maximize potential storage capacity, different construction techniques may have to be used in the Salina Group salts. Due to the small net salt thicknesses in some areas of the Commonwealth, a horizontal cavern development method may be required.

The lateral and vertical extent of any CO₂ sequestration reservoir is very important to consider with respect to potential development of future natural resources within the Commonwealth that are located in formations below the Salina Group. The development and use of a salt cavern for

![Figure 2-6. Net thickness isopach of salt in the Salina Group (DCNR, 2009)](image)

CO₂ storage has a distinct advantage over other storage reservoirs in that the areal extent of the storage site is well defined. If salt caverns are properly sited, this would be advantageous if drilling was required below the Salina Group because the area of CO₂ storage would be well known and defined. However, if not properly sited, it may inhibit or eliminate the potential for extracting mineral resources below the Salina Group.
Figure 2-7. Salina Group cross section locations (Harper, 2008)
Figure 2-8. Salina Group cross section A-A’, northern Pennsylvania (Harper, 2008)
Figure 2-9. Salina Group cross section B-B’, west-central Pennsylvania (Harper, 2008)
Figure 2-10, Salina Group cross section F-F', central Pennsylvania (Harper, 2008)
2.4.5 Accessibility

The following factors must be assessed with considering the accessibility of a potential CO₂ storage reservoir:

- Areal extent of the reservoir
- Capacity of the reservoir
- Proximity of cultural resources
- Proximity of major sources of CO₂
- Potential for development
- Proximity of gas storage caverns
- Proximity of oil and gas reservoirs

Based on the factors listed above, the Salina Group offers several advantages for use as a storage reservoir. The Salina Group is mostly restricted to the western and north-central portions of Pennsylvania. While there are a relatively limited number of sources in north-central Pennsylvania, there are various large sources in the western portion of the state. The thickness of this unit, particularly the net salt thickness, changes significantly throughout the region. The distribution of population centers in western Pennsylvania may pose some siting challenges but none that could not be overcome. North-central Pennsylvania has much smaller and more widely dispersed population centers and therefore would be a better option for a CO₂ storage facility based on potential conflicts with urban/suburban development.

The process and expense of creating salt caverns can be quite large, particularly with respect to brine-water disposal. The western and north-central portions of Pennsylvania contain oil and gas fields and a number of locations currently being used to store natural gas. Stratigraphically, the Salina Group generally underlies most of the major oil and gas fields and would not affect the future development of these units. Oil- and gas-producing units that underlie the Salina Group include Tuscarora Sandstone, Trenton, Black River, and Loysburg formations, Beekmantown Group, Gatesburg Formation, and Warrior Formation (Carter, 2007) and future exploration and development of oil and gas reserves could be hindered by storage of CO₂ in salt caverns above these units. Proper siting to consider current and future resource development will be important if sequestration is pursued using the Salina Group.

2.4.6 Brine Water Use/Disposal

Management of produced brine in the Commonwealth involves treatment at municipal sewerage facilities and disposal at Pennsylvania Department of Environmental Protection (DEP)-approved sites. Municipal sewage facilities do not typically have the capability to effectively treat the high chloride and total dissolved solids (TDS) levels that would be associated with brine. Effectively treating brine can require very expensive evaporation-based treatment systems. In some instances, the brine, in very small quantities, can be used to control dust on roadways. Ongoing research is being performed to investigate subsurface disposal of brine that is developed in the oil and gas industry. In addition,
guidelines with respect to the management of the TDS content of waste water are forthcoming from the Commonwealth and would significantly impact brine water treatment and/or disposal requirements. Formations suitable for CO$_2$ sequestration, including salt caverns, could potentially see competition from producers considering subsurface disposal of produced brine.

2.4.7 Capacity Assessment

The capacity of potential CO$_2$ storage in salt caverns will likely vary in different regions where the Salina Group is present and will be based on the following factors:

- Integrity of Unit G and the Bass Islands Dolomite
- Net thicknesses of the salt beds
- Geotechnical properties of the salt and interbedded units
- Surface topography
- Cultural resources
- Relative position with relation to potential sources of CO$_2$
- Type of cavern that can be constructed
- Size of the cavern that can be constructed
- Number of caverns that can be constructed
- Economic analysis
- Brine water handling requirements

The capacity of a single salt cavern depends on the cavern volume and CO$_2$ density, which is a function of pressure (i.e., filling pressure) and temperature. To obtain an accurate CO$_2$ density value, the salt cavern locations (including depth) and salt cavern design (for filling pressure) must be known to obtain pressure and temperature information. Design of the filling procedure and filling pressure is very important for CO$_2$ sequestration, especially considering the time scale for this type of application (Dusseault et al., 2001).

In general, the volume of a single cavern is determined after cavern design by the thickness of available salt layers, geometry of the cavern, and ratio of the height and diameter (H/D ratio) of the cavern. Suitable salt layers for cavern construction need to be sufficiently thick to leave intact salt “security” zones above and below the cavern to provide security against leakage (Dusseault et al., 2001). In general, the thicker the salt security zone over the cavern relative to the roof span, the more stable the cavern roof will be. Research indicates that the H/D ratio needs to be larger than 1 to limit shear damage (Han et al., 2006). For example, the salt caverns proposed by NE Hub Partners in Tioga County, Pennsylvania, have an H/D ratio of 1.56 (DCNR, 2009), which is described in more detail below.

For areas where multiple caverns are used for CO$_2$ storage, the minimum spacing between caverns should be considered for structural stability. The pillar to diameter (P/D) ratio is the measure of cavern stability when numerous caverns are located in the same salt mass. This ratio indicates the amount of salt remaining between caverns.
(i.e., pillars), relative to the cavern diameter. Because the overburden originally supported by the excavated salt must now be borne by the remaining pillars, this ratio needs to be sufficiently large to ensure structural stability. The minimum P/D ratio for waste disposal in salt caverns in Texas is 2.0, and for caverns designed specifically for SPR use (Phase II and III), the minimum P/D ratio is 1.8.

Accurate sequestration capacity assessment for salt cavern storage in Pennsylvania requires a detailed design for the caverns, which will be specific to types of salt layers in Pennsylvania. The design may require geotechnical modeling to help determine design parameters for long-term storage.

A review of the net salt thickness map of the Salina Group in Pennsylvania (Figure 2-6) indicates that Potter, Tioga, and Bradford counties are potentially the most suitable locations for salt cavern storage in the Commonwealth. The presence of impurities in the salt (e.g., interbedded materials other than salt), although not determined due to lack of data, can compromise the integrity of the structure and permeability of salt caverns and can potentially limit the extent of salt deposits suitable for CO$_2$ storage.

An order-of-magnitude estimate of the capacity of salt caverns for CO$_2$ sequestration is provided below. A more accurate estimate is not possible because of the data gaps and lack of detailed cavern design. The net salt thickness map (Figure 2-6) suggests that the area near the border of Potter and Tioga Counties, approximately 450 square kilometers (km$^2$) (within the 900-foot contour), is potentially suitable for constructing the caverns designed by NE Hub Partners (DCNR, 2009). For the NE Hub Partners design, 10 caverns were planned in each 900-acre area (3.6 km$^2$); therefore, if salt deposits in all of the 450-km$^2$ area are suitable for cavern construction, 1,250 caverns can be constructed. The volume of each such designed cavern is approximately 4.81×10$^7$ ft$^3$ (DCNR, 2009), and assuming the density of CO$_2$ to be 50 lb/ft$^3$, each cavern is estimated to be able to sequester 1.2 million short tons of CO$_2$. Therefore, the total capacity of the 1,250 caverns is 1,500 million short tons, which is just above total annual volume of carbon emissions from Pennsylvania sources (291 million short tons in 2004). As indicated above, this calculation is subject to significant uncertainty, in part because of the limited data used to prepare the salt thickness and cross sections maps. In addition, the calculation assumes that impurities within the salt deposits will not affect cavern construction anywhere within the 450-km$^2$ area. Nevertheless, the results suggest that the sequestration capacity potentially offered by salt caverns is relatively small (several years of CO$_2$ emission in Pennsylvania); meanwhile, the cost of constructing the number of caverns will likely be high, if there is no viable market available for the dissolved salt. Therefore, salt caverns are not likely to serve as the major CO$_2$ sequestration storage option in Pennsylvania.

### 2.5 Saline Unit Analysis

#### 2.5.1 Identification of Potential Units

As mentioned above, DCNR identified four potential target zones for CO$_2$ sequestration in their August 2009 report, three of which are saline formations with significant potential for carbon sequestration. These formations include the Upper Devonian
sandstone reservoirs, the Oriskany Sandstone and the Medina Group/Tuscarora Sandstone. The fourth identified unit is the Salina Group (discussed above in Section 2.4). The following provides an overview of these formations and their current uses:

- **Upper Devonian sandstone reservoirs.** The Upper Devonian includes various sandstones that have potential for carbon sequestration. These formations have been historically utilized for oil and gas production in the western portion of the state (DCNR, 2009).

- **Lower Devonian Oriskany Sandstone.** There are four main play areas associated with the Oriskany Sandstone (discussed further below). The Oriskany has historically been used for natural gas production at various fields (Figure 2-11) as well as for natural gas storage (Figure 2-12). In addition, the formation has been utilized to a small degree for brine disposal with a total of five such wells permitted for that purpose. These brine disposal wells are located in the western portion of the state (Figure 2-13) (Tetra Tech, 2009).

Figure 2-11. Oriskany Sandstone and Huntersville Chert Gas Fields (data from WIS, 2009)
Figure 2-12. Natural gas storage fields (data from WIS, 2009)
• Silurian Medina Group/Tuscarora Sandstone. The Medina Group/Tuscarora Sandstone consists of interbedded sandstones, mudrocks, and some carbonate rocks. There are numerous Medina gas fields in the northwestern portion of the state, with a few Tuscarora fields being located in the central portion of the state. Figure 2-14 identifies these gas fields. Only one Medina Group field, the Corry Storage field, situated in Erie County, Pennsylvania, has been converted to natural-gas storage (DCNR, 2009).
In addition to these primary candidates formations that were referenced in the subject DCNR report, the following additional formations are believed to have potential for carbon sequestration and worthy of further evaluation: sandstones of the Upper Devonian, the Silurian Bass Islands Dolomite, Cambrian Gatesburg Formation and basal Cambrian Potsdam Sandstone. The stratigraphic position of these units are shown on Figure 2-2 and Figure 2-3. As indicated, the Cambrian Gatesburg and basal Cambrian Potsdam formations are deeper than any of the formations covered in the DCNR report. The Bass Islands Dolomite is located stratigraphically above the Silurian Medina Group / Tuscarora Sandstone and Salina Group and beneath the Lower Devonian Oriskany Sandstone.

- Silurian Bass Islands Dolomite - Bass Islands lithologies vary laterally throughout the Appalachian basin, from intervals dominated by dolostone lithologies in the east to primarily limestone lithologies in the west. In Pennsylvania, the Bass Islands is a carbonate unit that includes limestone, dolomitic limestone, and dolostone. The Bass Islands Formation is productive in a few wells in the northwest portion of the Commonwealth (MRCSP, 2005b).

- Cambrian Gatesburg Formation - In core and outcrop in Pennsylvania, the Upper Sandy member of the Gatesburg Formation (called Rose Run sand by drillers) contains three principal facies: 1) sandstone; 2) mixed sandstone and dolostone; and 3) dolostone (Riley et al, 1993). It is noted that there is one brine disposal
• Basal Cambrian Potsdam Formation including any unnamed Rome trough sandstones - The stratigraphically complex basal Cambrian sandstones lie unconformably on the Precambrian basement. For the region, the MRCSP publication entitled, “Characterization of Geologic Sequestration Opportunities in the MRCSP Region, Phase I Task Report Period of Performance: October 2003 – September 2005” presented four basic units within this interval, each with distinctive stratigraphic and injection reservoir characteristics, which are discussed further below. The basal Cambrian sandstones are utilized for liquid disposal in Ohio (MRCSP, 2005b).

2.5.2 Geological Review and Potential Use in Pennsylvania

The following provides a summary of key geologic characteristics for the above-referenced potential carbon sequestration target formations. Overlying and underlying units are also discussed with regard to potential for facilitating containment.

Upper Devonian Sandstone Reservoirs

The following description from the August, 2009 DCNR report is provided for background on the geology and carbon sequestration potential of the Upper Devonian Venango Group:

“The excellent petroleum production history of the Venango Group sandstones in the subsurface of southwestern Pennsylvania suggests that these rocks might be suitable for the geological sequestration of CO$_2$…. This production history provides us with reasonably good capacity estimates and a proven pre-drilling seal (DCNR, 2009).”

“Venango Group sandstone reservoirs at depths greater 2,500 ft (762 m) in southwestern Pennsylvania are restricted to the lowermost sandstones (Gordon through Bayard and Lower Sandy zone) in pools developed along and adjacent to the border of Allegheny and Washington Counties, eastern and southern Washington County, and most of Greene County. Indeed, all of the Venango Group reservoirs, including the thicker Hundred-Foot zone sandstones, are suitably deep for CO$_2$ sequestration. The sandstone depths here range from 2,500 to 3,000 ft (762 to 914 m) (DCNR, 2009).”

“Porosity and permeability in the Venango Group sandstones of southwestern Pennsylvania range from 2.5 to 27 percent and 0.2 to 300 md, respectively … . The porosity is a hybrid of reduced primary pore space and enlarged secondary voids that formed through dissolution of mineral cements. Further petrographic analyses will be imperative, however, if the Venango Group sandstones are considered for CO$_2$ sequestration…. The variable amounts of carbonate cement,
clay minerals, and feldspar in the rocks pose some risk for inducing changes in the initial pore size distribution (DCNR, 2009).

“In summary, the Venango Group sandstone reservoirs in southwestern Pennsylvania are feasible targets for CO₂ sequestration, but offer limited storage capacity in that: (1) not all of the reservoirs occur at depths in excess of 2,500 ft (762 m); and (2) lateral/vertical variations in thickness and extent are expected for these reservoirs. The viability of these prospective sequestration formations is also limited by the unknown integrity of post-production cap rock and the high density of oil-and-gas wells in this area, which poses a real risk for CO₂ migration and leakage (DCNR, 2009).”

Figure 2-15 presents thickness and extent of the Venango Group Sandstone Formation.

![Figure 2-15. Thicknesses and extents of Venango Group Sandstones (DCNR, 2009, fig 3.4-2)](image)

Assessment of Carbon Sequestration Potential and Data Gaps:
One of the biggest drawbacks to using the Upper Devonian sandstone reservoirs as a sequestration target is the number of abandoned wells that have not been located throughout the Commonwealth and have not been properly plugged and abandoned. It is
likely that many of these wells will never be located, and in fact open-well bores may be located under structures, parking lots, churches, high schools, etc.

There is, however, potential in that portion of the Upper Devonian formation referred to as the Bradford Group Sands (Figure 2-16), especially for areas developed after the mid-1970s. Most of the wells in the Bradford are expected to be deep enough for sequestration (i.e., >2,500 ft) and modern fracturing, casing, cementing and plugging techniques were used. In addition, porosity and permeability and drill-stem test data are available for many of these wells. The principal advantage of considering these formations is their location near sources of CO$_2$ generation. Other Upper Devonian sandstone formations may also have potential where they are situated at depths greater than 2,500 ft.

![Upper Devonian Oil & Gas Sands](image)

**Figure 2-16. Upper Devonian Oil and Gas Sands Limits (Carter, 2007)**

**Oriskany Sandstone**

The following description taken from the August, 2009 DCNR report is provided for background on the geology and carbon sequestration potential of the Oriskany Sandstone:

“The Oriskany Sandstone is typically a “tight” rock – that is, one of low porosity and permeability. Primary intergranular porosity, which is the original porosity that developed during deposition of the sediments that became rock, is present only locally. Even so, secondary porosity, which is porosity that developed in rock after its deposition by fracturing and/or dissolution, is common in this formation…. Fracture porosity, where it occurs, aids greatly in fluid storage within the Oriskany (DCNR, 2009).”

“The Atlas of Major Appalachian Gas Plays$^{129}$ classifies four natural gas plays for the Oriskany based on these trapping mechanisms [Figure 2-17] (DCNR, 2009).”
Figure 2-17. Oriskany natural gas plays in the Appalachian basin (DCNR, 2009, fig 3.3-4)

“Salient characteristics of these four individual plays are summarized as follows:130

- The highest porosities in the Oriskany Sandstone are observed in the updip permeability pinchout, *Dop*, and the fractured Huntersville Chert and Oriskany Sandstone, *Dho*. Intergranular porosity, and to a lesser extent dissolution porosity, are observed in the *Dop*. Porosity is controlled by fracturing in *Dho*, with only minor secondary porosity from dissolution.

- The Oriskany Sandstone shows little variation in porosity and permeability in the *Doc* play, based on existing data. Additional data, however, are required to determine if the interpretation is correct, before extending this conclusion elsewhere, or if it is simply an artifact of the available, limited data.

- The tightest Oriskany Sandstone occurs in the *Dos* play, having calculated and measured porosities of less than 2 percent from Pennsylvania sample locations.

- Porosity in the *Dho* and *Dos* plays is largely controlled by fractures. Consequently, appropriate geophysical and seismic methods should be
employed to evaluate fracture porosity and conduct fracture analyses at any potential injection sites in these play areas (DCNR, 2009)."

“Permeabilities in the Oriskany Sandstone range from less than 0.1 to almost 30 md.\textsuperscript{179} Highly fractured rocks tend to have higher permeabilities, as do rocks in which carbonate dissolution has occurred. Permeabilities are lower where fractures have been healed by secondary mineralization, or where secondary dissolution of cements has been minimal. Injection of fluids, therefore, would be more favorable in areas close to an updip pinchout or along structures where fractures have not healed.

The Oriskany Sandstone has been used for the injection of industrial wastes in several wells in the basin, and for injection of natural gas for gas-storage purposes in numerous depleted gas fields…. These data clearly indicate that, even in areas of low porosity and permeability, the Oriskany can be used for sequestration of fluids as long as hydraulic fracturing or acidizing is applied prior to injection.

The largest single storage problem for sequestration of CO\textsubscript{2} in the Oriskany is the possibility of seal failure…. Mechanical seal problems would probably be more likely to occur in areas where the structural complexity places a porous or highly fractured rock in juxtaposition (vertical or lateral) with open fractures or high-porosity zones in the sandstone. The integrity of Oriskany reservoir cap rocks and fracture seals needs to be evaluated thoroughly for mechanical and, possibly, chemical alteration potential before any project would begin (DCNR, 2009).”

Figures 2-18 and 2-19 present Oriskany structure and thickness maps as prepared by DCNR.

![Figure 2-18. Oriskany Sandstone structure (DCNR, 2009, fig 3.3-2)](image-url)
Assessment of Carbon Sequestration Potential and Data Gaps:

The Oriskany Sandstone has significant promise for CO$_2$ sequestration, with the best opportunities probably associated with the Oriskany in fractured settings, potentially in combination with the Huntersville Chert where present. Targeting these areas will require utilizing seismic data. The following map (Figure 2-20) presents seismic data currently available to DCNR and supporting agencies.
There are significant questions concerning the containment and integrity of the Oriskany sandstone, particularly in areas where the trapping mechanisms are characterized by structure. This is of particular importance in Oriskany reservoirs located along the Pennsylvania-Maryland state line.

The potential cap rock in close vertical proximity to the Oriskany varies across the state. Figure 2-21 from the “Characterization of Geologic Sequestration Opportunities in the MRCSP Region, Phase I Task Report Period of Performance: October 2003 – September 2005” identifies these lithologies. As indicated, lithologies vary from chert (which can be fractured and utilized with the Oriskany as an associated injection target) to limestone or shale. Where limestone (Bois Blanc Formation) or shale (Needmore Shale) are present, they may function as cap rock.

![Figure 2-21](image)

Figure 2-21. “Map showing the variations in lithology of the rocks overlying the Oriskany Sandstone (MRCSP, 2005a, fig A11.8).”

The Onondaga Limestone may also serve as a suitable cap rock. Above the Onondaga lies the Marcellus shale. Although the Marcellus shale has potential for cap rock for sequestration purposes it is currently undergoing intense exploration and development within the state. Marcellus shale wells are typically hydraulically fractured as part of
well completion activities. This hydraulic fracturing will likely compromise the suitability of the Marcellus shale as a cap rock in many areas, and may impact the underlying Onondaga Limestone as well. This potential impact should be evaluated further.

It is also important to note that due to the relatively limited naturally occurring porosity and permeability within the Oriskany Sandstone, plans for utilizing it for carbon sequestration will require stimulation by hydraulic fracturing, acid treatment, etc. to enhance its permeability. The Oriskany Sandstone was evaluated as part of the pilot CO\textsubscript{2} injection project conducted at the Burger Power Plant in Shadyside, Ohio. Specific geologic formations that were assessed include the Oriskany Sandstone, dolostones of the Salina Group, and the Grimsby Sandstone. Although the injection results were not favorable, it should be noted that the units were not stimulated prior to injection. Stimulation of the injection zones may have helped to increase permeability and thereby increased injection volumes and rates.

**Bass Islands Dolomite**

The following description from the 2009 MRCSP publication entitled, “Characterization of Geologic Sequestration Opportunities in the MRCSP Region: Middle Devonian/Middle Silurian Formations” is provided for background on the geology and carbon sequestration potential of the Bass Islands Dolomite:

“In the Appalachian basin, the Bass Islands is only productive in a relatively small area of northwestern Pennsylvania and western New York (the “Bass Islands Trend”), which occurs in a narrow northeast-trending band that extends 84 mi (135.2 km) from Erie County, Pennsylvania, to Erie County, New York (MRCSP, 2009).”

“In Erie County, Pennsylvania, the Bass Islands is overlain by 20 ft (6.1 m) of Manlius Limestone of the Helderberg Group. Fifty-feet (15.2 m) of cherty sandy limestone of the Bois Blanc limestone unconformably overlies the Manlius Limestone, and in some parts of northwestern Pennsylvania, the Oriskany Sandstone is present between the Manlius Limestone and the Bois Blanc. A thick, combined interval of Onondaga Limestone and Devonian shale overlie the Bois Blanc, forming a tight seal over the Bois Blanc/Bass Islands interval. East of Erie County, Pennsylvania, and in southwestern New York, the Bass Islands Dolomite is equivalent to the Akron dolomite and is separated from the overlying Devonian-age Onondaga Limestone by an unconformity or erosional contact…. Throughout Pennsylvania, Ohio, and West Virginia, the Bass Islands Dolomite is underlain by evaporate deposits of the Salina Group (MRCSP, 2009).”

[Figure 2-22] “illustrates the structure of the Bass Islands Dolomite across the Appalachian basin using contour interval of 500 ft (152 m)…. The Bass Islands crops out in central Ohio and southwestern New York, and occurs as deep as 7,000 ft (2,134 m) in central West Virginia [Figure 2-22]. Within the Bass Islands Trend in northwestern Pennsylvania and southwestern New York, the
depths of this unit range from approximately 500 ft (152.4 m) to 1,500 ft (457.2 m) (MRCSP, 2009).”

[Figure 2-23] “illustrates the thickness of this unit across the Appalachian basin using a contour interval of 25 ft (8 m). Gross thicknesses range from less than 25 feet in western New York, western Ohio, and southwestern West Virginia to almost 100 ft (30.5 m) in central New York, north-central Pennsylvania, and the West Virginia panhandle (MRCSP, 2009).”

“The Bass Islands Trend is structurally controlled with low-angle reverse faults and thrust faults providing the trapping mechanism (MRCSP, 2009).”

Figure 2-22. Structure contour map drawn on top of the Bass Islands Dolomite in the Appalachian basin (MRCSP, 2009, fig. 3.4-3)
“Although not as regionally persistent as some other saline formations in the Appalachian basin (e.g., the Medina Group/“Clinton” Sandstone and Oriskany Sandstone), the Bass Islands Dolomite possesses certain reservoir characteristics that make it an attractive sequestration target. Where present, it is certainly deep enough to be considered a target, and the porosity and permeability values reported for this unit, ranging from 2 to 15 percent and 10 to 230 md, respectively, suggest that it could provide significant volumetric sequestration capacity (MRCSP, 2009).”

Assessment of Carbon Sequestration Potential and Data Gaps:

Although suitable injection intervals within the Bass Islands Dolomite are not believed to be regionally extensive, the formation can offer an attractive local target for carbon sequestration due to significant porosity and permeability development. Consideration should be given to depth in the extreme northwest portion of the Commonwealth to confirm any potential injection zone is below 2,500 ft (762 m) in depth. As indicated above, the Onondaga Limestone and Devonian shales have been referenced as cap rock situated stratigraphically above the Bass Islands. More work needs to be done to demonstrate the effectiveness of potential cap rock at specific potential injection sites.
Medina Group/Tuscarora Sandstone

The following description from the August, 2009 DCNR report is provided for background on the geology and carbon sequestration potential of the Medina Group/Tuscarora Sandstone. Figures 2-24 and 2-25 provide Medina Group/Tuscarora Sandstone structure and thickness maps for Pennsylvania.

“The Medina Group/Tuscarora Sandstone is considered an injection target, particularly for its prevalence throughout the Appalachian Basin as a reliable oil- and gas-producing reservoir, its sandstone lithologies, and the presence of less permeable confining rocks above and below the interval. Even so, factors such as the variability in lithology, the tight nature of this reservoir (with respect to both porosity and permeability), and the discontinuity of sandstone lenses in the northwestern portion of the basin, may limit the overall success of this as a CO$_2$ sequestration target (DCNR, 2009).”

![Figure 2-24. Medina Group/Tuscarora Sandstone structure contours (DCNR, 2009, fig 3.1-1)](image-url)
"The porosity and permeability of the Medina Group varies due to both depositional and diagenetic processes.... Medina Group porosities range from 2 to 23 percent across the basin and average 7.8 percent.\textsuperscript{154} Medina Group permeability values are widely variable, ranging from less than 0.1 md to 40 md.\textsuperscript{155} In northwestern Pennsylvania, Medina permeabilities occur on the lower end of this range.\textsuperscript{156}

As a sequestration target, the Medina Group/Tuscarora Sandstone is overlain by limestones, dolostones, and shales of the Clinton Group, and underlain by the Queenston Formation (Medina) and Juniata Formation (Tuscarora). These units should serve as effective seals above and below the Medina target based on their lithology and low-permeability characteristics, just as they currently serve as components of the stratigraphic trapping mechanism of this reservoir. Furthermore, the presence of extensive, mostly tight carbonate and evaporite rocks immediately above the Clinton Group contributes to the ability of this interval to prevent any vertical migration of gas out of the Medina Group.

In Pennsylvania, only one Medina Group field has been converted to natural-gas storage. The Corry Storage field, situated in Wayne Township, Erie County,
Pennsylvania, was discovered in 1947 and first underwent gas injection in 1955.\textsuperscript{157}

…Medina Group oil fields typically do not respond well to normal waterflooding for EOR. This is thought to be due to the relatively low permeability and heterogeneity of the reservoirs. Nonetheless, CO\textsubscript{2} enhanced recovery may prove to be much more effective in these reservoirs because of the ability of CO\textsubscript{2} to solubilize in the native oil and brine, thereby lessening their viscosity and allowing better flow through this low-permeability heterogeneous system. If this potential can be proven via a pilot project, a vast area of the Appalachian Basin becomes available for CO\textsubscript{2} sequestration with the potential to produce hundreds of millions of barrels of additional oil from reservoirs of this interval (DCNR, 2009).”

\textit{Assessment of Carbon Sequestration Potential and Data Gaps:}

The Medina Group/Tuscarora Sandstone, like the Oriskany Sandstone, is currently realizing production operations and is also used for natural gas storage. Wells penetrating the Tuscarora typically have cemented casing set through the pay. The casing is then perforated, and the well is stimulated using hydraulic fracturing. As a consequence, there remain questions concerning the sustainability of the cap-rock to hold and contain sequestered CO\textsubscript{2}.

The Medina Group/Tuscarora Sandstone is overlain by limestones, dolostones, and shales of the Clinton Group which seem to provide adequate cap rock; however, these units should be evaluated on a site-specific basis at potential injection sites. The Salina Group with its evaporite layers are located above the Clinton Group and can act as an effective seal, provided it is not being used locally for CO\textsubscript{2} injection (as discussed above).

With exception of the northwestern portion of the state, there are not a substantial number of penetrations of the Medina Group/Tuscarora Sandstone. Seismic information can help identify favorable areas for the Tuscarora by identifying folded and faulted areas where permeability may be enhanced as well as evaluating for integrity of cap rock.

\textbf{Gatesburg Formation}


“\textit{In core and outcrop in Pennsylvania,...the Upper Sandy member of the Gatesburg Formation [called “Rose Run sand” in the MRCSP report], contains three principal facies: 1) sandstone; 2) mixed sandstone and dolostone; and 3) dolostone (Riley et al, 1993).... Intergranular porosity is the most abundant porosity type in the [Gatesburg] and appears to be mostly secondary based on}
corroded grain boundaries…. Fracture porosity is the least common porosity type observed in cores, but it may be locally significant in areas adjacent to major fault systems (MRCSP, 2005a).”

“The major tectonic features affecting [Gatesburg] structure occur in northeastern Ohio, western Pennsylvania, eastern Kentucky, and western West Virginia. In western Pennsylvania, these include the Tyrone-Mt. Union and Pittsburgh-Washington lineaments, which have been interpreted as northwest-southeast trending wrench faults (Riley et al, 1993). In addition, numerous growth faults above basement rifts have been proposed that have been offset by movement along these major wrench faults…. A relationship between basement faults and paleotopographic highs on the Knox or [Gatesburg] has been proposed as a controlling factor in reservoir development and hydrocarbon production (MRCSP, 2005a).”
Figure 2-26. Structure contour map for the Upper Sandy member of the Gatesburg Formation and equivalent strata (MRCSP, 2005b, fig A4-4)
“The [Gatesburg] sandstone interval thickens gradually from zero feet at the western limit of the subcrop to about 200 feet throughout the area of eastern Ohio and northwestern Pennsylvania [Figure 2-27]. Various authors have indicated that the Rome trough was actively subsiding during [Gatesburg] deposition. Approximately 470 feet of [Gatesburg] was encountered in the Amoco #1 Svetz well in Somerset County, Pennsylvania before drilling was stopped at 21,640 feet; most of that thickness occurred in the uppermost sandstone body (MRCSP, 2005a).”
Suitability of CO₂ injection for the [Gatesburg] can be subdivided into three geographic areas for discussion: 1) within the [Gatesburg] subcrop trend; 2) downdip of the eastern edge of the subcrop; and 3) within the Rome trough. In most of these areas, the [Gatesburg] occurs at depths greater than 2,500 feet, which should be within the preferred condition to obtain adequate minimum miscibility pressures for CO₂. While the Rome trough was actively subsiding during [Gatesburg] deposition, large amounts of elasic sediment were probably built up in localized areas of Kentucky, West Virginia, and Pennsylvania. Wells such as the Amoco #1 Svetz well in Somerset County, Pennsylvania, with approximately 470 feet of [the Gatesburg], indicate the potential for large sequestration capacity at the greater depths in the Rome trough. In Ohio, a thick sequence of Ordovician shales and Black River and Trenton carbonates overlie the [Gatesburg] and serves as a confining unit. Below the [Gatesburg], a thick sequence of Cambrian dolostone and shale act as the confining unit between the Rose Run and earlier Cambrian sandstones (MRCSP, 2005a).

Assessment of Carbon Sequestration Potential and Data Gaps:

Due to the limited number of penetrations of the Gatesburg Formation in Pennsylvania, relatively little is known about the potential of the formation as a target for carbon sequestration. Much more basic information on the geology of the Gatesburg Formation (including variations in thickness, porosity and permeability, etc.) in Pennsylvania is necessary before it can be adequately evaluated. There appears to be potential to encounter relatively thick Gatesburg sandstone on downblocks of Precambrian basement faults (e.g., those associated with the Rome trough). Figure 2-28, taken from the MRCSP study, depicts the Rome trough and associated basement faults. Additional strategically located seismic data would be very valuable in attempting to identify such areas. Cap rock for the Gatesburg could include some of the overlying limestone units or Reedsville and/or Queenston Shale. The Beekmantown dolostones, which were greater than 3,000 ft thick in the Amoco #1 Svetz Well, also have significant potential for cap rock even though there may be some intervals within the Beekmantown that have cavernous porosity. These units would need to be evaluated on a site-specific basis at proposed injection sites.

It is noted that a DOE-funded carbon sequestration pilot project having the Upper and Lower Sandy members of the Gatesburg Formation as injection targets is being conducted at the American Electric Power (AEP) Mountaineer power station in New Haven, West Virginia. (It is noted that the formation nomenclature for the subject pilot test was “Rose Run”, which as mentioned above is the driller’s term for the Upper Sandy Member of the Gatesburg Formation, and “Copper Ridge” which is equivalent to the Lower Sandy member of the Gatesburg Formation”. Both formations are considered to have good injection potential and are scheduled to undergo CO₂ injection in the near future.
Figure 2-28. Map of major basement faults, precambrian tectonic provinces, elevation of top of the precambrian unconformity, and other structural features of the MRCSP Region (MRCSP, 2005a, fig 6)
**Basal Cambrian Sandstones**

The following description from the MRCSP publication entitled, “Characterization of Geologic Sequestration Opportunities in the MRCSP Region, Phase I Task Report Period of Performance: October 2003 – September 2005” is provided for background on the geology and carbon sequestration potential of Cambrian Mt. Simon Sandstone and other basal Cambrian sandstone formations:

“The stratigraphically complex basal Cambrian sandstones lie unconformably on the Precambrian basement. For the region, we have mapped four basic units within this interval [Figure 2-29], each with distinctive stratigraphic and injection reservoir characteristics: 1) the Mt. Simon Sandstone of the proto Illinois/Michigan basin area (Michigan, Indiana, western Kentucky, and western Ohio), 2) the unnamed dolomitic sandstones of the Conasauga Group (eastern Ohio, northern Kentucky, western Pennsylvania, and West Virginia), 3) Potsdam Sandstone (northern and north-central Pennsylvania), and 4) stratigraphically older unnamed basal Cambrian (Rome trough) sandstones in the fault-bounded Rome trough and eastern proto-Appalachian basin (eastern Kentucky, West Virginia, and western Pennsylvania) (MRCSP, 2005a).”
“The unnamed basal sandstones, Conasauga sandstones, and Potsdam Sandstone of eastern Ohio, West Virginia, and Pennsylvania range from 50 to 150 feet. However, this is a total thickness of the interval; the amount of porous/permeable sandstone within the interval is uncertain and is highly variable and discontinuous…. Within the Rome trough, the basal sandstones appear to thicken southward independent of major faults, indicating that the sandstones may be pre-
rift deposits unaffected by movement on the major bounding faults of the Trough. Post-depositional structural movement, however, influenced depth and local thickness preservation (MRCSP, 2005a).”

Figure 2-30, taken from the MRCSP document “Assessment of Geological Sequestration Potential in Pennsylvania” shows the thickness of the Potsdam Sandstone in northwestern Pennsylvania relative to basement faults. As indicated a maximum thickness of greater than 200 ft was estimated for a portion of the study area. Figure 2-31 shows structure on top of the Potsdam with interpreted influence from some of the basement faults.

![Isopach map of the Potsdam Sandstone](image-url)
Figure 2-31. Structure contour map on top of the Potsdam Sandstone (MRCSP, 2006, fig 3)

Figure 2-32 from the poster entitled “Depth Relationships in Porosity and Permeability in the Mount Simon Sandstone (Basal Sand) of the Midwest Region: Applications for Carbon Sequestration” shows that for Pennsylvania the depth to the basal Cambrian sandstones vary from approximately 6,500 ft (northwestern Pennsylvania) to greater than 20,000 ft (central portion of Pennsylvania). It is noted that the Mt. Simon Sandstone is not present in Pennsylvania, but is equivalent to the Potsdam Sandstone; therefore, the depth shown on Figure 2-32 would correlate to depth to the Potsdam Sandstone.
Assessment of Carbon Sequestration Potential and Data Gaps:

Due to the limited number of penetrations of the basal Cambrian sandstones in Pennsylvania, relatively little is known about the potential of the formations as targets for carbon sequestration. Much more basic information on the geology of this interval (including variations in thickness, porosity and permeability, etc.) in Pennsylvania is necessary before it can be adequately evaluated. There appears to be potential to encounter relatively thick basal Cambrian sandstone on downblocks of Precambrian basement faults (e.g., those associated with the Rome trough). Additional strategically
located seismic data would be very valuable in attempting to identify such areas. Likewise, there is limited data on immediately adjacent potential cap rock. Cap rock for the basal Cambrian sandstones could include the Reedsville and/or Queenston Shale and Beekmantown dolostones, as well as the Trenton, Black River, and Loysburg limestones. These units, and any other relatively thick and laterally continuous low-permeability units would need to be evaluated on a site-specific basis at proposed injection sites.

2.5.3 CO2 Injectivity Testing Results

As mentioned above, the actual capacity of a formation is dependent on a variety of factors. A recent investigation (ARI, 2009) at two potential sequestration sites in Pennsylvania illustrates this. The researchers investigated sequestration in the Oriskany Sandstone at the Punxsutawney-Driftwood Field in Elk and Cameron counties and sequestration in the Medina Group at the Conneaut field in Erie and Crawford counties. The results indicate that the Oriskany provides much higher CO$_2$ injectivity and storage capacity than the Medina, due in part to much higher permeability at the Oriskany field (ARI, 2009). This demonstrates the need for the collection of site-specific field data which would provide more rigorous estimates for CO$_2$ storage capacity and injection potential.

The following notes on injectivity testing were obtained from the DOE and MRCSP websites:

Injection of 60,000 t was injected successfully into the Bass Islands Dolomite at a site in Gaylord, Michigan over two separate periods. While the specific characteristics of the formation may differ between Michigan and Pennsylvania, it is encouraging that this test was successful. In a three-week period in February-March 2008, 10,000 t was injected into the Bass Island Dolomite at a depth of about 3,600 ft. A second injection of 50,000 t was conducted between April and July 2009. The bottomhole pressures during the first injection at a rate of 600 t/day were stable at about 2,000 pounds per square inch (psi) to 2,020 psi. The researchers concluded that the formation may be able to sustain a higher injection rate.

In contrast to the Michigan test, an injection test near Shadyside, Ohio about 10 miles west of the Pennsylvania border was not successful into three formations: the Oriskany Sandstone at depths from 5,923 ft to 5,953 ft, the Salina Group at depths from 6,900 ft, and the Medina Group, Grimsby Formation at a depth of about 8,200 ft. A small-scale test was conducted in September 2008 to try to inject 3,000 t of CO$_2$ into the three formations. During the test injection, the bottomhole pressure in one of the formations, the Grimsby sandstone, increased rapidly from 800 pounds per square inch gauge (psig) to about 5,500 psig over less than 3 hours. The conclusion from this test was that the true injectivity of the three formations was less than expected due to lower porosity and permeability. The cores from the Salina Group had the highest porosity, 2 to 10 percent, among the three formations. These results illustrate the importance of heterogeneity and the usefulness of actual small-scale injection tests.
A third successful injection test was conducted in September 2009 into the Mount Simon Sandstone (stratigraphically equivalent to Pennsylvania’s Potsdam Sandstone) at a site near East Bend, Ohio at depths between 3,410 ft and 3,510 ft. The injection of 1,000 t was conducted in two 500 t steps. Detailed analysis of the results is underway, but the site appears to have good injectivity and storage potential. This formation is not present in Pennsylvania based on information from the MRCSP characterization work (MRCSP 2005), although further exploration in the deep Cambrian basal sandstones within the Rome trough would be needed to confirm its absence.

2.5.4 Regional Conceptual Model

The following discusses potential for carbon sequestration in the various geologic provinces of Pennsylvania based on the rocks which are present and structural features of the provinces.

2.5.4.1 Appalachian Plateau Geologic Province

Of the geologic provinces in Pennsylvania, the Appalachian Plateau Province seems to offer the best opportunities for carbon sequestration based on available data, and the fact that most of the larger sources of CO₂ are situated in this province. The various formations described above as candidates for carbon sequestration are all present within this province. In certain areas, particularly along the western side of the province, there have been hundreds of thousands of wells drilled; however, only a limited number of wells have been drilled deeper than the Medina Group /Tuscarora Sandstone throughout much of the province. Very few wells have been drilled in the eastern portion of this province (i.e., northeastern Pennsylvania). In evaluating specific sites it is important to recognize that relatively complex faulting may have impacted the potential sequestration targets and even cap rocks. Many of these faults “ramp up” from the Salina salt and “die out” in the Devonian shales. Situations may exist where these faults might enhance permeability in injection intervals but not impact potential cap rocks. This should be evaluated on a site-by-site basis. There is also potential for favorable accumulation/preservations of Cambrian sandstones and possibly younger formations on downblocks associated with Rome trough and related faulting which runs through a large portion of this province. Seismic line data combined with well control is critical to identifying and evaluating such localized thicker potential sequestration targets.

2.5.4.2 Ridge and Valley Geologic Province

Potential exists for repeated permeable intervals related to fracturing and faulting of sedimentary rocks, which could be encountered several times in a vertical well due to thrust faulting. However, the extensive thrust faulting in this area, with many of the faults expressing themselves at the surface, can compromise the integrity of cap rocks. Considering the extent of the province, the amount of drilling is relatively minimal, and much more data is necessary due to the structural complexity. Seismic data is particularly important to evaluate potential for geologic carbon sequestration potential here.
2.5.4.3 Reading Prong

There may be potential for geologic carbon sequestration in the sedimentary rocks that underlie the metamorphic rocks of the Reading Prong. More data is needed to further evaluate this potential.

2.5.4.4 Gettysburg-Newark Basin

There may be potential for geologic carbon sequestration in the sandstones or conglomerates or possibly other units within this province; however, more data is needed to further evaluate this potential.

2.5.4.5 Piedmont Geologic Province

Little is known about the subsurface in this province which consists of complex folded and faulted metamorphic rocks. There is potential for localized fracturing of the rocks related to these structures. More information is needed to properly evaluate this province in terms of potential storage reservoirs and cap rock.

The potential geologic carbon sequestration targets vary across the state due to the lateral extent of the target formation related to deposition or erosion and the dramatic changes which occur structurally across the state. The following map, Figure 2-33, summarizes, to the extent possible based on available data, potential injection targets across the state.

![Figure 2-33. Saline unit screening map](image-url)
Potential injection and cap rock formations in Pennsylvania are depicted on Figure 2-34. As discussed above, the indicated intervals should be evaluated on a site-specific basis to confirm they have adequate properties to meet objectives of geologic carbon sequestration.
Figure 2-34. Stratigraphic column indicating potential sequestration targets and cap rock (adapted from Carter, 2007)
As indicated above, there is limited “deep well” data in the Commonwealth, particularly outside the Appalachian Plateau province. Figure 2-35 illustrates the distribution of wells drilled in Pennsylvania that have a total depth in excess of 10,000 ft. As indicated, there are a limited number of wells which reach this depth, and can therefore be utilized to help evaluate the potential of deeper potential geologic carbon sequestration targets.

![Figure 2-35. Wells greater than 10,000 ft in depth (data from WIS, 2009)](image)

Table 2-1 summarizes key available data by formation for characteristics important for evaluating potential candidates for carbon sequestration. Such information should be routinely updated as more information is gathered on potential carbon sequestration targets.
Table 2-1. Summary of available data for evaluating potential geologic candidates for carbon sequestration

<table>
<thead>
<tr>
<th>Formation Name:</th>
<th>Venango Group (Upper Devonian)</th>
<th>Oriskany</th>
<th>Bass Islands</th>
<th>Medina Group/ Tuscarora Sandstone</th>
<th>Gatesburg</th>
<th>Potsdam</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Parameter</strong></td>
<td><strong>Units</strong></td>
<td><strong>Value</strong></td>
<td><strong>Value</strong></td>
<td><strong>Value</strong></td>
<td><strong>Value</strong></td>
<td><strong>Value</strong></td>
</tr>
<tr>
<td>Depth</td>
<td>ft</td>
<td>2500 - 3000</td>
<td>1200 - 10,000</td>
<td>1500 - 6000</td>
<td>1000 - 9000</td>
<td>31,333</td>
</tr>
<tr>
<td>Areal Extent</td>
<td>sq. miles</td>
<td>0 ,000</td>
<td>29,022</td>
<td>1000 - 9000</td>
<td>22,222</td>
<td>9,280</td>
</tr>
<tr>
<td>Lithology</td>
<td>Sandstone</td>
<td>Sandstone</td>
<td>Dolostone/Limestone</td>
<td>Sandstone/shale/carbonates</td>
<td>Sandstone/dolostone</td>
<td>Sandstone</td>
</tr>
<tr>
<td>Gross Thickness</td>
<td>ft</td>
<td>100 to 600</td>
<td>45</td>
<td>4 to 94</td>
<td>254</td>
<td>50 to 600</td>
</tr>
<tr>
<td>Net Thickness</td>
<td>ft</td>
<td>0 to 200</td>
<td></td>
<td></td>
<td>23</td>
<td>50 to 150</td>
</tr>
<tr>
<td>Porosity</td>
<td>%</td>
<td>5.2%</td>
<td>2 to 15%</td>
<td>7.8%</td>
<td>8%</td>
<td></td>
</tr>
<tr>
<td>Permeability</td>
<td>md</td>
<td>0.2 to 300</td>
<td>2.2</td>
<td>10 to 230</td>
<td>0.1 to 40</td>
<td>1 to 100</td>
</tr>
<tr>
<td>Pressure Gradient</td>
<td>psi/ft</td>
<td>0.433</td>
<td>0.433</td>
<td></td>
<td>0.433</td>
<td></td>
</tr>
<tr>
<td>Salinity</td>
<td>mg/L TDS</td>
<td>96,000 to 162,000</td>
<td>62,000 to 338,000</td>
<td>131,000 to 197,000</td>
<td>126,000 to 265,000</td>
<td></td>
</tr>
</tbody>
</table>

1 Data from 67 oil-and-gas wells and Blauch, et. al, 2009
2 Data from 11 oil-and-gas wells
3 Avg. thickness from ArcGIS shapefiles
4 Data from 2 oil-and-gas wells
5 Data from 7 oil-and-gas gas
All other data from MRCSP 2005 Phase I report and DCNR 2009 report
2.5.5 Capacity Assessment

Assessment of the capacity of saline formations and depleted oil and gas fields to sequester CO\textsubscript{2} is an important step in determining the carbon sequestration potential of an area of interest. Although some commonality exists in the various methods for capacity assessment, each method is influenced by available data and resources, the aims of the study, and whether site-specific or regional estimates are being generated (IPCC, 2005).

The scale at which estimates are made is important to consider. Regional assessments typically consider a geologic formation in its totality, incorporating its total horizontal and vertical extent and making estimates of its key geologic properties (e.g., porosity). This type of assessment produces an estimate of total potential capacity, but the actual capacity for a facility will most likely be less. More specific estimates of capacity should incorporate variations in geology as well as site-specific hydrogeologic properties.

The total potential capacity of a geologic formation is a good indicator of the potential of CO\textsubscript{2} sequestration sites. After the best candidates have been identified, however, more detailed estimates of capacity will be controlled by local and site-specific geologic, economic, safety and other environmental factors. These criteria must be assessed for the anticipated lifetime of the operation to determine whether storage capacity can match supply volume and whether injection rates can match the CO\textsubscript{2} supply rate, which is dependent on the size of the facility.

2.5.5.1 Storage Mechanisms

The mechanisms for CO\textsubscript{2} storage include volumetric, adsorption, solubility, and mineralization storage. Volumetric storage involves the injection of supercritical CO\textsubscript{2} into a geologic formation with the CO\textsubscript{2} occupying the pore space and displacing the existing formation fluid, unless it is stratigraphically trapped. In Pennsylvania, volumetric storage is suitable for depleted oil and gas fields and saline formations. Adsorption storage occurs when CO\textsubscript{2} adsorbs (attaches) to the organic matter or mineral surfaces of a subsurface formation. This type of storage can occur in coal beds and organic-rich (carbonaceous) shale formations in Pennsylvania. In the absence of CO\textsubscript{2}, methane is typically adsorbed to these surfaces. CO\textsubscript{2} sequestration in these types of formations tends to displace the methane because CO\textsubscript{2} has a greater affinity for adsorption than methane. This type of storage mechanism has the potential for not only sequestering CO\textsubscript{2} but providing a beneficial use by enhancing the recovery of coalbed methane and shale bed gas. Solubility storage typically occurs over long periods of time and represents the dissolution of supercritical CO\textsubscript{2} into formation fluids. Solubility storage is typically limited by extremely slow mixing rates in deep formations, high salinities, and limited interaction between the CO\textsubscript{2} plume and surrounding brine fluids. Solubility of CO\textsubscript{2} in brines is reduced at high concentrations, as discussed in the next section. Mineralization involves the conversion of CO\textsubscript{2} via reactions into insoluble carbonate minerals. Although this type of storage provides long-term stability, it is typically limited by very long reaction times and the presence of certain rock types (e.g., carbonates) (Figure 2-36).
In Pennsylvania, the primary mechanisms for CO₂ storage will be volumetric and adsorption storage, at least during the early phases of a CO₂ sequestration project. Although solubility and mineralization storage are important and provide long-term stability for CO₂ storage, these processes typically occur over long time frames (hundreds to thousands of years) and may be limited due to hydrogeologic conditions (i.e., the presence of certain rock types which favor mineralization).

2.5.5.2 Factors Affecting Storage Capacity

An estimate of the total potential capacity of a formation for CO₂ sequestration is based on total areal extent, thickness, and porosity. However, this type of estimate may overestimate actual capacity due to heterogeneities in porosity and thickness over short distances.

The extent of a CO₂ plume in a formation is determined by pressure, volume, and temperature properties of CO₂ (Burrus et al., 2009). The pressure and temperature determine the phase in which the CO₂ exists in the subsurface. At sufficiently high temperature and pressures, CO₂ exists as a supercritical fluid and has a high density. This increase in density means that the amount of CO₂ that can be stored as a supercritical fluid is several hundred times larger than what can be stored in the gaseous phase. The DOE guideline for the depth at which the pressures and temperatures necessary to maintain CO₂ in a supercritical phase is about 2,500 ft (762 m). This is considered the minimum vertical depth for CO₂ storage in geologic formations in Pennsylvania.
web-based calculator from the Massachusetts Institute of Technology (MIT) enables site-specific estimates for a given site if the pressure and temperature of injection are available (http://sequestration.mit.edu/tools/index.html).

The vertical extent of a CO₂ plume in a formation is constrained by the presence and extent of a suitable seal (cap rock) to prevent migration of CO₂ to the surface. The horizontal extent of a plume is influenced by its phase, volume, and injection rate along with the hydrogeologic conditions, which can isolate the CO₂ within the geologic formation.

Other factors include the following, as discussed below:

- Salinity
- Subsurface pressure
- Injectivity
- Wellbore type
- Impurities
- Minimum size

**Salinity**

Formation waters that are less than 10,000 milligrams per liter (mg/L) TDS, regardless of depth, are classified as underground sources of drinking water (USDWs). United States EPA has proposed that formations used for CO₂ sequestration must have a TDS concentration greater than 10,000 mg/L. The original proposed Underground Injection Control (UIC) regulations for CO₂ sequestration stated that a formation selected for CO₂ sequestration also must be located beneath the lowest USDW (EPA, 2008b). However, in an August 2009 addendum, United States Environmental Protection Agency (EPA) proposed that a state could implement a waiver process to allow injection where formations with TDS contents greater than 10,000 mg/L are located below the injection target when there would otherwise be no suitable location. There may be formations of sufficient depth, pressure, and temperature that are suitable for supercritical CO₂ sequestration, but, due to the presence of low salinity waters in or beneath the formation (i.e., less than 10,000 mg/L TDS), could not be used for CO₂ storage. In addition, salinity can potentially limit the storage capacity of a formation by reducing the amount of CO₂ that can be solubilized because the solubility of CO₂ decreases with increasing salinity. In some formations in Pennsylvania, formation waters have salinities as high as 200,000 mg/L TDS. At these levels, the solubility of CO₂ is reduced by as much as 50 percent (Figure 2-37).
Salinity levels should be considered when estimating capacity and evaluating the suitability of potential candidate formations. It is recommended that a study of salinity levels of candidate formations for sequestration be performed during the site characterization of a sequestration project.

Subsurface Pressure
Saline formations suitable for CO\textsubscript{2} sequestration may be pressurized to levels equivalent to the hydrostatic pressure gradient or even higher (overpressurization). In these situations, the formation may be limited in its capacity for CO\textsubscript{2} storage due to the additional compression needed under these conditions. Hydrostatic pressurization or overpressurization should not be a concern in a depleted oil and gas fields because those formations typically have formation pressures much less than the hydrostatic gradient. In addition, regulatory limits on injection pressure can potentially reduce the capacity of a formation for CO\textsubscript{2} sequestration. The proposed regulations for CO\textsubscript{2} sequestration state that the injection pressure should not exceed 90 percent of the fracture pressure gradient for the cap rock which overlays a storage formation (EPA, 2008b).

Injectivity
The rate at which CO\textsubscript{2} can be injected into a subsurface formation is known as injectivity. Injectivity is determined by the characteristics of the formation as well as the type and size of well used, type of well completion, and number of wells. The key characteristic of the formation in determining injectivity is permeability, which is a measure of the relative ease with which a porous medium can transmit a fluid under a potential gradient. Porosity and permeability are not always correlative. A high-porosity sandstone
formation may have low permeability, and low-porosity sands may have high permeability due to natural fracturing.

A formation may be suitable for CO$_2$ sequestration given certain factors but offer too little permeability to meet capacity requirements. Determination of the hydraulic characteristics of the storage formation should be obtained during site characterization, including the use of pressure transient testing to provide estimates of formation permeability.

Wellbore Type

Horizontal and vertical wells are two types of injection wells that can be used for CO$_2$ sequestration. Generally, horizontal wells are expected to have a higher injection rate capability than vertical wells, particularly in formations with relatively small vertical thickness (DOE, 2008). Formations that are compartmentalized horizontally are likely to attain a higher CO$_2$ storage capacity using horizontal wells. Conversely, a formation with vertical flow barriers (interbedded low-permeability units) is more likely to have higher CO$_2$ storage capacity injecting in vertical wells.

Subsurface characteristics (e.g., thickness of the sequestration formation, permeability) at a particular site will be important in determining the type of well to be used for CO$_2$ sequestration.

Impurities

The presence of impurities in the CO$_2$ stream (e.g., sulfates, nitrates, hydrogen sulfide) may affect the capacity for CO$_2$ storage in geologic formations. Impurities in the CO$_2$ stream could affect the compressibility of the injected CO$_2$ and hence the formation volume needed for storing a given amount of CO$_2$. In saline formations, the presence of impurities affects the rate and amount of CO$_2$ storage through dissolution (solubility storage) and mineralization. For adsorption storage (e.g., coal beds), the presence of impurities can reduce the amount of storage available for CO$_2$ because some impurities (hydrogen sulfide [H$_2$S] and sulfur dioxide [SO$_2$]) preferentially adsorb because they have a higher affinity to coal than CO$_2$, thus reducing the storage capacity for CO$_2$ (Chikatamarla and Bustin, 2003).

Minimum Size

The minimum size of a subsurface formation being used for CO$_2$ sequestration is another important factor in assessing capacity. A minimum size (e.g., one based on anticipated CO$_2$ volumes) should be selected to eliminate any potential reservoir that will not be capable to receive CO$_2$ over the time span considered for CO$_2$ sequestration. Desirable demonstration sequestration projects have minimum sizes of approximately 71 million cubic feet (2 million cubic meters), which is equivalent to storing approximately 1 million tonnes of CO$_2$ (Burruss et al., 2009). A more relevant minimum size determination should be related to the size of the facility and the amount of CO$_2$ emissions to be sequestered. For example, a 1,000-megawatt (MW) coal-fired power plant that emits 8 million tonnes of CO$_2$ per year would require a minimum storage
volume equivalent of 400 million tonnes of CO₂, which is the total amount of CO₂ emitted over the typical 50-year lifespan of a power plant (Brennan and Burruss, 2006). A site which can store the CO₂ emissions from several facilities would be more useful than a site which can store the emissions from only one plant.

A subsurface formation may be suitable with respect to a variety of factors for CO₂ sequestration but lack sufficient areal extent to store the anticipated volume of CO₂ during the operational and post-operational lifespan of a facility. It is anticipated that more rigorous methods of capacity estimates, including computer modeling, would be required for long-term estimates for a particular site or facility.

2.5.5.3 Capacity Estimates

The Commonwealth of Pennsylvania emits approximately 132 million tonnes of CO₂ per year from approximately 70 large point sources (DCNR, 2009), as summarized on Figure 2-28 and in Table 2-2.

![Figure 2-38. Map showing major CO₂ sources by type in Pennsylvania (DCNR, 2009)](image)
Table 2-2. Major source categories in Pennsylvania

<table>
<thead>
<tr>
<th>Category</th>
<th>Millions tonnes CO$_2$/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power</td>
<td>116</td>
</tr>
<tr>
<td>Iron and Steel</td>
<td>3.2</td>
</tr>
<tr>
<td>Refineries</td>
<td>7.2</td>
</tr>
<tr>
<td>Cement</td>
<td>4.6</td>
</tr>
<tr>
<td>Gas processing</td>
<td>0.1</td>
</tr>
<tr>
<td>Ethylene production</td>
<td>0.5</td>
</tr>
<tr>
<td><strong>Sum</strong></td>
<td><strong>132</strong></td>
</tr>
</tbody>
</table>

Nearly 90 percent of Pennsylvania emissions are presently from power plants. Figure 2-39 shows the names, capacities, and locations of power plants within the Commonwealth. Power plants with capacities greater than 300 MW are denoted with red dots. It is more cost effective to focus on sequestering CO$_2$ from power plants of this size or larger. The majority of large power plants are located in the southwestern portion of Pennsylvania.

![Figure 2-39. Power plants larger than 300 MW](image)

Assessment of the capacity of geologic formations to store CO$_2$ is based on a number of different methodologies used by various researchers over the past decade. Although there is no single accepted methodology, most involve estimating the total pore volume for the geologic formation and then estimating the fraction of total storage that is available for potential storage. The Regional Carbon Sequestration Partnerships (RCSPs), including the MRCSP, use a consistent methodology for estimating storage...
capacity for each of the mechanisms by which CO₂ can be sequestered in subsurface formations, as discussed in Section 2.5.5.1.

The geological assessment of carbon sequestration potential conducted by the MRCSP during its Phase I study indicated that Pennsylvania has a large capacity for CO₂ sequestration. The results are summarized in Table 2-3 and indicate that storage in saline formations has the highest potential capacity for storage in Pennsylvania (MRCSP, 2005a). The assessment focused only on areas in the western part of the Commonwealth and did not include formations in the central and eastern portions of Pennsylvania, including deeper Ordovician and Cambrian formations. Thus, the total potential capacity for CO₂ storage in the Commonwealth is uncertain because this approach does not consider certain formations and areas of Pennsylvania.

<table>
<thead>
<tr>
<th>Sequestration Target</th>
<th>Storage Mechanism</th>
<th>Amount (GT)</th>
<th>Percent of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Saline formations</td>
<td>Volumetric</td>
<td>75.6</td>
<td>85.4</td>
</tr>
<tr>
<td>Carbonaceous shales</td>
<td>Adsorption</td>
<td>12</td>
<td>13.6</td>
</tr>
<tr>
<td>Depleted oil and gas fields</td>
<td>Volumetric</td>
<td>0.8</td>
<td>0.9</td>
</tr>
<tr>
<td>Unmineable coal beds</td>
<td>Adsorption</td>
<td>0.08</td>
<td>0.1</td>
</tr>
</tbody>
</table>

In Pennsylvania, the Oriskany Sandstone (a saline formation) has a potential storage capacity of 7.6 gigatons (GT) based on an areal extent of 29,022 square miles (mi²) and an average porosity of 10 percent. The deeper Medina Group/Tuscarora Sandstone has a potential storage capacity of 36 GT, based on an areal extent of 31,333 mi² and an average porosity of 8 percent. The primary reason the potential capacity of the Medina Group/Tuscarora Sandstone is larger than the Oriskany Sandstone is its greater gross thickness (average thickness of the Medina is 254 ft compared to the average thickness of the Oriskany, which is 45 ft, in Pennsylvania). Depleted oil and gas fields in Pennsylvania have a potential storage capacity of 0.76 GT. Of this, 0.31 GT (41 percent) is estimated to occur at depths greater than 2,500 ft (762 m) in the subsurface.

As mentioned previously, research at two potential sequestration sites in Pennsylvania indicates that the Oriskany provides much higher CO₂ injectivity and storage capacity than the Medina, due in part to much higher permeability at the Oriskany field (ARI, 2009). This demonstrates the need for the collection of site-specific field data which would provide more rigorous estimates for CO₂ storage capacity and injection potential.

2.5.6 Geochemical Considerations

CO₂ in the subsurface can also undergo a series of geochemical processes with the rock and formation fluid that can potentially increase storage capacity and effectiveness. As mentioned above, solubility trapping occurs when CO₂ is dissolved in formation waters. The primary benefit of solubility trapping is that once CO₂ is dissolved, it no longer exists as a separate phase, thereby eliminating the buoyant forces that drive it upward (IPCC, 2005). Following this, CO₂ will form ionic species as the rock dissolves, accompanied by a rise in the pH. Finally, some fraction may be converted to stable
carbonate minerals (mineral trapping), the most permanent form of geological storage (Gunter et al., 1993).

Geochemical considerations are critical with regard to the potential effectiveness of geologic carbon sequestration. Despite the importance of geochemical conditions, relatively limited research on these factors have been conducted related to potential injection target formations. The following discusses some of the key factors.

As discussed previously, the solubility of CO$_2$ is related to the salinity levels of the formation water. Salinity levels of Oriskany Sandstone formation water range up of 200,000 ppm. At these levels, the solubility of CO$_2$ is expected to be reduced by approximately 50 percent compared to its solubility at lower salinity levels (see Figure 2-37). Salinity levels should be considered when estimating capacity and evaluating the potential of potential candidate formations. It is recommended that a study of salinity concentrations in candidate formations be performed.

Consideration of the variable amounts of carbonate cement, clay minerals, and feldspar in sandstone formations is important because they may induce changes in initial pore size distribution. CO$_2$ injected into these sandstones could mobilize residual oil, dissolve into brine, and promote dissolution of the carbonates, feldspars, and clays. The brine could become supersaturated with dissolved solids. The kinetics of dissolution and precipitation and associated potential changes in pore size distribution will require further petrographic study, geochemical modeling, and testing. Experience from the EOR industry in dealing with fast reactions, such as gypsum precipitation, and their effects on injectivity may provide a useful analog to guide the operation of CO$_2$ sequestration facilities. The geochemical interactions and engineering impact of chemical precipitation on formation injectivity needs to be evaluated after collecting chemical and geochemical data at potential locations in Pennsylvania.

In summary, there is a need to conduct geochemical assessments to collect relevant data on brine composition and mineralogy in formations that might be considered for CO$_2$ sequestration. Additionally, it is recommended that simulation of potential chemical reactions using geochemical models be conducted. The aqueous geochemistry of host formations must be sufficiently well understood to predict whether chemical reactions will take place with the injectate, and if they do, what the consequences may be. If the interaction causes rapid precipitation, there is potential for permeability loss in the vicinity of the injection well, which could lower injectivity and reduce the lifetime of the injection well. On the other hand, precipitation of carbonate minerals, particularly after injection has ceased, could offer benefits by converting dissolved-phase CO$_2$ to a stable mineral form that would prevent migration away from the injection zone.

2.5.7 Accessibility

Important to the development of saline formations for geologic carbon sequestration is the accessibility in terms of geographic proximity to the wells that will be used for this purpose. Logic and economics would dictate that these injection wells would be located in close proximity to the plants where the CO$_2$ is generated. Thus, future studies should
focus on saline formations in areas of the Commonwealth where the largest generators of CO₂ are located (e.g., Beaver, Allegheny, Westmoreland, and Indiana Counties). However, facilities could be located in other areas because CO₂ can be transported via pipeline in a supercritical phase.

2.5.8 Injectivity

As discussed previously, the rate at which CO₂ can be injected into a subsurface formation is known as injectivity. Injectivity is determined by the characteristics of the formation as well as the type and size of well used, the type of completion, and the number of wells. Injectivity is a calculated variable that is derived from formation parameters including effective thickness, permeability, and reservoir pressure. Permeability is the key formation parameter for determining injectivity.

Estimates of formation permeability on a regional scale can be made using existing well data, if available, from cores with porosity and permeability data. Much of these data are available and can be accurately mapped in Pennsylvania for oil and gas fields that have a high density of cored wells. However, in other potential sequestration formations where there is little historical well activity (e.g., deep saline formations), such measurements are usually not available.

On a formation level, permeability can be challenging to estimate. It is typically not acceptable to apply the permeability results from a single cored well to the entire formation. There are a number of reasons for this, including heterogeneities within the formation, presence of faults or fractures, and changes in migration pathways, all of which can cause variations in the permeability of a formation. These factors govern the actual storage and accessible capacity of a single wellbore in the reservoir. Figure 2-40 outlines the importance of heterogeneity and its different scales, from a regional perspective to an individual core sample from an individual well.

![Figure 2-40. Examples of scale on formation heterogeneity (Salieri et al, 1968).](image)

One of the principal reasons that permeability can be difficult to determine is that the lateral continuity or discontinuity of permeability between wells is usually unknown.
Typically, the greater the number of wells penetrating a formation leads to greater certainty in determining the degree of continuity of permeability in a formation, or conversely, the degree of heterogeneity or differences in formation permeability. A larger spacing between wells usually results in greater uncertainty in formation permeability (Figure 2-41). Because a particular sequestration site may have little or no existing well data, it is evident that lateral continuity and heterogeneity can represent one of the principal components of uncertainty associated with a sequestration project.

Figure 2-41. Well spacing and the determination of formation heterogeneity (Barber et al, 1983).

Figure 2-42 illustrates the variation of permeability across a formation. As mentioned above, the results of core tests on a single well may not be representative of the entire formation. The figure displays the publicly available core data for 100 vertical wells installed in a formation in Alberta, Canada, to the core results of a single well. In this case, it is evident that the permeability derived from the core results of a single well would not be a representative permeability for the entire reservoir. This illustrates the need for data collection from as many wells as possible to estimate formation permeability.
2.5.8.1 Effects of Faults and Fractures

The presence of faults and natural and induced fractures in saline formations and oil and gas fields is also important in determining injectivity. For carbon storage sites to be economically optimal, they must have sufficient permeability (injection capability) and high storage capacity. Natural and induced fractures are critical for providing adequate contact and permeability with saline formations, coal seams, and petroleum reservoirs. For naturally fractured reservoirs (NFR), considerations of fracture spacing, fracture continuity, and fracture permeability are critical for injection capability and storage capacity considerations. For induced (man-made) fractures, parameters such as fracture pressure (initiation, propagation pressure, and in-situ stress) need to be measured. Although naturally induced fractures and man-made fractures may enhance storage capacity, they may also act as potential conduits for leakage.

2.5.8.2 Approaches for Focused Study

Use of regional well data can help focus efforts on potentially successful locations for sequestration projects; however, site-specific data collection is critical for accurate estimates of injectivity and other factors related to CO₂ injection. Specifically, tests of permeability, storage capability, fracture pressure, well tubing integrity, casing integrity, and injection packers should be conducted.

Formation permeability can be determined from hydraulic tests conducted at test wells at pilot-scale and demonstration projects. These tests include, but are not limited to, step-rate and constant-rate injection/falloff tests for determination of formation permeability, as well as determination of formation fracture pressure. Knowledge of these parameters can help refine estimates of storage capability at a particular sequestration location. In
addition, tests such as packer tests and mechanical integrity tests can be used to test the mechanical integrity of the injection wellbore. To test well and cap rock integrity, production logging tools such as temperature logs, radioactive tracers, and spinner logs can be used during well installation.

It is anticipated that injection wells used for CO$_2$ sequestration will have requirements similar to other waste injection wells with respect to demonstrating that the injection zone is isolated from other formations/zones. Geophysical logging tests are typically performed as part of this demonstration and include, but are not limited to, temperature survey logs, radioactive tracer surveys, oxygen activation logs, and cement logs.

2.5.9 Potential Impacts to Oil and Gas Reserves

Potential impacts of geologic carbon sequestration on oil and gas reserves have been recently exacerbated by drilling in the Marcellus Shale. Some within the industry have suggested that as many as 100,000 Marcellus Shale wells will be drilled. Many of these wells are drilled horizontally and achieve stimulation via massive hydraulic fracturing. It should be noted that the Marcellus Shale is the ultimate cap rock for the Oriskany Sandstone, although in some places other formations directly overlie the Oriskany Sandstone. The development of the Marcellus Shale creates difficulty with respect to its potential function as a cap rock and the resulting containment of any CO$_2$ sequestered in the Oriskany. In terms of the deeper saline formations, wells installed into these units will penetrate through the Marcellus Shale. In addition to the Marcellus, Pennsylvania is home to an active oil and gas industry that during a typical year drills thousands of producing oil and gas wells. These wells penetrate the entire geologic section from the Upper Devonian through the Silurian. Each of the wells drilled to the saline units will penetrate these same formations. The crucial elements of containment include well integrity (increased casing and cement requirements) and cap rock integrity which results in isolation of these producing formations. The preferred approach would be to designate specific areas for CO$_2$ injection only, away from areas of active oil and gas operations.

2.5.10 Current and Historical Oil and Gas Considerations

There are literally thousands of wells in the Commonwealth that date back to Drake’s well of August 1859. Cementing was introduced into the basin during the mid-1930s, and at that time, only the deep production string was cemented. Hydraulic fracturing was invented in the late 1940s-early 1950s. Therefore, many of the thousands of wells in the Commonwealth were completed without the use of cement or were plugged using techniques not appropriate for containment. In addition there are tens of thousands of “orphan” wells that were not properly abandoned. The probability of sequestered gas release from these wells is quite high. Current UIC regulations require an assessment of other wells within an area near the well, as well as an estimate of the expected plume area over the life of an injection project. There are methods that can detect old casings, and new cementing techniques are available. However, some areas of the Commonwealth may not be feasible for CO$_2$ sequestration because of the large number of deep wells.
The most likely migration pathways associated with future well construction are via gaps in cap rock and along non-sealing faults. In addition to these obvious pathways, there are potential difficulties with well construction that include casing string leakage and incomplete cement sheaths.

### 2.6 Summary and Recommendations

#### 2.6.1 Independent Review

The DCNR August 2009 publication “Geologic Carbon Sequestration Opportunities in Pennsylvania” was reviewed. The document was very well written and contained valuable information on the four units that were selected as potential CO₂ storage reservoirs. The primary focus of the report was in western and north-central Pennsylvania, where abundant subsurface geologic data is available through oil and gas drilling logs. The DCNR maintains a comprehensive database of oil and gas drilling records, and those data were used to generate structure contour maps and isopach maps of the various identified units. The data used to generate the maps primarily were derived from in-state resources. This section includes recommendations for gathering and evaluating additional data to build on the DCNR August 2009 report.

#### 2.6.2 Salt Caverns

Significant salt layers exist in the western and north-central portion of the Commonwealth. The DCNR has gathered information regarding the salt units and several cross sections have been developed. There are many more wells in the region that should be included in the evaluation and more detailed maps of the salt should be developed. This would involve detailed review of historical logs and data from other resources. The following is a brief summary of findings to date:

- The net thickness of the salt in the Salina Group is greatest in the north-central portion of the Commonwealth, with net thicknesses of just over 900 ft. Net thicknesses of salt in the southwestern portion of the Commonwealth are over 500 ft. Based on existing data, the greatest potential for salt cavern development and use would be in the north-central portion of the Commonwealth.

- The Salina Group consists of seven distinct units (A through G). The C unit and the G unit do not contain salt. The F unit appears to have the most significant layers of salt and would likely be the best target for storage caverns.

- The confining unit of the Salina would likely be the G unit, which is primarily composed of anhydrites, shales, and dolostones.

The following are some considerations and recommendations for data collection to fill key data gaps:

- Conduct more detailed mapping of the Salina Group, particularly the salt zones within this formation. Additional data can be obtained through detailed review of existing well data, geophysical seismic collection, gravity and microgravity.
surveys, and available data from surrounding states. Based on the proposed
design presented in the August 2009 “Geologic Carbon Sequestration
Opportunities in Pennsylvania” that was prepared by the DCNR, a net salt
thickness of nearly 900 ft would be required. This does not, however, take into
account the thickness of the interbedded shales, dolostones, and anhydrites.

- Once more detailed information is available on the salt layers, other salt cavern
development methods should be explored to obtain maximum potential for
volume development. In areas where thick salt layers are present between
interbedded shales, dolostones, and anhydrites, a horizontal cavern could
potentially be developed, thus reducing the net salt thickness that is required.

- Development of salt caverns will generate enormous amounts of high salinity
water that will have to be utilized as a commodity or reinjected into deeper
unused saline units. If the salt cannot be marketed and has to be disposed, the use
of these types of storage caverns could be cost prohibitive.

- Based on some historical isolated problems with gas storage in salt caverns,
proper characterization will be vital for permanent storage. In addition, the design
of the injection system will be important to reduce the potential for CO₂ leakage.

- The siting of any storage cavern will be important. If natural resources (e.g., oil
and natural gas) are located in units underlying the salt caverns, it may preclude
them from being developed.

- The structural geology along with detailed geotechnical and geomechanical
conditions would have to be understood for effective salt cavern storage. By
having a better understanding of the characteristics of the salt beds, the risk of
future leakage can be reduced.

2.6.3 Saline Units

We concur that the three saline formations identified as potential sequestration targets in
the DCNR study (i.e., Upper Devonian Venango Group, Oriskany Sandstone, and
Medina Group/Tuscarora Sandstone) have potential to be viable sequestration targets
provided site-specific evaluation is favorable. Other Upper Devonian sandstones,
Silurian Bass Islands Dolomite, Cambrian Gatesburg Formation, and deeper basal
Cambrian sandstones also offer significant potential and deserve closer evaluation. The
overall recommendation is to select candidate areas where sites large enough to store at
least 30-50 million tons of CO₂ appear feasible, and then collect missing data to confirm
the storage capacity and injectivity at one or more of those sites. The following are
recommendations to fill key data gaps and otherwise assess potential of the candidate
formations and areas:

- Other factors (e.g., proximity to sources, storage capacity, etc.) being the same,
formations deeper than the Upper Devonian should be given preference due to
potential for out-of-zone migration from the Upper Devonian sandstones via
improperly plugged wells. Certain counties also have large numbers of deep oil and gas wells, which may locally preclude sequestration in the deeper formations.

- Particularly for the potential sequestration targets below the Upper Devonian, seismic data can be very valuable to help identify favorable areas for sequestration related to structural position (and fracturing), integrity of cap rock, potential thickness of unit (e.g., basal Cambrian sandstones in Rome trough area), etc. After all seismic data available to DCNR and cooperating agencies are reviewed in consideration of well and other geologic data, it is recommended that additional seismic coverage be acquired to fill data gaps in high potential areas.

- On a site-specific basis, test potential cap rock intervals through permeability testing of core samples, petrographic analysis, and other means to confirm properties are favorable for containment. These data should be entered in the carbon sequestration network (CSN) database proposed in DCNR’s August 2009 report.

- Use the CSN database to collect fracture pressures for each cap rock interval obtained by laboratory testing or preferably field-determined means. Such data can be utilized to identify maximum injection pressures for CO₂ injection which will not compromise integrity of the cap rock.

- In evaluating potential candidate areas and formations, consider the potential increase in porosity and permeability that may result from stimulating the formation (e.g., through hydraulic fracturing and acidizing). Where available, the success of methods used for enhancing oil and gas production in the area (e.g., for the Oriskany Sandstone) should be reviewed and the most effective methods selected.

- Conduct geochemical testing for each target formation to determine whether the reaction with CO₂ may result in reductions in permeability, mobilization of hydrocarbons (e.g., for EOR), and solubilization (e.g., with respect to the salinity of formation waters).

- Develop three dimensional models portraying sequestrian reservoir and cap rock thickness, structure and key characteristics (e.g., permeability, fracture pressure, etc.) utilizing GIS and the CSN database.

- Evaluate feasibility of utilizing abandoned gas storage fields in Pennsylvania for carbon sequestration. Factors which should be considered include proximity to major CO₂ sources, capacity, integrity of wells in the field, data on effectiveness of containment, acquisition costs, etc.

- Identify at least three specific candidate sites for CO₂ injectivity testing considering proximity to a large source of CO₂, anticipated injectivity and storage capacity (following stimulation if necessary), presence of cap rock of suitable
thickness and integrity, lack of pathways for migration out of the injection zone (e.g., poorly plugged wells, faults, etc.), cooperation of landowners and leaseowners, etc. Ideally, sites selected will have potential for multiple formations which can undergo injectivity testing. Rank potential injectivity testing sites based on criteria discussed in this report and perform injectivity testing at the best candidate site(s).

Following successful pilot testing at a selected site(s), consideration for key components of the proposed rule for Class VI CO$_2$ geologic sequestration wells must be kept in mind when developing any potential storage field. These components include:

- Geologic site characterization to ensure that geologic sequestration (GS) wells are appropriately sited
- Requirements to construct wells with injectate-compatible materials and in a manner that prevents fluid movement into unintended zones
- Periodic re-evaluation of the area of review around the injection well to incorporate monitoring and operational data and verify that the CO$_2$ is moving as predicted within the subsurface (e.g., modeling)
- Testing of the mechanical integrity of the injection well, ground water monitoring, and tracking of the location of the injected CO$_2$ to ensure protection of underground sources of drinking water
- Extended post-injection monitoring and site care to track the location of the injected CO$_2$ and monitor subsurface pressures
- Financial responsibility requirements to assure that funds will be available for well plugging, site care, closure and emergency and remedial response.

2.6.4 Regional Data Gaps

The Commonwealth of Pennsylvania has a rich history of oil and gas, starting with the famous Drake well. Even so, the majority of the oil and gas wells have been drilled in the western and north-central portions of the Commonwealth. Using a cut-off of 2,500 ft (the minimum recommended depth for CO$_2$ storage), all the oil and gas wells in DCNR’s WIS that were drilled below that depth are shown in Figure 2-43. There are approximately 67,000 wells in WIS that meet this criterion. The vast majority of these wells are located in the Appalachian Plateau Geologic Province, with a relatively limited number of wells in the other provinces. Only a few wells are identified as being below 2500 ft in the southeastern portion of the state. Unfortunately, this area coincides with many of the larger sources of CO$_2$.

Based on the distribution of well data, it may seem that geologic storage in the eastern portion of the Commonwealth may not be suitable. However, the lack of data pertaining
to these smaller geologic provinces should not preclude the possibility of long-term CO$_2$ storage. Geologic exploration using geophysics and drilling test wells will help to obtain a better understanding of the stratigraphy and potential for long-term CO$_2$ storage potential in the eastern portion of Pennsylvania. All such data gathered should be incorporated into the CSN database.

Figure 2-43 – Oil and gas wells in DCNR’s Wells Information System database greater than 2,500 ft in depth.
3.0 LEGAL LIABILITY ASSESSMENT: LEGAL ISSUES AND RISKS IN GEOLOGIC CARBON SEQUESTRATION

3.1 Introduction: Overview of Legal Risks and Issues

Any new technology faces legal uncertainties that can pose barriers to its implementation. In the case of GS of CO$_2$, there are three principal areas of uncertainty that pose potential implementation barriers. First, it is unclear who may own the rights to inject CO$_2$ into the subsurface—the owner of the surface rights or the possible owners of the mineral estates—and it is unclear how to acquire those rights. The second uncertainty is posed by the question of the risks of liability—what are the risks, who bears the risks (e.g., generators, transporters, arrangers, property owners, mineral rights owners), and how can and should these risks be managed or spread (insurance, pooled funds, immunity). The third uncertainty relates to the regulatory regime that will attach to these activities—who will regulate (state, federal, local), pursuant to what authority will they regulate, and how will they regulate (what will be the substantive requirements). This report will therefore evaluate each of these areas—property rights, liabilities and regulatory regime—and suggest alternative legal and policy structures that might be employed, with appropriate legislative action, to assist in the safe and effective implementation of a CCS network in the Commonwealth of Pennsylvania.

The proposed CCS network will involve capture of the CO$_2$ emissions at various types of manufacturing plants, transport through a pipeline, and compression of the CO$_2$ to a supercritical liquid phase and injection by way of deep wells into subsurface geologic formations. The issues presented by carbon capture and pipeline transport do not present particularly unusual issues. Carbon capture does not present legal issues that are particularly different from implementation of any other air pollution control technology. Similarly, pipeline transport does not present unusual regulatory, liability or regulatory issues; indeed, there are already pipelines transporting CO$_2$ for commercial use in the United States. This legal analysis will therefore focus on the issues relating to geologic sequestration, and simply note where there are significant issues relating to the other stages.

In GS, CO$_2$ is compressed to a supercritical liquid phase and injected into formation where it can be contained permanently (on the order of thousands to millions of years). Carbon dioxide is currently injected into oil and gas wells for recovery of oil and gas and it can be sequestered in depleted formations. In Pennsylvania, it can also be injected into pore space in deep saline formations, oil and gas reservoirs, carbonaceous shales, deep coal bed, and thick bedded salt. In the case of sequestration using salt beds, water will be injected to create a cavern by dissolving and removing the salt and CO$_2$ will then be injected into the cavern.

We will first investigate pertinent property rights issues and examine the nature of the property rights that will be implicated when CO$_2$ is injected, an issue often expressed as the right to pore space. We will examine the various areas of law that will inform how the courts might rule based on Pennsylvania law. Further, we will examine the law of other states where the issue of underground injection has been more specifically
addressed. We will examine who owns the right to the pore space (or the right to inject) and how it could be acquired to establish a CCS network. This will involve a discussion of both the nature of the right that would be acquired (fee title, easement, lease) and how it would be acquired, including the questions such as whether the Commonwealth already holds the right and whether there is a right of eminent domain. In this analysis, we will examine analogous situations, such as the measures employed to develop natural gas storage sites. We will conclude with recommendations for dealing with these issues, including consideration of state model laws, legislation before the Pennsylvania General Assembly, and the role that could be played by state and federal lands.

The report will next address potential liabilities that could arise from GS, including the risks of liabilities for injury or property damage caused by seismic displacement or surface collapse, ground water contamination, sudden release of CO\textsubscript{2} or contaminants, such as hydrogen sulfide to the surface, and displacement or contamination of resources. We will describe the legal theories that might apply to create liability and who might be held liable. At the current stage, liability cannot be ruled out; there will be a risk of liability to all parties who may be involved. We will therefore conclude by examining the possible roles for the state and mechanisms that will minimize risks and manage liabilities. A separate section of this report (Section 5.0) will deal more extensively with the role of insurance in spreading risk and minimizing liability.\footnote{In the property rights and liabilities section, the report will also deal with the question of whether title to or ownership of carbon dioxide will be a factor in assessing liability. As in the case of liability for releases of hazardous and toxic substances, the issue of title to the substance will likely be of only incidental importance to liabilities for personal injury and property damage. Title would be important if carbon dioxide were a valuable commodity. We will proceed with the assumption that captured CO\textsubscript{2} will not have commercial value.}

The report will next examine the pertinent regulatory framework. It will first address the regulatory framework for dealing with climate change which in turn will drive the need for carbon sequestration. Because this framework is rapidly evolving and most responsibilities are not fixed, we will primarily examine how the limited laws and regulations in place treat geologically sequestered carbon, the treatment of geologic sequestration in major pending bills, and some of the considerations applicable to responsibility and credit for geologically sequestered CO\textsubscript{2} that may be released in the future.

Well structured regulation represents perhaps the best mechanism for reducing damages from GS and thereby reducing risk. A predictable and comprehensive regulatory regime also reduces uncertainty and will facilitate implementation.\footnote{An example of this phenomenon was presented by the adoption of the Municipal Waste Regulation, 25 Pa. Code § 94.2 (1998), which vastly increased the environmental protectiveness of the regulatory regime for municipal waste. Following the adoption of these regulations, permitting of new, sound municipal...} The report will therefore
next turn to the regulatory regime that will likely govern GS and measures that could be taken by Pennsylvania to create a regulatory structure that would promote the safe and predictable implementation of GS technology. We will describe the geologic sequestration regulations that have been proposed under the underground injection control program of the federal Safe Drinking Water Act (the “Proposed GS UIC Regulations”). We will next examine the other state and federal statutes that could pertain to GS and either authorize state or federal regulation or response authority or provide a basis for imposing liability. We will also examine briefly some of the regulatory issues presented by the treatment of saline water at the mouth of the injection well. Finally, we will examine the regulatory approaches taken or under consideration in other states, internationally and in proposed state and federal legislation. We will also describe potential regulatory approaches that Pennsylvania might take.

The CCS network will ultimately need to be described in a series of contractual relationships. We will therefore next describe some contractual issues. This section will conclude with a summary of our recommendations.

3.2 Property Rights Issues

3.2.1 Nature of the Right to Pore Space

Pennsylvania recognizes three discrete estates in land: (1) the surface estate; (2) the mineral estate; and (3) the right to subjacent support. Because each of these estates are viewed as being separate, distinct, and severable, each estate may be held by a different owner. Pennsylvania’s rich history of coal mining and oil and gas development makes it common for the ownership of mineral rights to be severed from the ownership of the surface estate. Pennsylvania courts have recognized the mineral owner’s right to protection from unreasonable encroachment or damage and have held that the surface

(...continued)

waste landfill capacity increased, so that importation of municipal solid waste from other states into the Commonwealth became a concern.


5. Chartiers Block Coal Co. v. Mellon, 25 A. 597, 598 (Pa. 1893) (“Formerly a man who owned the surface owned it to the centre of the earth. Now the surface of the land may be separated from the different strata underneath it, and there may be as many different owners as there are strata…”).

owner’s interest in the surface estate is generally subject to the mineral estate.⁷ Although oil and gas differ from other minerals because of its capability for subsurface movement,⁸ Pennsylvania courts have considered oil and gas to be “minerals.”⁹

In evaluating the respective rights of the surface and mineral estate owners, Pennsylvania uses basic contract law principles focusing on the parties’ intent, the language of the conveyance and the circumstances surrounding the transaction.¹⁰ Once an interest in a mineral estate is conveyed from the surface owner to another party, the surface owner’s interest becomes subject to the mineral estate and the rights and incidents that accompany it.¹¹ The court has gone further to specify that the owner of the mineral estate has the right to use as much of the surface as is reasonably necessary to properly develop and exploit its minerals.¹² A lease of all oil and gas rights creates a determinable fee in the oil along with an attendant property interest in the surface estate.¹³ Rights to different minerals can be conveyed separately, so that coal rights, oil and gas rights, salt rights, and carbonate rights might all be held by separate owners.¹⁴ Although the issue is far from clear, it appears that the property rights in natural gas and oil, unless explicitly conveyed to another party, belong to the surface owner of the land.¹⁵

Pennsylvania courts have also found that the law relating to property rights in oil and gas ownership is similar to that which governs the ownership of mineral rights and coal.¹⁶ Since oil and gas are considered as ‘minerals,’ the surface owner may choose to sever the

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⁸ Westmoreland Gas Co. v. DeWitt, 18 A. 724, 725-27 (Pa. 1889) (“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.”).
¹¹ Brady, 425 A.2d at 729.
¹² Chartiers, 25 A. at 599.
¹⁴ Hoge, 468 A.2d at 1383.
¹⁵ Id.
¹⁶ Duquesne Natural Gas Co. v. Fefolt, 198 A.2d 608, 610 (Pa. Super. 1964) (“So far as the law of property is concerned the ownership of oil and gas is similar to that of coal…”).
mineral interest from their estate. Specifically, the Pennsylvania Supreme Court has indicated that, “Gas is a mineral, though not commonly spoken of as such, and while in place it is part of the property in which it is contained…Gas necessarily belongs to the owner in fee, so long as it remains part of the property.” The Court in Hoge did, however, state that ownership of gas could be lost through subsurface migration to neighboring property.

Although this law may provide guidance on the treatment of CO₂ as a useful product, for the purpose of this study we must address the right to the permanent disposal of CO₂ as a waste product. The best method of approximating how property laws will be evaluated with regards to GS projects is to consider analogous activities. Pennsylvania’s property law with respect to the right to store natural gas can be analogized to CO₂ disposal. The right to natural gas storage is retained by the surface owner unless it is severed through a lease or conveyance. Pennsylvania courts have indicated that the surface owner maintains the right to natural gas storage unless the oil and gas lease explicitly conveys the right to store gas to another party.

Where the storage right has been conveyed, this storage right may not apply to CO₂ unless it is deemed to be a ‘gas’ for purposes of the storage lease. In instances where the storage right has been conveyed, the right to store CO₂ may not apply unless it is deemed to be a ‘gas’ for purposes of the storage lease. In instances where the storage right has been conveyed, the right to store CO₂ may not apply unless it is deemed to be a ‘gas’ for purposes of the storage lease.

17 Id.
18 Id.
19 There will likely be no market for the stored CO₂, thus it is likely that it will be considered to be a waste. Although CO₂ emitted into the ambient atmosphere is not a “solid waste,” it is likely that CO₂ injected into the subsurface will be classified as such. The federal Resource Conservation and Recovery Act defines “solid waste” as “any garbage, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations, and from community activities.” 42 U.S.C. § 6903(27). The Pennsylvania Solid Waste Management Act defines “solid waste” as “Any waste, including but not limited to, municipal, residual or hazardous wastes, including solid, liquid, semisolid or contained gaseous materials.” 35 Pa. Stat. Ann. § 6018.103. Because the carbon dioxide and other materials will have been compressed to a fluid, they will be a discarded liquid resulting from industrial or commercial activities and therefore a solid waste. If one determined that it was not a liquid because that definition would require that the substance be a liquid at ambient temperature and pressure, the material would still be a solid waste because it would be a “contained gaseous” material.

21 Id. at 778.
right to store gas was previously conveyed, it may be necessary to acquire the right to store CO₂ from both the surface owner and the gas storage owner. On the other hand, the need to acquire the right to store CO₂ from the gas storage owner may only be necessary in instances where the CO₂ will be stored in an already depleted oil or gas reservoir intended to operate as a natural gas storage facility.

Another analogy that can be drawn to GS with regards to Pennsylvania property law is to the ownership of coal bed methane (CBM). Ownership of CBM is comparable because it has economic value and can be recovered through the use of technology. Since CBM is classified as a mineral, the Pennsylvania Supreme Court in United States Steel Corp. v. Hoge found that the owner of the coal estate possessed ownership rights to the CBM.22 In providing the rationale for its decision, the Court stated that: “[A]s a general rule, subterranean gas is owned by whoever has title to the property in which the gas is resting.”23 Nevertheless, the Court in Hoge also stated that the coal owner’s interest reverts back to the surface owner by operation of law at some time subsequent to the removal of coal.24 Considering the reversion of the coal owner’s interest and the lack of a discussion regarding pore space ownership, it is unclear whether the owner of the mineral estate in coal would be permitted to inject CO₂ into the coal for permanent sequestration, since this could result in a permanent interest in the estate. As a practical matter, however, CO₂ would likely only be injected into unmineable coal beds. Therefore, the owner of the coal rights would likely retain the ownership right to the coal bed stratum and the right to use that stratum for GS.

Extension of the treatment of CBM to storage in other formations would suggest considerable uncertainty. While one would need to obtain the rights to extract salt from a salt bed from the owner of the mineral estate, the cavern left behind could be considered the property of the surface owner.25 On the other hand, since a significant amount of the salt formation would necessarily be left in place, the owner of the mineral rights might retain ownership in the cavern. The treatment of CBM might also suggest that the surface owner would retain the rights to space (essentially caves) in deep karst formations and the pore space in sandstone formations. Karst formations are subterranean landscapes shaped by the dissolution of layers of soluble bedrock, usually carbonate rock such as limestone or dolomite. Nevertheless, the fact that the minerals have not been removed could also lead a court to conclude that the mineral owner retains those rights.

The right of ownership in CBM is tempered by the rights of other property owners. The law attempts to protect each estate owner’s right of enjoyment in his strata without

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22 468 A.2d at 1384.
23 Id.
24 Id. at 1383.
infringing upon existing property rights. The law provides that the mineral estate owner has the right to reasonably use the surface estate to access their mineral property. The mineral owner’s right to reasonable use is somewhat limited because they must demonstrate “due regard” to the surface owner’s interests.

The right of the mineral owner to reasonably use the surface estate can be interpreted as permission to drill through the coal seam to access property interests in oil or gas. This would require any GS facility owner operating in a mineral estate with a coal seam to also obtain a fee interest in the coal seam underlying the surface for CO₂ storage space. Furthermore, any CO₂ storage space located beneath a coal seam will most likely have to penetrate the coal seam when drilling the injection well, making some part of the coal seam unworkable and entitling the owner to a right of compensation.

In these instances, additional protections are needed to ensure the right of the coal seam owner to access and mine coal. Any law protecting these competing property interests should balance the rights of the owners and operators of a CCS network against the rights of coal owners. Likewise, the owners of a CCS network must take into consideration the rights of CBM owners when conducting operations and summarily avoid infringing on the CBM owners’ rights to access and withdrawal. The best suggestion for managing these competing property interests is legislative action clearly defining the rights of the respective property owners. The legislation should also clearly define the respective rights to surface support and the possibility of subsidence to the surface.

An additional analogy can be drawn between GS and potable ground water use to the extent that GS utilizes saline formations (also known as saline aquifers). Pennsylvania follows the “reasonable use” doctrine which maintains that the surface owner is able to use or withdraw as much water as it desires so long as the water is used in a reasonable and beneficial manner. Use of water in a capacity that is unrelated to the land is also considered per se unreasonable. Since GS is related to the land, GS would likely satisfy this criterion and be considered a reasonable use. While it is unclear whether this doctrine would apply at all to saline formations, a surface owner might argue that the

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26 Chartiers, 25 A. at 595-597.
27 Id. at 599.
28 Id.
30 Id.
right to inject CO₂ represents a use of ground water to which it is entitled. This is an issue that will require clarification.

In summary, various competing interests must be considered when evaluating the impact of a GS facility on the rights of property owners. The operation of the facility may directly conflict with ownership of the mineral estate through the occupation of the strata where the minerals can be extracted. In addition, the operation of a CCS network may directly impede a mineral owner’s access to, and the surface or mineral estate owner’s right to use the surface to access, subsurface property. A CCS network might also negatively impact ground water property rights or a previously conveyed natural gas storage right. The legislature will need to clarify the competing and undecided interests in property law. In the absence of legislation, the CCS network owners and operators will need to negotiate separate agreements with surface owners, coal seam owners, if any, the owners of other mineral rights, and the owners of subsurface oil and gas production and storage rights in all areas to which the CO₂ might migrate. The CCS network owner must be sure to receive a permanent property interest in the strata and to define the portion of the strata that will be to be used for GS.

3.2.1.1 Pennsylvania Right of Capture/Reasonable Use: Oil, Gas, and Water

Pennsylvania law relating to oil, gas, and ground water, respectively, may also be applicable to GS. Because these substances migrate into the subsurface, the applicable law may be applied to CO₂ after it is injected and migrates.

A court may apply the inverse of the rule of “capture” in oil and gas law to GS. In Westmoreland Gas Co. v. DeWitt, over one hundred years ago, the Pennsylvania Supreme Court recognized the rule of capture. In this case the Court first set forth the premise that oil and gas are to be considered minerals ‘ferae naturae.’ In its analysis, the Court stated that oil and gas belong to the owner of the land so long as they are on the owner’s premises and subject to control. Conversely, if oil and gas migrate to a second property, title to the gas vests with the property owner that captures the oil and gas. The Court held that “if an adjoining, or even a distant, owner, drills his own land, and taps your gas, so that it comes into his well and under his control, it is no longer yours, but his.” Thus, Pennsylvania’s rule of capture equates possession of oil or gas with title.

At least one state, Texas, has recognized a negative rule of capture under certain circumstances. In Railroad Comm’n v. Manziel, the Texas Supreme Court stated: “[J]ust as under the rule of capture a land owner may capture such oil or gas as will migrate from adjoining premises to a well bottomed on his land, so also may he inject into a formation substances which may migrate through the structure to the land of others, even if it results in the displacement under such land of more valuable substances with less valuable

32 18 A. at 725.
33 Id.
34 Id.
substances.”  

_35_ Manziel involved the migration of water from a secondary enhanced oil recovery project and concerned the extraction and storage of hydrocarbons.  

Although the negative rule of capture has not received widespread support, it is significant because of the Texas Supreme Court’s indication that an injection should be treated similarly to a withdrawal with regard to mineral rights.

The law relating to ground water use may also be considered, particularly with respect to injections into deep saline formations. Pennsylvania follows the “reasonable use” doctrine with regards to ground water rights.  

The “reasonable use” doctrine allows a surface owner to withdraw as much water as they deem appropriate provided that the ground water is used in a reasonable and beneficial manner. Although this is a relaxed standard, the Court has generally ruled that it is unlawful for the landowner to use fresh ground water in a capacity unrelated to the land. GS would likely be considered a reasonable use.

3.2.1.2 Subsurface Trespass

There is a risk that subsurface injection of supercritical CO\(_2\) may be considered a trespass rather than the inverse of capture. In order for an adjacent property owner to prevail upon a claim for subsurface trespass in the GS context, it is likely that he must demonstrate that he has suffered both reasonable and foreseeable damage as a result of the unauthorized use of pore space. Even if an injecting party holds the appropriate rights regarding the tracts actually used for GS, the injecting party could be found liable for subsurface trespass if CO\(_2\), whether injected or sequestered, migrates into neighboring tracts. Various property rights and legally recognized interest may be impacted by the storage of CO\(_2\) in the pore space during GS operations. Specifically, the legal rights of surface owners, mineral owners, and lessees of mineral estates can be negatively affected by GS activities.

GS operations can be analogized with natural gas storage, EOR, and waste water storage. Pennsylvania law on subsurface trespass is relatively undeveloped in comparison to the laws of other jurisdictions. Below is a review of how United States jurisdictions have handled subsurface trespass issues with regards to natural gas storage, EOR, and waste water storage.

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35  361 S.W.2d 560, 568 (Tex. 1962).
36  361 S.W.2d at 561-62.
37  _Id._ at 568.
38  _Brown_, 42 A. at 886.
3.2.1.3 Natural Gas Storage

Natural gas storage has been an ongoing practice in the United States for almost one hundred years.\(^{39}\) The natural gas storage process involves the injection of natural gas into the subsurface for temporary storage.\(^{40}\) This process is the most analogous to GS operations because it involves the injection of a gas into an underground pore space for storage. The primary difference between the current methods of storing natural gas and the proposed GS operations is that the current process of natural gas storage is finite in duration and involves a continuous cycle of gas injections and withdrawals. Also, one could argue that natural gas storage involves the storage of a valuable commodity, while GS would involve the storage of CO\(_2\), which is a waste product. Nevertheless, because natural gas storage involves injection, storage and monitoring, a CCS network would present issues similar to those faced by a natural gas transmission and storage facility.

In an early case, *Hammonds v. Cent. Kent. Natural Gas. Co.*, the Kentucky Court of Appeals held that natural gas injected for storage was released back into nature and must be considered abandoned and thus, had no owner.\(^{41}\) The court held that no trespass occurred when natural gas migrated to a neighboring property because the injector no longer possessed title to the natural gas once it was injected for storage.\(^{42}\) Following the theory of ferae naturae, the court indicated that once the gas was returned to nature that it was subject to appropriation by the first person able to capture the gas.\(^{43}\) Under the court’s reasoning, the injecting party cannot be found liable for subsurface trespass because once the gas migrates to a neighboring tract, since it is no longer the property of the injecting party.\(^{44}\) Other courts have rejected this theory of ownership rights in the context of natural gas storage.\(^{45}\) Nonetheless, it may be more widely accepted in dealing with CO\(_2\), which has no commercial value.

Texas courts have held that natural gas injected for storage remains the personal property of the injecting party and cannot be ‘captured’ or ‘abandoned’ even if the gas migrates beneath neighboring tracts.\(^{46}\) The fact that the injecting party retains title in the natural gas raises the possibility of a successful cause of action for subsurface trespass. In *Lone Star Gas Co. v. Murchison*, a gas storage company acquired the right to natural gas

\(^{39}\) Interstate Oil Compact Comm’n, *A SURVEY OF UNDERGROUND NATURAL GAS STORAGE PROJECTS IN THE UNITED STATES* (1943).


\(^{41}\) 75 S.W.2d 204 (Ky. Ct. App. 1934).

\(^{42}\) *Id.* at 205.

\(^{43}\) *Id.*

\(^{44}\) *Id.*


\(^{46}\) 353 S.W.2d 870, 876 (Tex. Civ. App. 1962).
storage and did not lose title even when the gas migrated to another property.\(^{47}\) In *Emeny v. U.S.*, the Federal Court of Claims, applying Texas law, held that the owners of the surface estate retained all the rights to geological subsurface pore space storage.\(^{48}\) Neither case, nor any other Texas case, actually addresses the issue of subsurface trespass. The courts’ reluctance to address subsurface trespass may be attributable to the difficulty in proving actual damages with subsurface migration of natural gas beneath a neighboring tract of land.

In *Mapco v. Carter*, the Texas Supreme Court found that the mineral owner possessed the rights to the subsurface storage area, entitling him to compensation from use of the storage area.\(^{49}\) In this case, the mineral owner had created a space within a salt cavern for natural gas storage. Salt is considered a mineral under Texas law, as it is under Pennsylvania law. Since the walls of the cavern were constructed out of an established mineral, the mineral owner had the exclusive right to storage. It is important to note that *Mapco*’s holding may be limited to instances when the storage space is comprised of a mineral. This decision would be directly applicable to use of salt formations for CO\(_2\) disposal.

Although no jurisdiction has recognized a claim for subsurface trespass based on the migration of natural gas from a reservoir to a neighboring tract of land, a court would likely rule differently if a neighboring landowner suffered actual and calculable damages. The owner of any estate, surface, mineral or subjacent support, who can demonstrate actual damages to their estate as a result of CO\(_2\) migration would likely be able to prevail on claims of trespass, nuisance or negligence. Most courts would be unlikely to issue an injunction to stop GS activities, however, if the sequestration or injection was conducted with the support of a regulatory permit. To avoid a claim for damages based on the foregoing claims, it would be wise to acquire sequestration or storage rights from each and every affected party. Moreover, if CCS comes into widespread use, storage capacity will be a valuable commodity and using it without compensating the owner will damage the owner, who will be unable to sell it to others. Therefore, the cautious approach will require that the CCS project sponsor include obtaining all the property rights to the storage reservoir for the area where the injected CO\(_2\) could reasonably move.

### 3.2.1.4 Enhanced Oil Recovery Issues

For more than forty years, the United States Oil and Gas Industry has injected and effectively stored CO\(_2\) in tertiary EOR operations. As a result, there is already in place a CO\(_2\) industry infrastructure comprising over 13,000 permitted CO\(_2\) injection wells, with more than 6,000 of those wells being active. Although EOR operations function with the intent of reusing the maximum amount of the injected CO\(_2\), the Marcellus shale committee contends that at least 50% of the injectable CO\(_2\) is incapable of being

\(^{47}\) *Id.*, 353 S.W.2d at 876.


\(^{49}\) 817 S.W.2d 686, 687 (Tex. 1991).
recovered for reuse and remains stored in the underground formation.\textsuperscript{50} The CO\textsubscript{2} stored in the EOR process is physically similar to the CO\textsubscript{2} that would be stored as part of the GS process. Texas has conducted more EOR operations than other states and has developed the most comprehensive laws regarding subsurface trespass in EOR operations. While Texas probably recognizes a cause of action for subsurface trespass, the issue is far from decided.

In \textit{Railroad Comm'n of Tx. v. Manziel}, the Texas Supreme Court indicated that the traditional rules of trespass may not be appropriate for subsurface trespasses when the activity is aimed at benefitting the public in a case involving the migration of water from a secondary recovery project.\textsuperscript{51} The Court’s discussion also suggests that a regulatory order, issued in the public’s interest, may limit a traditional trespass claim. In its reasoning, the Court indicated that the issuance of an order that includes a finding of fact that no harm will result to neighboring properties, would not prevent a private cause of action in tort, but could limit the actual damages awarded. The Texas Court went further by stating that a trespass requires an actual injury and that the injury should not be inferred when the physical invasion occurs far below the surface of the land. Texas courts have also recognized a cause of action for subsurface trespass being challenged is in the context of secondary recovery of fracture treatment.\textsuperscript{52} Still, no successful cause of action for subsurface trespass for migration of CO\textsubscript{2} during EOR operations has succeeded, presumably, because of the difficulty associated with proving damages.

3.2.1.5 Waste Water Storage

For decades, U.S. companies have injected waste water into deep subsurface geological formations. Instances have occurred where injected waste water has laterally migrated to the subsurface of an adjacent property. While courts have not recognized a cause of action for subsurface trespass in instances where waste water has migrated to a neighboring property, they have recognized the possibility of a successful cause of action for the landowner who suffers actual intrusion and actual harm due to an encroachment of waste water onto their property.\textsuperscript{53}

In \textit{Chance v. BP Chemicals, Inc.}, the Ohio Supreme Court held that a cause of action for trespass against the injecting party is not insulated from liability merely because the

\begin{itemize}
\item http://www.pamarcellus.com/MSC-Fracing.pdf.; Conversely, other commentators suggest that no one is certain that the unrecovered CO\textsubscript{2} remains in the subsurface pore space. Because these commentators are unsure as to the whereabouts of the unrecovered CO\textsubscript{2}, the CO\textsubscript{2} is considered “lost.”
\item 361 S.W.2d at 568.
\item \textit{Mission Resources, Inc. v. Garza Energy Trust}, 166 S.W.3d 301 (Tex. App. 2005).
\end{itemize}
injecting party obtained the appropriate regulatory permit for the activity.\textsuperscript{54} The injecting party, in this case, obtained permits for three sandstone injection wells from the State of Ohio and the EPA. The plaintiffs alleged that injectate from BP’s injection wells had laterally migrated below their property, unlawfully interfering with their property rights. The plaintiffs contended that the defendants’ injections made the subsurface unusable for the purpose of oil and gas extraction. Their complaint alleged that the property value was decreased because of the damage caused by the pressure used by the defendants to inject the waste into the substrata of their property. The plaintiffs requested $1 billion in general and punitive damages based upon claims for trespass, nuisance, negligence, strict liability, and fraudulent concealment.

The trial court limited the cause of action to trespass and granted directed verdicts on behalf of the defendants with regards the claims for ultra-hazardous activity, fraud and nuisance. Although the Ohio Supreme Court stated that the operation of wells pursuant to a permit did not preclude liability for trespass, it also stated that the aggrieved party had the burden of proving that a trespass occurred.\textsuperscript{55} The Court explained that subsurface rights to exclude invasions are valid so long as the invasions actually interfere with reasonable and foreseeable use of the subsurface. Thus, physical damage or interference with use must be shown to be associated with any alleged trespass and the Court found the plaintiffs’ claims too speculative.

In another decision, Mongrue v. Monsanto, the Fifth Circuit Court of Appeals found that a subsurface trespass claim was a valid cause of action and that a valid permit does not preclude a claim of trespass for the disposal of waste water through an injection well.\textsuperscript{56} The plaintiffs in this case also alleged that the waste water injected by the defendants had migrated to the subsurface of their property and that this constituted a taking without compensation. Although a cause of action for subsurface trespass was not the focus of the case and damages were not allowed in this instance, the court did explicitly indicate that a cause of action for subsurface trespass may exist.

In an unpublished opinion, the Texas Court of Appeals stated that “some measure of harm must accompany the migration for there to be impairment.”\textsuperscript{57} The court noted that the legal trend is to recognize that property owners do not have the right to exclude deep subsurface migration of fluids. Nevertheless, the court did expressly indicate that if the migrated waste had caused some measure of harm, that the owner of the estate would be entitled to some level of damages from the injector.

Both Chance and Monsanto suggest that if the property rights are not obtained, CCS network owners and operators may be exposed to liability for subsurface trespass.

\textsuperscript{54} 670 N.E.2d 985, 993 (Ohio 1996).
\textsuperscript{55} \textit{Id}.
\textsuperscript{56} 249 F.3d 422 (5th Cir. 2001).
\textsuperscript{57} \textit{Lone Star Gas Co.}, 353 S.W.2d 870.
Conversely, both cases indicate that the burden of proof is on the aggrieved party to prove the trespass occurred. Proving actual damages serves as the primary barrier to succeeding on a claim for subsurface trespass for waste water storage. The landowner may be able to prove ownership of the subsurface strata and perhaps an actual intrusion, however, proving actual damages can be far more challenging.\textsuperscript{58}

### 3.2.1.6 Fracing in Marcellus Shale

The law relating to hydraulic fracturing (also known as “fracing”), used to extract natural gas from gas reservoirs in shale formations such as Marcellus Shale natural gas formation, presents another useful analogy to GS. Fracing a well involves cementing a well casing at a desired vertical depth and firing a charge into the formation at the end of the wellbore. The charge perforates the steel casing, cement and shale formation providing a pathway for fresh water injection. The injection consists of 99.5% water and sand, along with a miniscule amount of additives that are mixed into the wellbore and are not exposed to the environment. The injection is administered under pressure and fractures the rock adjacent to the wellbore.\textsuperscript{59}

Once the injection fractures the rock and there is a corresponding decrease in water pressure, approximately 20\% of the injection fluid returns to the surface through the wellbore’s protective casing. The released injection fluid is gathered at the surface for transportation to a permitted disposal facility. Additional amounts of water used in the fracing process remain in the shale formation at a depth of approximately one mile. These additional amounts gradually return to the well site and are collected at that time for removal and treatment. Fracing is analogous to GS activities in that it involves the injection of a substance for storage in subterranean pore space for an extended period of time. Unlike GS, eventually the injection liquid used in fracing will return to the surface.

Since fracing in the Commonwealth of Pennsylvania is a relatively new phenomenon, there is an absence of law on the issue of ownership of the underground pore space and liability for subsurface trespass. Other jurisdictions have analyzed subsurface trespass issues in conjunction with fracing. Specifically, the Texas Supreme Court in \textit{Coastal Oil & Gas Corp. v. Garza Energy Trust} found that the victim of the encroachment must suffer an injury in fact in order to have an actionable trespass claim.\textsuperscript{60}

The Court went further, distinguishing between surface and subsurface trespass, by stating: “If the intrusions of salt water are to be regarded as trespassory in character, then common notions of surface invasions, the justifying public policy considerations behind secondary recovery operations could not be reached in considering the validity and reasonableness of such operations.”\textsuperscript{61} The Court also evaluated whether fracing of a

\textsuperscript{58} Mapco, 817 S.W.2d at 687.

\textsuperscript{59} http://www.pamarcellus.com/MSC-Fracing.pdf.

\textsuperscript{60} 268 S.W.3d 1, 12-13 (Tex. 2008).

\textsuperscript{61} Id.
natural gas well extending onto neighboring property constituted trespass. Although the Court did not rule that a subsurface invasion did not constitute a trespass, the Court indicated that the rule of capture precluded the existence of a trespass claim citing public policy considerations. This Texas Supreme Court’s decision in *Coast Oil & Gas Corp.* could be useful in providing a mechanism for GS activities provided that there is a recognition that GS serves the public’s interest.

### 3.2.2 Who Owns the Right to Pore Space?

It is the clear majority view that the owner of the surface estate retains ownership of the pore space, notwithstanding a prior conveyance of the mineral estate. This is the approach that is taken in the model GS laws, the statutory law of Wyoming, and the majority of states that have ruled on the issue.

#### 3.2.2.1 Model Laws and Wyoming Approach

In December, 2002, the Interstate Oil and Gas Compact Commission (IOGCC) formed a Geological CO₂ Sequestration Task Force to examine the technical, policy and regulatory issues related to the safe and effective of CO₂ into the subsurface. The members of the task force included representatives from IOGCC member states and international affiliate provinces, state, and provincial oil and gas agencies, the U.S. DOE, and other interested parties. In early 2005, the task force developed a series of model statutes for regulatory guidance to states interested in pursuing Geological Carbon Sequestration. The task force concluded that, because of the states’ jurisdiction, experience, and expertise in the regulation of oil and gas production and natural gas storage, it would be appropriate for the states to regulate CCS activities. The IOGCC model statutes served as the basis for Wyoming’s regulation of CCS networks.

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62 The Interstate Oil and Gas Commission formed a Geological CO2 Sequestration Task Force to examine the technical, policy and regulatory issues related to the safe and effective of CO2 into the subsurface. The task force developed a series of model statutes for regulatory guidance to states interested in pursuing Geological Carbon Sequestration, available at http://www.iogcc.state.ok.us/model-statutes.


64 *Id.*


66 *Id.*
On March 4, 2008, Wyoming became the first state to adopt comprehensive GS legislation. Wyo. Stat. § 34-1-152 provides that the surface owner owns the pore space underlying its lands. The statute specifically provides that pore space is conveyed with the overlying real property unless the pore space has been previously conveyed or explicitly excluded from the conveyance. Pore space can be transferred or conveyed in a similar fashion to a mineral estate, however, no conveyance of a mineral estate automatically includes the conveyance of pore space in the absence of an express declaration. This statute also includes language recognizing and maintaining the dominance of the mineral estate over the surface estate, so that it does not interfere with the state of Wyoming’s already established common law. The primary issue with this statute is that it does not provide an answer to the issue of when a party seeking to sequester CO$_2$ obtains rights to the pore space from the surface estate owner, but fails to obtain the right to use the surface. The pore space owner’s right to use the surface estate is limited by the language included in the instrument of conveyance.

The Wyoming legislature also passed two accompanying pieces of legislation to further define the property rights of the interested parties. Wyo. Stat §§ 30-5-501 and 35-11-313 explicitly recognize the dominance of the mineral estate by stating that the legislation shall not “affect the otherwise lawful right of a surface or mineral owner to drill or bore through a geologic sequestration site” so long as the drilling is conducted in conjunction with the relevant permit and safety requirements. These statutes are based upon the model statutes drafted by the IOGCC Task Force on Carbon Capture and Geological Storage. The legislation operates to clearly define the property rights of individual estate holders while maintaining the existing and established common law of the state.

Although Wyoming has no case law addressing the ownership of pore spaces, the statutes referenced above clearly indicate that the surface owner possesses a property right in the storage space absent an express indication otherwise in the instrument of conveyance. Neither Wyoming case law or statutory law expressly determines whether federally-owned or Indian-owned mineral rights include ownership of pore spaces. The last word on this issue will likely come from the Wyoming Supreme Court when it is first faced with this issue.

### 3.2.2.2 Other States Approaches

Several states have addressed the issue of pore ownership through various court decisions. Below is an overview of how states have decided issues with regards to ownership of pore space. The ownership rights in the state of Texas and Ohio were previously addressed in the above sections.

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3.2.2.2.1 West Virginia

In *Tate v. United Fuel*, the West Virginia Supreme Court of Appeals found that ownership of the pore space belonged to the surface owner because the deed to the surface estate only expressly excluded the right to produce minerals. Surface owners would argue that the Court’s decision supports the proposition that the mineral estate’s interest in the pore space terminates when the extraction and production activities cease. Mineral owners would argue that the Court’s decision was guided by the unique factual circumstances surrounding the case and that the unique language of the deed created the ownership interest in the pore space for the surface estate.

3.2.2.2.2 Oklahoma

In *Ellis v. Arkansas-Louisiana Gas. Co.*, the Tenth Circuit ruled that pore space generally belonged to the surface owner for the purposes of gas storage. The court did indicate that in this circumstance the existence of a prescriptive easement provided the right to the pore space to the mineral estate. The court’s decision seems to indicate that the default rule is that the surface owner maintains the right to the pore space unless such right is expressly conveyed to the owner of the mineral estate or, as in this case, through prescriptive easement.

3.2.2.2.3 Louisiana

In a case involving compensation for the taking of storage space, the district court applying Louisiana law, found that after the extraction of minerals, storage space belonged to the surface owner. Denying the mineral estate owner’s claim for compensation, the court indicated that under no circumstances would the mineral estate owner automatically be found to have an ownership interest in the pore space for storage purposes. This case explicitly gave the owner of the surface estate the right to authorize the storage of natural gas.

3.2.2.2.4 Michigan

The Michigan Court of Appeals has ruled that the storage space left after the excavation of minerals belongs to the owner of the surface estate. In its ruling, the court limited the mineral owner’s estate solely to the minerals, to the exclusion of the property surrounding the minerals. Nevertheless, the court clearly indicated that so long as oil and gas remain in the pore space, the mineral owner may preclude the surface owner from using the storage space as “only the surface owner…possesses the right to use the cavern for storage of foreign minerals or gas, and then only after the mineral owners have

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69 71 S.E.2d 65 (W.Va. 1952).
70 609 F.2d 436 (10th Cir. 1979).
extracted the native gas from the cavern.”\textsuperscript{73} The approach followed in Michigan seems to place the right to authorize storage in the pore space in the hands of the owner of the surface estate once there is no debate over whether native gas remains in the pore space.

3.2.3 Acquisition of Rights for CO\textsubscript{2} Disposal (“Pore Space”)

Even if the issues regarding who owns the right to sequester were clarified, in order to implement a CCS network, the right must be acquired. Acquisition raises multiple additional issues, including the following: (1) what type of interest (fee, leasehold, easement) should be acquired? (2) how can the project owner obtain the rights when there are multiple land owners, many of whom will be unwilling to sell?; and (3) how can the right be valued?

3.2.3.1 Nature of the Acquisition

A CO\textsubscript{2} sequestration right may be transferred or obtained in the form of a: (1) lease; (2) license; (3) easement; (4) an outright conveyance; or (5) a statutory mechanism such as unitization. Under the IOGCC Model Statute, it is recommended for an operator of a GS facility to obtain all ownership interests in a subterranean reservoir to acquire rights in the pore space.\textsuperscript{74} This approach is also usually taken by those developing gas storage facilities.

It is likely that the only feasible method of acquiring property rights necessary to perform GS activities is through the use eminent domain. The IOGCC Model Statute suggests this method of acquisition of property rights which is already utilized to obtain property rights for natural gas storage projects.\textsuperscript{75} One of the advantages of using eminent domain is that it allows states to use well-established mechanisms of the state oil and gas agencies that are familiar with drilling and reservoir regulations. Many states have adopted condemnation statutes allowing a gas storage operator to condemn rights in underground reservoirs. In Pennsylvania, condemnation is only permitted for gas storage reservoirs whose gas reserves are depleted or exhausted at least 80%.\textsuperscript{76} The acquisition

\textsuperscript{73} Id.


\textsuperscript{75} IOGCC, Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces (2007) (IOGCC Guide). The Model Statute and Regulations are included as Appendices I and II respectively.

\textsuperscript{76} 58 Pa. Stat. Ann. § 601.401(a)(1) (“The right of eminent domain shall not be exercised to acquire for the purpose of gas storage: any interest in any geological stratum within the area of the proposed storage reservoir and the reservoir protective area, unless the original recoverable oil or gas reserves within such proposed storage reservoir have been depleted or exhausted by at least 80% and unless and until the condemnor shall have acquired the right by grant, lease or (continued...)
of a gas storage right by condemnation has been classified as an easement, and not a taking in fee absolute.\textsuperscript{77} The classification of a gas storage right as an easement is important for the purposes of determining compensation. Damages in a condemnation proceeding in these instances could be limited to a diminution in value of the burdened fee estate.

Another common method of conveying oil and gas rights is in the form of a lease. Considering the subsurface trespass issues described above, any reservoir used in a GS project will most likely require the purchase of all property rights that could be impacted by the project. Thus, negotiating a lease for all of the respective property rights involved in the GS project could be both extremely expensive and time-consuming, but is still preferable to purchasing an outright conveyance of all of the property rights. Furthermore, Pennsylvania has a long established practice and body law with regards to oil and gas leases.

Any mechanism involving acquisition of the property rights—whether by easement, lease, or fee and whether by consent or condemnation—will face two additional obstacles. First, there will be some uncertainty as to where the CO\textsubscript{2} will migrate so that it may be difficult to identify all necessary properties \textit{ab initio}\.\textsuperscript{78} Second, even in sparsely populated parts of Pennsylvania, land tenure is highly fragmented,\textsuperscript{79} unless the wells are sited on large contiguous tracts of state forest land, interests will need to be acquired from many parties.

On the other hand, condemnation is not a tool that is usually used to obtain a lease. The use of a lease would only be utilized in combination with some other mechanism. For example, the Commonwealth might condemn an easement and lease the pore space to a third party project owner or operator. The Commonwealth might also use a mechanism such as a statutory unitization lease, as described below.

One mechanism that has been used in oil and gas states to deal with similar problems is compulsory unitization. A variation of that could be used to address ownership issues for


\textsuperscript{78} There will always be a degree of uncertainty regarding the extent of stored CO\textsubscript{2} migration, however, many geologists indicate that CO\textsubscript{2} migration is predictable. Any project should project, via modeling studies, the likely extent of the dispersion of the full capacity of the CO\textsubscript{2} being injected over the fields lifetime. For further clarification and discussion of the issue please see Section 3.6.2.

\textsuperscript{79} McWilliams et al 2004 at 12.
GS. Pennsylvania law 58 Pa. Stat. Ann. § 407, gives the Oil and Gas Commission (OGC) the power to establish well spacing and drilling units of certain sizes and shapes for each pool of oil or natural gas. The OGC allows well operators or land owners that are “directly and immediately affected by the drilling” of a well drilled into the Onondaga horizon to apply for a well spacing order. The OGC also has the power to issue a mandatory spacing order, restricting the location of two wells within a specified distance. Under involuntary unitization, once a certain percentage of owners in a field agree to unitize their interests, an application is submitted to the OGC. Once the unit is approved, the interests of all of the owners are ‘pooled’ and each owner is entitled to a fair share of the royalties or of the minerals produced. Although unitization is currently only used for the purpose of mineral extraction, the process could be useful in the establishment of a reservoir for GS.

The acquisition of the necessary pore space in fee simple would come at too high of a cost to the state. CO₂ sequestered in deep geologic pore space could migrate laterally over a potentially very large area. GS may interfere with competing subsurface uses. These competing uses include subsurface uses include ground water recovery, hydrocarbon production, and natural gas storage and compression. In order to ensure that the GS operator will not be liable for subsurface trespass, it would be necessary to acquire the property rights of all of the potentially affected property owners. To purchase these property interests in fee simple would result in a prohibitive financial cost.

3.2.3.2 Potential Cost of Pore Space

Once pore space or property ownership is established, it will be necessary to compensate the property owner for usage of their property for CO₂ storage. It is common for oil and gas storage operators to enter into a storage lease that provides annual rental payments to the property owner. Gas storage leases typically cost a minimum of $20 per acre per year. In the context of GS, the cost for the pore space may be much more difficult to ascertain. Because of the massive size required for most GS projects, a rental cost based upon land size may be exceedingly expensive. For a sequestration project of 1,000 square miles, or 640,000 acres, a price of $20 per acre per year would result in a rental cost of $13 million per year. Thus, rental costs determined according to the

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80 58 Pa. Stat. Ann. § 407 ("The commission shall, to carry out the purpose of this act, and upon proper application and notice given as hereinafter provided, and after a hearing as provided in said notice, enter an order establishing well spacing and drilling units of a specified and an approximate uniform size and shape for each pool.").

81 Id.

82 The acquisition of pore space in fee simple absolute may be more feasible if the CCS Network is located on State Forest land. Unfortunately, the use of State Forest land would cause other issues. For further discussion of the issues surrounding GS on State Forest land see Section 3.2.4.
calculations used typically with natural gas storage will result in a financial barrier that will deter the existence of GS projects.

If a property right to the pore space is obtained through eminent domain, the Supreme Court has held that the property owner is entitled to just compensation for the taking. The Supreme Court in *Brown v. Legal Foundation of Washington* held that just compensation is measured by the property owner’s loss rather than the government’s gain.\(^8\) Logically one would assume that if a court determines that the economic loss to the property owner as a result of CO\(_2\) storage on their property is zero, the activity would not be considered a taking under an a Fifth Amendment analysis.\(^8\) Thus, courts have generally found that just compensation for property in these instances is the fair market value of the property at the time of the taking. Nevertheless, the Court has refused to apply the fair market value of the property as the sole measure of just compensation, especially in instances where it may be impossible or extremely difficult to determine a fair market value because of too few similar sales.

Another method of determining compensation for pore space usage is to follow the approach utilized in oil and gas unitization. Oil and gas unitization brings together the leases and wells overlying a producing formation so that they are combined and administered as one unit.\(^8\) This type of arrangement allows multiple lessees to share in the risks and costs of oil and gas production and to share in the benefits of production. Owners of the oil and gas interests in receive compensation for, or take in the form of oil and gas, the minerals garnered from their unit in proportion to their interest in the unit.

Unlike oil and gas unitization, pore space unitization would involve the pooling of real property interests in the subsurface pore space for the purpose of permanent CO\(_2\) sequestration. Moreover, since CO\(_2\) sequestration does not result in the production of any mineral the compensation scheme would not be directly applicable. Wyoming passed legislation suggesting that compensation to the pore space owner should be proportionate to the economic benefit enjoyed by the CO\(_2\) injector and addressing unitization.\(^8\) Another consideration may be necessary for the long-term harm caused by CO\(_2\) storage that may not be immediately recognizable. Since the potential economic benefits of GS are currently unknown, it is difficult to ascertain the potential revenue generated from GS and the compensation necessary to provide to the owner of the pore space property rights.

\(^8\) Id. at 237.
\(^8\) Howard R. Williams and Charles J. Meyers, Oil and Gas Law Vol. 1 § 222 at 1109-1110 (Matthew Bender 2006).
3.2.3.3 Public Trust Doctrine

On May 8, 1971, the Pennsylvania Constitution was amended to include the following language: “The people have a right to clean air, pure water, and to the preservation of the natural, scenic, historic and esthetic values of the environment. Pennsylvania’s public natural resources are the common property of all of the people, including generations yet to come. As trustee of these resources, the Commonwealth shall conserve and maintain them for the benefit of all people.”\(^{87}\) The Pennsylvania Constitution states further that “[a]ny right, grant or privilege heretofore or hereafter granted or given, by the Commonwealth of Pennsylvania, in the bed of any navigable waters within or on the boundaries of this Commonwealth, is hereby declared void, whenever the same becomes or is deemed derogatory or inimical to the public interest, or fails to serve the best interests of the Commonwealth.”\(^{88}\) In order to evaluate whether pore space is considered “navigable waters” under the public trust doctrine, one must evaluate how Pennsylvania courts have defined the term.

Pennsylvania courts have utilized the navigable-in-fact to determine whether a body of water should be considered part of the public trust.\(^{89}\) In Mountain Props., Inc. v. Tyler Hill Realty Corp., 767 A.2d 1096, 1099-110 (Pa. Super. 2001); Pa. Pwr. & Light Co. v. Maritime Mgmt., 693 A.2d 592, 594 (Pa. Super 1997). The court explicitly expressed the rule for determining whether a body of water is considered ‘navigable’ for purposes of the public trust doctrine: “[t]he rule for determining whether bodies of water are navigable is whether they are ‘used, or susceptible of being used, in their ordinary condition, as highways for commerce, over which trade and travel are or may be conducted in the customary modes and trade and travel on water.’”\(^{90}\) The court stressed that a navigability determination should be based upon whether the water was used or is usable as a broad highroad for commerce and the transport of goods and people.

In refusing to extend the definition of “navigable waters” to recreational uses, the court in Mountain Props., Inc. found that a lake not used for commercial purposes cannot be considered a navigable body of water. The court explicitly stated that “the circumstance of changing the definition of navigability is best addressed by the legislature due to the takings problem created by vesting title in the Commonwealth to a vast expansion of navigable (public) waterways.”\(^{91}\) In another case, the Pennsylvania Supreme Court also held that the Pennsylvania government was unable to instigate actions against private individuals

\(^{87}\) Pa. Const. art. I, § 27.


\(^{90}\) Mountain Props., Inc., 762 A.2d at 1100 (quoting Lakeside Park Co. v. Forsmark, 153 A.2d 486, 487 (Pa. 1959)).

\(^{91}\) Id.
in the name of the public trust doctrine.\(^{92}\) In *Nat'l Gettysburg Battlefield Tower, Inc.*, the Court’s opinion indicates a fear of state government officers using the public trust doctrine to infringe on the rights of private property owners. The Court also questioned whether the government could act to vindicate public trust rights against private parties at all, fearing that it would cause due process and equal protection violations. For the foregoing reasons, it is highly likely that the public trust doctrine will most likely be ineffectual with regards to GS.

### 3.2.4 Conclusion: Legislative Needs for GS Property Rights Issues

Acquisition of the property rights necessary to develop a CCS network suffers from a number of both legal and practical barriers. First, the nature of the right to use subsurface strata for sequestration and who owns the right is not settled. Second, there are uncertainties regarding how many properties may be affected and, therefore, who may own the rights. Third, given the fragmentation of ownership across the landscape and between owners of different estates (various mineral estates and the surface estate) through Pennsylvania, it will be difficult to assemble the property rights. There are a variety of possible solutions to these problems, many of which solve some, but not all, of the problems.

One mechanism will be to identify a large contiguous block of land which is owned by a single landowner who owns all mineral and surface rights and to site the GS wells there. Some have suggested that CCS networks might be limited to large blocks of unoccupied federal land in the West for this reason. Both Pennsylvania GS bills take this approach. The proposed Senate bill (S1733) requires siting the CCS network in the 2.1 million-acre State Forest system. The proposed House bill (H.R. 2454) authorizes siting the GS facilities in State Forests and provides owners with eminent domain by making them public utilities.

This approach alone, however, will still face practical difficulties due to the nature of land tenure in the State Forests. All public lands, both state and federal, in Pennsylvania were acquired from private owners after the creation of the State Forest system in 1898.\(^{93}\) Accordingly, in many cases, the mineral rights were severed and are still owned by private parties. Moreover, unlike Western public lands, there are often many private parcels in close proximity to State Forests. Often, the Commonwealth has acquired the ridges, while the adjoining valleys remain in private hands. There are some areas, such as the Deep Valleys regime, where the Commonwealth owns large contiguous blocks of land and owns all of the rights. Unfortunately, these are the areas most remote from the

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electric generation plants. They are also the areas where DCNR has established many of its wild and natural areas or are under consideration as old growth or bioreserve areas. Accordingly, siting GS pipelines and wells in these areas are more likely to have adverse ecological effects, will be more likely to face opposition and are less likely to obtain necessary approvals after analysis under programs such as the National Environmental Policy Act (NEPA), 42 U.S.C. §§4321-4370f, Sections 402 and 404 of the Clean Water Act, 33 U.S.C. §§ 1342, 1344, and the Endangered Species Act, 16 U.S.C. §§1531-1544.94

A second approach is to pass legislation that clarifies the nature of the right to sequester \( \text{CO}_2 \), vest it in a particular owner, and provide means to acquire that right, such as condemnation. This is the approach that has been used in the model laws adopted by Wyoming. This approach is a necessary but not a sufficient step to facilitate GS development. Many of these owners will be unwilling to sell the right, so that use of condemnation will likely be necessary, increasing costs, delays and opposition. Moreover, this approach still faces the problem that, in some cases, the extent of the area over which \( \text{CO}_2 \) will migrate will be difficult to determine.

A third approach that could be combined with the clarification of property rights would be to create a variant of the unitization programs used for oil and gas in some other states.95 If, by statute, all affected property owners are required to participate in the unitization and awarded proportional compensation, property owners whose property rights are affected could share in compensation and, if additional properties are affected due to migration, they could also be awarded compensation. Fixing the value of the compensation may be difficult and the value of the right to sequester is likely to increase as the technology is proven and the cost/value of \( \text{CO}_2 \) emission allowances increase over time. Until there is a market for determining the value of pore space, a statutory value should be assigned, as is done by some European nations.

The most effective approach would likely seek to combine the three methods. One will need to clarify property rights, as is done by the model laws, in all cases. Locating sites on or near state-owned land will likely facilitate acquisition of property rights and reduce the number of owners with whom the GS project sponsor will need to deal. Unitization will further facilitate this process and eliminate the issues presented by migration, at least as long as the plume remains within Pennsylvania.96

94 See, Chart of Potential Regulatory Approvals, Appendix 3.6.10.4.
95 See discussion on unitization at 3.2.3.1.
96 As noted below, if the plume migrates across state lines, it is possible that the law of the other state will be applied. Facilitating federal legislation, see discussion at Section 3.3.3.3, or an interstate compact with neighboring states will be necessary to create consistent rules across state lines. Siting the facilities where state lines will not be crossed will reduce this risk.
3.3 Potential Legal Liabilities and Risks from Geologic Sequestration of Carbon

Dioxide and Related Issues

3.3.1 Causes of Potential Liability

There are a number of risks from transport and geologic sequestration of CO\(_2\) that can give rise to liability on the part of the CO\(_2\) generators as well as the owners and operators of the pipelines and wells. These include seismic displacement or earthquakes, contamination of ground water, massive releases that can smother humans, livestock and wildlife, and contamination of valuable resources.\(^{97}\) In the following sections, we briefly describe these risks, which are evaluated elsewhere in this report, and then describe the legal theories under which liability might arise. Although in all cases, there are potential defenses to liability, in the absence of settled case law, we must assume that each of the parties in the chain of title to the CO\(_2\) will face potential liability for damages arising from the sequestration. We will therefore suggest potential legislative and contractual approaches for reducing, defining, or limiting these risks of liability.

3.3.1.1 Seismic Displacement /Surface Collapse

There have been instances in which injection wells in California have induced an earthquake, due to lubrication of a fault. In the case of CO\(_2\) injection wells, large volumes of a supercritical liquid phase will be injected into formations where it could cause displacement. Earthquakes and other displacement that is manifested on the surface could cause property damage and personal injury.

3.3.1.2 Ground Water and Surface Water Contamination

CO\(_2\) injections could also cause contamination of ground water. This could occur by three mechanisms. First, CO\(_2\) will react with ground water to produce carbonic acid and cause contamination by dissolving heavy metals, as occurs in the case of acid mine discharges. Second, the gas may contain contaminants, such as hydrogen sulfide which could contaminate ground water. Third, injection will likely displace deep saline ground water. Although injection will take place in formations that are not used for potable water if the acidic water or saline water is displaced such that it migrates to a potable aquifer, it could adversely affect water supplies and possibly surface water. There is also a possibility for personal injury if contaminated ground water is ingested.

Activities on the surface also pose the potential of causing ground water or surface water contamination. Creation of a cavern in a salt formation will result in large amounts of saline water being recovered at the surface. If not handled properly, this water could contaminate both surface water and ground water.

3.3.1.3 Sudden Release of Carbon Dioxide or Contaminant

Another risk that could lead to liability arises from the possibility that if large amounts of CO$_2$ are released into the ambient surface environment at one time, the CO$_2$ could displace oxygen, smothering people and livestock. This concern arises from two incidents in which CO$_2$ collecting underneath volcanic lakes in Africa was released suddenly—Lake Nyos and Lake Monoun in Cameroon.\textsuperscript{98} In both cases, CO$_2$ was released suddenly in a lake where the topographic features contained the CO$_2$. Because CO$_2$ is heavier than oxygen and nitrogen and was released so suddenly that it could not mix, it displaced the oxygen and people and livestock were smothered. In the case of Lake Nyos, more than 1,700 people were killed when the CO$_2$ was released in a volcanic crater and then flowed down through narrow valleys, where it was contained. Lake Monoun, with fewer people killed, had a “limnic eruption” caused by a landslide or another disruption that released CO$_2$ under water.\textsuperscript{99} Concerns have been raised that local populations could be threatened if a large amount of CO$_2$ is released from a pipeline break in a valley or other confined area or if sequestered CO$_2$ migrates and collects in a place where a similar massive release might lead to a similar event.\textsuperscript{100}

Protective and preventative measures being employed at the lakes involve monitoring and allowing controlled outgassing, so that the CO$_2$ mixes with nitrogen and oxygen. The proposed EPA Safe Drinking Water Injection well regulations call for monitoring of where the CO$_2$ goes after it is injected.\textsuperscript{101} If there were a threat of a release in a place where CO$_2$ is being contained, then a controlled release might be used to eliminate the risk of a sudden release. Siting criteria assuring that the strata into which anything would be injected and to where it could migrate would be far below the altitude where people live. Nevertheless, monitoring needs to be required and corrective action planned to assure problems do not arise.


\textsuperscript{99} Id.

\textsuperscript{100} Brown et al, supra. As discussed earlier, these risks can be minimized through the use of safety and monitoring systems. The best solution to prevent a massive release of CO$_2$ is the development of a thorough regulatory structure addressing these issues. In order to properly discuss all possible liability issues, however, it is important to address the impact of a massive release of CO$_2$.

3.3.1.4 Displacement or Contamination of Resources

Injected CO$_2$ could also displace or move natural gas, oil or ground water that would otherwise be accessible to estate holders. It could contaminate mineral resources, such as natural gas, coal, or salt making them inaccessible or unusable.

3.3.1.5 Gas Pipelines

CO$_2$ pipelines pose risks, but do not pose substantially different risks from other pipelines. Indeed, there are already CO$_2$ pipelines carrying CO$_2$ from wells to sites where it is used. The principal risk posed by the pipeline is of a massive release. While there is some risk of smothering, the principal risk is the release of toxic hydrogen sulfide. In this case, however, CO$_2$ pipelines do not present a significantly different risk than other pipelines, such as natural gas pipelines, which can also experience accidents resulting in personal injury and property damage. Consequently, the remainder of this section will focus primarily on the risk of sequestration in injection wells.

3.3.2 Legal Theories

Analysis of liability issues and risks associated with CCS requires identification of various legal theories pursuant to which claims may be brought. Unfortunately, there are no legal precedents for liability associated with underground injection and long-term storage of CO$_2$ in the United States. Accordingly, claims arising from factually analogous situations, under Pennsylvania law and the laws of other jurisdictions, must be analyzed to create a framework that will benefit project planning and influence regulatory impact.

Claims, however, may not be analyzed in the abstract; a right to damages or other compensation for a subsurface harm will likely be predicated on determining who is the owner of the pore space, the empty subterranean space where CO$_2$ will be sequestered, and who the owner of the sequestered CO$_2$ is. To that end, case law discussing property rights in the context of hazardous waste injection and the storage and distribution of natural gas is particularly beneficial. The following primary theories sounded in tort will be analyzed below: strict liability/ultra-hazardous activity; nuisance; negligence; nuisance or negligence per se; trespass; and waste. In addition, we include a brief discussion of who may be a liable party in the event that an accident actually occurs.

3.3.2.1 Strict Liability/ Ultra-Hazardous Activity

In the event that compressed CO$_2$ escapes or otherwise migrates from an underground distribution or transportation system—for example, if a valve is cracked or malfunctions—it is conceivable that a court would determine that the CO$_2$ had been placed into the stream of commerce when it was placed into the distribution or transportation system, in which case strict liability premised on the RESTATEMENT (SECOND) OF TORTS § 402A may attach. Pennsylvania’s recognition of § 402A liability can be traced back to Webb v. Zern. Under § 402A:

(1) One who sells any product in a defective condition unreasonably dangerous to the user or consumer or to his property is subject to liability for physical harm thereby caused to the ultimate user or consumer, or to his property, if

(a) the seller is engaged in the business of selling such a product, and

(b) it is expected to and does reach the user or consumer without substantial change in the condition in which it is sold.

In a fairly recent decision, a group of plaintiffs alleged that natural gas, which had leaked from the natural gas company’s distribution system, caused an explosion at an apartment building, and that the natural gas company was strictly liable under § 402A. The natural gas company filed preliminary objections and argued that the gas was not a product, and that the company provided a service, prior to the gas entering the consumer’s meter, and concluded that a “sale” had not occurred. In overruling the preliminary objections, the court concluded that a sale is not necessary, only that a product be placed into the stream of commerce. The court referred to the “special responsibility” doctrine established in Francioni v. Gibsonia Truck Corp. and concluded that the gas entered the stream of commerce as soon as it was placed into the delivery system. Importantly, based on precedents established in Francioni, and Kalumetals Inc. v. Hitachi Magnetics Corporation, §§ 402A liability may also attach to additional parties including lessors of storage space, and other bailors who are in possession of the compressed CO₂ at the time injury is caused.

Even if strict liability does not attach under §402A, compression, transportation, and storage of compressed CO₂ for CCS may be an abnormally dangerous or ultra-hazardous activity—a separate basis for strict liability. Liability for injury caused by an abnormally dangerous activity had its genesis in England in the case of Rylands v. Fletcher. There, the water from defendants’ reservoir had escaped into an abandoned mine, from where it had spread through connecting passages to flood plaintiff’s mine. Liability was imposed even though the defendants were found to be free of fault. The court said that a

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104 Id. at 148.
105 Id.
108 Francioni, 372 A.2d at 368-69.
109 Kalumetals, 21 F. Supp. 2d at 515-16.
110 (1868) 3 H.L. 330 (L.R.).
person who for his own purposes uses his land unnaturally to keep and store thereon anything likely to do mischief if it escapes, must keep it at his peril, and if he fails to do so, he is absolutely liable for damages which are the natural consequence of its escape.\textsuperscript{111}

An ultra-hazardous activity is defined as one that (1) necessarily involves a risk of serious harm to the person, land, or chattels of others that cannot be eliminated by the exercise of utmost care and (2) is not a matter of common usage. In the \textit{Restatement (Second) of Torts} §§ 519-524A (1977), the phrase abnormally dangerous activity is substituted for the term ultra-hazardous activity found in the \textit{Restatement of Torts} §§ 519-524 (1938). The \textit{Restatement (Second) of Torts} § 519, approved by the Pennsylvania Superior Court in \textit{Albig v. Municipal Authority of Westmoreland County},\textsuperscript{112} states:

\begin{itemize}
  \item[(1)] One who carries on an abnormally dangerous activity is subject to liability for harm to the person, land or chattels of another resulting from the activity, although he has exercised the utmost care to prevent the harm.
  \item[(2)] This strict liability is limited to the kind of harm, the possibility of which makes the activity abnormally dangerous.\textsuperscript{113}
\end{itemize}

In ascertaining whether an activity shall be deemed abnormally dangerous, Section § 520 lists the following factors to be considered: (a) existence of a high degree of risk of some harm to the person, land or chattels of others; (b) likelihood that the harm that results from it will be great; (c) inability to eliminate the risk by the exercise of reasonable care; (d) extent to which the activity is not a matter of common usage; (e) inappropriateness of the activity to the place where it is carried on; and (f) extent to which its value to the community is outweighed by its dangerous attributes.\textsuperscript{114}

In \textit{Albig}, property owners sustained property damage when water escaped from a reservoir. The property owners filed suit against the owner of the reservoir and a mining operator who was conducting operations underneath the reservoir. The Superior Court concluded that the mine operator was solely liable for plaintiffs’ damages. Where the value of the reservoir outweighed its potentially dangerous qualities, maintenance of the reservoir was not an abnormally dangerous activity.\textsuperscript{115} As such, the defendant owner was only liable to plaintiffs if it was negligent. It is conceivable that the value of sequestered CO\(_2\) also outweighs its potentially dangerous qualities, thus precluding a cause of action premised on an abnormally dangerous activity theory. Nevertheless, this conclusion is subject to judicial weighing and balancing of many factors, and it is difficult to predict whether GS is actually an abnormally dangerous activity.

\textsuperscript{111} \textit{Id.} at 338.
\textsuperscript{113} \textit{Restatement (Second) of Torts} § 519 (1977).
\textsuperscript{114} \textit{Restatement (Second) of Torts} § 520 (1977).
\textsuperscript{115} \textit{Albig}, 502 A.2d at 661.
3.3.2.2 Nuisance

In addition to the strict liability claims discussed previously, it is likely that a nuisance claim will be brought if compressed CO$_2$ interferes with the use and enjoyment of property. Nuisance claims can be divided into two categories: public nuisance and private nuisance. With respect to private nuisance, the Pennsylvania Supreme Court, in Waschak v. Moffat,\(^\text{116}\) adopted the standard set forth in the Restatement, which states as follows:

The actor is liable in an action for damages for a non-trespassory invasion of another’s interest in the private use and enjoyment of land if,

(1) the other has property rights and privileges in respect to the use or enjoyment interfered with; and

(2) the invasion is substantial; and

(3) the actor’s conduct is a legal cause of the invasion; and

(4) the invasion is either (i) intentional and unreasonable; or (ii) unintentional and otherwise actionable under the rules governing liability for negligent, reckless or ultra-hazardous conduct.\(^\text{117}\)

As will be discussed in more detail under the section discussing trespass below, it may be difficult for plaintiffs to prove actual interference with the use or enjoyment of land if the invasion takes place several thousand feet below the surface of the property. It is important to recognize that if the invasion actually interferes with the surface, a private nuisance claim would likely stand.

The *Restatement (Second) of Torts* defines a public nuisance as “an unreasonable interference with a right common to the general public.”\(^\text{118}\) To maintain a private cause of action for public nuisance, plaintiffs must be able to allege that they have “suffered harm of a kind different from that suffered by other members of the public” in the exercise of a “right common to the general public that was the subject of interference.”\(^\text{119}\) A unique factual scenario would need to arise before a plaintiff could establish a private cause of action for public nuisance associated with CCS. A claim for public nuisance


\(^{117}\) *Restatement (Second) of Torts*, § 822 (1979).

\(^{118}\) *Restatement (Second) of Torts* § 821B(1) (1979); *see also, Graham Oil Co. v. BP Oil Co.*, 885 F. Supp. 716 (W.D. Pa., 1994).

\(^{119}\) *See, Philadelphia Elec. Co. v. Hercules, Inc.*, 762 F.2d 303, 315 (3d Cir.1985) (citing *Restatement (Second) of Torts* § 821C(1) (1979)).
would most likely be brought by the government or an agency or department charged with implementing a specific statutory scheme, in the event that one were enacted which specifically applied to CCS.

3.3.2.3 Negligence

In the event that a GS-related accident occurs, it is likely that a negligence claim will be brought by the injured party(s). A negligence action involves a foreseeable risk of injury and conduct unreasonable in proportion to the danger; thus, the essence of the negligence complaint is that the defendant’s conduct fell below the standard established by the law for the protection of others against unreasonable risk of harm. The failure to do what a reasonable person would do under like circumstances, is based on the negligent conduct that occasioned the injury.\(^\text{120}\) Proof that conduct may have been negligent in the sense that it displayed carelessness, recklessness, or inadvertence, is not sufficient to establish a cause of action.\(^\text{121}\) To prevail on a cause of action in negligence, a plaintiff must establish the following:

1. a duty or obligation recognized by the law, requiring an actor to conform to a certain standard of conduct;
2. failure to confirm to the standard required;
3. a causal connection between the conduct and resulting injury; and
4. actual loss or damage resulting to interests of another.\(^\text{122}\)

Thus, a negligence action requires allegations that establish the breach of a legally recognized duty or obligation that is causally connected to the damages suffered by the claimant.\(^\text{123}\) Breach of a statutory duty, without proof of causation and injury, is insufficient to establish a claim sounding in negligence.\(^\text{124}\)

Creation of a regulatory framework, performance of an appropriate risk assessment, and initiation of risk-reduction measures will likely reduce potential exposure to liability

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\(^\text{122}\) See e.g., Petrucelli v. Bohringer & Ratzinger, 46 F.3d 1298 (3d Cir. 1995); see also, Reeves v. Middletown Athletic Ass’n, 866 A.2d 1115 (Pa. Super. 2004).


premised on negligence. Even so, GS-related mishaps will likely give rise to a negligence action.

3.3.2.4 Nuisance or Negligence Per Se

In general, the doctrine of negligence per se does not create an independent basis of tort liability but rather establishes, by reference to a statutory scheme, a standard of care appropriate to the underlying tort.\(^{125}\) Holding a person negligent per se on the basis of a statutory violation is only proper where the statutory violation was a proximate,\(^{126}\) and efficient cause of the accident.\(^{127}\) Moreover, there must be a direct connection between the harm meant to be prevented by the statute and the injury complained of for liability to be imposed on the basis of the violation of the statute.\(^{128}\) Negligence per se may be declared without any argument or proof as to the particular circumstances because it violates a statute or municipal ordinance. \textit{Id.} When analyzing negligence per se claims, the purpose of the statute must be to protect the interest of a group of individuals, as opposed to the general public, and the statute must clearly apply to the conduct of the defendant.\(^{129}\) The relationship between whether a statute provides a private cause of action and whether it protects individual harm that would support application of the doctrine is very close. The absence of a private cause of action in the statutory scheme is an indicator that the statute did not contemplate enforcement for individual harms.\(^{130}\) Liability for nuisance or negligence per se claims associated with harm flowing from a GS-related accident would likely be predicated on enactment of a specific statutory scheme which sets forth the applicable standard of care with respect to handling, transporting, and storing compressed CO\(_2\).

On the other hand, sudden losses of CO\(_2\), hydrogen sulfide, or ground water contamination could be deemed to constitute a violation of the Pennsylvania Air Pollution Control Act, the Pennsylvania Clean Streams Law, the Safe Drinking Water Act—if the EPA promulgates additional regulations, or equivalent laws in neighboring states if the injury manifests itself in another jurisdiction.

Without a statutory framework, CCS project developers and CO\(_2\) generators may be exposed to haphazard application by courts of various standards which are likely to produce varying results. To the contrary, statutory standards could actually enhance


compensation to injured parties, especially if insurance is available. While it is possible that the two holdings could be restricted to the facts and statutes involved, the Pennsylvania Supreme Court’s reasoning is better suited to the extension of the damages remedies to other state environmental citizen suit provisions.

3.3.2.5 Trespass

It is theoretically possible that CO$_2$ injectate could laterally migrate below neighboring properties and, thus, give rise to a trespass claim. Pennsylvania law conforms to traditional notions of trespass, which is defined as the intentional entry upon the land of another. Under the Restatement standard, one is subject to liability to another for trespass, irrespective of whether he thereby causes harm to any legally protected interest of the other, if he intentionally:

1. Enters land in the possession of the other, or causes a thing or a third person to do so,
2. Remains on the land, or
3. Fails to remove from the land a thing that he is under a duty to remove.

No actual injury need be alleged because harm is not to the physical well being of the land, but to the landowner’s right to peacefully enjoy full, exclusive use of her or his property. Nevertheless, given that compressed CO$_2$ may be injected several thousand feet below the surface, it may be difficult to prove any interference with the right of peaceful enjoyment.

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134 RESTATEMENT (SECOND) OF TORTS § 158 (1965).

Some courts have addressed trespass and migration issues in the context of hazardous waste injection. For example, in *Chance v. BP Chemicals*, the court truncated surface and subsurface property ownership rights and found that an owner’s subsurface rights to exclude invasions are only valid as long as the invasions actually interfere with the reasonable and foreseeable use of the subsurface. The court held that the plaintiffs’ claims were too speculative because they were unable to prove physical damage or interference with use of the subsurface. The *Chance* decision is important because it demonstrates the difficulty courts have with delineating the limits of surface and subsurface property rights. Under the Pennsylvania standard discussed above, no actual injury need be alleged, however, it is conceivable that a court in Pennsylvania, like the *Chance* court, could place limits on a landowner’s subsurface property rights.

In *Mongrue v. Monsanto Co.*, the court held that waste water that had possibly migrated under the plaintiff’s property did not constitute a taking without just compensation, but in *dicta* stated that the property owners “may recover under a state unlawful trespass claim…regardless of the [fact that the injector had a permit] allowing for injection.” Nevertheless, although the plaintiffs had originally charged a trespass claim, it was later dropped on appeal, which prevented recovery. Under this approach, it appears that a plaintiff could establish a trespass claim if he or she could actually prove that a migration had actually occurred.

### 3.3.2.6 Waste (As In Displacement or Contamination of Resources)

Waste is a tort, which may be defined as the destruction, misuse, alteration, or neglect of the premises by one lawfully in possession of the premises, to the prejudice of another person’s estate or interest in the property. It may be any destruction done or permitted with respect to lands, houses, gardens, trees, or similar property by the current tenant, or an unreasonable and improper use and abuse, mismanagement, or omission of duty touching real estate by the person in possession. Pennsylvania cases discussing the doctrine of waste deal with, among others, factual scenarios involving plowing land, cutting timber, and mining activities. In addition to the claims discussed above, it is likely that a waste-based claim could arise from CCS activities.

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137 *Id*.
138 249 F.3d 422 (5th Cir. 2001).
139 *Id*.
For example, in *Phillips Petroleum Co. v. Stryker*, a case involving secondary oil recovery activities and field unitization, water flooding on an adjacent parcel to a producing unit had drained oil reserves. The jury awarded damages of $26.9 million based on claims of negligence, nuisance, trespass, fraud, and punitive damages for draining oil and gas reserves. After being upheld on initially on appeal, the Alabama Supreme Court reversed the lower court’s judgment and found that based on the Alabama Code, the plaintiff should have petitioned for inclusion in the unit. The court stated “an owner of interests outside a unit should not be entitled to damages from the operator of the unit if the circumstances are such that he can protect himself by engaging in an independent operation, or if he has been extended a fair opportunity to participate in the Unit." No damages were awarded as a result of the reversal. Nevertheless, Alabama clearly has a public policy that encourages secondary recovery and provides for inclusion in a unitized field by statute. Unlike Alabama, Pennsylvania does not provide for field unitization by statute. Thus, *Phillips Petroleum* provides an example of the type of liability that might flow from an activity that impacts another’s rights to oil, gas, or mineral interests.

### 3.3.3 Potentially Liable Parties: Commonwealth, Other Sponsors, and Generators

It is likely that a number of distinct parties will participate and share responsibility for various components of CCS-related activities. In order to capture the gas and later compress it and inject it into the earth, a number of steps need to be taken. For example, a power producing company, or some other CO\(_2\)-emitting institution, will likely be responsible for capture. The CO\(_2\) will then be funneled into a pipeline and sent to a storage site. The supercritical liquid phase CO\(_2\) will be compressed at the plant gate prior to pipeline transportation and then injected for subsurface storage.

If a CCS-related accident does occur, the list of potentially responsible persons is of considerable length. Among others, all of the following parties likely have interests that may be impacted by an accident: (1) injector, (2) owner of the injected material, (3) surface owner; (4) mineral owner(s), (5) mineral lessee(s); (6) neighboring surface owner(s); (7) neighboring mineral owner(s); (8) neighboring mineral lessee(s); (9) manufacturer(s) of products used to transport and store the compressed CO\(_2\); (10) power plant operators and other CO\(_2\) generators, and (11) state sponsors.

Courts have differing views on whether the injector can be found liable for the migration of gas from an underground natural gas storage facility. Some case law suggests that the injecting party no longer possesses title to natural gas once it is stored in the subsurface, rejecting injector liability for the subsurface trespass of natural gas. Other decisions

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144 723 So. 2d 585 (Ala. 1998).
145 *Id.*
146 *Hammonds v. Central Kentucky Natural Gas Co.*, 75 S.W.2d 204 (Ky. Ct. App. 1934).
have indicated that the injector retains ownership of stored natural gas. Retention of title by the injecting party raises the possibility of a successful cause of action for subsurface trespass. Although no court has assessed damages for a claim of subsurface trespass, the possibility exists that a court will find a party engaging in CCS liable for subsurface trespass if the charging party can prove actual damages. For a more in depth discussion of liability, see Sections 3.2.3 and 3.3.2.5.

Depending on the facts which give rise to the claim, an injured plaintiff is most likely to bring causes of action against the following parties: (1) injector, (2) owner of the injected material, (3) surface owner; (4) manufacturer(s) of products used to transport and store the compressed CO$_2$; (5) power plant operators and other CO$_2$ generators, and vi) state sponsors, if any.

3.3.3.1 Commonwealth Liability and Sovereign Immunity

The Commonwealth is contemplating participating in the development and operation of a CCS network. To the extent that the Commonwealth does participate, it will be exposed to liability. There are mechanisms that the Commonwealth can employ to shield CCS participants from liability; there are also limitations that must be considered when developing these mechanisms.

The Eleventh Amendment provides immunity to a state from suits in federal court by citizens of another state, and by its own citizens, unless the state has explicitly waived immunity. The Eleventh Amendment also bars federal consideration of a purely state law claim against a state. Further, the Eleventh Amendment bars actions against a state officer in his official capacity, except where the suit seeks to enjoin a state official’s future violation of federal law.

Note that the Eleventh Amendment does not prevent a state from being sued in another state’s court. A state can only avoid suit in the court of a sister state if the court

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147 Lone Star Gas Co., 353 S.W.2d at 876.
150 See Ex parte Young, 209 U.S. 123, 159-60 (1908) (holding the Eleventh Amendment did not bar an action in federal court to enjoin a state official from violation of the Fourteenth Amendment); Edelman, 415 U.S. at 662-66 (holding that the state was the real party in interest for a damages claim against a state official and that therefore the Eleventh Amendment barred the claim); cf. Presbyterian Church (U.S.A.) v. United States, 870 F.2d 518, 523 (9th Cir. 1989) (holding that Section 702 of the Administrative Procedure Act waives sovereign immunity for non-monetary claims against the United States and noting that Section 702 was meant to address Ex parte Young and its progeny).
151 Nevada v. Hall, 440 U.S. 410, 426-27 (1979) (finding that a California court was not barred from exercising jurisdiction over the state of Nevada in a personal
declines to exercise jurisdiction on the basis of comity. Because suits against one state in
another state’s court tend to complicate political matters, a suit in another state may be
unlikely to proceed, but neither Pennsylvania nor DCNR would enjoy constitutionally-
mandated sovereign immunity from a suit filed in a neighboring state.

In *Nevada v. Hall*, for example, the United States Supreme Court held that the
recognition of interstate sovereign immunity was not constitutionally mandated by the
Eleventh Amendment or the Full Faith and Credit Clause. Thus, the California court was
not required to recognize the state of Nevada’s sovereign immunity or its statutory
limited waiver cap. 152 The Supreme Court of Delaware has also addressed the issue of
interstate sovereign immunity and upheld a Delaware Superior Court’s monetary
judgment against the State of Maryland. 153 Relying on *Hall*, the Delaware Supreme
Court rejected Maryland’s argument that Delaware must recognize the sovereign
immunity Maryland would have enjoyed had the suit been brought in a Maryland
court. 154 Therefore, if DCNR is acting or causes harm in a sister state, it may be subject
to suit in that state.

By statute, and pursuant to Section 11, Article I of the Pennsylvania Constitution,
Pennsylvania retains sovereign and official immunity from suit except when the General
Assembly waives the immunity. 155 Nevertheless, sovereign immunity does not bar suits
seeking to compel state officials to perform non-discretionary ministerial duties, or suits
to restrain state officials from preventing performance of a contract entered into by a
Commonwealth agency. 156

In certain enumerated instances, Pennsylvania has explicitly waived sovereign immunity
as a defense to actions against “Commonwealth parties.” 157 A “Commonwealth party” is

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defined as “[a] Commonwealth agency and any employee thereof, but only with respect to an act within the scope of his office or employment.”¹⁵⁸ A Commonwealth agency includes any “executive agency,” which is defined as “the Governor and the departments, boards, commissions, authorities and other officers and agencies of the Commonwealth government, but the term does not include any court or other officer or agency of the unified judicial system, the General Assembly and its officers and agencies, or any independent agency.”¹⁵⁹ Where a state agency is an “arm of the state,” it typically enjoys the same sovereign immunity protection of the Eleventh Amendment as the state itself.¹⁶⁰

Municipal authorities formed under the former Municipal Authorities Act (MAA) Act of May 2, 1945, P.L. 382, as amended, 53 Pa. Con. Stat. Ann. § 306 (establishing the purposes and powers of municipal authorities), are not Commonwealth agencies for purposes of sovereign immunity; however, an entity created by the state to perform a state function may be entitled to use the defense. In Smith v. Endless Mountain Transportation Authority, the court determined the lower court had sufficient evidence to support a finding that the EMTA was a local agency.¹⁶¹ In Rawlings v. Bucks County, a county water and sewer authority, created pursuant to the MMA, was found not to be a commonwealth agency and not entitled to sovereign immunity.¹⁶² Insofar as sovereign immunity protects the Commonwealth purse, a determination as to whether a governmental agency is subject to that immunity must look to whether the particular enabling statute grants authority to exercise the public powers of the Commonwealth as an agent thereof, as well as to the source of the agency’s creation, control, and funding.¹⁶³

DCNR was created as an administrative department within the executive branch of the Pennsylvania government for the purpose of providing more focused management of the Commonwealth’s recreation, natural and river environments.¹⁶⁴ This status is similar to other executive agencies, such as the Southeastern Pennsylvania Transportation

¹⁶¹ 878 A.2d 177,180 (Pa. Commw. 2005). Such evidence included resolutions of the municipalities creating the joint authority and the Certificate of Incorporation issued by the state stating it was formed under the MAA.
Authority, which courts have held enjoy sovereign immunity under Pennsylvania law, unless explicitly waived as a “Commonwealth party.” DCNR will enjoy sovereign immunity under Pennsylvania law, unless explicitly waived as a “Commonwealth party.”

In certain enumerated instances, Pennsylvania has explicitly waived sovereign immunity as a defense to actions against Commonwealth parties for damages arising out of a negligent act where the damages would be recoverable under the common law or a statute creating a cause of action if the injury were caused by a person who did not have the defense of sovereign immunity. One enumerated instance includes the following real estate exception:

“A dangerous condition of Commonwealth agency real estate and sidewalks, including Commonwealth-owned real property, leaseholds in the possession of a Commonwealth agency and Commonwealth-owned real property leased by a Commonwealth agency to private persons, and highways under the jurisdiction of a Commonwealth agency, except conditions described in paragraph (5) [related to potholes and other dangerous conditions of highways].”

In order for sovereign immunity to be waived, the Commonwealth must have actual or constructive knowledge of the defect. The Commonwealth will not have waived immunity unless it is deemed to control it. The Commonwealth’s right or duty to enter, inspect, and maintain a property is not control where there is no title, ownership, or physical possession.

In addition, the claim for damages for injuries caused by a substance or an object on Commonwealth real estate must allege that the dangerous condition derived from, originated from, or had as its source, the Commonwealth realty itself. It must be a defect in the property or in its construction, maintenance, repair, or design. In another case, the Department of Transportation (DOT) was found to be immune from liability in a landowner’s action against it, alleging that the DOT had negligently caused a creek to overflow onto the landowner’s property. The court found the real estate exception did not apply because the DOT had not artificially diverted the water from its natural flow, nor had it unreasonably increased the quantity of water flowing in the creek.


168 Jones v. SEPTA, 772 A.2d 435 (Pa. 2001) (pedestrian who tripped on rock salt on train platform could not recover).

While the Commonwealth may waive sovereign immunity in any new legislation that is passed, it is likely that sovereign immunity has already been waived by a number of statutes that could potentially impose liability. For example, at least one court has found that sovereign immunity did not bar a suit against DCNR brought under the Dam Safety and Encroachment Act (Dam Act). The Dam Act included the Commonwealth and its departments within the definition of “person.” The Dam Act makes it unlawful for any “person” to violate the provisions of the Dam Act and provides a remedy against any person who is in violation. The court therefore concluded that the legislature intended for Commonwealth parties to be subject to suit under the Dam Act for violations of that act. Whether sovereign immunity has been waived will depend upon the nature of the cause of action and the specific language found in applicable statutes.

While the state may benefit from sovereign immunity, immunity does not extend to independent contractors doing work for the state. On the other hand, if the contractor performs work in accordance with the state’s contract specifications, not their own, and is not guilty of negligence nor willful tort, they are not liable for any damage that might result. If the Commonwealth agency contractor performs work in accordance with specifications given to it by the state, they may not be found liable. Where sovereign immunity has been waived, there may be limitations on claims against the Commonwealth. Pa. Const. art. I, § 11 provides that suits may be brought against the Commonwealth of Pennsylvania in such manner, in such courts and in such cases as the legislature may by law direct.

GS legislation enacted should either preserve sovereign immunity or, if the state chooses to waive immunity through legislation, designate the manner in which it can be sued. For example, when the General Assembly waived sovereign immunity under the Sovereign Immunity Act, it limited the circumstances where the Commonwealth could be found liable to those causes of actions within the statute. Intending to insulate government from exposure to tort liability, the exceptions to immunity are strictly construed. In drafting CCS legislation, the General Assembly should consider the timing, the courts and limiting the amount of recovery.

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171 Id.
3.3.3.2 State Powers To Enter Into Contracts and Allocate Risks

If sovereign immunity is waived, the state can be held jointly and severally liable for the harms. To limit its exposure where the real estate exception does apply, the state can allocate its risk through contract. “When the General Assembly specifically waives sovereign immunity, a claim against the Commonwealth and its officials and employees shall be brought only in such manner and in such courts and in such cases as directed by the provisions of Title 42 (relating to judiciary and judicial procedure) or 62 (relating to procurement) unless otherwise specifically authorized by statute.”

DCNR is authorized to contract to exercise the powers and fulfill the duties established by the Conservation and Natural Resources Act, §318.

Title 62, the Commonwealth Procurement statute, “applies to every expenditure of funds, other than the investment of funds, by Commonwealth agencies under any contract, irrespective of their source” and does “not apply to contracts between Commonwealth agencies or between the Commonwealth and its political subdivisions.” Title 62, §1702 states that “[t]he General Assembly under Section 11 of Article I of the Constitution of Pennsylvania does hereby waive sovereign immunity as a bar to claims against Commonwealth agencies brought in accordance with Sections 1711.1 (relating to protests of solicitations or awards) and 1712.1 (relating to contract controversies) and Subchapter C (relating to Board of Claims) but only to the extent set forth in this chapter. Under Section 1712.1, contractors may file claims with the contracting officer “for controversies arising from a contract entered into by the Commonwealth.” An independent administrative board, the Board of Claims, has exclusive jurisdiction to arbitrate claims arising from contracts entered into by a Commonwealth agency and filed in accordance with Section 1712.1, except parties are not precluded “from seeking nonmonetary relief in another forum as provided by law.” Title 62, §1723.

The state, in contracting with others to perform carbon sequestration activities, can draft indemnification provisions in those contracts to allocate the risks to the proper actor. While such provisions could not control third party actions, as between the contracting parties, they could hold the party most able to mitigate the risk accountable.

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176 See Powell v. David Drumheller, 653 A.2d 619 (Pa. 1995); Crowell v. City of Phila., 613 A.2d 1178 (Pa. 1992) (which holds that a government unit may be subject to liability, despite the presence of an additional tortfeasor, if the government unit’s actions constitute negligence concurrent with that of the third party so as to preclude indemnity from the third party); see also Peterson v. Philadelphia Hous. Auth., 623 A.2d 904, 907 (Pa. Commw. 1993) (stating conversely, if it is determined that the government unit is vicariously liable, and only secondarily liable for the third party’s negligence, then indemnity is not precluded and the real estate exception does not apply).


3.3.3.3 Limitations On The Commonwealth’s Ability to Shield Participants from Liability

Although Pennsylvania can assign or limit liability arising from GS, there are constitutional limits to the Commonwealth’s ability to do so if the injury occurs outside of Pennsylvania. In cases where an injury occurs outside of Pennsylvania, under the Erie 179 doctrine, where the law of two states may apply, courts will balance the interests and apply the law of the state with greatest interest in the outcome of the issue being considered. 180 Under such an analysis, if an injury occurs outside of Pennsylvania, the courts may apply the law of the state where the injury occurs rather than the law of the state where the sequestration/disposal takes place.

States may influence the balance through expressions of legislative intent. For example, New Jersey’s expression of a strong interest in generating income to clean up hazardous waste sites has often been applied to apply New Jersey law to provide insurance coverage for hazardous site cleanup and interpret certain pollution exclusions not to apply. 181 A similar articulation of a strong Commonwealth policy in Pennsylvania legislation defining and limiting liability would make it more likely that a court would apply Pennsylvania law to an accident occurring in another state. On the other hand, this result could not be guaranteed.

3.3.3.4 Commonwealth Power to Indemnify Participating Utilities/Power Producers or Otherwise Assume Exclusive Liability

While the Commonwealth may choose to waive its sovereign immunity and assume liability for the risks created by a CCS network, the Constitution prohibits the Commonwealth from creating liability or potential liability through indemnity provisions. Article VIII, Section 8 of the Pennsylvania Constitution provides: “The credit of the Commonwealth shall not be pledged or loaned to any individual, company, corporation or association nor shall the Commonwealth become a joint owner or stockholder in any company, corporation or association.” 182 This provision has been interpreted as establishing a general rule that the Commonwealth may not indemnify third parties. A CCS program based on the notion that the Commonwealth will indemnify participating utilities or other third parties would therefore be constitutionally impermissible.

179 Erie Railroad Co. v. Tompkins, 304 U.S. 64 (1938).
181 Id.
3.3.4 Conclusion: Legislative Approaches to Liability

All of the parties involved in GS could potentially face liability for personal injury and property damage arising from transportation and sequestration of CO₂ and waste products such as hydrogen sulfide—the power plant and industrial generators, those who transport it, and those involved in the disposal. Planning and regulation that minimize the risk of adverse results are a necessary first step in facilitating development of GS. This study and the regulatory structures discussed in the next section of this report are necessary elements of a risk minimization strategy. In recognition of this fact, both GS bills before the Pennsylvania General Assembly and the proposed GS UIC Regulations under the federal Safe Drinking Water Act call for regulation, permitting, and a post closure emergency response program for GS wells. (See Section 3.6.2.)

Even with the best structured regulatory program, accidents will happen. In the case of a still largely untested technology, the risks of accidents are higher. Accordingly, GS will likely not be financeable unless mechanisms can be created that will fix and limit the exposure of those implementing the technology. There are a variety of mechanisms whereby this can be accomplished. These include the following: (1) providing full or partial immunity from liability to some or all of actors; (2) acquiring commercial insurance; (3) creating an alternative to insurance such as a liability fund; (4) transferring liability to the government statutorily, by having the government assume responsibility for the activity or by providing indemnification; and (5) various combinations and permutations of the foregoing.

Providing full immunity by statute is problematic because it can leave injured parties without a remedy and will likely generate even greater opposition to siting GS facilities. Providing blanket limited liability, such as occurs in admiralty and in the case of airline accidents is another possibility. Nevertheless, in both those examples, those whose right to recovery will be limited will be undertaking the risk voluntarily and this approach is more likely to be deemed acceptable. Putting an upper limit on all liability from a GS facility in a similar way will likely generate opposition to siting these facilities in the same way that blanket liability would put some of the costs of this activity on those who did not voluntarily accept the risk. Providing qualified immunity for some participants may present fewer problems, if a mechanism is provided to compensate those who may be adversely affected. This is the approach that is taken in the Pennsylvania GS bills, where the generators are provided with immunity after they transfer CO₂ to the GS well and liability is transferred to others.

The most common mechanism for managing the risk of liability is to acquire commercial insurance. The availability of commercial insurance is discussed in Section 5.0 of this report. As noted there, although insurance will likely be available, coverage will be limited in time, so that there will be gaps that will need to be filled with other mechanisms.

In cases where commercial insurance is limited or not available, other alternatives can be employed. One such mechanism, employed by proposed House Bill 80 (HB 80), is to create a liability fund that is funded by taxes or fees imposed on the activity and which
assumes the liability not covered by insurance. Another mechanism involves transfer of liability to the government by either statutorily transferring the liability, having the government undertake the activity itself or having the government provide indemnification. There are constitutional restrictions on Pennsylvania providing indemnification. On the other hand, liability can be statutorily imposed and the government can achieve the same effect by undertaking the activity itself and providing immunity to other participants. The latter mechanisms are employed in the Pennsylvania GS bills discussed below.

As is often the case, combinations of these mechanism will likely be most effective and most cost effective; consequently, the Pennsylvania GS bills should employ an integrated approach. Commercial insurance should be required, as should the provision of financial assurance mechanisms for post closure monitoring and care. These can be supplemented by the creation of indemnity funds that are funded with tax dollars and a surcharge or tax on the production of CO$_2$ or the CCS network. This allows funding for areas that are neglected by insurance coverage and other financial assurances. Providing a transfer of liability not covered by these other mechanisms to the Commonwealth, through the Commonwealth’s involvement and the provision of immunity from the participants who take all required precautions and comply with law, will provide assurances to investors and to the public who may be affected.

3.4 Title or Ownership of Carbon Dioxide

The decision regarding which party will maintain title to the CO$_2$, once it is sequestered, does not resolve questions on the issue of liability. While ownership of the stored CO$_2$ may be a helpful factor for the court in deciding liability for any tortuous conduct attributable to GS, title of the CO$_2$ cannot be equated with legal responsibility. In order to determine liability, the court will have to consider other factors. Nevertheless, under HB 80 / SB 92, as will be discussed below, the legislature has provided that both title and liabilities will be transferred from the generator to the owner of the facility. The Act further provides that liability will be transferred to the Commonwealth and paid out of a liability fund.

3.5 Emerging GHG Regulatory Structures

The demand for GS is being driven by the need to reduce emissions of CO$_2$ and other GHGs into the atmosphere. In developing a model for a CCS network, it will therefore be important to consider the rules for measuring and accounting for CO$_2$ that is injected into GS wells rather than emitted into the atmosphere, and for allocating the regulatory risks if that CO$_2$ is released from the GS formation into the ambient atmosphere. These

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183 See Section 3.3.3.3.
184 The amount of the surcharge should be determined by the legislature.
185 Pa. HB 80, § 8.2.
186 Id., § 8.3.
issues will need to be addressed regardless of the national and international regulatory regime that will apply to GHGs, whether it be a cap-and-trade program, traditional technology-based regulation, or some other mechanism. Although there is no definitive regulatory program governing accounting for GHG releases from GS, this report will describe the current regulatory program and some of the approaches taken in pending legislation to issues relevant to CCS.

Comprehensive regulation of GHG emissions in the United States is inevitable, regardless of whether Congress acts on pending legislation. This is the result of the Supreme Court’s decision in *Massachusetts v. EPA*, where the Court reversed EPA’s decision refusing to regulate emissions of greenhouse gases from automobiles and trucks under section 202 of the Clean Air Act. The Court held that: (1) states had standing to challenge EPA’s denial of a petition to regulate mobile source, based on impacts of GHG emissions on the Massachusetts coastline, coupled with the special status of states; (2) there is authority to regulate emissions of CO$_2$ and other GHGs as “pollutants” under the Clean Air Act, and (3) under section 202(a)(1) of the Clean Air Act, EPA was required to determine whether GHG emissions “cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare” (the “endangerment finding”) and, if EPA made the endangerment finding, it would be required to develop regulations unless it could point to a specific statutory provision that would authorize a decision not to regulate.

In response to *Massachusetts*, on July 30, 2008, EPA issued an Advance Notice of Proposed Rulemaking on *Regulating Greenhouse Gas Emissions Under the Clean Air Act*, in which EPA discussed the likelihood of a comprehensive regulatory program for GHG emissions under the Clean Air Act, noted that similar or identical triggers for regulation are found in sections 108, 111, 213, and 231 of the Clean Air Act, and discussed options for undertaking economy-wide regulation under the Clean Air Act. It contains a thoughtful analysis of categorical standards for GHG emissions under all of these sections and possible establishment of a cap-and-trade regulatory program. Since the new Administration took office, EPA has issued a series of regulations implementing many of the regulatory proposals described in the ANPR. These include a proposed endangerment finding, a decision granting California’s application for a waiver of preemption of its GHG emissions standards for

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188 42 U.S.C. § 7521.
189 *Id.*, §7521(a)(1).
191 42 U.S.C. §§ 7408, 7411, 7547, 7571.
automobiles, a final rule requiring reporting of greenhouse gas emissions, proposed automobile emissions regulations, a proposed prevention of significant deterioration (PSD) tailoring rule, and a proposed PSD interpretive regulation.

Although the endangerment finding, standing alone, would not itself impose any requirements on industry or other entities, The endangerment finding triggers the requirement for automobile emissions regulations. As made clear in the interpretive rule and the PSD tailoring rule, the establishment of any emissions regulations will trigger requirements for Best Available Control Technology for new and modified air pollution sources and will require the establishment of new source performance standards. Although EPA’s proposed tailoring regulations would limit which facilities would be required to obtain permits and be subject to best available control technology (BACT) analysis, these requirements would still cover nearly 70% of the nation’s largest stationary source GHG emitters—including power plants, refineries, and cement production facilities. How these requirements might impact technology choice—particularly deployment of CCS—is unclear at the present time. On the other hand, if and when CCS has been shown to be feasible, it is possible that it will be required.

There are two comprehensive climate bills before the United States Congress. In June of this year, the House of Representatives passed the American Clean Energy and Security Act of 2009 (ACESA), also referred to as the Waxman-Markey Bill, H.R. 2454. Senators Kerry and Boxer have also introduced Senate Bill S.1733 (Boxer-Kerry). Both bills include similar provisions dealing specifically with GS (see Section 3.6.) Both bills would put in place a series of actions to deal with both the mitigation of climate change through emission reduction and adaptation to protect critical natural resources and assets.

A key aspect of both climate bills is the creation of a program to control GHGs through creation of a cap-and-trade system driven by a system of “allowances”. Each allowance represents the global warming impact of the equivalent of emitting one metric tonne of CO₂. The total amount of emissions each year is capped (and the cap declines year over year) to meet the reduction goals set out in the legislation. Stationary sources would be allowed to emit only the number of metric tons of GHGs for which they were awarded or could purchase allowances. The bills both include provisions for allocating or auctioning those allowances. Because the number of allowances will decline, they may eventually drive industry to CCS or away from fossil fuel fired electric generation altogether. For

196 Released Sept. 30, 2009, see http://www.epa.gov/NSR/fs20090930action.html.
example, under ACESA’s cap-and-trade program, emissions will need to be reduced by 83% from 2005 levels by 2050 and allowances will decline commensurately. 199

Both bills will also likely require the establishment of technology based emissions limits for GHG emissions that may require CCS. S1733 would retain the current technology based requirements of the Clean Air Act. Although ACESA would eliminate some of those provisions, Section 116 of ACESA creates a new Section 811 of the Clean Air Act, which would require EPA to establish GHG emissions standards for coal and petroleum coke fired Electricity Generating Units (EGUs). These regulations will require specific percentage emission reductions. Emissions limits must go into effect four years after EPA issues a report finding that there are, in operation, sources with CCS totaling at least four gigawatts in generation capacity. These emissions limitations will be in addition to the requirement that fossil-fuel fired EGUs must obtain emissions allowances under the cap-and-trade program established by ACESA.

Finally, it should be noted that new legislation and regulations may not be the only legal requirements that drive demand for CCS. Two courts of appeals have recently reversed district court opinions to hold that emitters of GHGs may be subject to suits based on claims of public and private nuisance and other common law claims. In Connecticut v. American Electric Power, 200 the Second Circuit held that a number of states could raise public nuisance claims against six domestic coal fired electricity plants, seeking injunctive relief requiring control of their greenhouse gas emissions. In Comer v. Murphy Oil USA, 201 the Fifth Circuit held that victims of Hurricane Katrina can sue major greenhouse gas emitters seeking damages for nuisance and other common law claims. Litigation could, therefore, drive demand for mechanisms, such as CCS, to limit emissions.

3.5.1 Accounting for Greenhouse Gas Emissions

Whether GHG regulation takes place pursuant to the existing provisions of the Clean Air Act or new legislation, both emissions and CCS will be subject to regulations that will require that regulated entities keep track of greenhouse gas emissions and their fate. The regulatory program for emissions calculations and reporting under the existing authority of the Clean Air Act is discussed below. The proposed legislation would impose additional requirements. For example, ACESA would create a new Section 713 of the Clean Air Act will require regulations establishing a GHG Registry. Those regulations will require reporting on GHG emission and “the capture and sequestration of greenhouse gases.” 202 The regulations must take into account “best practices” for measurement,
accounting, reporting, and verification. The legislation further provides that these reporting regulations establish measurement protocols for CCS networks, taking into account the regulations promulgated under Section 813.203

The proposed climate bills will require that rules be developed for geologic sequestration sites to assess the amounts of carbon dioxide injected and any leakage. In addition, for these storage facilities, they must buy allowances to cover leakage. Under some circumstances, in addition to a one-to-one offset for leakage, a site emitting excess GHG’s may need to buy a penalty allotment of allowances. Due to these requirements, the monitoring, measurement and verification requirements serve both as a tool for management of the site, from a health and safety perspective, and as a key part of a national compliance regime. As discussed below, similar requirements will be imposed pursuant to existing law even if the proposed legislation does not pass.

3.5.2 Federal Law Applicable to the Treatment of CCS in Greenhouse Gas Emissions

Reporting and Emissions Limitations

On September 22, 2009, EPA Administrator Lisa Jackson signed the final rule on mandatory reporting of GHG emissions.204 In general terms, the rule requires facilities engaging in certain listed activities (utility-scale electricity generation among them) to monitor and to report GHG emissions, and requires facilities engaging in other activities to monitor and to report GHG emissions if direct GHG emissions from that facility exceed 25,000 metric tons CO$_2$ per year.205 CCS and GS are not among the listed activities, and thus a CCS or GS facility would be covered by the rule only if direct GHG emissions from stationary fuel combustion units at the facility (having aggregate capacity of 30 mmBtu/hr or more) exceed 25,000 metric tons per year.206

Commercial suppliers of GHGs and certain feedstocks are also covered by the rule.207 Subpart PP of the rule, dealing with Suppliers of CO$_2$, includes within its scope facilities that operate CCS systems to capture their own process emissions. Yet, the same section excludes stand-alone GS facilities. The rule states:

“§ 98.420 Definition of the source category.
(a) The CO$_2$ supplier source category consists of the following:

203 Id. § 713(b)(1)(J).
204 For access to the preamble, rule and other documents, see http://www.epa.gov/climatechange/emissions/ghgrulemaking.html
205 See 40 C.F.R. § 98.2(a)).
206 See Id. § 98.2(a)(3).
207 Id. § 98.2(a)(4).
(1) Facilities with production process units that capture a CO₂ stream for purposes of supplying CO₂ for commercial applications or that capture and maintain custody of a CO₂ stream in order to sequester or otherwise inject it underground. Capture refers to the initial separation and removal of CO₂ from a manufacturing process or any other process.

* * *

(b) This source category is focused on upstream supply. It does not cover:

(1) Storage of CO₂ above ground or in geologic formations.”

EPA addressed this apparent conflict at length in the preamble to the rule, confirming that if a facility captures CO₂ from a production process unit and sequesters that CO₂ on-site, it is covered by Subpart PP. It appears that stand-alone GS and other CO₂ storage facilities are excluded from Subpart PP under Section 98.420(b)(1).

The rule does not provide any guidance as to how sources utilizing CCS systems who do not maintain custody of the gas stream would account for the reduction in GHG emissions achieved by CCS. This is a likely profile for users of a large-scale GS system, and would appear to provide a large “loophole” in the GHG reporting rule. Nevertheless, because the largest GHG producers, such as electric generating units, are covered by the rule under Section 98.2(a)(1) regardless of the quantity of GHG emissions, these sources will be required to report GHG data even if they were to capture 100% of their GHG emissions.

In the preamble to the rule, EPA acknowledged that GS sites may ultimately play an important role in controlling GHG emissions, and foretold a future rulemaking that would be directed at collecting information from GS facilities. EPA states:

“EPA believes information on the end-use will provide some idea of the amounts of CO₂ which are emitted. Where that end-use is geologic sequestration (at EOR [enhanced oil recovery] or other types of facilities), EPA will need additional information on the amount of CO₂ that is permanently and securely sequestered and on the monitoring and verification methodologies applied. With respect to EOR, the geology of an oil and gas reservoir can create a good barrier to trap CO₂ underground. Because these formations effectively stored oil or gas for hundreds of thousands to millions of years, it is believed that they can be used to store injected CO₂ for long periods of time.

However, EPA also recognizes that the requirements to identify a suitable GS site extend beyond geophysical trapping parameters alone and include: the evaluation and appropriate management of potential leakage pathways, appropriate rate and pressure of injection, appropriate monitoring, and other such features….
Given the comments in support of downstream data collection, particularly with respect to EOR systems and CO₂ geologic sequestration (at EOR or other types of facilities), EPA plans to issue a new proposal on geologic sequestration and will consider how to address emissions and sequestration at active EOR facilities. EPA will take action on this issue in the near future with the goal that data collection for these types of facilities can begin as quickly as possible. EPA will seek comment on monitoring, reporting, and verification methodologies which can be used to determine the amount of CO₂ emitted and geologically sequestered at active EOR facilities and geologic sequestration sites where CO₂ is injected (for long-term storage) into saline formations, oil and gas reservoirs, or other geologic formations.  

Until this promised future rulemaking comes to pass, stand-alone CSS/GS systems are not required to report GHG emissions. The reporting rule does apply, however, to the primary users of such systems—electricity generation units—regardless of the quantity of GHGs actually emitted. The rule does not provide any specific authorization for deducting captured GHGs from a covered facility’s emissions. For most facilities, CO₂ emissions will be calculated from formulae based on fuel use, which necessarily assume no capture. Only at facilities with continuous emission monitoring systems measuring actual CO₂ emissions would the deduction of captured CO₂ be possible, even if it is not explicitly barred by the rule.

3.5.3 Regional GHG Management Systems

There are three regional GHG management systems: the Regional Greenhouse Gas Initiative (RGGI) in the northeast; the Midwestern Greenhouse Gas Reduction Accord (Midwest Accord); and the Western Climate Initiative (WCI). Of these, RGGI is the most advanced, with member states having adopted implementing legislation, and with GHG allowance auctions already taking place. Both WCI and the Midwest Accord have formulated design principles (at least in draft form), and WCI is farther along the path towards implementation. These three schemes adopt the same basic approach. Some, though not all and not identical, industry groups are required to monitor, to report, and to offset GHG emissions with allowances or offsets, or both. None of these programs, as currently delineated, would apply to GS facilities in those jurisdictions. On the other hand, how these programs account for CCS and GS systems may be instructive for Pennsylvania’s effort.

RGGI is comprised of ten states, including four of the six states that border Pennsylvania: New York, New Jersey, Delaware and Maryland. Pennsylvania is an “observer” state, but has not implemented any of RGGI’s substantive requirements, or committed to doing

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208 Preamble, 479-481.
209 40 C.F.R. § 98.33(a)(1)-(3).
210 See id., § 98.33(a)(4).
so. In the simplest terms, RGGI requires that each covered source acquire one allowance for every ton of GHGs it emits. Allowances are auctioned through a common agent, and each source owner maintains an allowance “account” from which it must withdraw to cover its emissions. In addition to buying allowances, a source owner may create allowances by undertaking “offset” projects in one of the RGGI states. Only a short list of offset projects are eligible to create RGGI allowances. RGGI’s Model Rule does not contain any specific provision for CCS or GS. Neither CCS nor GS is on the list of approved offsets. Nevertheless, the Model Rule leaves room for the reasonable argument that GHGs captured before they are emitted to the atmosphere should be excluded from GHG emissions for which allowances must be purchased, just as any other process change that reduces emissions. Thus, for example, it appears that a facility in New York that captures its GHG emissions and delivers them by pipeline or otherwise into Pennsylvania’s GS system would not be required to apply allowances to those captured emissions under RGGI.\footnote{This analysis is based only on a review of RGGI’s Model Rule, and not on the applicable law in effect in any particular RGGI state, which may differ from the Model Rule in material respects. The Model Rule may be found at: http://www.rggi.org/docs/Model%20Rule%20Revised%2012.31.08.pdf.}

The Midwestern Accord consists of six US states and the Canadian province of Manitoba. None of these states borders Pennsylvania, though Ohio is an “observer” state. There is no model rule or implementing legislation in place for the Accord, but in June 2009 the Accord’s Advisory Group published its Draft Final Recommendations\footnote{Available at: http://www.midwesternaccord.org/GHG%20Draft%20Advisory%20Group%20Recommendations.pdf.} for the system’s design. Like the other regional systems, the Midwestern Accord system, as so delineated, would not cover all GHG sources, and GS systems are not among those covered. No specific treatment of CCS or GS is discussed in the recommendations. Sequestration in general is mentioned in the discussion of criteria for offsets that would be permitted under the Accord’s system. Sequestration is listed as an example of an offset project that may require confirmation with respect to the permanence criterion. (see Section 4.2.4) This treatment suggests that CCS/GS could ultimately be treated like an offset project. As an offset project, the GS system would be monitored to assure that the GHGs remained sequestered, and the original generator of the GHGs could be liable for obtaining additional allowances or offsets should it be discovered that GHGs were released from the GS site. On the other hand, the recommendations are quite general, and certainly leave room for the same argument raised above: that GHGs captured at the source and delivered to a GS facility should be excluded from the calculation of GHG emissions.

WCI is comprised of seven US states and four Canadian provinces, including the province of Ontario, with which Pennsylvania shares an international maritime border in
Lake Erie. WCI completed its Design Recommendations\(^{213}\) in 2008. Like the other two regional programs, WCI will originally cover only certain types of facilities, and CSS and GS facilities are not covered. Likewise, there is no specific discussion in the design document that addresses the treatment of GHGs that are captured and sequestered. It is certainly possible that GHGs generated by covered sources that are captured by CCS systems would not be included in the calculation of the facility’s GHG emissions.

### 3.6 Regulatory Issues Relating to Regulation of a CCS Network

This section addresses the regulatory requirements that will be applicable to the siting, construction, operation, and closure of the pipelines and sequestration wells that will constitute the CCS network. There are currently no laws or regulations designed specifically to regulate CCS. Creation of a sound, coordinated, and predictable regulatory mechanism will ultimately be the best means to manage the risks of GS and to reduce opposition. In the next section, we will therefore examine proposed federal and state laws and regulations, as well as model regulations for regulating CCS. These will describe the likely federal regulatory regime with which Pennsylvania’s CCS network will need to comply and suggest the regulatory structure that the General Assembly should consider creating in Pennsylvania to facilitate implementation of the network.

We will next examine the many state and federal statutory and regulatory requirements that will or may apply to development and operation of the network under existing law. These must be considered for two reasons. First, in many cases, laws and regulations may apply to various aspects of CCS, but both their applicability and effect are unclear. In these cases, existing state statutes may authorize the development of regulations specific to CCS and it will be important to coordinate their requirements into a comprehensive program for regulation of CCS. Second, there are other regulatory requirements that must be considered because they create requirements applicable to siting and permitting requirements which must be satisfied in order to implement the CCS network. A comprehensive listing of permits that may be required appears in Appendix 3.6.10.4 of this report.

#### 3.6.1 Proposed Federal Legislation

There are a number of bills before the United States Congress that, if adopted, would govern the legal requirements applicable to development of a CCS network. The comprehensive climate bills before the United States Congress have very similar provisions encouraging CCS and incorporating GS projects into their proposed federal regulatory regime. ACESA, passed by the House of Representatives in June 2009, includes, in addition to those measures discussed above, a series of measures to support both limited demonstrations of CCS and provisions to encourage early movers to deploy CCS by rewarding them with bonus amounts of free allowances and a section (Section 113) dealing with CCS that commissions a study and a report as to the legal framework

\(^{213}\) Available at http://www.westernclimateinitiative.org/document-archives/wci-design-recommendations.
for geologic storage sites. S1733, introduced by Senators Kerry and Boxer, includes provisions similar to ACESA.\footnote{See, Christine Tezak, Side-by-Side Analysis of House and Senate Climate Bills, Baird Energy & Environmental Policy Research (Oct. 5, 2009).} Senate Bill 1013 (S1013), introduced by Senator Bingaman, and Senate Bill 1502 (S1502), introduced by Senator Casey this year also address CCS-related issues. In addition to these bills, as has been discussed earlier in Section 3.6.2, the EPA has also been working on proposed revisions to the UIC provisions under the Safe Drinking Water Act. The pertinent provisions of Senate Bills 1733 (S1733), S1013, and S1502 will be discussed below.

Subtitle B of Title I of ACESA, the only bill passed by either house, expressly addresses CCS. Section 111 requires the DOE to submit a report, similar to this one, addressing the barriers to commercial use of CCS technology and Section 112 requires EPA to prepare a similar report and to identify what can be accomplished with existing legislation. Section 113 calls for the establishment of an expert panel to address the application of existing law to geologic sequestration activities. Section 114 authorizes the establishment of the carbon storage research corporation, a private industry organization with authority to make assessments against various entities involved in fossil fuel electricity generation and use the funds to issue grants, contracts, and other financial assistance to promote carbon capture technology.

ACESA also requires the development of regulations governing CCS. Section 112 would add a new Section 813 to the Clean Air Act, requiring EPA to establish a coordinated approach to certifying and permitting geologic sequestration, requiring that EPA promulgate regulations within two years, addressing monitoring, recording keeping, and reporting. That section also amends Section 1421 of the Safe Drinking Water Act to require EPA to promulgate the UIC regulations for CO\(_2\) GS (discussed in Section 3.6.2, of this report) within one year.

Section 115 of ACESA requires the issuance of GHG emissions allowances to support commercial deployment of carbon capture technologies. EGUs that apply CCS to flue gas from at least 200 megawatts of generation capacity are eligible to receive bonus allowances. These allowances will subsidize the initial application of CCS technology, with the first capacity developed receiving greater support.

S1733 includes many of the same provisions that deal with CCS as does the House bill. It authorizes (without appropriations) a CCS demonstration and early deployment program. It requires that a national strategy be developed for CCS and that, not later than one year after the date of enactment, EPA, in consultation with the Department of the Interior, submit to Congress a report describing that strategy. The strategy must address the key legal, regulatory, and other barriers to the commercial-scale deployment of CCS. The bill requires two additional reports: (1) a study of the legal framework for geological storage sites and (2) a study of environmental statutes that might be applied CO\(_2\) injection and geological storage activities.
S1733 requires the Administrator of EPA to promulgate regulations to protect human health and the environment by minimizing the risk of escape to the atmosphere of CO$_2$ injected for purposes of GS. These regulations must include: (1) a process to obtain certification for GS; (2) requirements for monitoring, recordkeeping, and reporting for emissions associated with injection into, and escape from, geological storage sites; (3) public participation in the certification process that maximizes transparency; and (4) sharing data among States, Indian tribes, and the Environmental Protection Agency. S1733 would also amend Section 1421 of the Safe Drinking Water Act$^{215}$ to require EPA to promulgate CO$_2$ UIC regulations similar to those that have been proposed by EPA and are discussed in Section 3.6.2.

One issue that needs to be addressed by federal regulation is the question of liability in a public-private partnership for a governmental organization involved in the facilitation or deployment of CCS technology. The question of liability may depend upon whether involvement by a governmental organization creates an implied certification of the availability of safe storage in the underground pore space. S1013 attempts to address the question of governmental liability.

S1013 creates a definition of liability to be utilized in indemnification agreements. Specifically, S1013 defines legal liability for GS as either: (1) bodily injury, sickness, disease or death of an individual; (2) loss of or damage to property, or loss of use of property; or (3) injury to or destruction or loss of natural resources, including fish, wildlife, and drinking water supplies. S1013 also empowers the Secretary of Energy with the ability to indemnify the recipient of a public-private partnership agreement from liability resulting from a demonstration project in excess of the amount of liability covered by insurance. Conversely, S1013 prohibits the Secretary of Energy from indemnifying the recipient of a public-private partnership agreement from liability arising from grossly negligent conduct or intentional misconduct.

The liability shield in proposed by S1013 could force the government to assume legal liability for the consequences of demonstration projects. One possible outcome of S1013 would be that the government may be liable for any site “certified” as acceptable for GS by the DOE, EPA, or any other government entity. Thus, passage of S1013 could result in state or federal government liability for any leakage of CO$_2$ from a site certified by a government agency for GS.

A common assumption for proposed regulatory frameworks of CCS in the US and in emerging international treaties on climate mitigation, is that the government will take legal responsibility for the long-term stewardship of CO$_2$. One issue that must be addressed is the specific point in time when the government will assume liability. Some suggest that the government should not assume liability for GS until the CO$_2$ has been stored for a period of 50 years. Other commentators suggest that the transition period for...
from private liability to government liability for GS should be no longer than a few years. Other scientists contend that the transition period from private to government liability should be site specific and that setting a deadline would be counterproductive. In order to properly facilitate CCS network development, a definitive approach must be determined for the transfer of liability from the private parties to the public parties involved.

S1502, introduced by Senator Casey this year, is entitled the Carbon Storage Stewardship Trust Fund Act of 2009. The purposes of this Act are to: (1) promote the commercial deployment of carbon capture and storage as an essential component of a national climate mitigation strategy; (2) require private liability assurance during the active project period of a carbon dioxide storage facility; (3) establish a Federal trust fund consisting of amounts received as fees from operators of carbon dioxide storage facilities; (4) establish a limit on liability for damages caused by injection of CO₂ by CO₂ storage facilities subject to certificates of closure; (5) establish a program: (A) to certify the closure of commercial CO₂ storage facilities; and (B) to provide for the transfer of long-term stewardship to the Federal Government for carbon dioxide storage facilities on the issuance of certificates of closure for the facilities; (6) provide for the prompt and orderly compensation for damages relating to the storage of CO₂; and (7) protect the environment and public by providing long-term stewardship of geological storage units.

3.6.2 Safe Drinking Water Act: Issues and Proposed Regulation

The principal federal law that will govern CCS is the Safe Drinking Water Act, which regulates underground injection wells to protect ground water quality. The Safe Drinking Water Act requires EPA to promulgate regulations for “State underground injection control programs” “to prevent underground injection which endangers drinking water sources.” States are required to develop programs implementing these regulations and where a state does not implement an adequate program, EPA will promulgate a program for that state. States are free to impose more stringent requirements than those of the federal government. EPA’s current UIC program does not address geologic sequestration of CO₂. On the other hand, in 2008, EPA proposed regulations under the Safe Drinking Water Act program governing underground injection of CO₂ for GS. On August 31, 2009, EPA issued a Notice of Data Availability (NODA) and Request for additional comments summarizing new data and an alternative approach suggested by comments on the

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218 42 U.S.C. § 300h.
219 40 C.F.R. §§ 144-149.
proposed rule.\textsuperscript{221} These proposed regulations should be deemed the minimum standards that will govern Pennsylvania’s siting, design, and operation of GS wells.

The Proposed GS UIC Regulations would create a new Class VI category of injection well to account for the unique issues presented by underground injection of CO$_2$.\textsuperscript{222} These proposed regulations include standards for permitting Class VI wells, siting criteria, and requirements for geologic site characterization and evaluation of areas surrounding the well that might be affected; corrective action; well construction and operating requirement; mechanical integrity testing and monitoring; well plugging; post-injection site care; and site closure to protect underground sources of drinking water and against other potential dangers and financial responsibility. States are free to impose more stringent requirements.

The Proposed GS UIC Regulations include specific requirements for obtaining permits.\textsuperscript{223} These require geologic site characterization and modeling to assure that GS wells are sited in a “suitable geologic system,” as follows:

“The geologic system must be comprised of:

(1) An injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO$_2$ stream;

(2) A confining zone(s) that is free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected CO$_2$ stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).”\textsuperscript{224}

EPA or a state may, at its discretion, require additional confining units.\textsuperscript{225} Under the proposed regulations, the injection zone must be “beneath the lowermost formation containing an underground source of drinking water (USDW).”\textsuperscript{226} Nevertheless, in the NODA, EPA invited comments on providing a mechanism to allow a waiver to accommodate areas with very deep USDWs.

\textsuperscript{221} 74 Fed. Reg. 44802 (August 31, 2009).
\textsuperscript{222} 40 C.F.R. §§ 146.5(f), 146.81-146.96, 73 Fed. Reg. at 43534-43541.
\textsuperscript{223} 40 C.F.R. § 146.82.
\textsuperscript{224} Id., § 146.83(a).
\textsuperscript{225} Id., § 146.83(b).
\textsuperscript{226} Id. § 146.5(f); see also, id. § 146.86(b)(2) (requiring surface casing to “extend through base of lowermost USDW”).
An applicant for a UIC GS permit must, based on “computational modeling,” identify the area surrounding the GS project that “may be impacted by the injection activity” and predict fate and transport of the injected material. Monitoring, corrective action, and financial responsibility requirements must be based on this. Moreover, the proposed regulations require periodic re-evaluation of the area of review around the injection well to incorporate monitoring and operational data and verify that CO₂ is moving as predicted within the subsurface.

The Proposed GS UIC Regulations include injection well construction requirements. These generally require wells be installed with materials compatible with the material being injected, in a manner that prevents fluid movement into unintended zones, and in a manner that will accommodate monitoring and corrective action.

The proposed regulations’ operating requirements require that the owner or operator:

“ensure that injection pressure does not exceed 90% of the fracture pressure of the injection zone so as to assure that the injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW.”

The operator must maintain an operating pressure in the annulus greater than the injection, install and use continuous recording devices and an automatic shut-off device if operating parameters diverge from those required; and meet requirements for notification and corrective action if there is a shut down or loss of mechanical integrity.

The Proposed GS UIC Regulations require periodic testing to assure the mechanical integrity of the well, including tests at least once a year using tracer surveys, temperature or noise logs, or casing logs to assure the absence of fluid movement. They also require the development of detailed testing and monitoring plan to ensure that the GS project is operating as permitted and will not endanger USDW. This must include use of continuous recording devices, corrosion monitoring, ground water monitoring, pressure fall off testing at least every five years, and tracking of the location of the

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227 Id. §146.84.
228 Id. § 146.84.
229 Id. § 146.86.
230 Id. § 146.88.
231 Id. § 146.88(a).
232 Id. § 146.89.
233 Id. § 146.90.
injected CO$_2$ to ensure protection of USDW. Further, semi-annual reports are required.

The regulations also require that the permit application include an emergency and remedial response plant to address the movement of injection flues that may endanger a USDW during construction, operation, closure, and post-closure. If there is evidence that there may be endangerment, injection must immediately cease and the operator must notify EPA or the state within 24 hours, characterize the release, and implement the plan.

The Proposed GS UIC Regulations prescribe closure and post-closure requirements. The closure requirements call for flushing wells with a buffer fluid and for injection well plugging pursuant to a plan approved by EPA or the state. The proposed regulations call for extended post-injection monitoring and site care to track the location of the injected CO$_2$ and to monitor subsurface pressures. Unless the applicant can demonstrate that a shorter period is appropriate, the post-injection site care period must continue for at least 50 years after injection ceases or a longer period if, at EPA’s or the state’s discretion, a longer period is required to protect underground drinking water sources.

The owner or operator must also demonstrate and maintain financial responsibility requirements to assure that funds will be available for well plugging, site care, closure, and emergency and remedial response. This must be maintained until the end of the post closure injection site care period (50 years or longer).

Pennsylvania does not have a federally authorized state UIC program, so that the UIC program in Pennsylvania is currently administered by the EPA. The Pennsylvania Safe Drinking Water Act, does not authorize regulation of injection wells. Pennsylvania requires permits for the injection of CO$_2$ or other materials into oil and gas wells, but bases its authority to do so on the Clean Streams Law and the Oil and Gas

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234 Id.
235 Id. § 146.91.
236 Id., § 146.94.
237 Id. § 146.92.
238 Id. § 146.93.
239 Id. § 146.93.
240 40 C.F.R. § 147.1951.
That permit program would apply to CO₂ injection and sequestration into abandoned gas and oil wells, but would not cover other CCS wells. Moreover, the permit requirements are not tailored to the issues presented by CCS wells and would not satisfy the federal requirements.

3.6.3 The Pennsylvania Clean Streams Law Regulates Underground Disposal of Carbon Dioxide

The various activities associated with CCS (underground injection, subsurface drilling, and the creation of waste waters) may trigger regulation under the Pennsylvania Clean Streams Law (CSL). \(^{245}\) Except as provided by the CSL, no person may discharge industrial wastes or any substance of any kind resulting in pollution into “waters of the Commonwealth.” The statute states, “no person or municipality shall place or permit to be placed, or discharged or permit to flow, or continue to discharge or permit to flow, into any of the waters of the Commonwealth any industrial wastes, except as hereinafter provided in this act.” \(^{246}\) “Industrial waste” is defined as follows:

“‘Industrial’ waste shall be construed to mean any liquid, gaseous, radioactive, solid or other substance, not sewage, resulting from any manufacturing or industry, or from any establishment, as herein defined, and mine drainage, refuse, silt, coal mine solids, rock, debris, dirt and clay from coal mines, coal collieries, breakers or other coal processing operations. ‘Industrial waste’ includes all such substances whether or not generally characterized as waste.” \(^{247}\)

CO₂ emissions from power plants appear to fall into the statutory definition of “industrial waste.” Section 307 of the CSL then requires that industrial waste discharges into waters of the Commonwealth require a permit. \(^{248}\) “Waters of the Commonwealth” include ground water in addition to surface waters. \(^{249}\)

CSL regulations state that a National Pollution Discharge Elimination System (NPDES) permit issued for a discharge pursuant to Chapter 92 (for discharges to surface waters) is the DEP permit for purposes of permitting under Section 307 (for industrial waste discharges to waters of the Commonwealth). \(^{250}\) Certain activities are excluded from NPDES permitting requirements, including:

\(^{250}\) 25 Pa. Code § 92.5.
“Water, gas, or other material which is injected into a well to facilitate production of oil or gas, or water derived in association with oil and gas production and disposed of in a well, if the well is used either to facilitate production or for disposal purposes, is approved by authority of the Department, and if the Department determines that the injection or disposal will not result in the degradation of ground or surface water resources.”

This exclusion is specifically tied to “the production of oil or gas” and therefore probably does not encompass CCS. Technically, it appears that CCS requires permitting under Section 307 of the CSL as a discharge of industrial waste.

DEP has developed specific regulations governing potential pollution resulting from underground disposal. According to these regulations, DEP considers “the disposal of wastes, including stormwater runoff, into the underground as potential pollution, unless the disposal is close enough to the surface so that the wastes will be absorbed in the soil mantle and be acted upon by the bacteria naturally present in the mantle before reaching the underground or surface waters.” The regulations specifically prohibit the discharge of wastes into abandoned wells and the disposal of wastes into “underground horizons.” There is an exception for discharges into “underground horizons” when “the disposal is for the abatement of pollution and the applicant can show by the log of the strata penetrated, and by the stratiographic structure of the region, that it is improbable that the disposal would be prejudicial to the public interest and is acceptable to the Department.” CSL regulations do not provide any standards to determine whether disposal would be “prejudicial to the public interest.” On the other hand, DEP has determined for purposes of remediation under Pennsylvania’s Land Recycling Program that ground water will not be considered a current or potential source of drinking water where ground water has a background total dissolved solids concentration greater than 2,500 milligrams per liter. Therefore, DEP may find that disposal into underground horizons that impact only saline formations is not prohibited.

The CSL regulations provide very limited procedures for obtaining DEP authorization for underground disposal and state only that a permit issued under § 91.51 shall be issued in accordance with the Chapter 92 NPDES permitting requirements when applicable.

The CSL also has a prohibition against discharges of “other pollutions.” According to the statute:

> “Whenever the department finds that any activity, not otherwise requiring a permit under this act, including but not limited to the impounding, handling, storage, transportation, processing or disposing of materials or substances, creates a danger of pollution of the waters of the Commonwealth or that regulation of the activity is necessary to avoid such pollution, the department may, by rule or regulation, require that such activity be conducted only pursuant to a permit issued by the department or may otherwise establish the conditions under which such activity shall be conducted, or the department may issue an order to a person or municipality regulating a particular activity.”  

This catch-all provision for other pollution appears to leave the door open for the development of regulations. DEP may wish to use the CSL as the basis of authority to implement a Pennsylvania program to govern CCS wells similar to the program proposed for Class VI wells under the SDWA.

3.6.4 Pennsylvania Oil and Gas Law

Pennsylvania oil and gas laws regulate the injection of gases and other materials into oil and gas wells, but these laws were not designed to address the issues presented by CCS. The Oil and Gas Act specifically states that its purpose is to regulate the drilling of oil and gas wells for the purpose of developing oil and gas resources. CCS does not involve development of oil and gas resources, but nevertheless it is possible that oil and gas laws can be interpreted (or distorted?) to cover CCS activities.

The Pennsylvania Oil and Gas Act requires a permit for drilling a well or altering existing wells. The Oil and Gas Act defines “well” as:

> “A bore hole drilled or being drilled for the purpose of or to be used for producing, extracting, or injecting any gas, petroleum or other liquid related to oil or gas production or storage, including brine disposal, but excluding bore holes drilled to produce potable water to be used as such.”

“Gas” is further defined as “any fluid, either combustible or noncombustible, which is produced in a natural state from the earth and which maintains a gaseous or rarified state at a standard temperature of 60 degrees Fahrenheit and pressure of 14.7 PSIA, any

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manufactured gas, any byproduct gas or any mixture of gases.”

The Oil and Gas Act regulations also require a permit for “drilling of a disposal or enhanced recovery well or alteration of an existing well.” The terms “disposal well” or “enhanced recovery well” are not defined.

Despite the fact that the oil and gas law may not adequately address all the issues raised by CCS, the core activity that CCS encompasses, namely drilling a bore hole for the purpose of injecting a gas, fits within the existing definitions. The Oil and Gas Act could provide a basis of authority, or another basis in addition to the Clean Streams Law, for DEP to develop a Pennsylvania program to regulate CCS wells.

The permitting requirements found in the regulations provide guidance as to what requirements can be expected from future CCS regulation. Permits to drill oil or gas wells typically require a number of location waivers and variances because wells must be located a certain distance from property boundaries, wetlands, water bodies, buildings, and water wells. A permit application will also require an erosion and sedimentation control plan in accordance with 25 Pa. Code Chapter 102. Furthermore, permits for disposal wells will require an EPA underground injection control permit. CCS activities are likely to implicate similar issues and necessitate the same types of waivers, variances, and approvals.

The Oil and Gas Act also has provisions governing “gas storage operations.” These provisions apply to anyone injecting gas into or storing gas in a “storage reservoir.” A “storage reservoir” is defined as the “portion of any subsurface geological stratum or strata into which gas is or may be injected for the purposes of storage or testing the suitability of such strata or stratum for storage.” The definition requires that the purpose of injection be for “storage” or “testing.” CCS is often described as disposal, as opposed to storage, which may have the effect of making these regulations inapplicable.

3.6.5 Solid and Hazardous Waste Management

Under both federal and Pennsylvania law, “solid waste” is defined to include both liquid and contained gaseous wastes. Thus, supercritical CO$_2$ that would be stored in a GS system could fall under the solid waste regulatory scheme, and the GS system itself could be characterized as a solid waste treatment, storage, or disposal facility. A solid waste

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262 Id.
267 25 Pa. Code § 601.301(a) and (b).
that meets the definition of “hazardous waste” is subject to the requirements of the federal hazardous waste management scheme governed by the Resource Conservation and Recovery Act (RCRA). A “hazardous waste” is a solid waste that either is specifically designated as such or meets certain defined characteristics (flammability, reactivity, corrosivity, or toxicity). The transportation, treatment, storage, and disposal of hazardous wastes are comprehensively regulated under RCRA and the Pennsylvania Solid Waste Management Act (SWMA). Nevertheless, hazardous wastes that are disposed of in injection wells permitted by USEPA under its UIC program are excluded from regulation under RCRA. As Pennsylvania has incorporated the federal RCRA regulations by reference under SWMA, it is not clear whether a facility that holds a federally-issued UIC permit to inject the supercritical liquid phase into a GS system would require any further approval under SWMA, if the supercritical liquid phase was a hazardous waste.

If the supercritical liquid phase is not a hazardous waste, it would be characterized as a “residual waste” under SWMA. SWMA has specific regulations directed at various methods of waste disposal (e.g., landfills), but those existing schemes were not devised with the issues surrounding GS in mind, and it is not clear that any of them apply to disposal of residual waste by injection. For this reason, one policy choice that might be made would be to expressly exclude GS systems from regulation under SWMA in favor of a different regulatory scheme. For example, SWMA might be amended to exclude the supercritical liquid phase and perhaps other products and by-products of the CCS and GS systems from the definition of solid waste. On the other hand, SWMA may provide an existing source of authority for the regulation of the GS system as a solid waste management unit, and the act gives DEP wide latitude to adopt a regulatory scheme under SWMA that is specifically tailored to GS systems.

3.6.6 Regulatory Issues Arising From Salt Water Generation and Necessity of Disposal For Salt Water Formations

Drilling into a deep surface formation to sequester CO$_2$ will likely create a variety of solid waste, the handling and disposal of which will be regulated by the DEP. As seen in the recent subsurface activity arising from the Marcellus Shale Gas Field Exploration, the Commonwealth presently lacks the infrastructure to adequately manage wastes generated by drilling, particularly waste water.

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269 42 U.S.C. § 6901 et seq.
The proposed waste generating and handling activities should be subject to direct regulation under the Pennsylvania Clean Streams Law, the Solid Waste Management Act and regulations promulgated thereto. Indirect regulatory authority should arise under Pennsylvania laws and regulations governing operation of municipal or privately owned waste water treatment systems. Once extracted, brines and similar salt-laden waste will be subject to on-site collection, storage, and management regulations under the CSL. On-site disposal will likely require permits. Other solid wastes, such as rock, soil, and debris, will be required to be characterized, as the Solid Waste Management Act affords different levels of regulation depending on whether such waste would be classified as “clean fill,” “residual waste,” or “hazardous waste.” Generally, clean fill may be managed on site, while the other classes of waste would require permits for on-site management and disposal, or delivery to off-site disposal sites permitted to accept such classes of solid waste.

Complicating waste management issues at the present time, particularly for waste water, is the lack of reliable infrastructure for the off-site treatment and disposal of brines and salt water. Gas companies investing in the Marcellus shale that are required to manage similar waste waters, as well as “frac” water, generally are temporarily storing such waste waters at drilling sites, and then arranging to truck the waste waters to New York and Ohio facilities that have the capacity to manage such waste waters. Most private and publicly owned treatment facilities in Pennsylvania are aging, already over capacity and, as result, cannot accept additional waste water without substantial infrastructure investment, which would also include additional regulatory interaction with DEP to acquire permission to expand capacity, accept new waste streams, and acquire treatment technology adequate to protect watersheds.

Only now is the public sector reacting to such infrastructure shortcomings, as we are seeing a number of joint ventures among and between gas exploration companies and entrepreneurs to locate, permit, and build treatment centers for Marcellus shale waste water.

3.6.7 Hazardous Substance Release and Cleanup Statutes

The federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and its Pennsylvania counterpart, the Hazardous Sites Cleanup Act (HSCA) are not, strictly speaking, regulatory programs. Rather, these statutes impose liability for the remediation of contamination by hazardous substances that occurs outside of any regulatory program. Thus, if contamination arises from a permitted solid or hazardous waste disposal facility, the remediation of that contamination is generally

\[^{275}\text{42 U.S.C. }\S 9601 \text{ et seq.}\]
directed by the statutes and regulations governing solid and hazardous waste disposal facilities, and not by CERCLA or HSCA. Nevertheless, to the extent that the CCS and GS systems give rise to releases of hazardous substances outside such programs, CERCLA and HSCA might become applicable. In order for these statutes to become applicable, the substance released must meet the applicable definitions of “hazardous substance.” Although CO$_2$ is not a hazardous substance, contaminants such as Hydrogen Sulfide are, so disposal of CO$_2$ containing this substance could give rise to liability under CERCLA or HSCA.

3.6.8 National Environmental Policy Act

The National Environmental Policy Act requires federal agencies taking a “major federal action” to evaluate comprehensively the environmental impacts of the project as a whole, such as effects on environmental quality, biodiversity, and endangered species. While the specific form of the review process that takes place is dependent on the agency that is responsible for NEPA compliance, any large project that requires federal permits or receives federal funding will certainly be subject to some level of NEPA review. It is apparent that the injection wells, which will require a UIC permit from EPA, and the collection pipelines, which are likely to require federal permits under Section 404 of the Clean Water Act, among others, will bring the CCS/GS project within the scope of NEPA review.

The NEPA process provides another opportunity for objectors to the GS project to engage in litigation to impede the issuance of permits required by the facility. On the other hand, the obligations imposed on federal agencies (and in turn on project developers) are strictly procedural ones. NEPA requires that the agencies consider carefully the environmental effects of the projects before them, but does not require agencies to reach a particular decision. Thus, when project opponents file lawsuits alleging failure to comply with NEPA, the outcome turns on whether the agency engaged in a thorough, good faith review in accordance with its own procedures, rather than whether the agency should or should not have granted a permit, based on the results of that review.

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278 40 CFR § 300.5 (2009).

279 42 U.S.C. § 4321 et seq.

280 See 40 C.F.R. § 1508.18.

281 42 U.S.C § 4332.

282 See 40 C.F.R. § 1501.5.

283 See 40 C.F.R. § 1508.18.

3.6.9 Regulatory Issues Affecting CO₂ Pipelines

The Natural Gas Act (NGA) of 1938 authorizes use of eminent domain for the construction of natural gas pipelines, and that power has been held to extend to authorize condemnation of underground gas storage facilities. Nevertheless, there is no current Federal siting or eminent domain regulatory scheme for CO₂ pipelines. Rather, the current federal regulatory framework for CO₂ pipeline rate and access regulation can only be described as Byzantine:

The Federal Energy Regulatory Commission (FERC) has disclaimed jurisdiction over CO₂ pipelines under the Natural Gas Act;

The Surface Transportation Board (STB) has not opined on its jurisdiction over CO₂ pipelines under Title 49, United States Code;

The Interstate Commerce Commission (ICC) the predecessor of the STB disclaimed jurisdiction because CO₂ is a “gas” and, therefore exempt under Title 49, United States Code; and

The Bureau of Land Management (BLM) has imposed the equivalent of a common carrier obligation on CO₂ pipelines crossing Federal lands on the basis that CO₂ is “natural gas.”

Nevertheless, Cortez Pipeline Co., the case in which FERC disclaimed jurisdiction, was issued in 1979, long before the recent interest in controlling GHGs and carbon sequestration, and remains untested in the Court of Appeals. Cortez requested that the FERC issue a declaratory order stating that FERC did not have jurisdiction over the proposed pipeline because the supercritical liquid phase being transported was not “natural gas” within the meaning of the NGA. After FERC determined that no specific chemical composition under the NGA constituted natural gas, FERC evaluated Congress’ objectives in enacting the NGA and stated that “the goal of the NGA was to protect the consumers of a salable commodity from exploitation at the hands of the natural gas companies’ and was framed to afford consumers a bond of protection from excessive

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288 Id.
289 Cortez Pipeline Company, 7 FERC ¶ 61,024 (1979).
290 Id. at ¶ 61,041.
rates and charges.” The FERC considered whether to include the CO$_2$ pipeline within its jurisdiction in light of the general goal of the NGA, and found that “no goal or purpose of the NGA” would be advanced by asserting FERC jurisdiction over the CO$_2$ pipeline.

Given the recent attention on this topic, it would be interesting to consider whether the precedent of the 1979 case could be overcome by a different set of facts or more creative legal arguments. If FERC somehow found that it had jurisdiction over CO$_2$ pipelines under the NGA, that jurisdiction would only extend to interstate pipelines and not to lines that could be considered gathering or distribution lines. On the other hand, if FERC found that it could exercise jurisdiction over CO$_2$ lines under the Interstate Commerce Act (ICA), the ICA does not recognize a distinction between gathering and interstate transmission, with the general test for jurisdiction resting on whether the product is destined for interstate commerce. Further, even if FERC found that it could regulate CO$_2$ pipelines, the scope of that jurisdiction would presumably follow the existing precedent under the applicable statute. For example, under the NGA, FERC recognizes a jurisdictional exception for “private pipelines” that are generally owned by a company to serve its own plant facility and to transport gas owned by that same company.

Other agencies, such as the STB and BLM discussed above, also arguably could have a role in regulating or overseeing CO$_2$ pipelines, however, the extent of their respective authority remains largely untested.

As interest grows in building CO$_2$ pipelines, it is likely that additional Congressional attention will be focused on whether and how these pipelines should be regulated. The existing statutes governing natural gas (under the NGA) and oil and products (under the ICA) offer two models for regulation under the jurisdiction of the FERC. Although these options and others have received some preliminary legislative attention, legislative discussions are at a very preliminary stage and it would be premature to predict how the regulatory issues ultimately will be addressed.

Unlike rate regulation where the scope of the federal jurisdiction is uncertain, it appears clear that the federal safety standards for interstate pipelines also apply with equal force to interstate CO$_2$ pipelines. The safety aspects of CO$_2$ pipelines are regulated by the Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) under the Hazardous Liquid Pipeline Act of 1979. Note that it is sometimes difficult to determine the full scope of PHMSA’s reach to either private pipelines or pipelines that do not immediately appear to be interstate. PHMSA is typically reluctant to address questions of this sort in the abstract and more typically requires a detailed factual recitation before it will offer assistance in sorting out questions of potential jurisdiction.

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291 Id. at ¶ 61,042.
292 Id.
3.6.10 Regulatory Approaches in Other States

3.6.10.1 Wyoming

Through the passage of two pieces of legislation to foster CCS activity within the state, Wyoming became the first state to formally enact CCS legislation.\(^{293}\) The first piece of legislation, titled “Ownership of Pore Space” placed the ownership of pore space in the hands of the surface owner.\(^{294}\) This legislation allows for pore space ownership to be conveyed in the same fashion as a mineral interest, but indicates that no conveyance of mineral interests shall convey pore space unless the conveyance of pore space is expressly included in the document of conveyance.\(^{295}\) The statute also places an emphasis on the fact that the mineral estate remains dominant over the surface estate.\(^{296}\) In addition, the legislation requires a transfer of pore space to be accompanied by a description of any right to use the overlying surface estate. The pore space owners’ right to use the surface is restricted to what is described in the instrument of conveyance. Furthermore, the legislature specified that all conveyances after July 1, 2008, are to be construed in conformity with this legislation and that all conveyances before July 1, 2008, should be interpreted in conformity with this legislation. Any party that has an ownership interest in conflict with the legislation must prove their ownership rights by a preponderance of the evidence to the court.\(^{297}\)

The second piece of legislation passed, entitled “Carbon Capture and Sequestration,” calls for the management of CO\(_2\) sequestration under the UIC Program of Part C of the SDWA.\(^{298}\) The legislation gives the Wyoming Department of Environmental Quality (DEQ) the authority to create subclasses of wells, within the UIC program for the injection of CO\(_2\), that are designed to protect the public welfare and to set up a permitting structure.\(^{299}\) To encourage CCS, the statute also contains a provision allowing the DEQ to issue temporary permits for CCS pilot scale testing under the existing rules and regulations.\(^{300}\) This allows a CCS pilot program to occur without the imposition of any


\(^{295}\) Id.

\(^{296}\) Id.

\(^{297}\) H.B. 89 § 3, 59th Leg. (Wyo. 2008).


CCS-specific permit or bonding requirements. The requirements for obtaining a permit are included in the regulations.\textsuperscript{301}

Wyoming Statute § 35-11-313 also allows for the creation of a working group that will have the responsibility of consulting on draft permit requirements proposed by the administrator of the DEQ’s water quality division.\textsuperscript{302} The working group is comprised of the Wyoming’s oil and gas supervisor, the state geologist, and the director of the DEQ.\textsuperscript{303} The working group has the responsibility of developing bonding procedures and other methods of financial assurance to provide financial protection for the state if they are faced with mitigation or reclamation costs because of a CCS project.\textsuperscript{304} An additional function of the working group will be to develop the appropriate duration for the post-closure care period for the CCS network.

Another aspect of Wyoming Statute § 35-11-313 is that it places CO\textsubscript{2} injections within the jurisdictional purview of the Wyoming Oil and Gas Commission.\textsuperscript{305} The statute specifies, however, that the GS aspect of the CCS network is under the jurisdiction of the DEQ and is to be monitored under the UIC program.\textsuperscript{306} Conversely, any withdrawal of sequestered CO\textsubscript{2} is under the jurisdiction of the state’s Oil and Gas Commission so long as the extracted CO\textsubscript{2} is intended for commercial or industrial use.\textsuperscript{307} Although Wyoming’s CCS network regulation places the regulatory authority in the hands of the state, there is explicit language in the statute that allows the director of the DEQ to recommend changes to allow for consistency with any future rules or regulations promulgated by the EPA regarding GS.\textsuperscript{308}

3.6.10.2 Texas

The State of Texas has captured, transported, injected, and stored over 480 million tons of CO\textsubscript{2} in conjunction with EOR activities.\textsuperscript{309} The Railroad Commission of Texas (RCT) is currently responsible for the regulation of CO\textsubscript{2} injections used for EOR, but prior to the

\begin{itemize}
\item \textsuperscript{301} Wyo. Oil & Gas Conservation Comm’n Rules & Regs., Ch. 3 & Ch. 4 (2009), for injection well design and construction requirements.
\item \textsuperscript{303} Wyo. Stat. Ann. § 34-1-152(f) (2009).
\item \textsuperscript{304} Id.
\item \textsuperscript{305} Id. § 35-11-313(b); Wyo. Oil & Gas Comm’n Rules & Regulations, Ch. 4.
\item \textsuperscript{308} Id.
\item \textsuperscript{309} TxCCSA Executive Summary of Legislation to create the Regulatory Framework for the Geologic Storage of Carbon Dioxide, SB 1387, written by Senator Kel Seliger and Representative Myra Crownover.
\end{itemize}
passage of Senate Bill 1387 (S1387), there was no regulatory framework address CCS and the long-term storage of CO₂.  S1387, enacted September 1, 2009, provides a state-level regulatory framework for the storage and sequestration of CO₂.

S1387 amends the Water Code to provide the RCT with jurisdiction over CO₂ injection wells for “incidental” and “sequential” storage, as well as for wells that were originally under the jurisdiction of the RCT. This section of the legislation places the RCT in charge over saline formations and requires a permit from the RCT before the drilling of an injection well or the construction or operation of a GS facility. The RCT may issue a permit only after determining that the permittee’s GS activities will not: (1) endanger oil, gas, or other mineral formations; (2) harm human health or safety; or (3) involve a reservoir that is unsuitable to prevent escape or migration. The RCT is also provided with the authority to collect fees for permitting, monitoring, inspecting, and enforcing CCS network regulations. This legislation provides for consistency between the rules adopted by the RCT and the present and future rules promulgated by the EPA or other federal agencies regarding CCS network activity. Moreover, the statute requires a permittee to demonstrate evidence of financial responsibility on an annual basis.

This legislation also clarifies ownership rights by amending the Natural Resources Code to specify that the storage operator is the default owner of the stored CO₂. This section of the statute also gives the owner the ability to recover the stored CO₂ at a later time. Another aspect of the legislation is that it establishes a Trust Fund, funded by the money collected for permitting, monitoring, inspection, and enforcement, that is to be used for remediation and other purposes. This legislation authorizes the RCT to receive funds as the beneficiary of any financial security required for the management of injection wells or a GS facility. In addition, the new law mandates two interim studies to develop recommendations for managing GS on state-owned lands and to study the

310 Id.
311 S.B. 1387 (March 3, 2009).
319 Id.
320 V.T.C.A., Natural Resources Code § 120.003 (2009).
321 Id.
appropriate regulatory mechanism for GS in saline formations that do not produce oil, gas, or geothermal resources.

3.610.3 Illinois

In an effort to induce the FutureGen Alliance\(^{322}\) to build and operate the world’s first coal-fueled, near-zero emissions coal gasification/carbon sequestration power plant, the Illinois General Assembly proposed legislation that provides the Alliance with certain liability protection and land use rights, and guarantees the issuance of any required permits.\(^{323}\) The Clean Coal FutureGen for Illinois Act\(^{324}\) (FutureGen Act) was a significant inducement to the eventual selection of Mattoon, Illinois as the site for the FutureGen plant.\(^{325}\)

With respect to liability, the FutureGen Act creates a certain dichotomy between pre-injected gas and post-injected gas with the plant operator retaining liability associated with pre-injected gas and the state retaining liability for post-injected gas, as follows:

“If the FutureGen Project locates [at either of two] site[s] in the State of Illinois, then the FutureGen Alliance agrees that the Operator shall transfer and convey and the State of Illinois shall accept and receive, with no payment due from the State of Illinois, all rights, title, and interest in and to and any liabilities associated with the sequestered gas, including any current or future environmental benefits, marketing claims, tradable credits, emissions allocations or offsets (voluntary or compliance based) associated therewith, upon such gas reaching the status of post-injection, which shall be verified by the Agency or other designated State of Illinois agency. The Operator shall retain all rights, title, and interest in and to and any liabilities associated with the pre-injection sequestered gas. The Illinois State Geological Survey of the University of Illinois shall monitor, measure, and verify the permanent status of sequestered CO\(_2\) and co-sequestered gases in which the State has acquired the right, title, and interest under this Section.”\(^{326}\)

The FutureGen Act also required the state to procure an insurance policy from private insurance carrier(s), if, and to the extent that such a policy is available, to cover the

\(^{322}\) See http://www.futuregenalliance.org/ (describing FutureGen Alliance) (last visited July 8, 2008). “FutureGen is a public-private partnership to design, build, and operate the world’s first coal-fueled, near-zero emissions power plant, at an estimated net project cost of US $ 1.5 billion.” Id.


\(^{324}\) Public Act 95-18.


operators of the plant against any qualified loss stemming from a public liability action and indemnify the operator of the FutureGen site from liability from any public action that might be asserted against it. 327 The FutureGen Act also requires the Illinois Attorney General to represent operators of the facility and defend them against any public liability action, unless the Attorney General has a conflict of interest, in which case the State will pay FutureGen’s court costs and attorney’s fees. 328 Finally, the State of Illinois is required to issue all necessary and appropriate permits consistent with State and federal law and corresponding regulations. 329

Clearly, the FutureGen Act provided considerable financial and liability concessions to attract the plant. On the other hand, construction has not been completed, additional funding is needed, and it is possible that the project plans will change in the future. On July 14, 2009, the DOE issued a NEPA Record of Decision to move forward to commence the FutureGen CCS project. 330 The DOE and FutureGen Alliance signed a cooperative agreement to commence site-specific activities. 331 FutureGen Alliance is currently working towards developing a preliminary design, refining the cost estimate, creating a funding plan, expanding the sponsorship group, and conducting additional subsurface characterization. 332 Upon the completion of these activities, DOE and FutureGen Alliance will decide whether to continue with the project. Although the project is still in its early stages, DOE estimates that the CCS network at the outset may be operated at 60% capture to ensure plant integration and sequestration capability, but the network has the capability to capture 90% of carbon emissions by the third year of operations. 333

3.6.10.4 New York

The state of New York has recently issued a report entitled “Carbon Dioxide Capture and Sequestration: Developing a Regulatory Strategy for New York State” (NYSERDA, 2009). The report “summarizes the legal, permitting, and policy challenges that New York must address...[to develop a] comprehensive CCS regulatory program...[and] summarizes the currently legal, regulatory and permitting issues in New York that are applicable to the full range of CO₂ capture, transportation, injection and long-term storage activities...” The report includes a table, reproduced in Appendix 3.6.10.4, that

327 Id. § 1107/25-1107/30.
328 Id. § 1107/35.
329 Id. § 1107/40.
331 Id.
332 Id.
333 Id.
summarizes the permitting requirements that might apply based on current Federal law and the laws of the state of New York.

3.6.11 International Actions, Issues, and Case Studies

Outside of the U.S., there has been considerable effort devoted to the development of regulatory frameworks for CCS. The European Union (EU) issued a Directive in April 2009, for the creation of a regulatory framework for EU nations. The framework provides each member state with the ability to customize its nation’s regulatory framework. In addition to the Directive from the EU, the United Kingdom (UK) has published a record of their consultations and plans for CCS. Although other EU nations are in the process of developing regulatory regimes for CCS, this section focuses the regulatory framework promulgated in the UK. In addition, Australia has made progress in developing regulatory schemes for on-shore and off-shore CCS. The Australian government recently authorized the Gorgon project after the Federal government and the state government of Western Australia agreed to accept long-term liability for the CO\textsubscript{2} storage during the life of the natural gas project.

3.6.11.1 EU

In April 2009, EU issued a Directive seeking the establishment of a consistent regulatory framework for EU member nations. The crux of the Directive was to facilitate the development of a baseline set of regulatory structures for geological storage of CO\textsubscript{2} within the territory of the Member States. The Directive explicitly excludes the storage of CO\textsubscript{2} in storage complexes extending beyond the territorial scope of the Directive and in the water column. The Directive acknowledges that Member States should retain the right to select storage sites and situs location within their respective territories.

The Directive also focuses on the determination of underground storage capacity, the risks imposed by underground storage and communication with the public. In addition, the Directive provides suggested licensing requirements, including the requirement for obtaining a permit prior to the operation of a storage facility operation. Although the directive provides some basic regulatory suggestions, its provisions allow for member states to develop their own regulatory regimes. The EU Directive emphasizes that it is necessary to impose restrictions on the composition of the CO\textsubscript{2} stream consistent with the primary purpose of geological storage, which is to isolate CO\textsubscript{2} emissions from the atmosphere. These restrictions should also be based on a risk assessment of the threat that contamination may pose to the safety and security of the transport and storage network and to public health and the environment.

The Directive provides that: “Provisions are required concerning liability for damage to the local environment and the climate, resulting from any failure of permanent containment of CO\textsubscript{2}. Liability for environmental damage (damage to protected species and natural habitats, water and land) is regulated by Directive 2004 / 35 / EC of the European Parliament and of the Council of 21 April 2004 on environmental liability. Liability for climate damage as a result of CCS network leaks is covered by the inclusion of storage sites in Directive 2003 / 87 / EC, which requires surrender of emissions trading
allowances for any leaked emissions.” This provision suggests that once a commitment has been made to a national cap for CO₂ emissions, the EU expects that leakage would result in the assessment of penalties for “climate damage.”

The Directive considers closure, post-closure monitoring, and long-term monitoring and the assumption of liability by the national government for a CCS network. The Directive requires financial insurance from the injecting party to ensure that the injecting party has the requisite financial standing to address issues with regards to: (1) closure and post-closure storage; (2) obligations arising from inclusion under Directive 2003/87/EC; and (3) remediation in the event of an underground CO₂ leak. Member States should require the insurance finances to be provided in the form of a financial security or equivalent and should be sure to require the securitization or equivalent to be valid and effective before commencement of injection. Although the Directive is related to climate damage, there is no method provided for assessing the future impact of a leak on the climate. The Directive further states that the governments of the Member States may have to assume post-injection liability for the stored CO₂ and that the governments may be responsible for storage and monitoring costs. The operator should be required to make a financial contribution before the transfer of responsibility occurs for the CCS project to the appropriate government authority.

Finally, the Directive addresses transboundary issues in connection with CCS networks. Access to a GS storage site can be considered a condition for entry into or competitive operation within the internal electricity and heat market, depending on the relative prices of carbon and CCS. By establishing mechanisms for dispute resolution for transboundary issues, Member States will be able to expeditiously settle disputes regarding access to transport networks and storage sites. One suggestion offered by the Directive is for the authorities of the Member States to jointly determine the dispute resolution mechanism in cases of transboundary CO₂ transport, transboundary storage sites, or transboundary storage complexes.

UK and Norway have been actively developing their own respective regulatory frameworks for CCS. Both nations contend that one of the main barriers to commercial CCS is the determination of long-term liability for CO₂ storage. These nations have introduced regulatory frameworks for CO₂ storage that involve the government accepting long-term liability for CO₂ storage sites, with Australia and Japan following suit. With the various demonstration projects being suggested in the EU, the EU set aside funding and free carbon allowances to support these demonstrations (UK has agreed to put up additional funds outside of the EU commitment). Nevertheless, pilot projects are encountering difficulties in obtaining permits. The Vattenfall 30 MW test facility has been unable to obtain a permit for injection of CO₂. Local opposition appears the primary barrier to the commencement of demonstration projects.

3.6.11.2 UK

Department of Energy and Climate Change (DECC) in the UK has made significant advancements in the development of rules for permitting off-shore storage of CO₂. To prepare for the process, DECC has had several consultations with experts relating to coal-
fired plants with CCS. With a particular interest in the storage space under the North Sea, DECC requested commentary on a basic framework for permitting in the storage of CO₂ in offshore areas. In April of 2009, DECC published the results of these consultations.

DECC’s published results focused on several major themes with a focus on permits and regulation. DECC framework indicates that projects involving enhanced recovery of hydrocarbons and permanent underground storage of CO₂ will be able to operate under a single permit incorporating both permitting requirements. The relationship between The Crown Estate (TCE), a statutory body which acts on behalf of the Crown in its role as landowner within the area of the territorial sea and as owner of the sovereign rights of the UK sea bed beyond territorial waters, and the appropriate regulatory authority will be structured to avoid an overly intensive authorization process. DECC allowed for the transfer of responsibility for the storage site to the appropriate authority based upon the level of risk and the payment of transfer fees for future monitoring. The report also indicates that in situations where there are conflicting uses for off-shore underground storage space, priority will be given to activities that secure energy supply. Furthermore, the published report presented revised permitting requirement for CO₂ at off-shore sites.

The UK government has developed regulations for licensing storage sites. In addition, the UK government performed assessments concluding that the geologic formations under the UK continental shelf (UKCS) could hold a large amount of captured CO₂. These areas are considered part of TCE. TCE is considered a hereditary asset of the Crown to be managed by TCE. Moreover, TCE operates as a commercial landowner under the provisions of the Crown Estate Act of 1961.

Several sections of a June 2009 report, prepared for the DECC by NERA Economic Consulting, focused on transportation infrastructure that could be relevant to Pennsylvania. NERA was asked to analyze regulatory alternatives and other government actions necessary to efficiently develop a sound CCS transportation infrastructure. In preparation for the report, the consultant conducted a survey of regulatory frameworks in other industries and jurisdictions (including US interstate gas pipelines) and offered a variety of recommendations. Specifically, NERA recommends an economic mechanism that will allow CCS developers to capture the value of CO₂ abatement and use of the regulatory frameworks in other jurisdictions for the transport of hydrocarbons as a model for CCS network infrastructure.

NERA also suggested improvements in the regulation of CO₂ pipelines to promote efficient investment in new pipeline capacity. The report recommends the creation of an efficiently integrated network through the introduction of an obligation by pipeline owners to provide connections to other pipelines. This obligation removes the ability of incumbent pipeline operators to prevent new entrants into the market from constructing new pipeline capacity. This also ensures market competition by enabling pipeline developers with the ability to compete for the right to construct pipelines. In addition, the report focuses on efficient use of existing capacity by reducing the ability of incumbent
pipeline owners from monopolizing the pipeline construction market by setting tariff structures and requiring developers to provide platforms for secondary capacity trading.

3.6.11.3 Australia: A Case Study

Australia has followed a similar approach to the EU in attempting to address the issue of long-term liability involved in GS. The Australian case study, entitled the Gorgon CCS project, is being considered the harbinger for future CCS development. Australia’s Senate indicated that the Australian Commonwealth and Western Australian governments would jointly accept any long-term liability arising from the CO\textsubscript{2} storage. The CO\textsubscript{2} used in the natural gas storage project is compressed, dried, and liquefied. The supercritical CO\textsubscript{2} is then transported to the storage site below Barrow Island, where a total of 125 million metric tons of CO\textsubscript{2} will be kept during a 40-year period. Mostly due to the Australian government’s willingness to assume liability for potential long-term damages, Chevron Corp., Exxon Mobil Corp., and Royal Dutch Shell have agreed to invest in the Gorgon natural gas venture. There is hope that the Gorgon CCS project will set a precedent for future CCS development moving forward. Gorgon is the largest of ten proposed projects being planned. The Minister of Resources and Energy, Martin Ferguson, indicated that the government will only accept liability after they are certain that stored CO\textsubscript{2} poses no significant risk. Chevron estimates Gorgon will start exporting gas in 2014 and that the project will have a lifespan of at least 40 years. The injectors are liable for carbon storage during construction, operation, and for at least 15 years after closure. Government liability will begin in 2069 at the earliest. The government has structured the liability allocation so that the Federal government will assume 80% liability and the state government will assume 20% liability.

3.6.11.4 Det Norske Veritas’ Approach

Det Norske Veritas (DNV) initiated a joint industry project approximately one year ago. For the project, the existing pipeline standards were extended to incorporate specific guidelines for the transmission of CO\textsubscript{2}. The joint industry project, named CO\textsubscript{2}PIPETRANS, recently delivered the world’s first industry guideline for the safe, reliable and cost-effective transmission of CO\textsubscript{2} in pipelines. The partners include ArcelorMittal, BP, Chevron, Dong Energy, Gassco, Gassnova, ILF, Petrobras, Shell, StatoilHydro and Vattenfall, representatives of the Health and Safety Executive in the UK, the State Supervision of Mines in the Netherlands, and the Petroleum Safety Authority in Norway. The established guidelines provide recommendations and develop criteria for the development, design, construction, testing, operation, and maintenance of steel pipelines. These guidelines provide regulations for: (1) new offshore and onshore pipelines for the transportation of fluids containing CO\textsubscript{2}; (2) the conversion of existing pipelines to CO\textsubscript{2} pipelines; (3) the pipeline transportation of CO\textsubscript{2} captured from hydrocarbon streams and from anthropogenic CO\textsubscript{2} (from combustion processes and capture facilities); and (4) the pipeline transportation of natural (geological) sources for the purpose of enhanced oil recovery, and to other larger scale transportation of CO\textsubscript{2}.

The guidelines for the joint industry project will supplement current pipeline standards like ISO 13623, DNV OS-F101, ASME B31.4 and others. The purpose of the guidelines
is to provide support relating to specific CO₂ transportation issues for carbon capture and storage developers, pipeline engineering and construction companies, pipeline operating companies, authorities and certification companies. The guidelines should be available shortly, as they are scheduled to be converted into a DNV Recommended Practice.

In developing the guidelines and construction of the project, several issues were identified that need to be addressed. DNV is therefore initiating a Phase 2 process to create an updated Recommended Practice. The updated Recommended Practice is aimed at informing society at large and the industry to gather enough confidence to accept the risk of the activity.

3.6.11.5 Conclusion: Recommendations for a Sound Regulatory Program

Creation of a sound, coordinated and predictable regulatory mechanism will ultimately be the best means to manage the risks of GS and to reduce opposition. The Proposed GS UIC Regulations currently represent the best learning on mechanisms to manage risk, including requirements for siting, construction, operation, financial assurance, closure, and post-closure care. Pennsylvania does not currently have an approved UIC program and EPA manages the program. Nevertheless, Pennsylvania likely has the ample statutory authority to adopt similar or more protective regulations, and to obtain primacy or partial primacy. Adopting regulations that would allow Pennsylvania to implement both the federal and state programs would likely best promote GS by eliminating the need for two permits and two sets of regulations.

Pennsylvania could adopt regulations under current authority. However, creating explicit authority tailored to GS would be preferable. Failing to adopt a new state statute or comprehensive regulations would undermine development of GS and disserve protection of health and the environment, even if the federal UIC regulations are adopted. As discussed above, there are many Pennsylvania environmental laws that could apply to GS. Without a predictable and comprehensive regulatory scheme, those opposed to siting GS could cite those prohibitions and tie up the program in litigation.

In developing legislation and a regulatory program, including siting criteria, consideration must be given to several facts. First, a CCS network, like any major development project, will require many preconstruction and operating approvals, some of which (e.g. soil erosion and sediment control) will be required in all cases and others of which will depend on the siting or other facts (e.g. NEPA requires a major federal action to evaluate the potential danger to wetlands or endangered species the presence of those factors). Second, there will be opposition by those whose property is crossed by pipelines, or is located near the wells, and some will likely challenge permits. Sound siting and regulatory criteria will make the success of such challenges less likely.

Given the early stage at which both the technology and the regulatory processes stand, a number of key considerations that have been put forth through a number of stakeholder driven processes should be kept in mind:
i) Simple: Most studies suggest keeping the initial regulatory regime simple and clear. The nature of the regulations will evolve as the technological system being regulated evolves and as the role of the technology in addressing mitigation becomes clear. Another element of this recommendation is to rely on existing regulations and similar applications to build the full body of regulations.

ii) Flexible: Most stakeholder-driven guidelines argue for flexibility. Early deployment opportunities might well represent unique situations until the technology has been replicated sufficiently to identify patterns in the deployment activities. Early actions should allow some case-by-case variation in matters such as the proper MMV regime while not compromising the basic issue—secure storage.

iii) Novel concepts: Although several of the guidance documents reviewed argue against a focus on “exotic” aspects, the ability to address non-conventional opportunities or approaches as they are proposed should not be excluded. Rather, a process to treat a limited number of such proposals as “exemptions” or “variances” could be considered. The early regulatory framework should not inadvertently pick winning and loosing approaches. Sound technical criteria can be used to accept or reject such a proposal.

iv) Analysis in the UK suggests that the “economy of scale” is not necessarily the correct assumption. Early entry projects need to address public perception issues and allow for clear judgments as to safety and security. As the technology matures, pipeline networks could emerge naturally, driven by opportunity (cost savings, profit, maximizing reuse, etc.) not policy. Similarly, considerations for the best means to ensure that funds are available for remediation during post-closure, long-term stewardship may not be readily obvious at this point in time.

v) The formulation of regulations needs to rely on science and to reflect the evolution of the scientific understanding of key issues within the regulatory framework. For instance, the determination of the duration of the post-closure period should ultimately be based on science—and the proper duration of this period might vary from one site to another.

Finally, the legislature must consider the role of local government and zoning. Regional and statewide projects such as the CCS network should not be determined by local land use. Requiring consideration of regional land use and authorizing participation by local governments, combined with preemption of local land use controls is probably the most appropriate approach. Centralizing regulation at the state level, rather than the federal or local level, will best promote development of a CCS network.
3.7 Recommendations for Legislation to Promote and Regulate CCS

A number of organizations have made recommendations for regulatory and legal structures unrelated to Pennsylvania Law. Because they may include recommendations that may assist the Pennsylvania General Assembly in determining the legislative needs of establishing a CCS network, they are summarized in Appendix 3.7.

3.7.1 Other Resources

The research and development programs for capture technologies and for storage are continuing. One key outcome anticipated from the efforts across the Regional Carbon Sequestration Partnerships is a series of “Best Practices manuals”. Currently, a Best Practices manual entitled “Monitoring, Verification, and Accounting of CO\textsubscript{2} Stored in Deep Geologic Formations“ is available on the National Energy Technology Laboratory’s website.\(^{334}\) Others are being developed as test results become available and can be distilled into sound practices.

3.8 Proposed Pennsylvania Legislation

HB 80 and SB 92 are two bills designed to facilitate the siting and development of a carbon sequestration network that have been introduced to the Pennsylvania General Assembly.\(^{335}\) Both bills would amend the Alternative Energy Portfolio Standards Act\(^{336}\) (AEPS). Both would make “advanced coal combustion with limited carbon emissions” a Tier 2 technology and increase the required Tier 2 percentages. Both would further require that electric distribution companies purchase all of the advanced coal electricity generated up to a maximum of 3\% of the Commonwealth’s electricity, provided that this technology is available in the Commonwealth. Both would also authorize electric distribution companies to enter into long-term 25-year contracts for the purchase of electricity generated with advance coal technology, subject to approval by the Public Utilities Commission. Thus, there will be a guaranteed market for electricity generated with CCS technology within the Commonwealth.

Although they include many similar requirements, the two bills differ in that SB 92 mandates public development of the carbon sequestration network while the House Bill includes provisions that would accommodate either private or public development. Thus, SB 92 requires that the DCNR develop a carbon sequestration network of sequestration wells and pipelines and calls for that network to be sited on State forest land or “as otherwise acquired by DCNR.”\(^{337}\) SB 92 defines this network to be:


\(^{335}\) See HB No. 80, Printer’s No. 2413 (2009 Session); SB 92, Printer’s No. 683 (2009 Session).


\(^{337}\) SB 92, §3, adding AEPS § 8.1 (“AEPS § 8.1”).
“Geological subsurface formations within this Commonwealth with suitable cap rock, sealing faults and anticline used by the Department of Conservation and Natural Resources for the permanent storage of carbon dioxide from advanced coal combustion with limited carbon emissions plants or other sources within this Commonwealth along with the facilities necessary to transport the carbon dioxide from the surface to the subsurface formations and monitor the permanent storage of the carbon dioxide in subsurface formations. The term shall not include use of the carbon dioxide for enhanced resource recovery.”

SB 92 further authorizes DCNR to acquire geologic formations and facilities required by the network “by purchase, gift, lease, or condemnation,” and limits the use of the network to CO$_2$ generated within Pennsylvania. SB 92 requires DCNR to collect fees from entities that use the network (generators, transporters, and other users). The fees must be sufficient to recover the entire cost of the network less federal contributions, including acquisition and use rights, construction costs, insurance costs, and other operation and maintenance costs. A non-lapsing fund is created to receive these monies and dedicated to DCNR to own and operate the network. DCNR is further authorized to enter into contracts for the “development and operation of the CO$_2$ sequestration network, including site characterization, well construction, mechanical integrity testing, monitoring corrective action, and site closure. The bill prohibits any CO$_2$ from being accepted until “all applicable permits are approved.”

SB 92 further requires DEP to “develop regulations necessary to permit the siting and operation of the carbon dioxide sequestration facility.” It mandates that the regulations include the elements required by the Proposed GS UIC Regulations, as follows:

1. Risk assessment.

2. Geologic site characterization including, but not limited to, modeling and verification of fluid movement.

3. Corrective action.

4. Well construction, operation, and mechanical integrity testing.

5. Monitoring and site closure.

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338 SB 92, § 2.
339 Id. § 8.1(a).
340 Id. § 8.1(b).
341 Id. § 8.1(c).
342 Id. § 8.1(d).
Finally, SB 92 includes provisions governing liabilities and assigns those liabilities to the Commonwealth. It provides that title to the CO$_2$ will pass to the Commonwealth at the property line where the sequestration facilities are located. More importantly, it further provides that all liability will transfer to the Commonwealth with the title to the CO$_2$. It further provides that, after title transfers, the owner of the advanced coal combustion facility:

“[S]hall be immune from liabilities regarding the storage of carbon dioxide within and the release, escape or migration of carbon dioxide from the Commonwealth’s carbon dioxide sequestration network and subsurface storage site.”

HB 80 includes many similar provisions, but contemplates private or third party development. Thus, the House bill defines “carbon dioxide sequestration facility” identically to the Senate Bill’s definition of the “network”, with the exception that it does limit the definition to a facility developed by DCNR.

HB 80 prohibits operation of a carbon sequestration facility without a permit, requires the Environmental Quality Board to develop regulations governing the siting and operation of carbon sequestration facilities, and gives DEP all of the powers it has under the Solid Waste Management Act, to carry out and enforce the permitting requirements. The House Bill includes more detailed requirements regarding the contents of GS regulations, although a number of these requirements, such as those for financial responsibility, would not be necessary under SB 92, where the Commonwealth takes responsibility for the CCS network. The regulations required by the House bill must include at least the following elements:

(1) Geologic site characterization.

(2) Sequestration facility performance standards.

(3) Well location restrictions and well construction standards, including operation and mechanical integrity testing.

(4) Risk assessment, corrective action, and emergency response requirements.

(5) Monitoring, recordkeeping, and reporting requirements.

343 Id.

344 Id. § 8.1(f).


346 HB 80, § 3, adding AEPS § 8.1.
(6) Facility closure, postclosure, and final closure certification requirements.

(7) Financial assurance requirements, including bonding or insurance, in amounts sufficient to ensure the carbon sequestration facility will be constructed, operated, closed, and monitored during the postclosure period in accordance with regulations promulgated under this section.

(8) Fees in an amount sufficient to recover the department’s cost of administering this section.

(9) Fees for every ton of CO$_2$ accepted by a CO$_2$ sequestration facility in an amount sufficient to monitor and maintain the facility after final closure of the facility and take remedial actions if necessary after final closure of the facility. The fees shall be paid by the operator of a CO$_2$ sequestration facility to the department on a quarterly basis.

(10) Public notice requirements, including notification of a release.

(11) Criteria used to determine that CO$_2$ has been permanently sequestered.

(12) Other requirements necessary to evaluate the proposed CO$_2$ sequestration facility and to ensure safe and environmentally protective operation of the facility.\footnote{Id. § 8.1(b).}

Because the HB 80 contemplates private ownership, it includes somewhat different liability provisions. In Section 8.2, title to the CO$_2$ and all liabilities associated with it are transferred from the generating facility, as under the SB 92, but they are transferred “to the CO$_2$ sequestration facility” and the owner of the generation plant is thereafter “immune from liabilities” associated with the sequestration. HB 80 further provides that upon closure of the sequestration facility, title to the CO$_2$ and liability are transferred to the Commonwealth. HB 80 also establishes a Carbon Dioxide Indemnification Fund into which the fees referenced in Section 8.1 will be paid and which will be used to fund post-closure care and remedial response.

Like SB 92, HB 80 contemplates potential use of State forest land for the CCS network, but provides for ownership by entities other than the Commonwealth. It therefore authorizes DCNR to lease State Forest land to any person for the development and operation of the CO$_2$ sequestration facility and associated pipelines.\footnote{Id. AEPS § 8.4.} It also includes a provision that makes entities “transporting or conveying CO$_2$ by pipeline or conduit for compensation” public utilities subject to Pennsylvania Utility Commission regulation.\footnote{Id. AEPS § 8.5.}
3.9 Conclusion: Summary of Recommendations

In order to create a CCS network, Pennsylvania will need to address property rights issues, liability issues, and regulatory requirements. The Commonwealth will need to clarify the nature of necessary property rights necessary for sequestration and create a mechanism whereby those rights can be acquired. It will need to reduce uncertainties regarding exposure to liabilities and create a system to assure compensation of those who are injured. Finally, it will need to create a regulatory system that will prevent problems for arising and satisfy the necessary legal requirements for siting and permitting the system.

Acquisition of the property rights necessary to develop a CCS network faces legal and practical barriers. There are uncertainties regarding the nature of the right to use subsurface strata for sequestration, who owns the right, and how many properties may be affected. Given the fragmentation of ownership across the landscape and among owners of different estates (various mineral estates and the surface estate) throughout Pennsylvania, it will be difficult to assemble the property rights. Development of a CCS network can be facilitated through several mechanisms: (1) use of a large contiguous block of land that is owned by a single landowner who owns all mineral and surface rights to the extent feasible in Pennsylvania’s fragmented landscape, as contemplated by the Pennsylvania GS bills; (2) avoidance of the more remote portions of the state lands where ecological impacts will pose barriers to implementation; (3) passage of legislation that clarifies the nature of the right to sequester CO$_2$, vest it in a particular owner, and provide means to acquire that right, such as condemnation, such as is done by the model laws adopted by Wyoming; and (4) creation of a variant of the unitization programs used for oil and gas in some other states that would provide all affected property owners compensation for use of their subsurface strata for sequestration. Until there is a market for determining the value of pore space, a statutory value should be assigned, as is done by some European nations.

All of the parties involved in GS could potentially face liability for personal injury and property damage arising from transportation and sequestration of CO$_2$ and waste products such as hydrogen sulfide, the power plant and industrial generators, those who transport it, and those involved in the disposal. Even with the best structured regulatory program, accidents will happen. In the case of a still largely untested technology such as GS, the risks of accidents are higher. Accordingly, GS will likely not be financeable unless mechanisms can be created that will fix and limit the exposure of those implementing the technology. There are a variety of mechanisms whereby this can be accomplished. These include the following: (1) providing full or partial immunity from liability to some or all of actors; (2) acquiring commercial insurance; (3) creating an alternative to insurance such as a liability fund; (4) transferring liability to the government statutorily, by having the government assume responsibility for the activity or by providing indemnification; and (5) various combinations and permutations of the foregoing. A combination of these mechanisms, similar but not identical to those employed in the Pennsylvania GS bills, will likely be most effective and most cost effective. Commercial insurance should be required, as should the provision of financial assurance mechanisms.
for post closure monitoring and care. These requirements can be supplemented by the creation of indemnity funds that are funded with tax dollars or charges on disposal and will pick up what the insurance and financial assurance do not. Providing a transfer of liability not covered by these other mechanisms to the Commonwealth, through the Commonwealth’s involvement and the provision of immunity from the participants who take all required precautions and comply with law will provide assurances to investors as well as the public who may be affected.

Creation of a sound, coordinated and predictable regulatory mechanism will ultimately be the best means to manage the risks of GS and to reduce opposition to the creation of the CCS network. The Proposed GS UIC Regulations currently represent the best learning on mechanisms to manage risk, including requirements for siting, construction, operation, financial assurance, closure and post-closure care. Pennsylvania does not currently have an approved UIC program - EPA manages the program. Pennsylvania, nevertheless, likely has the ample statutory authority to adopt similar or more protective regulations and to obtain primacy or partial primacy. Adopting regulations that would allow Pennsylvania to implement both the federal and state programs would likely best promote GS by eliminated the need for two permits and two sets of regulations.

Pennsylvania could adopt regulations under current authority. However, creating explicit authority tailored to GS would be preferable. Failing to adopt a new state statute or comprehensive regulations would undermine development of GS and disserve protection of health and the environment, even if the federal UIC regulations are adopted. There are many Pennsylvania environmental laws that could apply to GS. Without a predictable and comprehensive regulatory scheme, those opposed to siting GS could cite to those prohibitions and tie up the program in litigation.

In developing legislation and a regulatory program, including siting criteria, consideration must be given to several facts. First, a CCS network, like any major development project, will require many preconstruction and operating approvals, some of which (e.g. soil erosion and sediment control) will be required in all cases and others of which will depend on the siting or other factors (e.g. NEPA will require a federal action, wetlands or endangered species the presence of specific factors). Second, there will be opposition by those whose property is crossed by pipelines or is located near the wells and some will likely challenge permits. Sound siting and regulatory criteria will make the success of such challenges less likely.

Finally, the legislature must consider the role of local government and zoning. Regional and statewide projects such as the CCS network should not be determined by local land use. Requiring consideration of regional land use and authorizing participation by local governments, combined with preemption of local land use controls is probably the most appropriate approach. Centralizing regulation at the state level, rather than the federal or local level, will best promote development of a CCS network.

The current bills before the Pennsylvania legislature will achieve some of the foregoing characteristics but not all. Facilitation of a CCS network will require all of the foregoing
characteristics. These characteristics, alone, however, will be insufficient. A governmental sponsor charged with implementing the program will also be necessary. Governmental sponsorship does not mean that the government will need to undertake the project, as under the Senate bill, but this approach should be authorized. Creation of a public private partnership may be more effective in financing the project and bringing it to completion. Therefore, the legislation should also include mechanisms that would contemplate private ownership or operation. This flexibility will be necessary to assure the best mix of financing and operational mechanisms.
### Appendix 3.6.10.4

Table 3.6.10.4. Potential Permits, Approvals, and Consultations Applicable to the CO₂ Pipeline and Geological Storage

<table>
<thead>
<tr>
<th>Agency</th>
<th>Permits/Approvals/Consultations</th>
<th>Applicability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Federal</td>
<td></td>
<td></td>
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<tr>
<td>NEPA</td>
<td>Environmental Impact Statement or Environmental Assessment</td>
<td>Entire project. If project requires a federal permit or receives federal funding</td>
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<tr>
<td>U.S. Army Corps of Engineers</td>
<td>Clean Water Act Section 404 Permit Rivers and Harbors Act Section 10 Permit</td>
<td>Pipeline. NWP 12 required if pipeline crosses regulated water body or jurisdictional wetlands</td>
</tr>
<tr>
<td>U.S. Environmental Protection Agency</td>
<td>Safe Drinking Water Act Underground Injection Control Permit</td>
<td>Injection Class II wells for a variety of waste fluid disposal, enhanced oil/gas recovery, and hydrocarbon storage needs. Class V experimental technology wells to demonstrate a developing technology may be subject to more flexible, yet fully protective, technical standards</td>
</tr>
<tr>
<td>U.S. Environmental Protection Agency</td>
<td>Prevention of Significant Deterioration Permit (State Part 231 Proposed)</td>
<td>Carbon Capture. If unit is installed at an existing facility it would result in the reduction of emissions</td>
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<tr>
<td>U.S. Fish and Wildlife Service</td>
<td>Section 7 Endangered Species Act Consultation</td>
<td>Entire Project. Consultation required if project is required to obtain federal approval (e.g., disturbance of federal wetland). A take permit would be required if there is a potential to take, or harass a threatened and endangered species</td>
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<tr>
<td>Advisory Council on Historic Preservation</td>
<td>Section 106, National Historic Preservation Act</td>
<td>Entire Project. Consultation required if project is required to obtain federal approval</td>
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<tr>
<td>U.S. Department of Transportation, Federal Highway Administration</td>
<td>Federal Highway Encroachment Permit</td>
<td>Pipeline. Required in pipeline crosses federal highway</td>
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<tr>
<td>State</td>
<td></td>
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<tr>
<td>State Environmental Quality Review Act</td>
<td>49CFR Part 195 - Design standards Environmental Assessment Form or Environmental Impact Statement</td>
<td>Applicable to pipeline design standards Entire Project. If project requires a state or local action</td>
</tr>
<tr>
<td>New York State Historic Preservation Office</td>
<td>Cultural Resources (Section 106/NHPA) Consultation/Clearance</td>
<td>Entire Project. Consultation required if state or federal approval is involved</td>
</tr>
<tr>
<td>New York State Department of Environmental Conservation</td>
<td>Air Emissions Part 201 Preconstruction Permit</td>
<td>Carbon Capture. If unit is installed at an existing facility it would result in the reduction of emissions</td>
</tr>
<tr>
<td>Agency</td>
<td>Permits/Approvals/Consultations</td>
<td>Applicability</td>
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<tr>
<td>New York State Department of Environmental Conservation</td>
<td>Water Quality Certification (Section 401 Permit)</td>
<td>Entire Project. If project construction disturbs one or more acres</td>
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<tr>
<td>Role</td>
<td>Permit/Permits Required</td>
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<tr>
<td>New York State Department of Transportation</td>
<td>State Pollution Discharge Elimination System (SPDES) Construction General Permit for Storm Water Discharges</td>
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<tr>
<td>New York State Department of Agriculture and Markets</td>
<td>Article 15 Protection of Waters; Article 24 Freshwater Wetlands; Article 25 Tidal Wetlands</td>
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<td></td>
<td>Well Drilling Permit (Issued to Well Driller/Operator)</td>
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<td></td>
<td>State Road Use Permits</td>
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<td></td>
<td>Highway Work/Utility/Non-utility Permits Consultation</td>
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<tr>
<td>Local</td>
<td>Consultation with respect to impacts to agricultural lands</td>
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<tr>
<td>County Highway Department</td>
<td>Road use permits</td>
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<tr>
<td>Town/County Planning Board</td>
<td>Building permits/zoning approvals</td>
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<td></td>
<td><strong>Pipeline.</strong> If project crosses federally regulated wetlands or protected streams and/or require permits under §404 CWA (navigable waters) or §10 Rivers and Harbors Act</td>
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<td></td>
<td><strong>Pipeline.</strong> If project involves excavation and fill in navigable waters or otherwise disturbs state regulated wetlands</td>
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<td></td>
<td><strong>Injection.</strong> Permits required for drilling activities and well plugging</td>
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<td></td>
<td><strong>Pipeline.</strong> Permits required if pipeline crosses a state highway</td>
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<td></td>
<td><strong>Entire Project.</strong> Consultation required if project impacts agricultural lands</td>
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<td></td>
<td><strong>Pipeline.</strong> If project crosses town/county road</td>
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<td></td>
<td><strong>Entire Project.</strong> If town/county has enacted local requirements</td>
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Appendix 3.7

United States Carbon Sequestration Council

The United States Carbon Sequestration Council (www.uscsc.org) has prepared a number of educational documents addressing some of the key questions. One of them (USCSC 2009), WANTED: A Legal & Regulatory Framework for CCS, addresses the nature of the missing pieces. They offer comments on framing the framework:

Three types of legal issues must be addressed to facilitate commercial scale CCS projects:

vi) The rules to protect the environment relating to the injection of CO₂ into saline geological formations.

vii) Rules may be needed to address potential adverse impacts on subsurface property rights, such as unintended movement of CO₂ into nearby oil or gas resources.

viii) The extremely long term nature of CCS projects (hundreds or thousands of years) is very difficult to address with traditional risk management mechanisms, like insurance.

The paper argues for adoption of interim rules as an option worth considering. This allows a limited number of projects to proceed while learning occurs both for those developing and deploying the technology and for those developing and proposing regulations.

Interstate Oil and Gas Compact Commission

The Interstate Oil and Gas Compact Commission prepared a number of reports on this issue starting in 20002. The report, Storage of Carbon Dioxide in Geologic Structures A Legal and Regulatory Guide for States and Provinces, The Interstate Oil and Gas Compact Commission, Task Force on Carbon Capture and Geologic Storage (IOGCC, September 25, 2007) went back to their earlier report (IOGCC, 2005) to repeat a key finding of that report: “...given the jurisdiction, experience, and expertise of states and provinces in the regulation of oil and natural gas production and natural gas storage in the United States and Canada, the states and provinces would be the most logical and experienced regulators of the geologic storage of carbon dioxide.”

Although the Task Force recognized in that earlier phase that states and provinces with Oil and Natural Gas Conservation Acts and states and provinces with natural gas storage statutes might be able to utilize those statutory and regulatory frameworks for CO₂ injection and storage, it also concluded that some modification of those frameworks might be advisable or necessary, particularly for the post-operational phase for which no regulations exist. The Task Force also recognized that further research into the ownership of subsurface storage rights with respect to CO₂ storage, as well as an analysis of the regulatory relevance of the UIC Program of the Safe Drinking Water Act and its applicability to CO₂ storage, would be useful to the states.
The 2007 report presents a Model CO₂ Storage Statute and Model Rules and Regulations governing the storage of CO₂ in geologic media and an explanation of those regulatory components. Also included herein is a report addressing the ownership and right of injection of CO₂ into the sub-surface. In preparing these models, the participants relied on several guiding principles in its drafting efforts. These principles are presented below:

**SEAMLESS** - The statutory and regulatory framework developed needed to be seamless to maximize economic and environmental benefits while providing a “cradle to grave” framework with fully integrated regulatory oversight and clearly identified risk parameters for industry.

**SIMPLE** - The temptation to over-regulate for the exotic needed to be avoided by developing a simple framework that initially addressed only those scenarios most likely to occur. It was recognized that, as necessary, regulations would be amended in the future based on the experience gained in the initial projects.

**FLEXIBLE and RESPONSIVE** - “One size will not fit all”. Proposed projects will have many site-specific variations throughout the states and provinces and therefore it was recognized that any regulatory framework needed to be flexible and responsive to the site variations and developing technologies. Regulatory experience and technology developments are certain to change over time and each project will only improve the regulatory and technical knowledge base.

**DOABLE** - Given the speed at which this issue is progressing, a regulatory framework that can be rapidly implemented and fielded was necessary. The Task Force recognized that problems will occur; however, it also recognized that most of those problems are issues with which the states/provinces and oil and gas industry have already dealt and will generally be easily solvable. The Task Force channeled its efforts to prevent the regulatory framework development process to be side-tracked by not trying to resolve every conceivable issue from the outset. The development of a regulatory framework will be an ongoing regulatory development process as experience is gained.

**POSITIVE PUBLIC PRESENTATION** - Geologic storage of CO₂ is an integral part of a solution that offers the potential for both economic and environmental benefits. Nothing will be achieved by regarding CO₂ geologic storage as a regulatory protection solution to a waste problem.

The effort did not propose Model Rules and Regulations for the Post-closure period. Based on the Task Force recommendation that the most efficient methodology to accomplish these tasks - and which can be readily fielded - is to utilize existing frameworks developed by the states for addressing abandoned and orphaned oil and gas wells, the state regulatory entity responsible would have the authority to implement any monitoring, verification, and remediation methods necessary to ensure the security of the carbon storage project (CSP). In addition, they felt that there are numerous innovative methodologies that could be employed, and many future methodologies might be developed that would be available to ensure the security of the CSP.
full investigation into existing and future methods will require more detailed regulatory research into the implementation of these approaches.

**International Risk Governance Council**

The International Risk Governance Council published a report, Regulation of Carbon Capture and Storage, in late 2008 (IRGC, 2008). They assessed the life cycle of a CCS project, shown in Figure yy.

Figure yy – Life cycle of a carbon capture and storage project

The report also discussed the different drivers that might apply to various nations (fail to compel) and assessed the state of knowledge and key uncertainties that could only be resolved by conducting carefully monitored projects.

The report included a number of policy recommendations. We repeat, here, only those focusing on developing a regulatory framework, not on the demonstration of a portfolio of technologies. They argue that the objectives of CCS are clear. CCS deployment must efficiently address the need to safely sequester billions of metric tons of carbon dioxide for hundreds to thousands of years. Therefore, the practice of CCS should maximize CO₂ emissions avoided. To achieve these objectives:
A. CCS regulation must:
   a. Establish a framework encouraging responsible operation and investment;
   b. Balance stability and predictability with flexibility and adaptability to new scientific information;
   c. Be based on solid technical findings; and
   d. Provide ease of implementation for both regulators and industry.

B. Site selection requirements for early sites must be especially rigorous...Licensing of these early storage sites should include demonstration of long-term predictable containment.

C. An evolutionary approach to developing CCS regulations should be adopted. Early CCS projects should be regulated under modifications to existing regulations. Results from early projects can then be used to create generalized CCS regulations to efficiently manage commercial deployment.

D. The following activities, vital for creating a mature CCS regulatory framework capable of managing widespread commercial deployment, cannot be completed until comprehensive, integrated technical results from early deployment are available:
   a. Determination of performance standards for geological storage;
   b. Establishment of links to carbon markets;
   c. Resolution of climate liability issues;
   d. Passage of legislation to structure long-term responsibility and liability for CCS sites, including mechanisms to fund long-term stewardship; and
   e. Establishment of an adaptive regulatory framework.

E. Political and economic barriers to CCS deployment must be addressed to create conditions where project financial backers can have confidence that investment decisions made now will earn a satisfactory economic rent, that a predictable regulatory framework will apply, and that liability issues will be resolved.

F. Effective risk communication by both regulators and industry is vital for public acceptance of CCS. Also, the public should be immediately and transparently informed of any event that indicates a problem with CCS.
G. Development of a regulatory framework is necessary but not sufficient to catalyze CCS deployment. Economic and political barriers will also need to be addressed. In fact, regulations governing geological storage site performance, climate liabilities, and long-term stewardship cannot be finalized in the absence of a climate regime.

World Resources Institute

The World Resources Institute (WRI 2008) issued “CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage in 2008. The report provided an overview of the system of technologies that make up carbon capture and storage. World Resources Institute (WRI) convened a diverse group of over 80 stakeholders to participate in these technical discussions with the caveat that the stakeholders agreed to focus the discussions and guidelines on how and not whether to implement a CCS project. These participants included representatives from academia, business, government, and environmental nongovernmental organizations (NGOs). Business participants included those most likely to be involved in CCS projects: fossil energy, electric utility, insurance and service providers. The guidelines developed reflect the collective agreement of the contributing stakeholders. The Guidelines, representing a collective summary of the views of the stakeholders may not represent the exact position of all stakeholders on all issues. WRI, in the Executive Summary also acknowledges that “...although this first edition of the Guidelines frames the important policy issues surrounding GHG accounting, liability, financial incentives, and long-term stewardship associated with CCS projects, the stakeholders acknowledge that more discussion—and in some cases experience - is needed to propose more robust Guidelines for these important areas.”

Many of the guidelines are similar to recommendations summarized elsewhere in this subsection. However, these bear on the issues that are crucial to those considering development of a regulatory framework that both ensures safe, secure storage for the early entry projects but that allows for the regulations to adapt to changes in the technology and to the learning that will accrue to all those involved in the sector – project performers, regulators, financiers, insurers, and the general public from early efforts. We will discuss a limited number that pertain to issues raised throughout this subsection.

Within the capture guidelines, the report emphasized that early commercial-scale projects may face novel challenges in achieving the theoretical maximum capture potential. This potential difficulty should be recognized in setting appropriate capture rates. The document felt that there was a potential risk of creating disincentives for reducing sources of anthropogenic CO₂ if the standards for the levels of co-constituents are set too stringently. For transport, pipeline design specifications should be fit-for-purpose and consistent with the projected concentrations of co-constituents, particularly water, H₂S, oxygen, hydrocarbons, and mercury. Existing industry experience and regulations for pipeline design and operation should be applied to future CCS projects. When siting pipelines, an efficient means of regulating the siting should be considered as a possible federal responsibility, one based on consultation with states, industry, and other stakeholders.
When considering storage, a large number of very detailed guidelines were offered. Rather than working through this list, we can cite several key points. For MMV, the WRI report made a similar recommendation to those offered by the IRGC and others. The MMV requirement should not be prescriptive as to how but should rather require formal, adaptive plans based on the use of necessary and sufficient approaches to ensure that the site is monitored through its characterization phase, during injection, throughout the post-closure period and, as needed, in the long-term. The area being monitored should be modified as warranted, based on data obtained during operations. It should include the project footprint (the CO$_2$ plume and area of significantly elevated pressure, or injected and displaced fluids). Ground water quality monitoring should be performed on a site-specific basis based on injection zone to USDW disposition.

The report provided guidelines dealing with risk assessment practices, proof of financial responsibility, proof of property rights and ownership, and critical issues that need to be considered for site selection and characterization. Ownership of pore space drew attention with the recommendation that “continued investigation into technical, regulatory, and legal issues in determining pore space ownership for CCS is warranted at the state and federal levels. Additional legislation to provide a clear and reasonably actionable pathway for CCS demonstration and deployment may be necessary.”

Further recommendations were made on injection emphasizing the need to require a field management plan as an early part of the permitting process. It went on to describe essential elements of such a plan. Site closure guidance called for continued monitoring through closure and strongly encouraged making the well plugging and abandonment data available through a publicly accessible registry. Finally, post-closure, sites certified as closed should be managed by an entity or entities whose tasks would include such activities as operating the registries of sites, conducting periodic MMV, and, if the need arises, conducting routine maintenance at MMV wells at closed sites over time. These entities need to be adequately funded over time to conduct those post-closure activities for which they are responsible. Indeed, given the need for ensuring safe long-term storage, one could argue for the need to demonstrate a plan for “field protection” well into the future until and unless methods to demonstrate that the CO$_2$ has been immobilized by a very sure form of trapping can be validated.

This document is consistent with the several other assessments described above. It argues that there is yet much that we need to know to address all possible issues in the varied geologic provinces into which we might seek to store carbon dioxide whether essentially pure or with limited amounts of other energy production by-products. However, the report also argues that “A key finding of the stakeholder process is that even though additional research is needed in some areas, there is adequate technical understanding to safely conduct large-scale demonstration projects.”
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4.0 SAFETY/RISK ASSESSMENT

4.1 Introduction

CCS is a practical approach for reducing greenhouse gas emissions that is being aggressively pursued, but technological challenges remain, and the potential health, safety and environmental risks contribute to the political hurdles that remain to be overcome (Smith et al., 2009). This section of the Assessment of Risk, Legal Issues, and Insurance for Geologic Carbon Sequestration in Pennsylvania identifies the potential human-health and environmental effects associated with (1) the capture of CO₂ and other trace gases at power plants and other industrial sources; (2) CO₂ transportation via pipeline to the geologic storage site; and (3) subsurface storage. A formal framework or CSM is developed for summarizing the relevant information from an extensive knowledge base and identifying and evaluating the potential risks. The existing knowledge that is crucial to critical planning and regulatory decisions includes the ongoing testing of CO₂ sequestration in seven different U.S. geological formations (Chu, 2009; DOE, 2009a), the results from the study of CO₂ in natural subsurface reservoirs in a wide range of geological settings throughout the world (IPCC, 2005), and the decades of practical experience transporting CO₂ via 5600 km of pipelines and injecting CO₂ for the purpose of enhanced oil recovery (Orr, 2009).

Risk is the product of the probability of an event occurring and the consequences of that event, where the consequences can be evaluated in terms of financial loss, human health effects, or environmental effects, e.g., the loss of beneficial uses of existing resources. The primary goal of this Safety/Risk Assessment is to utilize the information summarized and evaluated in the development of the CSM to address the following types of questions regarding CCS:

- What are the possible consequences or adverse outcomes?
- What is the probability or likelihood of these outcomes?
- What would be the possible safety, environmental, and financial consequences of each of the possible outcomes?
- What level of confidence is associated with the assessment of the potential risks?
- What are acceptable levels of various risks?

The technical approach used in this risk assessment relies heavily on existing and readily available information. The approach developed is general enough to accommodate the range of anticipated conditions at potential sequestration sites in Pennsylvania. While no specific sites have been identified within the Commonwealth, the risk assessment utilizes the extensive database describing geologic carbon sequestration opportunities (DCNR, 2009) as well as the results of numerous studies from the DCNR and reports by the MRCSP (2005a and 2005b). Following the identification of specific storage sites, a more focused risk analysis using detailed site-specific information will be required.

The risk assessment approach also draws heavily from the contributions of several published efforts, e.g., the Features, Events, and Processes (FEP) approach (Stenhouse et al., 2005), Probabilistic Risk Assessment (PRA) (Rish, 2005), the screening and ranking
framework (Oldenburg, 2008), and system modeling approaches (CO₂-PENS) for the development of performance assessments of geologic CO₂ sequestration sites (Stauffer et al., 2008). The attributes of other important risk assessment methodologies including international approaches are summarized in Box 4-1.

One of the primary influences on the scope and technical approach adopted for the Assessment of Risk, Legal Issues, and Insurance for Geologic Carbon Sequestration in Pennsylvania is the CCS Guidelines developed by the World Resources Institute (WRI, 2008). These guidelines were developed over a two-year period by experts in the field and with input from hundreds of informed stakeholders. These guidelines summarize the current understanding of the key technological challenges and the potential health, safety and environmental risks associated with the deployment of CCS. The development of these guidelines for the capture, transportation, and storage of CO₂ was based on the following principles (WRI, 2008):

- Protecting human health and safety.
- Protecting ecosystems.
- Protecting underground sources of drinking water and other natural resources.
- Ensuring market confidence in emission reductions through regulatory clarity and proper greenhouse gas accounting.
- Facilitating cost-effective, timely deployment.

These principles are directly relevant to the risk assessment task and have been adopted in the analyses presented in this document. The contributions of the WRI CCS Guidelines have also been extended with the development of more detailed information on certain aspects of the risk analysis, e.g., the evaluation of the potential toxicity of the captured CO₂ and trace gases that are transported by pipelines, and with unique issues in Pennsylvania related to risks associated with salt-bed storage. Useful information and analytical procedures from the risk assessment that was conducted for the U.S. Department of Energy’s FutureGen program (DOE, 2007a) have also been utilized in this risk assessment. For example, the data and methodology used to assess the probability of releases from CO₂ transportation pipelines as well as the possible consequences or adverse outcomes were obtained from the FutureGen risk assessment.
Box 4-1.
Summary of Risk Assessment Methodologies for CCS.

FEP and Scenario Analysis Tools
Approaches for analyzing Features, Events and Processes (FEPs) and scenarios have been developed internationally for nearly thirty years. Since the early work that aimed at evaluating the safety of underground repositories, methodologies for analyzing FEPs have continued to evolve. While the methodological details have differed in different programmes, FEP analysis has become a standard activity during safety assessments. In recent years there has been a move to develop standard lists of FEPs as a basis for these assessments. Several different institutes have developed generic FEPs databases for the geological storage of CO₂ such as by The Netherlands Institute (Wildenborg et al., 2005) and Quintessa (Savage et al. 2004). These will be augmented as the knowledge of the CO₂ geological storage technology expands. The FEP process essentially comprises FEP analysis, qualitative scenario definition, and conceptual modeling. There are different approaches to each of the steps. However, all are invariably based upon expert judgement. For some of the approaches, there is one final step that involves process level modeling based on the FEPs and scenario analysis, which brings the approach closer to quantitative risk/performance assessment tools.

<table>
<thead>
<tr>
<th>FEP and Scenario Analysis Tools</th>
<th>Description</th>
<th>Reference</th>
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<tbody>
<tr>
<td>FEP analysis</td>
<td>Development of a comprehensive project-specific FEP list; ranking the semi-quantitative probability and potential impact of individual events; and assignment to reference and variant scenarios; classification</td>
<td>Savage et al. 2004; Wildenborg et al., 2005</td>
</tr>
<tr>
<td>Scenario development</td>
<td>Define one scenario for initial consideration and then a series of alternative scenarios to represent possible future conditions.</td>
<td>TNO, 2003; Sandia, 2005; Metcalfe et al., 2009</td>
</tr>
<tr>
<td>Conceptual modeling</td>
<td>Provide information describing the scope of the assessment and interactions with other parts of the system. Rigorous computational models are then used to simulate the processes included in the conceptual models, allowing identification of the key processes to be simulated by more detailed engineering codes with varying levels of complexity.</td>
<td>Bailey et al., 1998; Ho et al., 2002</td>
</tr>
<tr>
<td>Process level modelling</td>
<td>Development of a system level performance assessment model involving the use of advanced numerical modeling techniques to simulate the behavior of the major compartments of the system.</td>
<td>Wildenborg et al., 2004; Maul et al., 2007.</td>
</tr>
</tbody>
</table>
The findings from the *Vulnerability Evaluation Framework for Geological Sequestration of Carbon Dioxide* developed by the U.S. EPA (EPA, 2008a) to systematically identify those conditions that could increase the potential for adverse impacts from geological sequestration are also directly incorporated into these analyses. The identified vulnerability factors that are relevant to Pennsylvania formations are explicitly addressed. In addition, unique issues in Pennsylvania related to potential salt-bed storage are evaluated. The key elements of the Draft Federal Requirements Under the UIC Program for CO₂ GS wells (EPA, 2008b) and Supplemental Notice (EPA, 2009a), which are focused on the protection of USDWs, are also addressed in this document.

By summarizing the existing information and addressing the key questions associated with the potential risks associated with CCS, the expectation is that this risk assessment will provide a guide for identifying the existence and assessing the magnitude of the potential risks associated with future CCS projects in the Commonwealth. This document should serve as guidance on the best technical approach that should be utilized in the evaluation of individual projects. The risk assessment is also intended to provide a basis of understanding that will improve communications between the technologists implementing CCS, legislative bodies responsible for developing regulations governing the development and implementation of CCS, and other persons interested in being informed on the new technology. Finally, the summary and organization of a transparent body of relevant information and evidence is also intended to contribute to the development of an effective risk management strategy.

### 4.1.1 Conceptual Site Model

A schematic of the conceptual site model (CSM) that is used to summarize the potential exposure pathways of CO₂ and trace components of the gas released during capture, transport and storage is presented in Figure 4-1.

#### 4.1.1.1 Potential Sources

The risk assessment is divided into three primary parts that correspond to the potential exposure sources: (1) **Capture** technologies will be deployed at power plants and other industrial facilities, (2) The location of suitable storage reservoirs in the Commonwealth may be distributed in such a way that pipelines will be required to **Transport** CO₂ from the capture site, and (3) the characterization of releases and the effects from geologic **Storage** sites are treated separately in the risk assessment. The common characteristics of all three sources considered in the risk assessment is the purity of CO₂ and the concentrations of other chemicals in the captured gases, which depend on the type of plant, fuel source and combustion process, capture process, and gas clean-up. However, the differences in the release mechanisms and migration pathways provide the rationale for treating the potential sources separately.
### Figure 4-1. Conceptual site model of major release mechanisms, exposure pathways and media and potentially exposed receptors.

**4.1.1.2 Primary Release Mechanisms**

A schematic of the CSM, focusing on the potential release mechanisms, is presented in Figure 4-2. The transport of the captured CO\textsubscript{2} to injection locations for targeted saline-formation and potential salt-bed storage sites is shown. The diagram also shows the transport of CO\textsubscript{2} to an EOR operation, abandoned oil and gas wells (a potential transport mechanism for the release of CO\textsubscript{2} back to the atmosphere), and a well to a USDW (that is potentially impacted by CO\textsubscript{2} released from the targeted storage formations). This figure also depicts two of the release mechanisms of concern that are discussed below: a surface release from a pipeline caused by excavation damage, the release from the injection well into non-target formations, and releases caused by displacement of the target reservoir from faults.

The potential releases from the capture and transport phases of CCS, i.e., releases associated with pre-injection, exhibit similarities. The post-injection release mechanisms are distinct.
4.1.2 Pre-Injection (Capture and Transport) Considerations

- **Plant equipment.** The main technologies used to capture CO₂ from power plants and other sources are post-combustion capture, pre-combustion capture, and oxy-fuel combustion. Depending on the plant type and capture processes, both the nature of the potential releases and the characteristics of the potential impacts differ.
• **Pipelines.** CO₂ is transported in a dense form, and depending on pressure and temperature of transportation operations in a supercritical phase, which has a very low viscosity and is, denser than air. The pipeline risk assessment evaluates the evidence that there is necessary information to enable the assessment of risk associated with an expanding CO₂ pipeline infrastructure with confidence.

• **Failure of above-ground injection well equipment.** Accidental releases can occur from valve failures at the injection wellhead or from damage by outside forces, e.g., vehicles. The amount of CO₂ that could be released during the operation phase is estimated based on expected well design and quantities of CO₂ injected per well based on information from the MRCSP tests and typical plant sizes in the Commonwealth.

### 4.1.3 Post-Injection Considerations

- **Failure of injection wells.** Failure from injection wells can occur if the wells are damaged, over-pressurized, or the CO₂ damages the well cement allowing CO₂ to migrate into the wellbore, into shallower formations or to the ground surface.

- **Leakage from existing deep wells.** Releases from existing deep wells can occur if the wells are improperly sealed or the CO₂ damages the well cement allowing upward migration. The existence of abandoned oil and gas wells are a primary concern where the wells penetrate the cap rock within the expected plume migration area.

- **Leakage through cap rock.** Relevant information on the properties of cap rocks for the identified geologic sequestration reservoirs in the Commonwealth includes the rock type, thickness, permeability, porosity, capillary entry pressure, and extent of weathering or fracturing. These properties influence whether gradual or catastrophic releases are a realistic possibility. Other important factors considered in the evaluation of the risk associated with post-injection releases are whether a single cap rock overlies a reservoir or if a series of relatively, impermeable formations are present, providing an additional safety factor.

- **Releases from faults.** Major faults in Pennsylvania are described and existing information is used to determine if faults displace the target reservoirs. A comparison of the location of potential CCS areas and fault locations is presented.

- **Lateral or vertical leakage into non-target formations.** Leakage into a non-target formation can occur due to failure of the injection well, migration through an improperly-sealed well bore or fault, or leakage of the cap rock.

**Special considerations.** In addition to the post-injection release mechanisms identified in Figure 4-1, there are several other potential effects associated with geologic storage of CO₂ and unique Pennsylvania characteristics that are addressed in the risk assessment.
• **Salt bed storage.** The use of salt beds for storage will require removal of brines. Leakage of brines can occur from the treatment process units, from a brine injection well to the same or different formation than being used for CO₂ injection, or from disposal sites such as impoundments or sludge landfills. Information on practices at salt storage projects in Pennsylvania and their experience with failures or other releases is evaluated.

• **Induced seismicity.** Injection of large volumes of fluid through deep wells has induced seismic events when the formation had low permeability. However, seismicity has not occurred when the injection was made into more suitable, permeable formations. Information on the general seismicity of Pennsylvania and past earthquakes is presented.

• **Ground dilation.** Pressure changes in reservoirs can result in dilation or subsidence at the surface. These effects are more likely to occur in unconsolidated formations such as clays. The presence of salt beds in Pennsylvania introduces the possibility of pressure effects due to thinning, creep, salt falls, or collapse of the salt beds (Thomas and Gehle, 2001).

### 4.1.3.1 Primary Migration Pathways

Four primary migration pathways are addressed in the risk assessment: migration through formations into the biosphere due to the release mechanisms discussed previously, atmospheric dispersion after gases reach the surface, mobilization of radon, and leakage into potable aquifers (Figure 4-1). Simulation models are generally used to estimate the release of CO₂ and trace gases from pipelines or well equipment at the ground surface into the atmosphere. In the transport section of the report an example simulation is conducted to estimate the expected number of people affected by a release given variable meteorological conditions including wind speed and direction along the entire route of a pipeline.

Three complementary approaches are used to evaluate the likelihood of releases and the potential impacts from the release of CO₂ and trace gases after the injection into subsurface reservoirs. The first approach is based on an analog database that includes site characteristics and study results from other CO₂ storage locations and from sites with natural CO₂ accumulations and releases. This database has previously been used for characterizing potential risks due to surface leakage through cap-rock seal failures, faults, fractures or wells (DOE, 2007a). The potential storage site characteristics are compared to the sites in the analog database to assess the likelihood and magnitude of releases of CO₂ to the atmosphere. The second approach is based on the evaluation of the key factors in the geologic carbon sequestration health, safety, and environment screening and ranking framework developed by Oldenburg (2008). This framework is used to compare and evaluate the formation types in Pennsylvania that could be potentially used for CCS. The third approach utilized the EPA’s vulnerability framework (2008a) to evaluate the existence of conditions that could result in adverse impacts.
4.1.3.2 Exposure Media, Exposed Receptors and Potential Effects

The potential human and environmental effects associated with CCS are expressed as a probability of occurrence and magnitude of the consequence. While the exposed media and receptors are similar for both the pre-injection and post-injection phases of CCS, the types of releases, the probability of their occurrence, and the nature of the effects are different. For this reason, the potential risks of pre- and post-injection are discussed separately below. However, a similar methodology, based on comparing the ratio between the predicted exposure concentrations and benchmark health-effect criteria, is used to assess the magnitude of the identified risks for human and ecological receptors.

4.1.4 Measurement, Monitoring and Verification, Risk Management and Risk Communication Plans

The development of site conceptual models and the results of the risk assessment also serve to explicitly identify the important parameters and the types and frequency of measurements that should be monitored to ensure the safety of the operating elements of the system, e.g., monitoring pipeline structural integrity, and to provide an accurate accounting of the stored CO\textsubscript{2} to ensure that the CO\textsubscript{2} will remain permanently sequestered. The role of MMV in the CCS program is discussed, and promising monitoring approaches and strategies are described. The findings from this risk assessment and the results from ongoing CCS demonstration projects are used to recommend risk management and risk communication plans.

4.2 Toxicity of CO\textsubscript{2} and Captured Gases

The conceptual model presented in Figure 4-1 identifies the exposure pathways -- sources, routes of exposures, and potential receptors. In Sections 4.3 and 4.4 the potential exposure pathways are examined in detail to evaluate potential risks. These risks are generally evaluated by comparing exposure concentrations to health-based criteria. The captured gas to which human and ecological receptors are exposed contains not only CO\textsubscript{2} but also co-constituents such as water vapor, methane, H\textsubscript{2}S, other oxides of sulfur (e.g., SO\textsubscript{2}), mercury, and various hydrocarbons. As a prelude to the risk evaluations, the toxicological characteristics of CO\textsubscript{2} and selected co-constituents of the capture gas are presented below.

CO\textsubscript{2} is present in the atmosphere at a concentration of about 390 parts per million (ppm) (NOAA, 2009), although concentrations are increasing and are the main reason for implementing CO\textsubscript{2} capture and sequestration. The most important underground source of CO\textsubscript{2} is gas releases from molten rock in volcanic areas. For example, the Yellowstone hydrothermal area is considered to release 16 million tons of CO\textsubscript{2} per year (IEA GHG, 2009). CO\textsubscript{2} is also released from other geological formations, such as sedimentary basins that are natural CO\textsubscript{2} fields. CO\textsubscript{2} is also a natural end product of human and animal metabolism. As a result, CO\textsubscript{2} influences the function of bodily processes, including control of breathing.
Hydrogen sulfide also occurs as a result of natural processes. It is in the gases from volcanoes, sulfur springs, undersea vents, swamps, and stagnant bodies of water. Bacteria found in the mouth and gastrointestinal tract produce hydrogen sulfide during the digestion of food containing vegetable or animal proteins. Normal atmospheric concentrations of H$_2$S in the United States are 0.00011–0.00033 ppm (ATSDR 2006). In the body, H$_2$S is primarily converted to sulfate and rapidly removed in urine. People usually can smell hydrogen sulfide at low concentrations in air, ranging from 0.0005 to 0.3 ppm.

Health effects from CO$_2$ and co-constituents are dependent on the concentration and length of exposure to each gas. Gaseous releases may occur rapidly for only a short-term (e.g., rupture of a pipeline) or slowly over a longer period of time (e.g., leakage from a pipeline or subsurface reservoir). In general, health protective criteria for CO$_2$ and co-constituents are lower for longer lengths of exposure (Table 4-1).

Workers potentially exposed to airborne gases leaking from pipelines or injection wells are covered by health and safety standards developed by the U.S. Department of Labor Occupational Safety and Health Administration (OSHA). The National Institute of Safety and Health (NIOSH) also evaluates and recommends occupational criteria, although only the Permissible Exposure Levels (PELs) promulgated by OSHA are legally enforceable. The PEL protective of workers exposed to CO$_2$ on a daily basis is 5,000 ppm (Table 4-1). In contrast, the worker-protective criteria for other co-constituents, such as H$_2$S and SO$_2$, are considerably lower (i.e., 10 and 5 ppm, respectively). Additionally, OSHA recommends that workers not be exposed to a maximum concentration of 50 ppm H$_2$S during any work-day.

NIOSH has determined concentrations of constituents that a worker could escape within a 30-minute period, or preferably less time, without injury or irreversible health effects. These concentrations are considered levels immediately dangerous to life or health (IDLHs). The IDLH for CO$_2$ is 40,000 ppm, while that for the co-constituent H$_2$S is only 100 ppm (NIOSH, 2005). These IDLHs could be considered upper bounds for workers potentially exposed to short-term gas releases, such as punctures or ruptures of pipelines.

As part of emergency preparedness a primary set of criteria, the Protective Action Criteria (PACs), have been developed to indicate safe levels of airborne constituents protective of the general public and workers. PACs have been developed by the Subcommittee on Consequence Actions and Protective Assessments (SCAPA, 2009) as levels below which most individuals would not experience serious health effects for exposures lasting one hour or less (DOE, 2009c). A PAC-2 is a level in air below which it is believed nearly all individuals could be exposed without experiencing or developing irreversible or other serious health effects or symptoms that could impair their ability to take protective action. For CO$_2$, the PAC-2 is 30,000 ppm, while that for H$_2$S is 27 ppm. The level below which there would be no effects for another co-constituent such as SO$_2$, if present, would be even lower, with a PAC-2 concentration of 0.75 ppm (Table Table 4-1). Other gradations of health effects and associated PAC concentrations for CO$_2$, H$_2$S, and SO$_2$ are provided in Table 4-1.
The Commonwealth of Pennsylvania has also established ambient air quality standards for one of the co-constituent captured with CO₂, specifically H₂S. These ambient air quality standards (25 Pa Code Paragraph 131.3) are intended to be the minimum acceptable air quality levels, but not necessarily the desirable air quality. The standards for H₂S are 0.1 and 0.005 ppm, averaged over one-hour or 24-hours, respectively (Table 4-1). These standards are being used to investigate malodor complaints (Pennsylvania Environmental Quality Board, 1998).
### Table 4-1. Health Risk Criteria for Selected Captured Gases

<table>
<thead>
<tr>
<th>Health Risk Criteria</th>
<th>Constituent Concentration (ppmv)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Occupational</strong></td>
<td></td>
</tr>
<tr>
<td>National Institute of Safety and Health</td>
<td></td>
</tr>
<tr>
<td>Immediately Dangerous to Life and Health Level(^1) (NIOSH, 2005)</td>
<td>40,000</td>
</tr>
<tr>
<td>U.S. Occupational Safety and Health Administration</td>
<td></td>
</tr>
<tr>
<td>Permissible Exposure Level(^2) (OSHA, 2009b)</td>
<td>5,000</td>
</tr>
<tr>
<td>Threshold Limit Value(^2) (OSHA, 2009a)</td>
<td>5,000</td>
</tr>
<tr>
<td><strong>General Public</strong></td>
<td></td>
</tr>
<tr>
<td>Pennsylvania Ambient Air Quality Standards(^3)</td>
<td></td>
</tr>
<tr>
<td>1-hour average</td>
<td>-</td>
</tr>
<tr>
<td>24-hour average</td>
<td>-</td>
</tr>
<tr>
<td>Protective Action Criteria (PAC)(^4)</td>
<td></td>
</tr>
<tr>
<td>PAC-0</td>
<td>5,000</td>
</tr>
<tr>
<td>PAC-1</td>
<td>30,000</td>
</tr>
<tr>
<td>PAC-2</td>
<td>30,000</td>
</tr>
<tr>
<td>PAC-3</td>
<td>40,000</td>
</tr>
<tr>
<td>Acute Exposure Guidelines (AEGL)(^2)</td>
<td></td>
</tr>
<tr>
<td>AEGL-1</td>
<td>-</td>
</tr>
<tr>
<td>AEGL-2</td>
<td>-</td>
</tr>
<tr>
<td>AEGL-3</td>
<td>-</td>
</tr>
<tr>
<td>Reference exposure concentration(^4)</td>
<td>-</td>
</tr>
</tbody>
</table>

**Notes:**
1 – Criteria applicable to releases of less than 1 hour.
2 – Criteria applicable to releases of up to 8 hours.
3 – Pennsylvania Ambient Air Quality Standards
4 – Criteria applicable to lifetime exposure (USEPA Integrated Risk Information System) (EPA, 2009c)

**Definitions:**
- **PAC-0**: The threshold concentration below which most people will experience no appreciable risk of health effects (U.S. Department of Energy [DOE, 2009c]).
- **PAC-1, AEGL-1**: The airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience discomfort, irritation, or certain asymptomatic, non-sensory effects. However, these effects are not disabling and are transient and reversible upon cessation of exposure (U.S. DOE and U.S. Environmental Protection Agency [EPA, 2009]).
- **PAC-2, AEGL-2**: The airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals could experience irreversible or other serious, long-lasting, adverse health effects or an impaired ability to escape (U.S. DOE and U.S. EPA).
- **PAC-3, AEGL-3**: The airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience life-threatening health effects or death (U.S. DOE and U.S. EPA).

Acute exposure guidelines (AEGLs) established by the EPA (2009b) are key components of the PACs. AEGLs have been developed for multiple time periods varying from 10 minutes up to 8 hours of potential worker or public exposures to gases. Since potential
pipeline releases could result in longer exposure periods, the more protective AEGLs for 8-hour exposures are also considered in estimating potential health effects (Table 4-1).

The EPA Integrated Risk Information System (IRIS) has also developed health-based air concentrations called reference concentrations (RfCs) for certain of the captured co-constituents that are estimates of a daily inhalation exposure of the human population (including sensitive subgroups) that are likely to be without an appreciable risk of deleterious effects during a lifetime. No RfC has been developed for CO$_2$. The highly protective RfC for H$_2$S is 0.0014 ppm and is based on effects observed in rats (i.e., nasal lesions) (Table 4-1). The significance of these observed effects and neurological symptoms reported for "low levels" of exposure to H$_2$S is unclear (EPA, 2009c), primarily because there is insufficient evidence to determine health effects in humans (Skrtic, 2006). Accordingly, additional research is being funded by the National Institute of Environmental Health Sciences on the effects of long-term low level H$_2$S exposure (Bates, 2007). The results of these studies should provide a more informed basis for evaluating low level releases of at least this one co-constituent potentially released from subsurface reservoirs of sequestered gases.

4.3 Pre-Injection Risk Assessment

The pre-injection risk assessment addresses the potential human-health risks associated with gaseous releases from the site of CO$_2$ removal (e.g., from the waste stream at power plants and other industrial facilities) and releases from pipelines that transport the CO$_2$ to injection sites. In both cases the magnitude of the potential risks is primarily influenced by the chemical and physical nature of the CO$_2$ and the concentrations of co-contaminants present in the captured gas as well as the proximity of the release to populated areas.

The risks from the power plant and capture process units at the plant are not quantitatively evaluated in this risk assessment. Releases within the plant and associated equipment and fugitive emissions are likely to remain within the plant property and thus are more likely to affect workers than the general public (DOE, 2007a). In addition, there are established procedures to protect workers under the auspices of OSHA, NIOSH, and state agencies.

4.3.1 Sources of CO$_2$ Emissions

4.3.1.1 Plant Facilities and CO$_2$ Capture Mechanisms

There are large pulverized coal plants, natural gas combined-cycle power plants, oil or fossil fuel #6 power plants, and other industrial facilities in Pennsylvania that generate CO$_2$. Figure 4-3 shows the major sources of CO$_2$ in the Commonwealth with annual CO$_2$ emissions ranging from 0.1 to 22 Million metric tons per year (MT/yr), of which 19 are power plants burning coal and with annual CO$_2$ emissions over 1 MT/yr (Table 4-2). The largest CO$_2$ sources are coal-fired power plants, followed by refineries and iron and steel plants. The 19 power plants have annual CO$_2$ emissions of more than 108.9 MT/yr, and four plants have emissions greater than 10 MT/yr. Coal is used to produce over
50 percent of the Commonwealth’s electricity, and Pennsylvania is the fourth largest coal producing state (DCNR, 2009).

Figure 4-3. Major CO$_2$ sources in Pennsylvania with the coal plants with greater than 1 MT/yr CO$_2$ emissions identified

Today, existing post-combustion pilot demonstrations worldwide are small (<0.2 MT/yr), and it is most likely that initial CCS projects in Pennsylvania will capture a fraction of the CO$_2$ emissions in slip-streams from existing coal-fired plants. Because of the long lead time and expense to build new plants, retrofits of existing plants with the post-combustion technology are more plausible in the near-term than shifting to new coal gasification or oxy-fuel plants. The implementation of post-combustion facilities also has the benefit of adding capacity in increments based on demand for CO$_2$ or the need to meet regulatory requirements. This lowers economic and technical risks.
Table 4-2. Power Generation Capacity and CO₂ Emissions of Commonwealth Coal-fired Power Plants

<table>
<thead>
<tr>
<th>Plant name</th>
<th>Plant county</th>
<th>Plant latitude</th>
<th>Plant longitude</th>
<th>Nameplate Capacity (MW)</th>
<th>Plant annual heat input (MMBtu)</th>
<th>Plant annual CO₂ emissions (tons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bruce Mansfield</td>
<td>Beaver</td>
<td>40.6344</td>
<td>-80.4200</td>
<td>2741</td>
<td>172068960</td>
<td>17654261</td>
</tr>
<tr>
<td>Homer City Station</td>
<td>Indiana</td>
<td>40.5306</td>
<td>-79.2136</td>
<td>2012</td>
<td>127218463</td>
<td>13052617</td>
</tr>
<tr>
<td>Conemaugh</td>
<td>Indiana</td>
<td>40.3842</td>
<td>-79.0611</td>
<td>1883</td>
<td>12026304</td>
<td>12336784</td>
</tr>
<tr>
<td>Keystone</td>
<td>Armstrong</td>
<td>40.6767</td>
<td>-79.3419</td>
<td>1884</td>
<td>11461353</td>
<td>11758723</td>
</tr>
<tr>
<td>PPL Brunner Island</td>
<td>York</td>
<td>40.1000</td>
<td>-76.6917</td>
<td>1567</td>
<td>90813813</td>
<td>9317423</td>
</tr>
<tr>
<td>Hatfields Ferry Power Station</td>
<td>Greene</td>
<td>39.8528</td>
<td>-79.9278</td>
<td>1728</td>
<td>88987877</td>
<td>9130158</td>
</tr>
<tr>
<td>PPL Montour</td>
<td>Montour</td>
<td>41.0711</td>
<td>-76.6742</td>
<td>1642</td>
<td>88827727</td>
<td>9112714</td>
</tr>
<tr>
<td>Eddystone Generating Station</td>
<td>Delaware</td>
<td>39.8580</td>
<td>-75.3230</td>
<td>1569</td>
<td>42580590</td>
<td>4172478</td>
</tr>
<tr>
<td>Cheswick Power Plant</td>
<td>Allegheny</td>
<td>40.5367</td>
<td>-79.7942</td>
<td>630</td>
<td>31220642</td>
<td>3198900</td>
</tr>
<tr>
<td>Shawville</td>
<td>Clearfield</td>
<td>41.0669</td>
<td>-78.3828</td>
<td>632</td>
<td>31014386</td>
<td>3182040</td>
</tr>
<tr>
<td>Elrama Power Plant</td>
<td>Washington</td>
<td>40.2500</td>
<td>-79.9167</td>
<td>510</td>
<td>24371235</td>
<td>2500488</td>
</tr>
<tr>
<td>Portland</td>
<td>Northampton</td>
<td>40.9100</td>
<td>-75.0789</td>
<td>621</td>
<td>21764976</td>
<td>2222962</td>
</tr>
<tr>
<td>Sunbury</td>
<td>Snyder</td>
<td>40.8361</td>
<td>-76.8250</td>
<td>477</td>
<td>20003244</td>
<td>2145793</td>
</tr>
<tr>
<td>Armstrong Power Station</td>
<td>Armstrong</td>
<td>40.9289</td>
<td>-79.4658</td>
<td>319</td>
<td>20894444</td>
<td>2143761</td>
</tr>
<tr>
<td>New Castle Plant</td>
<td>Lawrence</td>
<td>40.9378</td>
<td>-80.3681</td>
<td>354</td>
<td>16616255</td>
<td>1704816</td>
</tr>
<tr>
<td>Mitchell Power Station</td>
<td>Washington</td>
<td>40.2228</td>
<td>-79.9694</td>
<td>449</td>
<td>14830174</td>
<td>1520854</td>
</tr>
<tr>
<td>AES Beaver Valley Partners</td>
<td>Beaver</td>
<td>40.6558</td>
<td>-80.3556</td>
<td>149</td>
<td>12095399</td>
<td>1256387</td>
</tr>
<tr>
<td>Cromby Generating Station</td>
<td>Chester</td>
<td>40.1514</td>
<td>-75.5306</td>
<td>420</td>
<td>12790178</td>
<td>1247557</td>
</tr>
<tr>
<td>Titus</td>
<td>Berks</td>
<td>40.3061</td>
<td>-75.9081</td>
<td>261</td>
<td>12139886</td>
<td>1245480</td>
</tr>
</tbody>
</table>

The coal-fired plants are located mostly in the southwest and southeast of the Commonwealth, while smaller power plants, refineries, and a gas processing plant are located in the northwest. Suitable target formations have not yet been identified in the southeastern portion of the Commonwealth. Therefore, it is possible that the captured CO₂ may have to be transported by pipelines to reach a suitable formation.

For coal-fired power plants, there are three widely recognized types of technologies for capturing CO₂ from a power plant: (1) post-combustion; (2) pre-combustion; or (3) an oxy-fuel combustion process. Capture of CO₂ at existing pulverized coal power plants must be conducted after combustion using amine-based sorption, membranes or other solvent-based technologies. New coal plants may be built as integrated gasification combined cycle (IGCC) plants or as an oxy-fuel plant using an oxygen-rich combustion process. The process used to capture the CO₂ influences the purity of the CO₂ and the type and concentration of co-contaminants, as discussed in Section 4.3.1.2.

Processes currently being used for post-combustion capture include absorption of the CO₂ from flue gas using an amine solution such as monoethanolamine (MEA), a chilled ammonia process, and aqueous ammonia. Other methods being tested include use of physical solvents using ionic liquids, N₂/CO₂ membranes, cryogenic separation by
distillation or freezing and enzymatic CO₂ processes (DOE, 2007b). A post-combustion pilot plant in Wisconsin uses a chilled ammonia process to capture 15,000 metric tons/yr from a coal plant. At the Mountaineer coal-fired plant in West Virginia, the same process for capturing 100,000 metric tons/yr from a slip stream is planned.

IGCC plants gasify the coal followed by a shift gas reaction and glycol adsorption to separate the CO₂. The process yields CO₂ with traces of other gases including H₂S. The IGCC process can produce hydrogen-rich gas for use in gas turbines to produce electricity or to serve as hydrogen fuel for transportation. Alternative methods for pre-combustion capture of CO₂ from the flue gas include use of solvents such as methanol, amines, ionic liquids, polymer or ceramic-based membranes, or metal organic frameworks (WRI, 2008 and DOE, 2007b). The Great Plains Synfuels IGCC plant in Beulah, North Dakota has captured over 16 MT of CO₂ between 2000 and 2008. About 8,000 metric tons of CO₂ are shipped daily to Weyburn, Canada via a 205-mile long pipeline. Two IGCC plants are operating in the Netherlands and Spain and several new plants are planned in the US, Australia and other European countries.

Oxy-fuel combustion plants burn pulverized coal in an atmosphere where oxygen is mixed with recycled exhaust flue gas. Oxy-fuel combustion achieves a higher concentration of CO₂ in the flue gas, up to 80 percent, since the process decreases the nitrogen oxides present, making the CO₂ more efficient to capture using a solvent such as amines or the chilled ammonia process. Two pilot oxy-fuel plants are in operation in Europe and are planned in the US and Australia.

Capture processes used for other industrial facilities include amine and ammonia-based processes. For example, amine-based sorption is used to remove CO₂ from natural gas at the Sleipner natural gas processing facility in the North Sea, which is then injected into deep saline formations. Steel, refineries, and cement plants would also be able to use post-combustion processes for CO₂ capture.

4.3.1.2 Captured Gas Characteristics

The volume of CO₂ produced at coal-fired power plants in Pennsylvania varies from 1.2 MT/yr for a small 260 MWe plant to 17.6 MT/yr for a 2,741 MWe plant. The capture of approximately 1 MT CO₂/yr from flue gas slip streams is likely to be implemented first using current technology.

Flue gas from pulverized coal combustion is typically comprised of approximately 13% CO₂, 72% nitrogen, 3% oxygen, 8% water vapor, and about 4% NOₓ, SO₂, SO₃, and other impurities (Rochelle, 2009). The CO₂ content of coal flue gas varies from 12 to 15 percent, compared to natural gas plants with about 4-9 percent, 14 percent in biomass boilers and 25 percent in steel and cement plants.

The purity of the carbon dioxide and the concentrations of other chemicals in the captured gases depend primarily on the type of plant and capture process and to a secondary extent on the fuel source and combustion process. Potential trace gas components in a captured CO₂ stream from a gasification plant can include sulfur
dioxide, nitrogen oxide, hydrogen sulfide, hydrogen, carbon monoxide, methane, nitrogen, argon, mercury, cyanide, and oxygen (DOE, 2007a). Table 4.3 provides information on the range of CO₂ and other trace gases in the captured gas. Pre-combustion CO₂ from IGCC plants may contain H₂S, while CO₂ from oxy-fuel plants may contain more SO₂. Trace gases such as H₂S and SO₂ are toxic, and thus are a primary concern with respect to human health. For the example case presented below in Section 4.3.5, the captured gas was set at 95% CO₂ and 100 ppmv H₂S.

Table 4-3. Estimated Chemical Composition of Captured Gas by Plant Type

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Post-combustion Process</th>
<th>IGCC Plant</th>
<th>Oxy-fuel Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MEA Process</td>
<td>Chilled Ammonia Process</td>
<td>Glycol</td>
</tr>
<tr>
<td>CO₂</td>
<td>95 %</td>
<td>99.7 %</td>
<td>95 %</td>
</tr>
<tr>
<td>NH₃</td>
<td>NA</td>
<td>50 ppm</td>
<td>NA</td>
</tr>
<tr>
<td>NOₓ</td>
<td>20 ppmv</td>
<td>40-280 ppm</td>
<td>&lt;0.5</td>
</tr>
<tr>
<td>SO₂</td>
<td>10-20 ppmv</td>
<td>40-50 ppmv</td>
<td>NA</td>
</tr>
<tr>
<td>SO₃</td>
<td>NA</td>
<td>10-40 ppmv</td>
<td>NA</td>
</tr>
<tr>
<td>H₂S</td>
<td>NA</td>
<td>NA</td>
<td>0.01-1 %</td>
</tr>
<tr>
<td>H₂O</td>
<td>NA</td>
<td>0.3 %</td>
<td>100 ppmv</td>
</tr>
</tbody>
</table>

4.3.2 Pipeline Corridor Characterization and Transported CO₂ Characterization

4.3.2.1 Existing CO₂ Pipeline Network in the US

Pipelines have been used in the United States for transporting CO₂ from natural deposits to EOR sites since 1972 when the 140-mile long Canyon Reef Carriers Pipeline began operation in west Texas. Currently in the US, there are 3,600 miles of CO₂ pipelines of which about 3,000 miles are used for EOR projects (Parfomak and Folger, 2007). As shown in Figure 4-4, most of the major CO₂ pipelines are located in the western US, which has a lower population density and fewer surface waterbodies. The extended pipeline from the Jackson Dome natural CO₂ deposit in Mississippi to the Houston area is a new planned pipeline, as is the pipeline in Oklahoma. Both pipelines will transport CO₂ for use in EOR operations. In contrast, there are over 497,000 miles of pipelines in the US transporting natural gas, other petroleum products, and other hazardous liquids. Most of the pipelines transport natural gas, which extends across the country in a network of about 307,254 miles (Figure 4-5). The present network of CO₂ pipelines is about 1 percent of the total natural gas pipelines.

There are major differences in transporting natural gas and CO₂. Natural gas is lighter than air, so any leak will tend to move upwards. It is also flammable. CO₂ is transported as a supercritical fluid or liquid depending on ambient conditions. As a supercritical fluid the density of CO₂ resembles a liquid, but it expands to fill space like a gas. The CO₂ can form carbonic acid when mixed with water, which is highly corrosive, thus the moisture
content is maintained at a low level (200-500 ppm). When CO$_2$ is released from a pipe, it expands rapidly as a gas and can change to liquid and solid phases.

Figure 4-4. Major US CO$_2$ pipelines in 2005 (US DOT, 2005).
The present network of major CO$_2$ pipelines is summarized in Table 4-3. Pipelines installed since June 2005 include extensions in Mississippi, Louisiana, and Oklahoma. The diameters of the existing pipelines range from 8 in for the shorter lines to 30 in for the present longest line, the 505 mile Cortez pipeline from Colorado to west Texas. Pressures in the lines are not always available, but most lines are typically run at ambient temperature and high pressure, to keep the CO$_2$ under supercritical conditions. Booster pumps are used to maintain the high pressures over long distances.

Most of the above pipelines in the US are used for EOR and transport natural CO$_2$ to the oil fields. There are currently 86 CO$_2$-EOR projects in the US, which contributed to the production of 237,000 barrels of oil in 2006 (Kuuskraa and Ferguson, 2008). Between 1986 and 2006, the amount of oil produced from the CO$_2$-EOR projects has increased as the pipeline capacity and extent increased. Currently, there are two examples of industrial sources for CO$_2$. The Beulah-Weyburn pipeline transports captured CO$_2$ from the Dakota Gasification Company’s Great Plains Synfuels Plant near Beulah, North Dakota to the Weyburn oil field in southern Saskatchewan, Canada. This 205 mile long pipeline began operation in September 2000, and transports gas composed of 95% CO$_2$ with 1% H$_2$S at a rate of 8,000 metric tons daily. Part of the CO$_2$ waste stream with some nitrogen from a gas processing plant near La Barge, Wyoming is mixed with natural CO$_2$ and transported to EOR fields in Wyoming and Colorado in a series of four pipeline segments, which are 60 to 125 miles long (Wyoming Pipeline Authority, 2006). Planning is underway at two industrial plants, a fertilizer plant in Oklahoma and an ammonia plant in Louisiana, where CO$_2$ can be captured and used for EOR.
4.3.2.2 Pipeline Networks in Pennsylvania

There is an extensive pipeline network for natural gas and refined petroleum products in Pennsylvania (Figure 4-6). There are currently no CO$_2$ pipelines in the Commonwealth, although there are potential opportunities for future EOR operations. Because of the concentration of gas and oil fields in western Pennsylvania, pipelines are more numerous. There are pipelines entering the Commonwealth from the Philadelphia area. As seen in Figure 4-6, many of the major CO$_2$ sources are located along existing pipeline right-of-ways. Because there are fewer known deep saline reservoirs in eastern Pennsylvania, longer pipelines might be needed from sources in that area to a storage site. In western Pennsylvania, there are likely to be several potential storage reservoirs with sufficient capacity to inject CO$_2$ emissions over a 30- to 50-year period and permanently store the CO$_2$, so shorter pipelines would be required.
Table 4-3. CO$_2$ Pipeline Summary in United States

<table>
<thead>
<tr>
<th>Pipeline Name</th>
<th>Current Operator</th>
<th>Length, miles</th>
<th>Diameter, in</th>
<th>Capacity, MMCFD</th>
<th>Pressure, psi</th>
<th>Source</th>
<th>Use of CO$_2$</th>
<th>States Crossed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beulah-Weyburn</td>
<td>Dakota Gasification</td>
<td>205</td>
<td>14/12.75</td>
<td>240/150</td>
<td>2799/2964</td>
<td>IGCC Plant</td>
<td>EOR in southern Alberta</td>
<td>N Dakota, Alberta Canada</td>
</tr>
<tr>
<td>Bravo</td>
<td>BP Kinder Morgan</td>
<td>218</td>
<td>20</td>
<td>382</td>
<td>1800 - 1900</td>
<td>CO$_2$ deposit</td>
<td>EOR in west Texas</td>
<td>New Mexico, Texas</td>
</tr>
<tr>
<td>Bravo Extension</td>
<td>Transpetco, Kinder Morgan</td>
<td>120</td>
<td>12.75</td>
<td>175</td>
<td>1800</td>
<td>CO$_2$ deposit</td>
<td>EOR in Guyman, Oklahoma</td>
<td>New Mexico, Oklahoma</td>
</tr>
<tr>
<td>Central Basin Pipeline</td>
<td>Kinder Morgan</td>
<td>200</td>
<td>26 to 16</td>
<td>600</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in west Texas</td>
<td>New Mexico, Texas</td>
</tr>
<tr>
<td>Este</td>
<td>Kinder Morgan, Exxon Mobil</td>
<td>119</td>
<td>12 to 14</td>
<td>250</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in west Texas</td>
<td>Texas</td>
</tr>
<tr>
<td>Slaughter</td>
<td>Exxon Mobil</td>
<td>40</td>
<td>12</td>
<td>160</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in west Texas</td>
<td>Texas</td>
</tr>
<tr>
<td>West Texas</td>
<td>Trinity Pipeline, LP</td>
<td>127</td>
<td>12 to 8</td>
<td>100</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in west Texas</td>
<td>Texas</td>
</tr>
<tr>
<td>Llano</td>
<td>Trinity Pipeline, LP</td>
<td>53</td>
<td>12 to 8</td>
<td>100</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in New Mexico</td>
<td>New Mexico</td>
</tr>
<tr>
<td>Canyon Reef Carriers</td>
<td>Kinder Morgan</td>
<td>140</td>
<td>16</td>
<td>240</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in west Texas</td>
<td>Texas</td>
</tr>
<tr>
<td>Cortez</td>
<td>Kinder Morgan</td>
<td>502</td>
<td>30</td>
<td>1000 to 4000</td>
<td>1900 at End Hub</td>
<td>CO$_2$ deposit</td>
<td>EOR in west Texas</td>
<td>Colorado, New Mexico, Texas</td>
</tr>
<tr>
<td>McElmo Creek</td>
<td>Exxon Mobil</td>
<td>40</td>
<td>8</td>
<td>60</td>
<td>1900</td>
<td>CO$_2$ deposit</td>
<td>EOR in Utah</td>
<td>Colorado, Utah</td>
</tr>
<tr>
<td>Sheep Mountain A</td>
<td>BP Exxon Mobil</td>
<td>184</td>
<td>20</td>
<td>330</td>
<td>2050 at End Hub</td>
<td>CO$_2$ deposit</td>
<td>EOR in west Texas</td>
<td>Wyoming, New Mexico</td>
</tr>
<tr>
<td>Sheep Mountain B</td>
<td>BP Exxon Mobil, Amerada Hess, KM</td>
<td>224</td>
<td>24</td>
<td>448</td>
<td>2050 at End Hub</td>
<td>CO$_2$ deposit</td>
<td>EOR in west Texas</td>
<td>New Mexico, Texas</td>
</tr>
<tr>
<td>Jackson-Tinsley</td>
<td>Denbury Resources</td>
<td>31</td>
<td>8</td>
<td>NA</td>
<td>1200</td>
<td>CO$_2$ deposit</td>
<td>EOR in Mississippi</td>
<td>Mississippi</td>
</tr>
<tr>
<td>Delta</td>
<td>Denbury Resources</td>
<td>31</td>
<td>24</td>
<td>NA</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in Mississippi</td>
<td>Mississippi</td>
</tr>
<tr>
<td>Free State</td>
<td>Denbury Resources</td>
<td>86</td>
<td>20</td>
<td>NA</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in Mississippi</td>
<td>Mississippi</td>
</tr>
<tr>
<td>NEJD</td>
<td>Denbury Resources</td>
<td>183</td>
<td>20</td>
<td>NA</td>
<td>2200</td>
<td>CO$_2$ deposit</td>
<td>EOR in Mississippi</td>
<td>Louisiana</td>
</tr>
<tr>
<td>Lake St John</td>
<td>Denbury Resources</td>
<td>68</td>
<td>18</td>
<td>NA</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in Mississippi and Louisiana</td>
<td>Mississippi, Louisiana</td>
</tr>
<tr>
<td>Salt Creek Line</td>
<td>Exxon Mobil, Anadarko</td>
<td>125</td>
<td>16</td>
<td>150</td>
<td>2250</td>
<td>gas plant</td>
<td>EOR in Wyoming</td>
<td>Wyoming</td>
</tr>
<tr>
<td>Shute Creek - Rock Springs</td>
<td>Exxon Mobil</td>
<td>61</td>
<td>24</td>
<td>250</td>
<td>2300</td>
<td>gas plant</td>
<td>EOR in Wyoming</td>
<td>Wyoming</td>
</tr>
<tr>
<td>Rock Springs to Bairoil</td>
<td>Exxon Mobil</td>
<td>125</td>
<td>20</td>
<td>250</td>
<td>2250</td>
<td>gas plant</td>
<td>EOR in Wyoming</td>
<td>Texas</td>
</tr>
<tr>
<td>Rock Springs to Rangely</td>
<td>Chevron</td>
<td>120</td>
<td>16</td>
<td>100</td>
<td>2250</td>
<td>gas plant</td>
<td>EOR in Wyoming</td>
<td>Wyoming, Colorado</td>
</tr>
<tr>
<td>Monell Extension</td>
<td>Exxon Mobil</td>
<td>33</td>
<td>8</td>
<td>33</td>
<td>2250</td>
<td>gas plant</td>
<td>EOR in Wyoming</td>
<td>Wyoming</td>
</tr>
<tr>
<td>Borger</td>
<td>Chaparral Energy</td>
<td>86</td>
<td>8</td>
<td>&lt;43</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in Texas</td>
<td>Texas</td>
</tr>
<tr>
<td>Purdy-Velma</td>
<td>Chaparral Energy</td>
<td>23</td>
<td>NA</td>
<td>&lt;43</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in Texas</td>
<td>Texas</td>
</tr>
<tr>
<td>Purdy-Enid</td>
<td>Chaparral Energy</td>
<td>120</td>
<td>NA</td>
<td>&lt;43</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in Oklahoma</td>
<td>Oklahoma</td>
</tr>
<tr>
<td>Panhandle Oklahoma</td>
<td>Chaparral Energy</td>
<td>126</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>CO$_2$ deposit</td>
<td>EOR in Oklahoma</td>
<td>Texas, Oklahoma</td>
</tr>
</tbody>
</table>

Data were obtained for major pipelines operating in 2007. Other smaller pipelines connect from trunklines to the oil fields. Pipeline operators sometimes differ from owners, which may include multiple companies.
4.3.2.3 Pipeline Safety and Likelihood of Releases

A summary of previous pipeline or related equipment failures of CO$_2$ pipelines compiled from the Office of Pipeline Safety (OPS) database for 1986 to 2008 shows that the safety record for existing CO$_2$ pipelines is good. As shown in Table 4-4, incidents involving CO$_2$ pipelines between 1988 and 2008 have not resulted in any fatalities and the annual incident frequency is 0.23 per 1,000 km (OPS, 2009). The major cause of pipeline failure is damage (puncture or rupture) during excavation (Figure 4-7).
Table 4-4. Pipeline Safety Record (1988 – 2008).

<table>
<thead>
<tr>
<th>Pipelines*</th>
<th>Natural Gas</th>
<th>Hazardous Liquids</th>
<th>CO₂</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length (km)</td>
<td>494,477</td>
<td>251,253</td>
<td>5,581</td>
</tr>
<tr>
<td>Incidents</td>
<td>2038</td>
<td>3945</td>
<td>26</td>
</tr>
<tr>
<td>Fatalities</td>
<td>253</td>
<td>43</td>
<td>0</td>
</tr>
<tr>
<td>Injuries</td>
<td>224</td>
<td>233</td>
<td>1</td>
</tr>
<tr>
<td>Property Damage (in $M)</td>
<td>1,221.7</td>
<td>1,342.4</td>
<td>1.25</td>
</tr>
<tr>
<td>Incidents/1000 km/Yr</td>
<td>0.21</td>
<td>0.78</td>
<td>0.23</td>
</tr>
</tbody>
</table>

*Based on OPS Data 4/2009

These data presented in Table 4-4 can also be used to estimate pipeline failure rates and the probabilities of pipeline release incidents for different operating periods and pipeline lengths. For example, the accident data from 1988-2008 contained in the on-line library of the Office of Pipeline Safety (http://ops.dot.gov/stats/IA98.htm) were used to calculate the probability of pipeline ruptures. Four of the 26 accidents that occurred from 1988 - 2008 with the largest CO₂ releases (> 4,000 barrels) we have designated as rupture-type releases. For comparison, five miles of a CO₂ pipeline transporting 1 Mt CO₂ per yr would contain about 6500 barrels, depending on the pipeline diameter. Using the total length of pipeline involved of 5,581 kilometers (Table 4-4), the rupture failure frequency was calculated to be $3.41 \times 10^{-5}$/ (kilometer-year). The annual pipeline failure frequencies and the probability of at least one failure over a 50-year lifetime of the pipeline, calculated assuming the probability of failure to be exponentially distributed with the hazard rate equal to the product of the failure frequency and the pipeline length, are presented in Table 4-5.
Table 4-5. Probability of at least one pipeline failure (rupture) over a 50-year operating period for different pipeline lengths.

<table>
<thead>
<tr>
<th>Pipeline Length (km)</th>
<th>Probability of Pipeline Failure</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.6</td>
<td>0.003</td>
</tr>
<tr>
<td>18</td>
<td>0.03</td>
</tr>
<tr>
<td>50</td>
<td>0.08</td>
</tr>
<tr>
<td>80</td>
<td>0.13</td>
</tr>
<tr>
<td>160</td>
<td>0.24</td>
</tr>
</tbody>
</table>

4.3.3 Release Scenarios

The pre-injection release scenarios can include a complete rupture of the pipe, leakage due to a puncture, leaks from a valve or pump seal, and fugitive releases of captured gases from compression units. The primary release mechanism, releases to air, can lead to direct exposures to humans inhaling the released gases outdoors or indoors, or can induce secondary releases to other media, such as discharge to surface water or soil.

Two accidental release scenarios (pipeline rupture and puncture) are considered to represent the most likely cause of pipeline releases. Both these failure modes are simulated for the example case described in Section 4.3.5. A pipeline rupture release occurs when the pipeline is completely severed, typically by heavy equipment during excavation activities. A rupture can also result from longitudinal running fracture of a pipe or a seam-weld failure. All the fluid between the two nearest check valve stations is discharged from the severed pipeline within minutes.

A pipeline puncture is defined as a 3 by 1 inch hole. All of the fluid between the two nearest check valve stations would also discharge into the atmosphere, but the release occurs over a period of several hours.

Supercritical CO$_2$ has a very low viscosity, but is denser than air. The CO$_2$ will escape through an open orifice in the pipeline as a gas moving with the speed of sound, referred to as choked or critical flow (Bird et al., 2002). Choked flow is the maximum rate at which a gas escapes through an orifice without being accelerated by an explosion. In the rupture scenario, the escaping gas from the pipeline is assumed to escape as a horizontal jet at ground level, which is typically the worst case event for heavier-than-air gases (Hanna and Drivas, 1987). Because the released CO$_2$ is a denser-than-air gas, the CO$_2$ will not immediately diffuse upwards into the atmosphere but will be transported at ground level.

The volume of gas released from a rupture or puncture is based on thermodynamic properties of the gases, length and inner diameter of the pipe, and distance between check valves. Release of CO$_2$ under pressure typically causes rapid expansion and then a reduction in temperature and pressure, which can result in formation of solid-phase CO$_2$. For example, in the example pipeline release discussed below, 26 percent of the CO$_2$ goes
to the solid-phase, and 74 percent of the volume is released to the atmosphere in gaseous form.

The subsequent atmospheric transport and dispersion of the released CO$_2$ can be substantially affected by the temperature and density of the initially released CO$_2$ and the meteorological conditions at the time of the release. For example, the hazard associated with conditions of low wind speed and ground-based inversion conditions at night with fog could be increased. In terrain with significant variation in elevation, cold-air drainage at night could add to the severity of these conditions.

Accidental releases can also occur from valves at the injection wellhead or from damage by vehicles during injection. The amount of CO$_2$ that could be released from a well depends on well design, injection formation characteristics, and quantities of CO$_2$ injected per well. For example, the mass of CO$_2$ released from a well rupture in the FutureGen risk analysis varied from 2.9 to 22.6 metric tons at a pressure of 2,200 psi and 95°F (DOE, 2007a).

4.3.4 Exposure Analysis

4.3.4.1 Exposure Media and Receptor Groups

Releases to the atmosphere represent the primary exposure pathway considered in the exposure analysis. The receptor groups likely to be exposed by releases from pipelines or above-ground equipment at the plant or injection site are onsite workers and offsite populations. Although releases along pipeline corridors, at injection sites, and subsurface fluxes could affect sensitive vegetation and animals, ecological receptors are not addressed in this analysis.

In the exposure analysis, predicted air concentrations, based on simulated releases of CO$_2$ and trace gases, are compared to appropriate toxicity criteria for a specified exposure time. For pipeline ruptures the exposure time is short, while for the puncture scenario, the volume released is less, but the time of exposure is longer. Toxicity criteria for CO$_2$, H$_2$S, and SO$_2$ are discussed in Section 4.2. The estimated numbers of people potentially affected by pipeline failures at four FutureGen sites are shown in Table 4-6. Although not evident from this table, the greater number of affected individuals at Sites 3 (FG3) and 4 (FG4) is attributable to the location of the pipelines near more highly populated areas.
Table 4-6. Example of Expected Numbers of People Potentially Affected by Pipeline Releases.

<table>
<thead>
<tr>
<th></th>
<th>FG 1</th>
<th>FG 2</th>
<th>FG 3</th>
<th>FG 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipeline Length, miles</td>
<td>61.5</td>
<td>0.5</td>
<td>11</td>
<td>52-59</td>
</tr>
<tr>
<td>Pipeline Diameter, in</td>
<td>12.8</td>
<td>14.4</td>
<td>14.4</td>
<td>19.3</td>
</tr>
<tr>
<td><strong>Pipeline Ruptures</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of People</td>
<td>0</td>
<td>0</td>
<td>&lt;0.1</td>
<td>&lt;0.5</td>
</tr>
<tr>
<td>Affected by</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Adverse Effects from C</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>O2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of People</td>
<td>0.19</td>
<td>0.12</td>
<td>7.4</td>
<td>52</td>
</tr>
<tr>
<td>Affected by</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Adverse Effects from H</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2S</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Pipeline Punctures</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of People</td>
<td>&lt;0.01</td>
<td>0.01</td>
<td>&lt;0.1</td>
<td>0.2</td>
</tr>
<tr>
<td>Affected by</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Adverse Effects from C</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>O2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of People</td>
<td>&lt;0.1</td>
<td>&lt;0.2</td>
<td>1</td>
<td>6</td>
</tr>
<tr>
<td>Affected by</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Adverse Effects from H</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2S</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

From FutureGen Risk Assessment (DOE, 2007a).

4.3.4.2 Exposure Modeling for Pipeline Leaks

The transport of the released gases is estimated through atmospheric dispersion modeling. The predicted concentrations in air are then used to estimate the potential for exposure and any resulting impacts on human receptors. The effects of the releases to the atmosphere were simulated using the SLAB model (Ermak, 1990) and the Pipeline-Walk Methodology from the FutureGen risk assessment (DOE, 2007a). The “Pipeline-walk” method was developed to evaluate the effects of thermodynamically determined gas phase releases along the entire length of the pipeline and to calculate the number of individuals hypothetically exposed to carbon dioxide and hydrogen sulfide from simulated pipeline ruptures and punctures. The method moves along the pipeline at points 300 meters apart where a series of calculations and simulations are made using the SLAB model for the range of meteorological conditions likely to occur at a site. A detailed description is included in the FutureGen risk assessment (DOE, 2007a). The five main steps in the pipeline-walk method for pipeline rupture and puncture release scenarios are described below:

**Step 1. Summarize meteorological conditions that affect plume transport.** The meteorological data are used to estimate the proportion of time over a year in each atmospheric state (combinations of wind directions and stability conditions).

**Step 2. Simulate the area potentially affected by a pipeline release.** The SLAB model is run to determine the area of the potential impact zone for each of the defined atmospheric states. Separate runs are performed for the CO₂ and H₂S gases for each health-effect level and exposure period for the rupture and puncture scenarios.

**Step 3. Estimate population affected for each atmospheric state.** The areal extent of each predicted exposure zone for each gas is superimposed onto a map of the population density data along the pipeline route, as shown for an example of an individual release.
event in Figure 4-8. In this figure, the population density is shown by colored blocks as the number of people per sq km.

**Step 4. Determine the expected number of individuals potentially affected at the specified release points.** The affected population in each exposure zone is next multiplied by the proportion of the time (relative importance) in each of the defined atmospheric states. Since all the stability classes sum to 1, the sum of these products provides the expected number of affected individuals at any selected point along the pipeline.

**Step 5. Characterize the potential exposure along the entire pipeline.** Tabular and graphical summaries of the expected number of affected individuals at all points along the pipeline provide a comprehensive summary of potential health effects from a pipeline release.

![Figure 4-8. Example of H₂S plume from a hypothetical pipeline rupture.](image)

**4.3.5 Example Analysis**

To provide a representation of the potential effects of a CO₂ pipeline accident, an example simulation for a pipeline rupture and puncture was conducted using the SLAB model and the pipeline-walk method for a hypothetical pipeline 11 miles in length and
14.4 inches in diameter. The pipeline pressure of the CO\textsubscript{2} was assumed to be 2,200 psi and at approximately 35°C, which means the CO\textsubscript{2} would move in the pipeline in a supercritical state (Table 4-7). The distance was selected to represent a short route to a local sequestration site or a feeder line to a longer trunk line. The trunk line would be expected to reach a suitable sequestration site within the Oriskany sandstone formation from southeastern Pennsylvania. The pipelines from the plant to the injection site(s) are expected to be buried to a typical depth of 3.3 feet (1 meter) and check valves are expected to be set at intervals of 5 miles along the route. The pipeline release is expected to discharge to the atmosphere.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Example</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipeline Inner Diameter, inches (centimeters)</td>
<td>14.4 (36.7)</td>
</tr>
<tr>
<td>Pipeline Temperature, °F (°C)</td>
<td>95 (35)</td>
</tr>
<tr>
<td>Pipeline Pressure, psi</td>
<td>2,200</td>
</tr>
<tr>
<td>Distance to Example Site, miles (kilometers)</td>
<td>11 (18)</td>
</tr>
</tbody>
</table>

The volume of CO\textsubscript{2} would vary based on the plant size, but for this example, a pipeline capable of transporting 1MT/yr was used, which is likely for a slip-stream from a large coal-fired plant. The composition of the captured gas was estimated as 95% CO\textsubscript{2} and 0.01 percent H\textsubscript{2}S, <0.5 percent nitrogen, and 100 ppmv moisture content. The mass of CO\textsubscript{2} in the 5-mile section of pipe was calculated as 723,100 kg. The choked flow rate was estimated as 4,444 kg/sec over the release duration of 162 sec for a pipeline rupture. The portion of the CO\textsubscript{2} expected to be in the vapor phase after a release under supercritical conditions was estimated as 74 percent of the mass in the pipeline segment.

The SLAB atmospheric transport model was run for average meteorological conditions using wind rose data for a nearby city and atmospheric stability classes. For this example site, seven stability classes including F1, calm conditions, were simulated for the 12 wind directions. At this example site, calm conditions occurred about 22 percent of the time. Winds were from the west to northwest about 33 percent of the time, and from the east less than 7 percent of the time.

Simulations were conducted to determine the impact zone where people could be exposed to concentrations equal to the PAC-0 to PAC-3 health-effect criteria for CO\textsubscript{2} and H\textsubscript{2}S (See Section 4.2). The exposure periods for the pipe ruptures were 15 minutes and 8 hours for the punctures. For workers, a simulation was also made to determine the impact zone for 100 ppmv H\textsubscript{2}S.

The population density in the vicinity of the example site is shown in Figure 4-9. At the plant and well site, the density was 50 to 100 people per sq. mile, but increased as the route crossed a town where the density increased in a 1-mile section to greater than 5,000 people per sq. mile. This route follows an existing right-of-way for a natural gas
pipeline, illustrating that while using right-of-ways has benefits with respect to permitting, populated areas may not be avoided.

Figure 4-9. Example of hypothetical pipeline showing population density around the plant, injection well, and along the route of the pipeline with simulated plume extent.

The plume from a given pipe rupture is generally small in areal extent and its position depends on the wind direction, speed, and stability conditions at the time of the release. While the distance that a given exposure concentration could extend out from the pipeline is shown in Figure 4-9 as a guide, the plume would extend out from the pipeline only from the location of the release. The radial distance of 0.08 miles shown on the map represents the distance outward from the pipeline that a CO₂ concentration of 30,000 ppm over an averaging period of 15 minutes, the PAC-1 criteria, could extend from a hypothetical pipeline rupture. This distance is similar to the radial distance of 0.05 miles that an H₂S concentration of 27 ppm, the PAC-1 criteria, could extend during the dominant stability conditions. The furthest distance shown on the map represents the extent of an H₂S concentration of 0.51 ppm, the PAC-0, also during the dominant stability conditions. At these levels of CO₂ and H₂S, the general public could experience only transient and reversible effects. The distance of potential impact due to ruptures or punctures from the pipeline for the other exposure durations and concentrations for CO₂ and H₂S are shown in Table 4-9 and Table 4-9. The simulations using the SLAB model showed that during calm conditions, the H₂S plume could extend further for a rupture, but not a puncture. For example, the distance that an H₂S concentration of 27 ppm could
extend increases to 0.38 miles. However, as explained above, the actual plume from a specific release would cover a much smaller area depending on the wind and meteorological conditions at the time of the release. All conditions and wind directions are considered in the pipe-walk evaluation along the entire route of the pipeline, as discussed below.

<table>
<thead>
<tr>
<th>Release Type</th>
<th>Exposure Duration</th>
<th>Criteria, ppm</th>
<th>Distance, m</th>
<th>Met Condition*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rupture</td>
<td>15 minutes</td>
<td>40,000</td>
<td>90</td>
<td>D12</td>
</tr>
<tr>
<td></td>
<td>15 minutes</td>
<td>30,000</td>
<td>127</td>
<td>D12</td>
</tr>
<tr>
<td></td>
<td>15 minutes</td>
<td>5,000</td>
<td>811</td>
<td>C5</td>
</tr>
<tr>
<td>Puncture</td>
<td>8 hours</td>
<td>40,000</td>
<td>78</td>
<td>F1</td>
</tr>
<tr>
<td></td>
<td>8 hours</td>
<td>5,000</td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>

* Dominant Met Condition listed that occurred during cases with maximum distances.

<table>
<thead>
<tr>
<th>Release Type</th>
<th>Exposure Duration</th>
<th>Criteria, ppm</th>
<th>Distance, m</th>
<th>Met Condition*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rupture</td>
<td>15 minutes</td>
<td>0.51</td>
<td>1098</td>
<td>D7</td>
</tr>
<tr>
<td></td>
<td>15 minutes</td>
<td>27</td>
<td>86</td>
<td>D7</td>
</tr>
<tr>
<td></td>
<td>15 minutes</td>
<td>50</td>
<td>54</td>
<td>B3</td>
</tr>
<tr>
<td></td>
<td>15 minutes</td>
<td>100</td>
<td>34</td>
<td>B3</td>
</tr>
<tr>
<td>Puncture</td>
<td>8 hours</td>
<td>0.33</td>
<td>96</td>
<td>D7</td>
</tr>
<tr>
<td></td>
<td>8 hours</td>
<td>17</td>
<td>28</td>
<td>D12</td>
</tr>
<tr>
<td></td>
<td>8 hours</td>
<td>37</td>
<td>24</td>
<td>D12</td>
</tr>
</tbody>
</table>

* Dominant Met Condition listed that occurred during cases with maximum distances.

The expected numbers of people affected by exposure to CO\textsubscript{2} for a given duration at a time-weighted average concentration equal to a specified criteria from a puncture or rupture along the entire pipeline were predicted using the pipeline-walk methodology, as shown in Table 4-10. The expected numbers of people impacted by exposure to H\textsubscript{2}S from a rupture or puncture along the pipeline are shown in Table 4-11. In this example, part of the pipeline crosses a densely-populated area, so the number of people that could be affected varies along the route, as shown in Figure 4-10 for CO\textsubscript{2}. This figure shows that for about 80 percent of the pipeline route, the number of people potentially affected by transient effects of CO\textsubscript{2} was less than 1. However, at a distance from the plant of about 2 to 3 miles, the number of people that could be affected increased to 3 to 7 people. For the rupture scenario, the largest expected number of people potentially affected was from H\textsubscript{2}S, when about 31 people could experience adverse effects along about 0.2 miles of the pipeline (2 percent of the route), as shown in Figure 4-11. The expected number of
people potentially affected was between 10 and 30 for about 13 percent of the pipeline route. For the puncture scenario, the largest expected number of people potentially affected was from CO$_2$, when about 7.6 people could experience severe adverse effects along the same densely-populated section of the pipeline. For all scenarios, the expected number of people potentially affected was less than 1 along at least 60 percent of the route. Standard mitigation measures are available to protect the public in the populated section of the route by increasing the check valve spacing to 1 mile instead of 5 miles, which decreases the volume of gas that would be released in an incident, burying the pipe to more than 3 ft, and using an extra protective layer around the pipe. This example shows that population density is an important factor in selecting routes.

Table 4-10. Expected Number of People Affected by Example Pipeline Due to CO$_2$

<table>
<thead>
<tr>
<th>Release Type</th>
<th>Exposure Duration</th>
<th>Criteria, ppm</th>
<th>Number of People Potentially Affected</th>
<th>Length of Pipeline Affected (miles)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rupture</td>
<td>15 minutes</td>
<td>40,000</td>
<td>0-1</td>
<td>10.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1-10</td>
<td>0.7</td>
</tr>
<tr>
<td></td>
<td>15 minutes</td>
<td>30,000</td>
<td>0-1</td>
<td>8.7</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1-10</td>
<td>2.4</td>
</tr>
<tr>
<td>Puncture</td>
<td>8 hours</td>
<td>40,000</td>
<td>0-1</td>
<td>7.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1-10</td>
<td>3.7</td>
</tr>
</tbody>
</table>

Table 4-11. Expected Number of People Affected by Example Pipeline Due to H$_2$S

<table>
<thead>
<tr>
<th>Release Type</th>
<th>Exposure Duration</th>
<th>Criteria, ppm</th>
<th>Number of People Potentially Affected</th>
<th>Length of Pipeline Affected (miles)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rupture</td>
<td>15 minutes</td>
<td>50</td>
<td>0-1</td>
<td>5.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1-10</td>
<td>5.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>10-20</td>
<td>0.5</td>
</tr>
<tr>
<td></td>
<td>15 minutes</td>
<td>27</td>
<td>0-1</td>
<td>6.5</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>1-10</td>
<td>2.9</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>10-20</td>
<td>1.1</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>20-30</td>
<td>0.3</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>&gt;30</td>
<td>0.2</td>
</tr>
<tr>
<td>Puncture</td>
<td>8 hours</td>
<td>37</td>
<td>0-1</td>
<td>11.</td>
</tr>
<tr>
<td></td>
<td>8 hours</td>
<td>17</td>
<td>0-1</td>
<td>11.</td>
</tr>
</tbody>
</table>
Figure 4-10. Expected number of people potentially affected by 30,000 ppm CO$_2$ from rupture along route of example pipeline from plant to injection well

Figure 4-11. Expected number of people potentially affected by 27 ppm H$_2$S from rupture along route of example pipeline from plant to injection well
4.3.6 Summary of Risks Associated with Pipeline Releases

Pipelines are routinely used for long-distance conveyance of natural gas, CO₂ and liquids, such as crude oil, fuel oil, condensate, and gasoline. Previous studies have shown that releases caused by outside forces, corrosion and other pipe failures can be expected during the lifetime of the pipeline (Gale and Davison, 2004). Additionally, there are a number of recently published reports that address the safety of the transport of CO₂ by pipeline (e.g., Newcomer and Apt, 2008; Barrie, et. al., 2008; Eldevik and DNV, 2008; Duncan et al., 2009). The consensus is that knowledge gaps and uncertainties exist that limit the ability to accurately predict the risk of transporting large amounts of CO₂ by pipeline (Koornneef et al., 2008).

However, the 37-year history of CO₂ pipelines in the US has shown that this gas can be transported safely. Guidelines for pipe construction, monitoring, and other safety procedures have been developed under the direction of the Office of Pipeline Safety under the US Department of Transportation. PHMSA has recently set-up a steering committee and technical working groups to develop best practices land use standards for construction of new pipelines and operation of existing pipelines in populated areas (PHMSA, 2007). This manual will update the previous reports on pipeline siting called Transmission Pipelines and Land Use (TRB, 1988 and 2004). Continuing efforts are underway to improve the automated computer monitoring of pipelines (e.g., NTSB, 2005) and methods to reduce failures due to running fractures and corrosion. PHMSA, the states, and the pipeline companies have instituted extensive public education campaigns to explain about pipeline safety, emergency procedures, and how to find out if there is a pipeline in a given area. In 2007, a best practices manual on pipeline safety was published by the Common Ground Alliance (CGA, 2007). The manual has sections on setting-up and implementing a one-call system, referred to as “811”; planning and conducting subsurface work; locating, mapping, and marking underground pipelines; enforcement methods; and public education practices. Examples are included on how to mark pipelines and to report damage to a centralized system maintained by CGA, if damage occurs or is found. Monitoring and mitigation methods applicable to CO₂ pipelines are discussed in Section 3.5 of this report.

The most important factors to consider in evaluating the level of risk associated with pipeline transport of CO₂ are the location of the pipeline corridor, because of the potential to affect a larger number of people from a pipeline release in a populated area, and the concentrations of trace components, such as H₂S and SO₂, that can be highly toxic at even low concentrations.

4.4 Post-Injection Risk Assessment

The objective of a post-injection risk assessment is to predict both human-health and environmental risks once CO₂ and co-contaminant gases have been injected into subsurface formations. However, this analysis is highly constrained by the incomplete characterization of the target formations in Pennsylvania and by the fact that specific candidate storage sites have not yet been identified. For the Pre-injection Risk Assessment (Section 4.3), the lack of site-specific data was surmounted, to some extent,
by utilizing existing data on the expected chemical characteristics of the captured CO₂ and by taking advantage of previous modeling results to identify the primary risks and to conduct an example exposure analysis to quantify the magnitude of potential risks. This course is not feasible for the post-sequestration analysis that is highly dependent on detailed characterization of the subsurface formations that serve as storage sites. As a result, this analysis focuses on describing the primary scenarios for the release of CO₂ from storage formations and using the existing data, to the extent practicable, to qualitatively evaluate potential vulnerabilities associated with CCS in the Commonwealth.

The risk assessment is implemented using the following tools:

- A spreadsheet analysis developed by LBNL (Oldenburg, 2008) that estimates the integrity of the candidate formation to store CO₂, in the absence of wells that might penetrate the formation.

- An analog database that can be used to predict CO₂ releases based on similarities with the candidate storage reservoirs. See Appendix A for details of the database.

- A vulnerability analysis that addresses issues of specific concern to EPA.

A well-failure database that can estimate releases of CO₂, and the probabilities of these releases from wells that penetrate the storage formation and a database that can be used to estimate releases from other sources, such as faults are also included in Appendix A. This information is intended to be used in site-specific risk assessments, but the data to use this information in Pennsylvania is not presently available. For post-injection releases, the primary release mechanisms can be either short-term (catastrophic) or long-term. The term “catastrophic” refers to a large-volume, short-term release that most likely is event triggered (well failure, earthquake, etc.). The term catastrophic refers to the release magnitude, and does not necessarily refer to the consequences of the release, which may not be significant to either human health or the environment. These primary release mechanisms can produce direct exposures, be responsible for secondary releases such as discharge to surface waters, or lead to pressure impacts and land deformation or dilation. The secondary releases can then lead to exposures. The effects of the exposures for both human and ecological receptors are then evaluated and risk estimates are provided.

The time frame of the risk assessment includes the entire pilot and operational periods of CO₂ capture at the plant to plant closure (estimated to be 30 years to 50 years), and a much longer time period for the post-injection part of the risk assessment [i.e., on the order of 1,000 to 5,000 years] in order to address potential issues associated with slow leakage of the injected CO₂.

4.4.1 Release Scenarios

The primary release mechanisms identified in the conceptual site model (Figure 4-1) are described below.
4.4.1.1 Upward Leakage through Cap Rock and Seals

CO₂ can be released by upward migration through the cap rock from the unaltered native state reservoir. These release scenarios assume the flow and transport of CO₂ through the cap rock and integrate the influence of the following system properties and processes:

- The barrier to CO₂ flow provided by both the low permeability and the capillary entry pressure of the primary and secondary seals.

- Leakage through the seals due to flow through pre-existing fracture zones. This considers both the possible juxtaposition of permeable zones above and below the seals due to the fault throw, as well as the potential fracturing and fracture enhanced permeability of the seals in the fault zone (e.g., this is the mechanism for upward migration through seals at Crystal Geyser as proposed by Shipton et al., 2005).

- Leakage through the seals due to a facies change from impermeable to permeable strata within the seal lithologic group.

- The driving force applied by both the pressure and buoyancy of CO₂ in the reservoir. Note that while natural CO₂ reservoirs are often filled slowly without the large pressure increases expected during CO₂ sequestration, there are natural CO₂ reservoirs that are overpressured to levels expected during CO₂ sequestration. For example, the Jackson Dome CO₂ reservoir is overpressured at levels of 0.70 psi per foot and studies of this reservoir indicate that there is no evidence of CO₂ leakage.

- Slow diffusion through the seals. This release scenario is analogous to CO₂ leakage from natural CO₂ reservoirs in the absence of anthropogenic influences.

4.4.1.1.1 Catastrophic Failure and Quick Release

This release scenario evaluates the possibility that an eruptive release occurs from the CO₂ reservoir, where releases occur at very high rates almost instantaneously in an explosive eruption similar in nature to release events in volcanic areas. However, as noted in prior natural analog studies for CO₂ sequestration, and as confirmed by the information presented in the analog database, these types of releases have only occurred in VHM settings. No eruptive events have ever been recorded in sedimentary basins (IEA GHG, 2006a) nor have any been recorded for underground natural gas sites (IEA GHG, 2006b). Theoretical studies of the potential for eruptive releases due to pneumatic eruptions have also recently been studied by LBNL, who concluded that “...currently there is no evidence that eruptive release can be powered solely by mechanical energy of compression” (Pruess, 2006). Given these results from both analog and theoretical studies, it appears highly improbable that an eruptive release could occur in a stable sedimentary basin. If such an event were to be considered in this risk assessment, the frequency of such an event would be vanishingly remote (e.g., probability of less than 10⁻⁶ per 5,000 years).
4.4.1.1.2 Gradual and Slow Release

The release rates for this scenario depend on the dominant mechanisms at each site and are based upon CO$_2$ emission rates from analog sites with similar geologic conditions. Thus, for sedimentary basins, releases are constrained to either no leakage, or leakage rates at values between 0.000144 and 169 µmol/m$^2$-s (see Appendix A). Note that releases for most analog sites are often below the range of normal soil respiration rates for CO$_2$ (i.e., 0.05 to 20 µmol/m$^2$-s), and typically only exceed the range of normal soil respiration rates for CO$_2$ when faults are the dominant release pathway. The probability of this release rate is high, since it is based upon the best estimate of each site’s geologic conditions, and no failure mechanisms are necessary that may have a low probability of occurring.

Hydrogen sulfide migrating upward from the injection zone will encounter formation water and dissolve. Although the solubility of H$_2$S is greater at higher pH values, even at very low pH the solubility is sufficient to significantly limit the upward H$_2$S flux. Furthermore, some of the H$_2$S will be captured by the formation of metallic sulfides (e.g., FeS), elemental sulfur, and in the upper oxic portion of the permeable media, as sulfate.

4.4.1.2 Release through Faults

These release scenarios evaluate possible releases that could occur by migration through fault zones due to induced fracturing and re-activation of existing faults. Thus, these releases consider the flow and transport of CO$_2$ through the primary and secondary seals and integrate the influence of the following system properties and processes:

- Breach of the flow barrier provided by both the low permeability and the capillary entry pressure of the primary and secondary seals.

- Leakage through the seals can then occur due to either the possible juxtaposition of permeable zones above and below the seals due to the fault throw, or the potential fracturing and fracture enhanced permeability of the seals in the fault zone (this is the mechanism for upward migration through seals at Crystal Geyser as proposed by Shipton et al., 2005).

- The driving force applied by both the pressure and buoyancy of CO$_2$ in the reservoir provides the energy for creating and/or activating the faults.

As such, this leakage mechanism is analogous to CO$_2$ leakage from a natural CO$_2$ reservoir where natural processes have created fractures/faults that allow CO$_2$ to leak through the overlying seals and discharge at either the ground surface or into shallow groundwater. Key factors in estimating the potential for and impact of this scenario are the stress-conditions induced in the subsurface by CO$_2$ injection and reservoir pressurization, and the geomechanical properties of the rocks at the site. Leakage rates also integrate the impact of MMV measures that would be employed to detect micro-
seismicity associated with such events and alter the injection strategy to eliminate or minimize the continued creation and movement of fractures/faults.

4.4.1.2.1 Releases through Existing Faults due to Increased Pressure

The potential for release through existing faults due to increased pressure depends upon the presence or absence of faults within the plume footprint, and whether CO\textsubscript{2} injection increases reservoir pressure until it exceeds the dynamic fault-slip limit. The most likely release rate for this scenario depends on the extent of slip occurring on the fault and was estimated from the analog database using known CO\textsubscript{2} emissions from analog sites where faults breach the primary and secondary seals. Thus, sedimentary basin releases are constrained to leakage rates at between about 5 and 169 µmol/m\textsuperscript{2}-s. The probability of this release scenario is considered highly sensitive to site conditions, since it is dependent upon pre-existing stress conditions, the pressure requirements for injection, the nature of the overlying seals, and other attenuation mechanisms. For example,

- At some sites the minimum horizontal stress may be a very large compressive stress due to regional compressive stress; while at others, the minimum horizontal stress may be a very small compressive stress due to regional extensional stresses.

- At some sites the injection pressure may be very large due to low formation injection capacity; while at others, the injection pressure may be very low due to high injection capacity.

- At some sites the sealing formations may be thick and self-healing (such as salts); while at others, the sealing formation may be thin and brittle.

The most likely release duration for this scenario may be on the order of the entire duration of the CO\textsubscript{2} sequestration time period (i.e., 5,000 years). However, this depends on the magnitude of the leak, as high release rates are more likely to be detected and mitigated. Since the time period for emissions to reach the ground surface via faults through the seals is likely to be on the order of a single decade (Birkholzer et al., 2006), release durations could range from a few decades if mitigated to 5,000 years, if not mitigated.

4.4.1.2.2 Induced Faults due to Increased Pressure

The most likely release rate for this scenario depends on the extension of fractures through the cap rock(s), the extent of slip occurring on the fault, and was estimated using the analog database, based upon known CO\textsubscript{2} emissions from analog sites where faults breach the seals in a similar manner. Thus, sedimentary basin releases are constrained to leakage rates at between about 5 and 169 µmol/m\textsuperscript{2}-s, however, these releases are unlikely to be at the surface since fracturing is extremely unlikely to extend to the surface. These releases may then be further attenuated during transport to the surface such that only a fraction is released there, while the remaining fraction may impact geochemical conditions in intermediate depth formations. The probability of this release scenario is highly sensitive to site conditions since it is dependent upon site fracture and stress...
conditions, the pressure requirements for injection, and the nature of the overlying seals. For example,

- At some sites, the minimum fracture pressure may be low relative to operating conditions; while at others, the minimum fracture pressure may be high relative to operating conditions.

- At some sites, the injection pressure may be very high due to low formation injection capacity; while at others the injection pressure may be very small due to high injection capacity.

- At some sites, the sealing formations may be thick and self-healing (such as salts); while at others, the sealing formation may be thin and brittle.

Since the time period for emissions to reach the ground surface via faults through the seals are likely to be only on the order of a single decade (Birkholzer et al., 2006), release periods could range from a few decades if mitigated to 5,000 years if not mitigated.

4.4.1.3 Migration into Non-Target Aquifers

These release scenarios evaluate possible releases that could occur due to migration into non-target aquifers. This includes either upward migration through the cap rock (e.g., due to an unanticipated facies change from impermeable to permeable strata within the seals), or lateral migration out of the target zone (e.g., due to an unanticipated dip or stratigraphic connection within the injection horizon). Thus, these releases evaluate the flow and transport of CO$_2$ and integrate the influence of the following system properties and processes:

- The flow barrier provided by both the primary and secondary seals.

- The limitations on lateral flow imposed by the permeability, dip, and regional gradient in the injection horizon.

- Any leakage through the seals due to a facies change from impermeable to permeable strata within the seal lithologic group.

- The driving force applied by both the pressure and buoyancy of CO$_2$ in the reservoir.

- Slow diffusion through the seals and into deep regional aquifers.

This leakage mechanism is analogous to CO$_2$ leakage from natural CO$_2$ reservoirs in the absence of anthropogenic influence.
4.4.1.3.1 Migration due to Unknown Structural or Stratigraphic Connections

The potential for release due to unknown structural or stratigraphic connections is based upon the stratigraphic and structural setting of the site (e.g., the formation depositional environment), and the amount of uncertainty in the site characteristics due to data gaps that may be present at the site. The most likely release rate for this scenario depends on the types of facies changes that may occur and the flow and transport characteristics of the units, and was estimated using the analog database, based upon known CO$_2$ emissions from analog sites where facies changes provide pathways through the seals and/or laterally into deep regional aquifers. Thus, sedimentary basin releases are constrained to leakage rates between about 2.5 and 5 µmol/m$^2$-s. These releases may then be further attenuated during transport to the surface such that only a fraction is released there, while the remaining fraction may impact geochemical conditions at intermediate depths. The probability of these releases is considered highly sensitive to site conditions and data availability; e.g.:

- At some sites, the depositional environment may suggest excellent lateral and vertical continuity of seals; while at others, the depositional environment may suggest a fair chance of a lateral facies change in the seal or a vertical thinning of the seal formation.

- At some sites, there may be a wealth of data on geologic conditions; while at others, there may be very little data on the geologic conditions.

4.4.1.3.2 Migration due to Lateral Migration from the Target Zone

The potential for release due to lateral migration from the target zone can be estimated based upon the stratigraphic and structural setting of the site (e.g., the regional hydraulic gradient and/or dip), and the amount of uncertainty in the site characteristics due to data gaps that may be present at the site. The most likely release rate for this scenario depends on the types of lateral rate of escape from the target zone as well as the upward migration to shallow exposure points, the presence of spill points that should be avoided and was estimated using the analog database, based upon known CO$_2$ emissions from analog sites where high lateral flow rates provide pathways into deep regional aquifers. Thus, sedimentary basin releases are constrained to leakage rates between about 2.5 and 5 µmol/m$^2$-s. These releases may then be further attenuated during transport to the surface such that only a fraction is released there, while the remaining fraction may impact geochemical conditions at intermediate depths. The probability of this release rate is considered highly sensitive to site conditions and data availability; e.g.:

- At some sites, the formation dip may be flat and there may be a very low regional hydraulic gradient (i.e., suggesting limited lateral migration); while at others, the formation dip may be high and there may be a very high regional hydraulic gradient in the updip direction (i.e., suggesting the potential for lateral migration).

- At some sites, there may be wealth of data on the geologic conditions; while at others, there may be very little data on the geologic conditions.
4.4.1.3.3 Upward Migration through Wells

These release scenarios evaluate possible releases that could occur by upward migration through wellbores. Casing joints can be points that facilitate carbon dioxide movement outside or inside wellbores. Thus, these release scenarios evaluate the flow and transport of CO$_2$ through well conduits and integrate the influence of the following system properties and processes:

- Leakage via poorly constructed wells, improperly abandoned wells, and undocumented wells.

- The potential for leakage directly at the surface as well as flow behind the casing into intermediate and shallow depth formations which may also eventually release gas to the surface.

- Leakage is evaluated for releases directly from deep wells in the target sequestration reservoir. Leakage may also occur through intermediate and shallow depth wells via releases from the target sequestration reservoir that have migrated into intermediate and shallow depth horizons. However, releases from intermediate and shallow depth wells would be at lower frequencies and rates per well than leakage from deep wells.

This release mechanism is analogous to the leakage reported from natural gas industry experience, oil and gas industry experience, and experiences in natural CO$_2$ reservoirs. Thus, the data presented in the analog site and well failure databases could be used to define the relative frequency, duration, and magnitude of well releases at each site.

4.4.1.3.4 Poorly Constructed and Abandoned Deep Wells

The potential for release due to poorly constructed wells can be estimated based upon the number of wells present at the site and the probability of release due to well failure. This category is meant to cover all of the wells drilled through the primary seal and within the plume footprint. Two types of releases are possible, high rate releases that are assumed to be detected and mitigated (thus, active for only short time periods), and low rate releases that are not assumed to be detected and remain unmitigated (thus, potentially active for long time periods). The most likely release rate for poorly completed wells is based upon the number of wells present and the failure frequencies.

The most likely release duration for this scenario may be on the order of the entire duration of the CO$_2$ sequestration time period (i.e., 5,000 years) for slow leaks, but is likely to be limited to between 0.5 and 5 days for high rate releases based upon industry experience with well failures and mitigation. In some cases high release rates could be maintained longer than fire clays, depending on the difficulty to remediate the well.
4.4.1.3.5 Poorly Constructed and Abandoned Shallow Wells

The potential for release due to poorly abandoned wells is treated in the same manner as poorly constructed and abandoned deep wells. This category is meant to cover all the other wells whose maximum depth is above the base of the primary seal and within the plume footprint.

4.4.1.3.6 Undocumented Wells

The potential for release due to poorly abandoned wells is treated in the same manner as poorly constructed and abandoned deep wells.

4.4.2 Exposure Analysis

The existing data are used below to qualitatively evaluate potential vulnerabilities associated with potential storage sites in the Commonwealth.

4.4.2.1 Spreadsheet Analysis of Screening and Ranking Framework (Oldenburg, 2008)

The screening and ranking framework was developed to evaluate three basic characteristics of a geological storage site:

1. Potential of target formation to maintain long-term containment of CO₂.
2. Potential for secondary containment if the primary target site leaks.
3. Potential of the site to attenuate or disperse leaking CO₂ if the primary formation leaks and secondary containment fails.

An example of site performance in Oriskany Sandstone for a typical well in the Leidy gas field (Harper, 1990) is utilized in these screening-level analysis (see Figure 4-12). The information used from that figure are the formation-type sequences and associated depths. That information is highlighted in green in the figures. The depth below the surface in feet of each formation type and thickness is shown. In the density and porosity log, the Oriskany Sandstone (permeable zone) is shown to be located about 6800 ft below the surface. Directly above it is the Needmore Shale which acts as a primary seal, and directly above that is the Marcellus Shale Formation, which acts as a secondary seal.

Using available data, the site results are shown in Figure 4-13. The three attributes (primary containment, secondary containment, and attenuation potential) are all shown. Note that the primary containment is predicted to be good, while secondary containment and attenuation factors are fair, with relatively high uncertainties.

One of the limitations of this tool (as well as other screening level tools) is their limited ability to account for wells that may penetrate the storage site, or to reasonably account for faults. Figure 4-14 shows that in the Oriskany Sandstone wells are prevalent throughout the formation, and faults are prevalent over about 50% of the formation. These factors must be carefully considered when selecting candidate storage sites.
Figure 4-12. Geophysical log suite of the Oriskany Sandstone and associated rocks from a typical well in Leidy gas field, north-central Pennsylvania (from Harper, 1990).
Figure 4-13. HSE screening application to Oriskany Sandstone as storage reservoirs
Figure 4-14. Oriskany fault and well locations (Data from PA DCNR GIS database)
4.4.2.2 Analog Database Analysis

The analog database is described in detail in Appendix A, and is based on use of natural analogs (e.g., existing CO₂ injection sites throughout the world) where CO₂ leakage has been estimated. Using the appropriate data, the leakage rate of the target reservoir is estimated. The analog database also includes releases from different well types, such as abandoned or injection wells. A simplified analysis is shown here based on the Oriskany Sandstone as a possible injection reservoir. The analysis is limited by both data, and the fact that candidate injection sites have not yet been selected.

The analog database is used to estimate carbon dioxide leakage rates from a reservoir such as the Oriskany Sandstone (Figure 4-12) based on the sites in Figure 4-15. Note that the emissions from the sites have been sorted from low to high. Importantly, it turns out that all of the sedimentary basins fall at the lower end of emissions, while all the volcanic/hydrothermal/metamorphic settings (VHM) are at the upper end. Also shown on the plot is the typical range of soil respiration rates from the ground surface (approximately 0.1 to 20 µmol/m²-s). Note that the background CO₂ flux rates are as high as or exceed those for the sedimentary basins.

CO₂ fluxes from both natural and EOR sites in sedimentary basins range as follows:

- Fluxes were measured that are essentially zero at three sites (i.e., Vorderrhon, Germany; Farnham Dome, UT, USA; and Springerville-St. Johns, AZ-NM, USA). Note that in addition, there are several other sedimentary sites (e.g., Jackson Dome, MS and Sleipner, Norway) where it is strongly believed that there are no CO₂ emissions from the CO₂ reservoirs, but there are no flux monitoring data to support that assumption.

- Fluxes were measured at 0.01 to 1 µmol/m²-s at four sites (i.e., Rangely CO₂ EOR Project, CO, USA; Teapot Dome, WY, USA; Mesozoic carbonate, Central Italy; and Otway (Penola), Australia).

- Fluxes were measured at up to 1 to 10 µmol/m²-s at four sites (i.e., Weyburn, CO₂ Project, Canada; In Salah, CO₂ Project, Algeria; Otway (Pine Lodge, Permeable Zone), Australia; and Otway (Pine Lodge, Fault), Australia).

- Fluxes were measured at 5 to 170 µmol/m²-s at one site (i.e., Crystal Geyser-Ten Mile Graben (Fault Zone), UT, USA).

Thus, flux rates of CO₂ from the sedimentary CO₂ storage reservoirs are extremely low. At most locations that release CO₂, the rates are well below typical soil respiration rates. The only sedimentary basin reservoir where CO₂ fluxes significantly exceed typical soil respiration rates is associated with discharge from a fault zone (i.e., Crystal Geyser). Note also that despite the impacts of wells and injection pressures, the fluxes at CO₂ injection sites (Rangely, Weyburn, and In Salah) are still below typical respiration rates.
Figure 4-15. CO₂ emission rates for 28 analog sites (DOE, 2007a).

* These locations reported flux values of 0 µmol/m²/s
** These locations reported maximum flux values only
Table 4-12 shows release rates from two natural CO₂ sites with sandstone lithology and CO₂ storage zones slightly less than that of the Oriskany formation. Gradual leakage rates from these sites are low (within the natural background values), and suggest that leakage from the Oriskany sites would be comparable.

**Table 4-12. Comparison of CO₂ Release Rates from Sites**

<table>
<thead>
<tr>
<th>Category</th>
<th>Oriskany</th>
<th>Farnham Dome, UT</th>
<th>Teapot Dome, CO</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ zone depth, m</td>
<td>2,000</td>
<td>900</td>
<td>1,600</td>
</tr>
<tr>
<td>CO₂ zone lithology</td>
<td>Oriskany Sandstone</td>
<td>Jurassic Navajo Sandstone</td>
<td>Pennsylvanian Sandstone</td>
</tr>
<tr>
<td>CO₂ zone thickness, m</td>
<td>10-20</td>
<td>12-100</td>
<td>Unknown</td>
</tr>
<tr>
<td>CO₂ zone porosity</td>
<td>0.05</td>
<td>0.12</td>
<td>Unknown</td>
</tr>
<tr>
<td>CO₂ zone permeability, md</td>
<td>2.2</td>
<td>&gt;100(?)</td>
<td>Unknown</td>
</tr>
<tr>
<td>Gradual leakage flux, µmole/m²-s</td>
<td>Likely to be Background (0.1 to 10)</td>
<td>0&lt;sup&gt;a&lt;/sup&gt;</td>
<td>0.00482 to 0.1688</td>
</tr>
</tbody>
</table>

<sup>a</sup> Reported values

Table 4-13 summarizes results of the post-sequestration risk assessment in qualitative terms. Specific risks to human health and the environment can not at this time be estimated until specific storage formations and their locations are selected.

The general conclusions of this qualitative risk assessment are presented in the following notes that are referenced in the conclusions column in Table 4-13:

1. This type of release has been documented to occur only at VHM settings, and not in sedimentary formations of the type investigated here. Risks from this type of release are negligible.

2. Leakage rates for sedimentary basins are expected to be near natural soil respiration levels (0.1 to 10 µmole/m²-s) and not to cause risks.

3. Upward leakage through the injection wells has been documented to occur at other sites, but at low probabilities. If many injection wells are needed per site the probability of at least one failure could become unacceptably high, and potential risks could result.

4. Many deep oil and gas wells that could penetrate the storage formation exist in much of western and northern Pennsylvania. The potential therefore exists that CO₂ leakage from these wells could occur, proportionally increasing as the number of wells increases. This could provide a risk pathway.
5. Due to the long history of oil and gas exploration in Pennsylvania (over 150 years) it is likely that large numbers of abandoned wells exist at similar locations to the active oil and gas wells. Without implementing proper abandonment procedures, these wells could provide a leakage pathway to the surface, and a pathway for risks.

6. Faults do exist throughout much of Pennsylvania, particularly in the study area. Releases through faults due to the effects of increasing pressure and depend also on site location, and whether the faults overlap with the CO$_2$ plume.

7. See Note 6. Should such faults be induced, however, they may not reach the surface, and the CO$_2$ release would be attenuated along the pathway.

8. Based on the data in the analog database, leakages are expected to be constrained to be less than 10 $\mu$mol/m$^2$-s, which is near natural soil respiration levels. However this amount of CO$_2$ could potentially leak into non-target aquifers. Site specific data is needed for a more certain evaluation.

9. See Note 8.

10. Radon releases have not been known to intensify at storage sites, where MMV has been used. More discussion is provided in Section 4.4.4.
<table>
<thead>
<tr>
<th>Release Scenario</th>
<th>Exposure Duration</th>
<th>Potential Volume</th>
<th>Initial Release to</th>
<th>Receptors</th>
<th>Conclusions</th>
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</thead>
<tbody>
<tr>
<td>Upward leakage through the cap rock due to catastrophic failure and quick release</td>
<td>Short-term</td>
<td>Variable, could be large</td>
<td>Air</td>
<td>Humans</td>
<td>See Note 1*</td>
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<td></td>
<td></td>
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</tr>
<tr>
<td>Upward leakage through the cap rock due to gradual failure and slow release</td>
<td>Long-term</td>
<td>Small</td>
<td>Air, groundwater</td>
<td>Humans</td>
<td>See Note 2</td>
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<td></td>
<td></td>
<td>Ecological</td>
<td></td>
</tr>
<tr>
<td>Upward leakage through the CO\textsubscript{2} injection well(s)</td>
<td>Short-term and long-term</td>
<td>Variable, could be large</td>
<td>Air, groundwater</td>
<td>Humans</td>
<td>See Note 3</td>
</tr>
<tr>
<td></td>
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<td></td>
<td>Ecological</td>
<td></td>
</tr>
<tr>
<td>Upward leakage through deep oil and gas wells</td>
<td>Short-term and long-term</td>
<td>Variable, could be large</td>
<td>Air, groundwater</td>
<td>Humans</td>
<td>See Note 4</td>
</tr>
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<td></td>
<td></td>
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<td></td>
<td>Ecological</td>
<td></td>
</tr>
<tr>
<td>Upward leakage through undocumented, abandoned, or poorly constructed wells</td>
<td>Short-term and long-term</td>
<td>Variable, could be large</td>
<td>Air, groundwater</td>
<td>Humans</td>
<td>See Note 5</td>
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<td></td>
<td>Ecological</td>
<td></td>
</tr>
<tr>
<td>Release through existing faults due to the effects of increased pressure</td>
<td>Long-term</td>
<td>Variable, could be large</td>
<td>Air, groundwater</td>
<td>Humans</td>
<td>See Note 6</td>
</tr>
<tr>
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<td></td>
<td></td>
<td></td>
<td>Ecological</td>
<td></td>
</tr>
<tr>
<td>Release through induced faults due to the effects of increased pressure</td>
<td>Long-term</td>
<td>Variable, could be large</td>
<td>Air, groundwater</td>
<td>Humans</td>
<td>See Note 7</td>
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<td>Ecological</td>
<td></td>
</tr>
<tr>
<td>Lateral or vertical leakage into non-target aquifers due to lack of geochemical trapping</td>
<td>Long-term</td>
<td>Variable</td>
<td>Groundwater</td>
<td>Humans</td>
<td>See Note 8</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Ecological</td>
<td></td>
</tr>
<tr>
<td>Lateral or vertical leakage into non-target aquifers due to inadequate retention time in the target zone</td>
<td>Long-term</td>
<td>Variable</td>
<td>Groundwater</td>
<td>Humans</td>
<td>See Note 9</td>
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<tr>
<td>Radon release</td>
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<td>Low</td>
<td>Groundwater</td>
<td>Humans</td>
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<td></td>
</tr>
</tbody>
</table>

*The notes that describe the conclusions are presented in the text.*
4.4.3 Vulnerability Analysis for Storage Reservoirs

A vulnerability evaluation framework (VEF) was developed by EPA (2008a) to identify site-specific conditions that could lead to increases or decreases in susceptibility to consequences (i.e. release events and exposure) and to identify key areas where detailed evaluations should be conducted. The VEF is used as the basis for conducting a qualitative evaluation of a series of geologic attributes, potential media impacted, and receptors, as shown in Figure 4-16. Pennsylvania Act 129 requested an evaluation using this framework in addition to other investigations. For example, the Act imposes new requirements on electrical energy distribution companies, with the overall goal of reducing energy consumption and demand. The Act was signed into law in 2008.

This framework considers potential releases of CO$_2$ and effects from the zone of increased pressure. For both the injection zone and confining system, a procedure for detailed evaluations of each of the geologic attributes (e.g. faults/fracture zones) was developed to determine whether a given attribute represents low or high vulnerability for a given site. Some of the evaluations such as for the confining system require information...
on formation properties (e.g. permeability and capillary entry pressure of cap rock). Because specific sites have not yet been selected in Pennsylvania, detailed subsurface information is not available for the complete decision tree framework. Instead each of the confining system and injection zone attributes are discussed and data gaps identified. General information on potential receptors and use of surface and groundwater for public water supplies is presented.

The confining system evaluation (geologic attributes in Figure 4-16) uses information on the cap rock, existence of faults and fracture zones, tectonic activity, and susceptibility to geochemical or geomechanical changes that could result in leakage through the confining system. Information was compiled by DCNR for four primary target formations that may be suitable for sequestration in the Commonwealth, discussed in Section 2 of this report. While the type of confining system, thickness, and depth are generally known for each of the four formations, the specific properties needed for the VEF evaluation were not available. The cap rocks for the four potential injection zones are mostly shale but chert or limestone are present in some areas, as discussed in Section 2.3.3. Thick, unfractured shale would provide the best type of cap rock. Limestone is susceptible to dissolution if carbonic acid is formed as the CO$_2$ mixes into the formation fluids, typically brines. The properties required to evaluate potential pressure effects are lateral extent of the cap rock directly over the target injection zone, capillary entry pressure, and permeability.

The existence of faults in the deeper formations in the southern part of Pennsylvania is shown schematically in Figure 2-3. Detailed fault maps that cut the target formation were shown previously for the Oriskany sandstone (Figure 4-14) and are also available for the Medina Group formations. Faults are less of a concern with respect to the Salina salt beds, as the salt can self-seal. Detailed fault maps for the Upper Devonian formations were not available.

For several of the vulnerability factors, such as wells, sufficient data are available for more detailed analysis and are provided. Due to the long history of oil and gas production in Pennsylvania, there are numerous deep wells in the western part of the Commonwealth. The numbers of oil and gas wells that exceed 2500 ft, the minimum depth that is recommended for geologic sequestration, are shown in Table 4-14 by county, and the total numbers of wells are shown in Figure 4-17. In many counties, the total number of oil and gas wells number in the thousands, and many of those exceed 2500 ft in depth at densities of up to 20-50 wells/mi$^2$. For example, in Indiana County, over 11,000 wells exceed 2500 ft in depth. Thus, there is an elevated vulnerability to leakage in the western part of the Commonwealth due to deep wells that may penetrate the proposed storage reservoirs or cap rocks.
<table>
<thead>
<tr>
<th>County</th>
<th>Total Number of Oil &amp; Gas Wells</th>
<th>Number of Oil &amp; Gas Wells &lt; 2500 ft</th>
<th>Number of Oil &amp; Gas Wells ≥ 2500 ft</th>
<th>Minimum depth (ft)</th>
<th>Maximum depth (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adams</td>
<td>0</td>
<td>no oil and gas wells found</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Allegheny</td>
<td>1,641</td>
<td>611</td>
<td>847</td>
<td>340</td>
<td>7,312</td>
</tr>
<tr>
<td>Armstrong</td>
<td>8,371</td>
<td>550</td>
<td>7,524</td>
<td>131</td>
<td>15,574</td>
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<tr>
<td>Beaver</td>
<td>202</td>
<td>168</td>
<td>5</td>
<td>110</td>
<td>6,666</td>
</tr>
<tr>
<td>Bedford</td>
<td>19</td>
<td>0</td>
<td>19</td>
<td>4,712</td>
<td>7,986</td>
</tr>
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<td>Berks</td>
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<td>no oil and gas wells found</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Blair</td>
<td>2</td>
<td>0</td>
<td>2</td>
<td>3,517</td>
<td>6,864</td>
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<td>Bradford</td>
<td>64</td>
<td>5</td>
<td>59</td>
<td>948</td>
<td>14,125</td>
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<tr>
<td>Bucks</td>
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<td>Butler</td>
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<td>1,247</td>
<td>388</td>
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<td>Cambria</td>
<td>528</td>
<td>15</td>
<td>513</td>
<td>579</td>
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<td>Cameron</td>
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<td>5</td>
<td>89</td>
<td>1,250</td>
<td>9,790</td>
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<td>Carbon</td>
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<td>no oil and gas wells found</td>
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<tr>
<td>Centre</td>
<td>730</td>
<td>22</td>
<td>708</td>
<td>2,036</td>
<td>11,462</td>
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<td>Chester</td>
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<td></td>
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<tr>
<td>Clarion</td>
<td>3,836</td>
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<td>Clearfield</td>
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<td>23</td>
<td>4,255</td>
<td>1,042</td>
<td>13,351</td>
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<td>Columbia</td>
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<td></td>
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<tr>
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<td>744</td>
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<td>935</td>
<td>2,581</td>
<td>35</td>
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<td>251</td>
<td>2,801</td>
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<td>1</td>
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<td>Fulton</td>
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<td>Greene</td>
<td>2,387</td>
<td>398</td>
<td>1,704</td>
<td>52</td>
<td>76,414</td>
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<td>Huntington</td>
<td>3</td>
<td>0</td>
<td>3</td>
<td>5,579</td>
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</tr>
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<td>Indiana</td>
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<td>284</td>
<td>11,208</td>
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<td>Juniata</td>
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<tr>
<td>Luzerne</td>
<td>0</td>
<td>no oil and gas wells found</td>
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<tr>
<td>Wyoming</td>
<td>1</td>
<td>1</td>
<td>26</td>
<td>2,311</td>
<td>13,300</td>
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<td>McKean</td>
<td>19,752</td>
<td>14,066</td>
<td>581</td>
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<td>11,175</td>
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<td>395</td>
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<td>Mifflin</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Potter</td>
<td>1,127</td>
<td>889</td>
<td>118</td>
<td>2</td>
<td>9,880</td>
</tr>
<tr>
<td>Schuylkill</td>
<td>0</td>
<td>no oil and gas wells found</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Snyder</td>
<td>0</td>
<td>no oil and gas wells found</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Somerset</td>
<td>122</td>
<td>0</td>
<td>122</td>
<td>2,555</td>
<td>9,662</td>
</tr>
<tr>
<td>Sullivan</td>
<td>0</td>
<td>no oil and gas wells found</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Susquehanna</td>
<td>40</td>
<td>0</td>
<td>40</td>
<td>8,262</td>
<td>10,500</td>
</tr>
<tr>
<td>Tioga</td>
<td>121</td>
<td>35</td>
<td>55</td>
<td>666</td>
<td>13,508</td>
</tr>
<tr>
<td>Union</td>
<td>0</td>
<td>no oil and gas wells found</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Venango</td>
<td>14,950</td>
<td>11,113</td>
<td>1,435</td>
<td>10</td>
<td>10,815</td>
</tr>
<tr>
<td>Warren</td>
<td>12,607</td>
<td>9,805</td>
<td>1,308</td>
<td>80</td>
<td>10,030</td>
</tr>
<tr>
<td>Washington</td>
<td>4,731</td>
<td>1,109</td>
<td>2,629</td>
<td>557</td>
<td>12,191</td>
</tr>
<tr>
<td>Wayne</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>8,351</td>
<td>8,351</td>
</tr>
<tr>
<td>Westmoreland</td>
<td>5,537</td>
<td>416</td>
<td>5,053</td>
<td>441</td>
<td>8,868</td>
</tr>
<tr>
<td>Wyoming</td>
<td>4</td>
<td>4</td>
<td>0</td>
<td>1,395</td>
<td>1,721</td>
</tr>
</tbody>
</table>

The attributes used in the evaluation of the injection zone are shown in the bottom half of the geologic attributes column in Figure 4-16). Information on the potential injection
zones in the state is discussed in Section 2.3. More detailed information on storage capacity estimates are available based on modeling for two formations (ARI, 2009). The injection of CO\textsubscript{2} into two different reservoir types was modeled: the Oriskany Reservoir in the Punxsutawney-Driftwood Field in Elk and Cameron Counties, and the Medina Reservoir in Conneaut Field in Erie and Crawford Counties. A summary of their results is shown in Table 4-15. The modeling indicated the predicted superiority of horizontal injection wells over vertical injection wells in terms of higher injection rates (by about four times). They also extrapolated to 30 years, and predicted that 64 horizontal wells (or 250 vertical wells) in the Oriskany Reservoir could inject 10 Mt-CO\textsubscript{2} in 30 years.

Relative to the amount of CO\textsubscript{2} that needs to be injected per year from large point sources (over 100 Mt-CO\textsubscript{2}/yr), 10 Mt-CO\textsubscript{2} in 30 years is a small number (0.3%). Extrapolating the number of wells based on the results from the Oriskany Reservoir, 22,270 horizontal wells each injecting at 10 Mt-CO\textsubscript{2} in 30 years would be needed. Alternatively higher injection rates per well would be desirable, if such rates can be sustained. The modeling results showed that the storage capacity of the Medina formation, where evaluated in northwestern Pennsylvania, was limited. While extrapolations for the Medina Reservoir simulations were not made, an even higher number of injection wells would be needed for the same total volume injected. Erie County has numerous deep oil and gas wells, which could interfere with site selection.

Injection capacity of salt caverns is estimated based on the planned design of the cavern Preliminary estimates of storage capacity in the salt beds were available for a hypothetical cavern in the Salina Group. An example constructed salt cavern is shown in Figure 4-18. This cavern is estimated to be about 700,000 m\textsuperscript{3} in volume and could contain (when full of supercritical CO\textsubscript{2}) about 0.5 Mt-CO\textsubscript{2}. For a power plant operating for 30 years and injecting 2 Mt-CO\textsubscript{2}/yr, approximately 120 such caverns would be required, as each cavern would fill in about three months. This is a large number of caverns, and there are potential concerns with long-term stability of caverns, as discussed in Section 2.4.2. To obtain additional information on the construction, size, and stability of salt caverns, Mr. Doug Ruse (personal communication October 21, 2009), a principal with Cavern Engineering, and with 40 years of experience in the construction of salt caverns, was contacted. He generally confirmed that the size of the constructed caverns (for NG storage) are typically within the size range described here, and that stability and cavern size are closely related. He confirmed that large amounts of brine are generated that need to be disposed (often into deep injection wells, if available). The time required to construct caverns of this size is about a year, which is a relatively long period of time compared to how quickly they may fill with injected supercritical carbon dioxide.

Detailed information is needed for all four formations on injectivity and to refine the estimates of storage capacity, which are both used in the VEF evaluation for the injection zone. Pressure effects are also considered in the VEF (See middle column in Figure 4-16.) Additional information is also needed to evaluate the possible effects of the pressure front, which could contribute to leakage of brines or CO\textsubscript{2} into shallower formations or USDWs.
Table 4-15. Summary of ARI Modeling Analysis for Assessment of CO$_2$ Storage Site options in Western Pennsylvania

<table>
<thead>
<tr>
<th>Selected Geological Formations</th>
<th>Oriskany Reservoir in Punxsutawney-Driftwood Field; Elk &amp; Cameron Co.</th>
<th>Medina Reservoir in Conneaut Field, Erie &amp; Crawford Co.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CO$_2$ injection volumes</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vertical Wells</td>
<td>1.2 Mt-CO$_2$/well/30yr</td>
<td>0.04 Mt-CO$_2$/well/30yr</td>
</tr>
<tr>
<td>Horizontal Wells</td>
<td>4.7 Mt-CO$_2$/well/30yr</td>
<td>1.0 Mt-CO$_2$/well/30yr</td>
</tr>
<tr>
<td><strong>CO$_2$ plume size and shape</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vertical wells</td>
<td>7200’ after 30yr (2.7 mi$^2$)</td>
<td>-</td>
</tr>
<tr>
<td>Horizontal wells</td>
<td>14,400’ after 30yr (5.5 mi$^2$)</td>
<td>7,200’-9,600’ after 30yr (2.7 mi$^2$ - 3.6 mi$^2$)</td>
</tr>
<tr>
<td><strong>Properties</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td># Wells</td>
<td>~334</td>
<td>~1150</td>
</tr>
<tr>
<td>Field Size</td>
<td>27,700 AC</td>
<td>128,050 AC</td>
</tr>
<tr>
<td>Reservoir depth</td>
<td>6,540’</td>
<td>2,740’</td>
</tr>
<tr>
<td>Reservoir pressure</td>
<td>3,925 psi</td>
<td>250 psi</td>
</tr>
<tr>
<td>Injection pressure</td>
<td>4,000 psi</td>
<td>1,300 psi</td>
</tr>
<tr>
<td>Pay thickness</td>
<td>8’-10’</td>
<td>12’</td>
</tr>
<tr>
<td>Permeability</td>
<td>&lt;0.1-15 mD</td>
<td>&lt;0.1 to 0.3 mD</td>
</tr>
<tr>
<td>Porosity</td>
<td>5%</td>
<td>4%</td>
</tr>
<tr>
<td>Temperature</td>
<td>161°F</td>
<td>150°F</td>
</tr>
<tr>
<td><strong>Store 10 MT-CO$_2$ in 30yr</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td># horizontal wells</td>
<td>64</td>
<td>-</td>
</tr>
<tr>
<td>CO$_2$ plume size</td>
<td>350-400 mi</td>
<td>-</td>
</tr>
<tr>
<td># vertical wells</td>
<td>250</td>
<td>-</td>
</tr>
<tr>
<td><strong>Extrapolation: Store 116 Mt-CO$_2$/yr</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal wells</td>
<td>22,270</td>
<td>-</td>
</tr>
<tr>
<td>Vertical wells</td>
<td>87,000</td>
<td>-</td>
</tr>
</tbody>
</table>
Figure 4-17. Oil and gas wells deeper than 2500 ft. by county. Counties with no wells greater than 2500 ft. are colored yellow (Data from Well Information System (2009)).

Figure 4-18. The design configuration of a leached cavity planned by NE Hub partners, LP for storage of natural gas in Tioga County, Pennsylvania (from Ne Hub partners, L.P., 1996)
The VEF evaluation considers non-formation factors such as high population density (See impact categories in third column in Figure 4-16) over a site’s footprint (which may present health risks should leakage occur). Figure 4-19 shows the population density across the Commonwealth. Two major population centers presently exist: around the Philadelphia area to the east, and around Pittsburg to the west. As mentioned previously much of the eastern third of the Commonwealth has not yet been characterized for potential geological sequestration formations. In the western part of the Commonwealth, evaluation of storage sites must be done in consideration of the proximity of sites with high populations.

The effect of potential releases on drinking water sources is an important impact category in the VEF evaluation. Pennsylvania has more than one million private wells that supply water to more than three million rural residents. Each year more than 20,000 new wells are drilled. In addition, groundwater supplies base flow for more than 83,000 miles of streams and rivers. When considering those additional people who use groundwater part of the time, over 50% of the population uses groundwater directly. In contrast to rural residents, sources of water supplies for cities are primarily from surface water (Table 4-16).

Figure 4-19. Population density in Pennsylvania (Modified from PA DCNR GIS Database with US census data for year 2000).
Table 4-16. Drinking Water Information for the Ten Largest Cities in Pennsylvania

<table>
<thead>
<tr>
<th>City</th>
<th>Population</th>
<th>Drinking Water Source</th>
<th>Supply Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Philadelphia</td>
<td>1,517,550</td>
<td>Surface Water</td>
<td>Delaware River and Schuykill River</td>
</tr>
<tr>
<td>Pittsburgh</td>
<td>334,563</td>
<td>Surface Water</td>
<td>Monongahela River, Becks Run, and Aldrich intakes</td>
</tr>
<tr>
<td>Allentown</td>
<td>106,632</td>
<td>Surface Water and Groundwater (springs)</td>
<td>Little Lehigh Creek, Lehigh River, Schantz Spring, and Crystal Spring</td>
</tr>
<tr>
<td>Erie</td>
<td>103,717</td>
<td>Surface Water</td>
<td>Lake Erie</td>
</tr>
<tr>
<td>Reading</td>
<td>81,207</td>
<td>Surface Water</td>
<td>Lake Ontelaune</td>
</tr>
<tr>
<td>Scranton</td>
<td>76,415</td>
<td>Surface Water</td>
<td>Williams Bridge, Lake Scranton, Elmhurst, Dunmore #1, Dunmore #3, Dunmore #4, Dunmore #7, and Marshbrook Reservoirs</td>
</tr>
<tr>
<td>Bethlehem</td>
<td>71,329</td>
<td>Surface Water</td>
<td>Reservoirs in the Pocono Mountains</td>
</tr>
<tr>
<td>Lancaster</td>
<td>56,348</td>
<td>Surface Water</td>
<td>Susquehanna River and Conestoga River</td>
</tr>
<tr>
<td>Levittown</td>
<td>53,966</td>
<td>Surface Water and Groundwater (wells)</td>
<td>Delaware River and Groundwater (from 5 wells)</td>
</tr>
<tr>
<td>Altoona</td>
<td>49,523</td>
<td>Surface Water</td>
<td>12 Storage Reservoirs in the Juniata Watershed</td>
</tr>
</tbody>
</table>

Figure 4-20 shows the four major groundwater aquifers in Pennsylvania, along with well characteristics. The entire Commonwealth is underlain by one of the four aquifer types, with the most productive formation consisting of unconsolidated sand and gravel, which is located throughout much of the northern half of the Commonwealth. The most widespread aquifer is composed of sand and fractured shale, while the least productive are located in the southeastern part of the Commonwealth and are bedrock aquifers such as fractured schist and gneisses. The wells typically range from 20 ft to 250 ft, but may be as deep as 500 ft. These wells are much less than the depths to potential sequestration targets, which will be at least 2,500 ft deep, and in some cases up to 8,000 ft deep. The primary concern with respect to USDWs is to be sure that nearby faults, fracture zones, or abandoned oil and gas wells do not provide a potential conduit up from the injection zone to the groundwater. Proper siting and design of the injection well and equipment is also necessary to prevent damage to the cement or casing over time including the closure and post-closure period.

The preliminary VEF evaluation indicates that there are suitable sequestration formations in the western and northern parts of the Commonwealth. Detailed characterization to enable site selection to be accomplished is the next step, followed by a detailed VEF evaluation and risk assessments. In the eastern part of the Commonwealth, more geologic mapping, seismic investigations, and drilling of several deep wells at favorable locations is the next step.
For the most part, it was difficult to distinguish vulnerability factors between storage groups. The four formations evaluated (Medina Group, Salina Group, Oriskany Sandstone, and Upper Devonian) are located at least partly in the western part of the Commonwealth where numerous oil and gas wells are present. Thus, the presence of
deep wells and the potential for abandoned wells increases the potential leakage for all the formations. With respect to present seismic activity it is low for the entire state. Faults into the injection formation are present and therefore induced faulting could occur in the Media and Oriskany, if the injection rate used was too high for the formation. Ground dilation due to subsidence of a salt cavern is possible for the Salina Group, but less likely for the other formations, since there are thick sequences of rock over the potential injection zones. Because of the depth of the potential injection zones of greater than 2,500 ft and the shallow water supply wells, the potential impacts to USDWs may be small, but need to be evaluated since there is high uncertainty due to faults and deep wells. Impacts to surface water from the plant and surface operations are more likely than leakage from a deep injection zone. Radon is a potential human health impact, which does vary in the western part of the state, as discussed in Section 4.4.4.

Table 4-18 summarizes the analysis using the main attributes included in the VEF based on the information available. The analysis was conducted for the four potential injection formations, and includes the following categories:

- Faults and fracture zones,
- Other tectonic activity,
- Wells,
- Potable groundwater,
- Radon,
- Surface water, and
- Human health and environmental impacts.

For the most part, it was difficult to distinguish vulnerability factors between storage groups. The four formations evaluated (Medina Group, Salina Group, Oriskany Sandstone, and Upper Devonian) are located at least partly in the western part of the Commonwealth where numerous oil and gas wells are present. Thus, the presence of deep wells and the potential for abandoned wells increases the potential leakage for all the formations. With respect to present seismic activity it is low for the entire state. Faults into the injection formation are present and therefore induced faulting could occur in the Media and Oriskany, if the injection rate used was too high for the formation. Ground dilation due to subsidence of a salt cavern is possible for the Salina Group, but less likely for the other formations, since there are thick sequences of rock over the potential injection zones. Because of the depth of the potential injection zones of greater than 2,500 ft and the shallow water supply wells, the potential impacts to USDWs is considered small, but there is high uncertainty. Impacts to surface water from the plant and surface operations are more likely than leakage from a deep injection zone. Radon is a potential human health impact, which does vary in the western part of the state, as discussed in Section 4.4.4.
Table 4-17. Vulnerability Factors by CO₂ Storage Formation

<table>
<thead>
<tr>
<th>Category</th>
<th>Medina Group</th>
<th>Salina Group</th>
<th>Oriskany Sandstone</th>
<th>Upper Devonian</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Faults and Fracture Zones</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Earthquakes (last one 1.3 magnitude at 1 km located 15 miles SSW of Harrisburg)</td>
<td>not since 1990</td>
<td>not since 1990</td>
<td>unknown</td>
<td>not since 1990</td>
</tr>
<tr>
<td>Induced Faulting/Seismicity</td>
<td>possible in NW</td>
<td>low seismicity</td>
<td>possible in NW</td>
<td>low seismicity</td>
</tr>
<tr>
<td>Ground Dilation</td>
<td>possible</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Other Tectonic Activity</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deep faults present</td>
<td>few deep faults</td>
<td>none identified</td>
<td>faults in SW &amp; Central to North Central part</td>
<td>none identified</td>
</tr>
<tr>
<td>Geothermal activity</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td><strong>Wells</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil and Gas Wells</td>
<td>High¹</td>
<td>High¹</td>
<td>many in NW and central SW-N swath, High¹</td>
<td>High¹</td>
</tr>
<tr>
<td>Abandoned or Unknown Wells</td>
<td>Unknown²</td>
<td>wells in SW, Unknown²</td>
<td>Unknown²</td>
<td>Unknown²</td>
</tr>
<tr>
<td>Deep Water Supply Wells</td>
<td>Low³</td>
<td>Low³</td>
<td>Low³</td>
<td>Low³</td>
</tr>
<tr>
<td><strong>Potable Groundwater</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Migration to USDW</td>
<td>Unknown⁴</td>
<td>Unknown⁴</td>
<td>Unknown⁴</td>
<td>Unknown⁴</td>
</tr>
<tr>
<td>Displacement of Brine into USDW</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Radon</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td><strong>Surface Water</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Migration into SW</td>
<td>Unknown⁷</td>
<td>Unknown⁷</td>
<td>Unknown⁷</td>
<td>Unknown⁷</td>
</tr>
<tr>
<td>Leakage into SW</td>
<td>Unknown⁸</td>
<td>Unknown⁸</td>
<td>Unknown⁸</td>
<td>Unknown⁸</td>
</tr>
<tr>
<td><strong>Changes to Human Health and Environment Due to Above Categories</strong></td>
<td>Possible human health and environmental impacts</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

¹ Oil and gas wells at depths of greater than 2500’ are plentiful, and may offer conduits for leakage to the surface.
² Little is known about abandoned wells. However, due to the large number of oil and gas wells that have been drilled, the possibility exists that abandoned wells offer conduits for leakage to the surface.
³ Due to aquifer depths that are limited to approximately 300’, deep water supply wells are likely to be more than 2000’ above CO₂ storage locations.
⁴ The potential storage formations are 2000’ or more below USDWs and vertical migration of CO₂ into those formation does not appear to be probable, although the uncertainty level is high. Also, there is a very high density of wells all over the Commonwealth that need to be considered.
⁵ Because potential storage formations are 2000’ or more below USDWs, brine displacement is unlikely to affect USDWs.
⁶ There is no evidence of enhanced radon migration at the few CCS sites where such studies have been done.
⁷ The probability of direct migration into surface water is uncertain, due to depth of storage formations (>2500’).
⁸ The probability of leaks into surface water is uncertain. However, the Commonwealth has over 80,000 miles of surface water channels, indicating more detailed analysis are needed.

4.4.4 Radon

Radon is naturally present in soils across the United States. Because radon volatilizes and can be transported with soil gas, it can enter homes through their foundations and
potentially cause human health risks. Figure 4-21 (a) shows the nationwide distribution of radon, and Figure 4-21 (b) shows the distribution in PA. The maps are color coded with three colors to represent the three zones:

<table>
<thead>
<tr>
<th>Zone 1 counties</th>
<th>Zone 2 counties</th>
<th>Zone 3 counties</th>
</tr>
</thead>
<tbody>
<tr>
<td>have a predicted average indoor radon screening level greater than 4 pCi/L (pico curies per liter) (red zones)</td>
<td>have a predicted average indoor radon screening level between 2 and 4 pCi/L (orange zones)</td>
<td>have a predicted average indoor radon screening level less than 2 pCi/L (yellow zones)</td>
</tr>
<tr>
<td>Highest Potential</td>
<td>Moderate Potential</td>
<td>Low Potential</td>
</tr>
</tbody>
</table>

(a) EPA Map of Radon Zones Across USA

(b) Pennsylvania distribution of radon in soil by county and by zone. (PA Dept. of Environmental Protection)

Figure 4-21. Radon distribution by county
In PA well over half of the Commonwealth has been designated by EPA as zone 1 (highest potential). Much of northwest and southwest PA are designated as zone 2 (moderate potential).

At present there is little if any evidence that radon mobilization will be enhanced by CCS activities, but very little information is present in the analog database on radon. One exception is the Weyburn site, where radon concentrations were estimated at eleven locations, including background locations. The concentrations at all the locations, including the background location were very similar, indicating that near-surface soil gas associated with carbon sequestration activities did not contain elevated levels of radon. This provides some evidence that elevated concentrations of radon would not be expected. By further populating the Analog Database with more information on radon at storage sites, this analysis can be further examined.

4.4.5 Summary of Post-Injection Risk Assessment

Because the Pennsylvania DCNR has not yet selected candidate geological sites for carbon dioxide storage, the post-injection risk analysis was conducted in a predominantly qualitative manner. This approach was necessary because site specific information needed to perform a quantitative risk assessment was not available.

A summary of the major findings of the post-injection risk assessment is as follows:

1. The spreadsheet approach of Oldenburg (2008) was used to evaluate geological storage formations for their appropriateness for long-term carbon dioxide storage. Only one formation was evaluated in this analysis, and it was the Oriskany Sandstone. The spreadsheet made predictions of the likely integrity of the primary and secondary seals, and the attenuation should the seals fail. While the results showed that the primary seal is likely to have appropriate characteristics needed for storage. The performance of the secondary seal and attenuation mechanisms were more uncertain and less promising.

2. Due to the large numbers (thousands) of oil and gas wells (and possibly as many abandoned wells) that were drilled deeper than 2500’ bgs (the minimum depth for carbon storage sites) over the past 150 years, there is a risk that these wells can act as conduits for carbon dioxide leakage to the surface, assuming the wells intersect carbon dioxide plumes. Such wells need to be properly plugged to minimize potential carbon dioxide leakage.

3. If gradual releases of carbon dioxide occur through the cap rock seals, those releases (from sedimentary storage sites) are likely to be small, and in the range of natural background respiration rates.

4. An analysis of the modeling completed by ARI (2009) indicates that their simulated injection rates are very small compared to the injection rates needed to sequester carbon dioxide at a rate that is a high fraction of that generated by large point sources within the Commonwealth. At the injection rates used, thousands of
injection wells would be required at rates needed to meet Commonwealth-wide sequestration targets. Further, such a large number of injection wells could create risks of carbon dioxide releases from failure of those wells.

5. An analysis of the capacity for salt caverns (created from the salt beds) indicated that the capacity per cavern is likely to be small compared to the amount of carbon dioxide generated by many power plants. Development of these caverns for a single plant could be a continuous process over the lifetime of the plant. Additionally, the environmental impacts could be significant because of the large amounts of fresh water needed, and the disposal of large quantities of brine.

6. One of the important conclusions of the vulnerability analysis is that, since aquifers and drinking water wells exist throughout the entire Commonwealth, and are an important drinking water source for millions of people, the risk exists for potential contamination of a portion of these sources if a release occurs along faults, fracture zones, or improperly sealed wells.

4.5 MMV Strategies/Guidelines

An effective MMV plan is essential to ensure the safety of the individual operating components of the CCS system and to provide an accurate accounting of the stored CO₂. This terminology follows that used by the WRI CCS Guidelines (WRI, 2008) and the DCNR 2009 report on Geologic Sequestration; DOE also uses the term MVA for Monitoring, Verification, and Accounting for the same general concept. Guidelines and descriptions of the individual elements of an effective MMV strategy and proposed monitoring requirements are described in the WRI CCS Guidelines, the Report on MMV Best Practices (DOE, 2009b), DOE, 2008, and the report on Geologic Carbon Sequestration Opportunities in Pennsylvania (DCNR, 2009). Here the goals and objectives of the monitoring of CCS operations, from the site characterization phase and continuing through the closure and post-closure phases are described. Potential mitigation methods to minimize pipeline leaks, injection well leaks, and leaks from the target sequestration formation such as through abandoned or improperly plugged wells are also presented. The state-of-the-art and the efficacy of available methods are reviewed to provide an evaluation of the technological readiness of CCS. The efforts to develop new MMV methods are also identified.

4.5.1 Monitoring Goals and Objectives

Regulatory requirements are an essential motivation for the development of effective monitoring programs. In July 2008, the US EPA (2008b) proposed regulating new CO₂ injection wells for geologic sequestration under the existing UIC Program, authorized under the Safe Drinking Water Act (SDWA). The primary goal is to protect USDWs, defined as a permeable zone containing water with total dissolved solids < 10,000 mg/L. A new well class, Class VI, has been proposed for deep injection wells to saline formations for geologic sequestration. New monitoring requirements have also been proposed to demonstrate well integrity, location and movement of the plume and pressure front, verification of quantity of carbon stored, and to determine if CO₂ has reached
underground sources of drinking water or the ground surface. The proposed rule requires pressure gauges in the first formation overlying the confining zone or the use of indirect geophysical techniques. Well operators would also be required to monitor groundwater quality and geochemical changes above the confining zone.

Pennsylvania Act 129, which defines “carbon dioxide sequestration” as the storage of carbon dioxide in a supercritical phase within a geological subsurface formation such as a deep saline formation with suitable cap rock and leak detection monitoring equipment, requires an assessment of vulnerability factors that could contribute to potential risks to individuals, property, and the environment associated with the geological sequestration of CO₂ in a Commonwealth network. Information on appropriate methods for MMV and mitigation of effects is required, but the required methods have not been prescribed by Commonwealth regulations. Instead, the Act suggests following the CCS Guidelines developed by WRI (2008).

The goals specified by DOE (2008) to account for retention of CO₂ in the subsurface formations to support a future system of CO₂ Emission Credits provides another stimulus for effective monitoring and verification methods. DOE’s goal is to have methods that can demonstrate 95% retention of CO₂ by geologic sequestration by 2008 and 99% retention by 2012. These goals imply the ability to detect CO₂ leakage into the atmosphere of 5% and 1%, respectively.

4.5.2 Monitoring Chronology and Potential Risks

Monitoring requirements and methodologies at specific CCS sites differ during four distinct time periods as depicted in Figure 4-22:

- Pre-operation phase (Baseline characterization of target formation and seals).
- Operation phase (Pipeline, injection wells, target formation, USDWs, surface monitoring).
- Closure phase (Proper plugging of wells, target formation pressure).
- Post-closure phase (Confirm CO₂ is being retained in target formation and no leaks to USDWs or surface).

This figure illustrates how the risk from injection operations change over time, increasing during the operation phase, but then declining after the injection wells are properly plugged. In the post-closure phase, the pressure in the injection formation decreases and the CO₂ is trapped by a variety of mechanisms such as dissolution into brine, precipitation of carbonate minerals, or stratigraphic trapping where it occurs. The risk profile following closure in a salt cavern is quite different, in that if the injection well is plugged and the cavern closed, the pressure will increase over time, as salt creeps into the cavern decreasing its size. The CO₂ in the cavern remains in a dense gas phase, rather than dissolving into a brine like it does in a saline injection zone. Salt can self-heal small fractures, as long as the roof of the cavern remains intact.
The focus of the pre-operation monitoring is to establish baseline conditions in the target injection formation with respect to key properties such as porosity, permeability, thickness, lithology, pressure gradient, any evidence for over or under-pressurization of the reservoir, and seasonal variations in pressure, temperature, or fluid composition. Water sampling over an annual period in the lowermost USDW and a nearby surface water body is also recommended to provide sufficient data for comparison following injection.

Once injection operations begin, there are several different types of monitoring requirements:

- Pipeline monitoring to confirm normal operation and to detect leaks
- Injection equipment monitoring to confirm proper operation of injection well(s)
- Mechanical integrity testing of injection well on annual basis or alternative test
- Pressure monitoring to track changes in subsurface formation as gas is injected
- Tracking of the CO$_2$ migration in the injection zone to confirm that it is being retained in the target formation and to refine subsurface models
- Early warning of CO$_2$ or fluid movement out of the injection zone to USDWs, shallower formations, soil, soil gas, or the atmosphere
- Measuring and verifying amount of CO$_2$ routed in pipeline, injected into well(s), and stored in formation.
During the closure phase monitoring is conducted to confirm the proper plugging and abandonment of the injection well(s) and any monitoring wells that are not being retained. Continued monitoring of the lowermost USDW and the deepest permeable formation above the injection zone is recommended during the closure period to be sure that the injected fluid has not migrated upward out of the injection zone. Pressures in permeable saline formations will decline following injection, so the frequency of direct monitoring after the injection operations can decrease. However, this is not the case for salt bed caverns used for injection (Ratigan, 2003), where the pressure increases in response to closure of the cavern and other processes can result in both increases and decreases, as discussed elsewhere in this report.

Monitoring during the post-closure period is recommended by the US EPA under the proposed UIC program for CO\textsubscript{2} injection sites. The proposed requirements for the post-closure period are to continue tracking the position of the CO\textsubscript{2} plume and the pressure front to confirm that no migration into an USDW has occurred and that displacement of brine or other gases such as methane has not occurred. The pressure buildup zone extends over a much larger area than the CO\textsubscript{2} plume (Benson, 2007), and thus a larger area needs to be monitored for pressure and potential brine displacement. The proposed time frame for geologic sequestration sites under the proposed UIC regulations is at least 50 years, unless a different time period is approved by the US EPA based on site conditions. Once a demonstration has been made that the CO\textsubscript{2} plume and the pressure front have stabilized, the site can be formally closed.

4.5.3 Monitoring Methods

The selection of MMV methods needs to consider site-specific conditions including the land surface and geologic conditions, pipeline and compressor configuration, injection well and equipment characteristics; potential human health and environmental effects; and proximity to receptors. Methods that are applicable to the operation, closure, and post-closure phases of geologic sequestration in deep saline formations are described below. A summary table of the uses, benefits and limitations of the methods is provided in Table 4-18.

4.5.3.1 Pipeline Monitoring and Mitigation Measures

Monitoring of the pipeline is designed to demonstrate that all equipment is operating normally. Parameters that are typically measured under guidelines of the federal Office of Pipeline Safety include: flow rate, pressure, and temperature of the supercritical fluid. Supervisory Control and Data Acquisition Systems (SCADA) monitor changes in these parameters from normal ranges to identify leaks and set-off alarms. Other measurements may include fluid density, moisture content, and checks on the electric current of the pipe cathodic protection system.
## Table 4-18. MMV Methods for CCS Sites

<table>
<thead>
<tr>
<th>Method</th>
<th>Uses</th>
<th>Benefits</th>
<th>Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Groundwater Samples</td>
<td>Detect pH effects, alkalinity changes, and mobilization of metals</td>
<td>Direct measurement</td>
<td>Requires wells</td>
</tr>
<tr>
<td>Surface Seismic Techniques (2-D, 3-D, and 4-D)</td>
<td>Provides depths and general types of subsurface formations and depth to water; can distinguish CO₂ from brines</td>
<td>Non-invasive; Good areal coverage</td>
<td>Not all formations have distinct signals</td>
</tr>
<tr>
<td>Subsurface Seismic Techniques (Vertical seismic profiling and cross-well)</td>
<td>Provides detail on CO₂ fluid movement in injection zone and nearby formations; VSP and Cross-well methods not as widely used.</td>
<td>More detailed information</td>
<td>Requires wells and subsurface sensors and sources</td>
</tr>
<tr>
<td>Microseismic Monitoring</td>
<td>Tracks occurrence of small events that could represent induced seismicity, overpressurizing of formation, or leaks into other regions than intended target</td>
<td>Passive leak detection method</td>
<td>Requires interpretation to identify reason</td>
</tr>
<tr>
<td>Pressure Monitoring</td>
<td>Tracks changes in pressure in injection &amp; overlying formations &amp; wells</td>
<td>Direct measurement; Good indicator for leak detection</td>
<td>Requires transducers at specific depths and locations</td>
</tr>
<tr>
<td>Flux Monitoring</td>
<td>Detects CO₂ fluxes from soil and along fault and fracture traces</td>
<td>Direct method</td>
<td>Variable, uncertain</td>
</tr>
<tr>
<td>Eddy Covariance</td>
<td>Detects CO₂ concentrations in atmosphere above ground</td>
<td>Covers large area in real time</td>
<td>Needs special equipment &amp; data processing</td>
</tr>
<tr>
<td>Tracers</td>
<td>Detect CO₂ migration into USDW or other formation; may be able to distinguish injected and natural CO₂</td>
<td>Direct method</td>
<td>Requires wells</td>
</tr>
<tr>
<td>Stable Isotopes</td>
<td>Detect CO₂ migration into USDW or other formation</td>
<td>Direct method</td>
<td>Requires wells</td>
</tr>
<tr>
<td>Electrical Geophysical</td>
<td>Detect changes in fluids of deep wells</td>
<td>Indirect method</td>
<td>Requires wells for logging</td>
</tr>
<tr>
<td>Electromagnetic Techniques</td>
<td>Measure relative conductivity of subsurface formations and fluids</td>
<td>Allows rapid data acquisition</td>
<td>Interferences by metal casing</td>
</tr>
<tr>
<td>Surface Deformation</td>
<td>Detect changes due to pressure effects using tiltmeters or InSAR</td>
<td>Non-invasive</td>
<td>Requires detailed analysis</td>
</tr>
<tr>
<td>Gravity Methods</td>
<td>Can detect pool of CO₂ if leaks into shallow formations</td>
<td>Non-invasive</td>
<td>Limited to use for shallow formations</td>
</tr>
</tbody>
</table>
To protect against the release mechanisms identified in Section 4.3.3, the pipelines are usually comprised of coated carbon steel with cathodic protection, are typically buried at least 3 ft below ground, have check valves at intervals along the pipeline, and are strengthened at load-bearing sites such as railroad crossings. Automated control systems such as SCADA are not specifically required by present regulations but are used by most operators of CO₂ pipelines along with other computerized pipeline monitoring (CPM) systems to help detect leaks. SCADA for pipelines consists of a software system linking a main control computer to field sensors for pressure, temperature, and flow rates (NTSB, 2005). The system has graphical and tabular output to alert the pipeline controller of abnormal conditions, alarms that can be set when specified conditions occur, and the ability to control pipeline components such as pumps and valves. Monitoring of pipeline conditions on a 24-hour basis using CPM can alert controllers of overpressure situations or pressure drops. The controller can then change operation of automatic shutoff valves or relief valves to isolate pipeline sections.

Research is currently underway to determine the best methods to protect against pipeline failures. CO₂ pipelines are susceptible to running fractures, because the CO₂ can undergo phase changes from dense liquid to gas during decompression. A recent report (Leis and Forte, 2007) discusses designs to minimize the potential for these types of failures and engineering models to predict the extent of the fracture. Internal and external wraps and heavier pipe sections can be used as protection, although the need for continued corrosion protection has to be considered when selecting pipe materials. Other factors in pipeline failures are equipment malfunctions such as valves freezing or breaking and gasket or seal leaks. Supercritical CO₂ can damage some elastomer sealing materials (Gale and Davison, 2004). Internal pipeline inspection methods include smart pipeline inspection gauges (pigs) that are instrumented, linked to computer systems, and can be located using GPS positioning (Trench, 2003). The pigs can detect corrosion pitting and other internal or external imperfections based on changes in the magnetic field induced in the pipeline wall.

As a mitigation measure in case of leaks, check valves are placed along the pipeline at frequent intervals, e.g., 5-10 miles in rural areas or 1-2 miles in densely-populated areas. If a leak occurs, only the fluid volume between the check valves would escape. Measures to avoid pipeline failures include: cathodic protection and coating to prevent external corrosion, pressure testing prior to installation, visual inspection and aerial surveys along pipeline right-of-ways to identify signs of damage or encroachment by vegetation or structures, a public awareness program on the locations of pipelines, and training of pipeline operator staff and controllers on emergency procedures. Increasing the depth of cover of a pipeline can help reduce the potential for inadvertent contact from excavation or construction activities, particularly in densely-populated areas. Pipes can be buried deeper beneath rivers to avoid damage by dredging or boats or pipe bridges can be used.

4.5.3.2 Injection Well Monitoring and Mitigation Measures

Monitoring of the injection well includes measurements at the well surface, within the well annulus, and at the bottom of the well. Before beginning injection, mechanical integrity testing is required to confirm the proper construction of the well. Well logs are
typically run to provide additional baseline information on the injection formation, primary seal, and other formations. Well logs may include: cement and casing imaging, temperature, noise, caliper, resistivity/SP, and wireline log monitoring to determine baseline fluid composition, porosity, saturation, and permeability. Both mechanical integrity testing and well logs can be run at later times to monitor the well condition and changes in formation properties throughout the injection period. Specific parameters that should be measured in the injection well during operations and after injection stops are summarized in Table 4-19.

<table>
<thead>
<tr>
<th>Table 4-19. Parameters for Injection Well Monitoring</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>During Operations</strong></td>
</tr>
<tr>
<td>Injection Rate</td>
</tr>
<tr>
<td>Volume Injected</td>
</tr>
<tr>
<td>Injection Pressure</td>
</tr>
<tr>
<td>Reservoir Pressure</td>
</tr>
<tr>
<td>Reservoir Temperature</td>
</tr>
<tr>
<td>Reservoir Fluid TDS</td>
</tr>
<tr>
<td>CO₂, O₂, and H₂S Monitors</td>
</tr>
</tbody>
</table>

Well blowouts occur when the pressure in the well is not properly controlled, resulting in fluid flow out of a well. This can occur due to mechanical equipment failure of pumps, valves, tubing, gaskets, or back-flow preventers, damage from external force, or operator error. Well blowouts during installation into natural reservoirs with CO₂ such as in 1982 at the Sheep Mountain Field in Colorado (Duncan et al, 2009) have occurred. However, this type of event would not occur at a geologic sequestration site, since there is no CO₂ present in the target formation. At CO₂-EOR operation sites, well blowouts during workovers of wells connected to a reservoir containing CO₂ have occurred (Skinner, 2003), which is possible at a CCS site. Control of the pressure is difficult due to the rapid expansion of CO₂ when a leak occurs, which results in cooling of the fluid and release of a mixture of gas, liquid, and solid particles. Protective measures include automated 24-hour control systems of surface valves and pumps, blowout prevention stacks that have stored quantities of drilling mud or brine-based “kill fluid”, and use of CO₂, O₂, and H₂S monitors around the injection well. Mitigation measures and blowout prevention systems are described in Table 4-20.
Table 4-20. Well Blowout Prevention Systems and Other Mitigation Measures

<table>
<thead>
<tr>
<th>Mitigation Measure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Automated 24-hour control systems of surface valves and pumps</td>
</tr>
<tr>
<td>Automatic shut-off valves if earthquake or injection tubing break detected</td>
</tr>
<tr>
<td>Blowout prevention stacks that have stored quantities of drilling mud or brine-based “kill fluid” CO$_2$, O$_2$, and H$_2$S monitors around injection well</td>
</tr>
<tr>
<td>Reduce injection pressure in formation by reducing injection rate to well or stopping injection</td>
</tr>
<tr>
<td>Ability to pump CO$_2$ out of formation via separate tubing or well</td>
</tr>
</tbody>
</table>

4.5.3.3 Subsurface Reservoir Monitoring to Track CO$_2$ Migration

Seismic methods are the primary non-invasive methods used to detect CO$_2$ in the subsurface. These measurements are used to confirm that the CO$_2$ is entering the desired formation and not short-circuiting back up the wellbore or seeping through the primary seal, and to calibrate the simulation models used to predict movement of the injected fluid. There are a variety of methods that can be used, depending on the type of formation, depth, nature of the fluid being injected and surface access:

- Acoustic seismic (2-D, 3-D, and 4-D (time-lapse) to estimate saturation and permeability).
- Acoustic emissions (tracks noise made by CO$_2$ movement in formation pore space).
- Reflection (2DSR and 3DSR) to track CO$_2$ movement and distinguish brines.
- Vertical seismic profiling (VSP) uses sensors and sources at depth in wells.
- Cross-well seismic (also uses subsurface sensors in multiple wells).
- Microseismic (Continuous monitoring for small seismic events using sensitive geophones around injection site).

Seismic methods have been widely used at the DOE Regional Partnership test sites, as described in the Best Practices Manual (DOE, 2009b). The specific methods have to be selected based on site conditions. For example, the microseismic monitoring at a test site in Michigan recorded numerous events unrelated to the actual injection and the cross-well seismic profiling identified a shallow anomaly not associated with CO$_2$ movement (Gerst et al, 2008). The 4-D seismic methods have not been as successful in detecting differences in the presence of CO$_2$ due to small variations in the velocities when the sensors are not permanently positioned. Thus, use of 2-D and 3-D seismic methods and reflection are more commonly recommended.

In addition to the above seismic methods, there are additional techniques to detect CO$_2$ migration into shallower formations. Example methods include:
• Use of tracers and isotopes for CO$_2$ detection.

• Geochemical changes (e.g., pH in water samples from deepest permeable formation above injection zone).

• Electrical geophysical methods for brine movement detection such as resistivity and self-potential logs.

• Electromagnetic techniques to measure relative conductivity of subsurface formations and fluids.

• Gravity surveys, downhole gravity monitoring or microgravity surveys.

Tracers that have been tested include: noble gases, perfluorocarbons such as PFT, and stable isotopes such as the $^{12}$C to $^{13}$C ratio. Addition of mercaptans to the captured gas to detect leaks at the surface has been suggested, although since most of the captured gas is likely to contain sulfur compounds (e.g., H$_2$S or SO$_2$) this may not be necessary to produce a noticeable odor.

Methods for detection of CO$_2$ migration into USDWs include direct groundwater sampling for pH, alkalinity, major ions including Ca, and trace gases. At sites where radon or methane may be a concern, these substances could be measured to see if these gases have been displaced by CO$_2$ or brines moving up into the shallower formations. Downhole logging methods using electrical and electromagnetic techniques are well-established in the oil and gas industry and have been widely used to characterize potential sequestration formations. Surface-based geophysical methods have been tested, but may not be as useful given the sequence of alternating layers of permeable and relatively impermeable formations of different salinities. Electromagnetics at the surface or as a cross-well technique are not recommended (Wright, 2008). Gravity methods do not work as well at depth for distinguishing density differences due to CO$_2$ and can be hard to interpret since there are multiple causes for gravity anomalies (DOE, 2009b).

4.5.3.4 Surface Methods for CO$_2$ Leak Detection

Indirect methods have been proposed for detecting leaks at the ground surface including:

• Soil gas.
• Vegetation stress monitoring.
• CO$_2$ flux measurements in soil.
• Eddy covariance to detect surface fluxes of CO$_2$.
• Remote sensing (Color infrared, hyper-spectral Imagery, LiDAR, InSAR).

A potential drawback to some surface methods is that there is typically high seasonal variability in CO$_2$ fluxes to the surface and CO$_2$ content in soil gas due to the variability in natural soil respiration. Thus, a leak may not be easy to distinguish from the natural variability. Remote sensing methods using the visible and near infrared spectrum can
detect stressed vegetation, and when combined with LiDAR can be used to estimate biomass changes.

Another approach that has been tested to determine the effect of CO₂ injection at the surface is to use tiltmeter arrays to detect crustal deformation due to expansion of the formations or hydro-fracturing (Zambrano-Narvaez et al, 2008). Testing at a CO₂ injection site in Alberta found that deformation of 0.5 to 2 mm could be detected after injection at a depth of 400 m, but changes in temperature, rainfall, and ice thaw caused interferences with the sensors.

While these surface methods can be useful in detecting leaks to the surface, other subsurface methods and injection well monitoring are necessary to detect any CO₂ releases before it can migrate to USDWs and to avoid large releases along faults or wells due to over-pressurization in the injection zone.

4.5.3.5 Mitigation for CO₂ Releases from the Subsurface

Selection of an appropriate location and geologic formation for CO₂ injection is a major step in protecting against leaks to the surface or USDWs. Potential risks from subsurface leaks are at the highest level during the injection operations, a period when monitoring of the pipeline, injection well, subsurface formations, and at the ground surface would also be at maximum level. As shown previously in Figure 4-22 risks tend to increase as more CO₂ is injected into a formation, but decline when injection stops. The nature of the decline curve may be exponential or more gradual, depending on the injection capacity and pressure of the target formation. For example, a tighter formation (less permeable with a lower porosity) would mean that the CO₂ does not migrate as far from the injection well.

Mitigation for leaks from injection wells have been discussed previously. If a leak was discovered in a deep, but overlying formation or along a fault or fracture zone, the injection pressure could be reduced or stopped as long as provision for storage of the gas was available at the injection well site. Microseismic monitoring is one technique that could be used to identify activation of a fault or unintentional fluid movement. There would be time, as long as the fault does not reach the surface, to notify water supply agencies using shallow groundwater in a region prior to any gases or brines reaching the depth of the supply wells. In addition, most selected sites for large-scale injection are likely to have multiple seals over the injection zone, which would prevent migration to a USDW or the surface.

4.5.4 Summary and Future Developments

The development of effective MMV methods is one of the technical challenges facing CCS as it moves from the demonstration phase with 3 MT of CO₂ captured and stored from power plants or natural gas cleanup operations (Haszeldine, 2009), to the scale-up phase with large demonstrations planned at 36 power plants worldwide, to the construction of tens to hundreds of large CCS plants worldwide between 2020 and 2030. MMV tools have improved significantly in breadth of application, sensitivity, and
resolution during the demonstration phase of the CCS technology. As noted above, a wide range of methods have been developed and tested to monitor the movement of CO₂ from the capture site, along pipeline corridors, and into and within geologic storage sites.

Recently, DOE has extended their MMV research program (DOE, 2009a) to develop and test new methods and improved algorithms that meet the following goals:

- Complete a material balance with 99 percent accuracy and develop MMV protocols that enable 99 percent of stored CO₂ to be credited as net emissions reduction in 2012

- Demonstrate by 2018 that a suite of technologies coupled with simulation models can be used to accurately determine leakage rates from a storage reservoir.

Adequate MMV technology exists today for the ongoing demonstration projects, but new and innovative methods that can be applied in a wide range of conditions are needed to ensure the ability to detect and monitor the movement of CO₂ within storage reservoirs, the ability to detect and respond to changes in the containment of the stored CO₂, and to assess the environmental, safety and health impacts in the event of releases to the atmosphere or groundwater should such occur.

**4.6 Risk Management and Communication Plan**

The goal of the Risk Management and Communication Plan is to build regional and site-specific knowledge that can be used to (1) achieve maximum CO₂ capture potential; (2) facilitate transparent communication between project developers and operators, policy makers, regulators, and the public to develop a fuller appreciation of all the factors involved; and (3) minimize risk and establish a technical basis for activities during the pre-injection, injection, and post-injection/closure phases of the project.

The risk analysis framework described in Sections 4.1 to 4.4 provides the starting point for building this plan. The risk assessment described the primary hazards associated with the implementation of CCS, e.g., the effects of the release of CO₂ and trace chemicals from the transportation pipelines, and the releases of CO₂ from the storage reservoirs resulting in contamination of USDW. The risk assessment also identified a number of uncertainties, e.g., the effectiveness of salt bed formations as CO₂ storage sites, and the injectivity and storage capacity of the target geologic formations. The risk management plan needs to fully describe these uncertainties that affect CO₂ sequestration opportunities in Pennsylvania and to develop action plans to resolve the major ones. An effective communication plan is needed to inform the stakeholders and promote the acceptance of the CCS technology.

Four key elements of the risk management and communication plan are described. Specific actions are described that are needed to address identified uncertainties, and general guidance and recommendations for constructive steps forward.
4.6.1 Plan Context

The context or project frame of the risk management and communication plan must be defined. This requires a clear statement of scope of the project; the tasks and goals both within the project frame and those that are out of frame need to be explicitly defined. Organizational issues are also an important consideration. Deployment of CCS will require numerous and frequent interactions among technologies, markets, institutions, regulators, and the public. Understanding the responsibilities and the relationship among the participants is essential to the decision-making process. Finally, a list of specific actions is required to initiate the plan.

4.6.2 Site Selection

Site selection is the single most important step to minimize risk and achieve maximum CO₂ capture potential. Pennsylvania is currently at that stage in the CCS program that presents an opportunity to conduct an initial screening of potential sites in a cost-effective manner. This step will result in the early elimination of unsuitable sites using information that, for the most part, is easily attainable. The required information to conduct an early screening is presented in Table 4-21. For sites where power plants already exist some of the categories are not applicable and can be ignored. The minimum-requirement criteria in the table provide a starting point and can be modified as appropriate. Note that many of the qualifying criteria are related to evaluation of surface and atmospheric information, such as surface terrain and atmospheric dispersion characteristics.

Since there is no perfect site that is likely to exceed all the specified criteria, a ranking system can be developed that helps to distinguish the best sites. The screening approach can also be modified to utilize a subset of these factors. Some of the most important factors are described below.

Referring to the formation properties in the table, the depth of the storage formation should be greater than 2,500 ft in accordance with DOE guidelines to maintain the CO₂ as a supercritical fluid. The USGS uses 3,000 ft as a minimum and has also suggested a maximum depth of 13,000 ft, to avoid the cost of extra compression (Burruss et al, 2005), although that limit could be modified if appropriate. The capacity is a function of thickness of the porous layers in a formation, porosity, and areal extent. The porosity should be a weighted average to account for the natural heterogeneity in a given formation from as many core samples or well logs as possible in order to get a representative estimate. The areal extent should only count the portion of the formation that is within the desired depth range and that has an adequate primary seal. The goal is to derive a reasonable estimate of the storage capacity, and the sites can be ranked by capacity, if desired. Large sites that can store CO₂ from more than one power plant for a 40-50 year time frame may be highly desirable.

The primary seal should have a thick lithology with low porosity and permeability and a high capillary entry pressure. The presence of secondary seals above the primary seal minimizes CO₂ leakage to the surface. The presence of known faults or fracture zones
that cross both the seal and the storage formation decrease the integrity of a seal, and could make a potential storage formation undesirable for geologic sequestration.
### Table 4-21. Qualifying Criteria for Selection of Candidate carbon storage sites by the Commonwealth of Pennsylvania (after DOE, 2007a)

<table>
<thead>
<tr>
<th>Power Plant Site Characteristics</th>
<th>Minimum Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Physical Characteristics</strong></td>
<td></td>
</tr>
<tr>
<td>Location</td>
<td>No international impacts or issues</td>
</tr>
<tr>
<td>Size</td>
<td>200 acres, contiguous</td>
</tr>
<tr>
<td>Topography</td>
<td>Flat site or with acceptable slope across site</td>
</tr>
<tr>
<td>Control</td>
<td>Ability to acquire or lease land</td>
</tr>
<tr>
<td>Seismic stability</td>
<td>Low risk (peak ground acceleration &lt;30% g and 2% chance of exceedance in 50 years)</td>
</tr>
<tr>
<td>Flood plain</td>
<td>100 acres above 100-year floodplain</td>
</tr>
<tr>
<td><strong>Other Site Characteristics</strong></td>
<td></td>
</tr>
<tr>
<td>Existing site hazards</td>
<td>Not on current national priority list (NPL) or subject to Nuclear Regulatory Commission (NRC), and no hazardous waste currently generated, treated, or stored on-site</td>
</tr>
<tr>
<td>Road access</td>
<td>Improved roads close to site boundary</td>
</tr>
<tr>
<td>Proximity to proposed target formation</td>
<td>Prefer target formation close to site</td>
</tr>
<tr>
<td>Air dispersion</td>
<td>Prefer favorable terrain for dispersal</td>
</tr>
<tr>
<td>Existing land use</td>
<td>Ability to zone for project</td>
</tr>
<tr>
<td><strong>Proximity to sensitive areas</strong></td>
<td></td>
</tr>
<tr>
<td>Restricted air space</td>
<td>Compatible with existing military airspace</td>
</tr>
<tr>
<td>Large population centers</td>
<td>No nearby large population centers</td>
</tr>
<tr>
<td>Active exploration areas for oil and gas</td>
<td>Sites should not overlap with these types of areas.</td>
</tr>
<tr>
<td>Controlled air space</td>
<td>250 foot stack height allowed</td>
</tr>
<tr>
<td>Cultural resources</td>
<td>No known resources in disturbed area</td>
</tr>
<tr>
<td>Threatened and endangered species (TES) and critical habitat</td>
<td>None or minimum affected area</td>
</tr>
<tr>
<td>Proximity to public access areas</td>
<td>Not next to national or state park, national monument, wildlife refuge</td>
</tr>
<tr>
<td>Proximity to Class I visibility areas</td>
<td>&gt;60 miles from Class I visibility areas</td>
</tr>
<tr>
<td>Proximity to Tribal lands</td>
<td>If on or next to Tribal land, Tribe must support site</td>
</tr>
</tbody>
</table>
Table 4-21 (continued). Qualifying Criteria for Selection of Candidate carbon storage sites by the Commonwealth of Pennsylvania (after DOE, 2007a)

<table>
<thead>
<tr>
<th>Power Plant Site Characteristics</th>
<th>Minimum Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cooling Water</strong></td>
<td></td>
</tr>
<tr>
<td>Access to cooling water</td>
<td>&gt;2,500 gallons per minute (gpm) 24 hrs/day year-round</td>
</tr>
<tr>
<td>Adequacy under low flow conditions</td>
<td>7Q10 &gt;2500 gpm, if source is river</td>
</tr>
<tr>
<td><strong>Exposure to Natural Hazards</strong></td>
<td></td>
</tr>
<tr>
<td>Hurricanes</td>
<td>Prefer low risk. Eastern part of State at higher risk</td>
</tr>
<tr>
<td>Tornadoes</td>
<td>Prefer low numbers and intensities within 50 km of site.</td>
</tr>
<tr>
<td><strong>Surface Characteristics</strong></td>
<td></td>
</tr>
<tr>
<td>Access to land surface above formation</td>
<td>&gt;60 percent of land accessible for monitoring</td>
</tr>
<tr>
<td><strong>Subsurface Characteristics</strong></td>
<td></td>
</tr>
<tr>
<td>Mineral rights</td>
<td>Ability to obtain rights to inject 50 to 200 MT of CO(_2) over 30 to 50 years and rights for adjacent formations</td>
</tr>
<tr>
<td>Water Rights</td>
<td>Ability to obtain rights to inject 50 to 200 MT of CO(_2)</td>
</tr>
<tr>
<td>Drinking water</td>
<td></td>
</tr>
<tr>
<td>Total dissolved solids (TDS)</td>
<td>Target formations not current source of drinking water</td>
</tr>
<tr>
<td>Water resource usage</td>
<td>Target formations not future source of drinking water</td>
</tr>
<tr>
<td><strong>Formation Properties</strong></td>
<td></td>
</tr>
<tr>
<td>Orientation</td>
<td>Prefer low structural dips of target formation</td>
</tr>
<tr>
<td>Depth</td>
<td>Depth to top of storage formation exceeds 2500 ft; depth to bottom of formation does not exceed 13000 ft</td>
</tr>
<tr>
<td>Faults</td>
<td>Prefer low risk; e.g., sealing faults that do not intersect primary seal</td>
</tr>
<tr>
<td>Primary seal</td>
<td>Thick lithology, regionally extensive, continuous out to extent of expected CO(_2) plume boundary; low porosity/permeability; high capillary entry pressure.</td>
</tr>
<tr>
<td><strong>Storage Capacity</strong></td>
<td></td>
</tr>
<tr>
<td>During test phase</td>
<td>Capacity &gt;4 MT over 4 years</td>
</tr>
<tr>
<td>Post-test phase</td>
<td>Capacity of 50-200 MT over 30-50 years</td>
</tr>
<tr>
<td>Injection rate capacity</td>
<td>Allow injection rate consistent with storing desired capacity over 30-50 years.</td>
</tr>
</tbody>
</table>
Table 4-21 (continued). Qualifying Criteria for Selection of Candidate carbon storage sites by the Commonwealth of Pennsylvania (after DOE, 2007a)

<table>
<thead>
<tr>
<th>Power Plant Site Characteristics</th>
<th>Minimum Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Safety and Security</td>
<td></td>
</tr>
<tr>
<td>Public access areas (PAAs)</td>
<td>Site not on PAAs (national or state parks, etc) and bottomhole of injection well &gt; 10 miles from PAAs</td>
</tr>
<tr>
<td>Marine shorelines and lakes</td>
<td>Bottomhole of injection well &gt; 10 miles from major waterbody (for example Lake Erie)</td>
</tr>
<tr>
<td>Sensitive features</td>
<td>Bottomhole of injection well &gt; 10 miles from major dams, reservoirs, Class I UIC wells, or hazardous waste storage facilities</td>
</tr>
<tr>
<td>Relation of primary seal to active or transmissive faults</td>
<td>No known historically active fault or hydraulically transmissive fault in vicinity of expected CO₂ plume over time</td>
</tr>
<tr>
<td>Transmission</td>
<td></td>
</tr>
<tr>
<td>Grid proximity</td>
<td>Prefer close; provide length of proposed corridor and map showing interconnection point to grid, corridors and plant</td>
</tr>
<tr>
<td>Voltage</td>
<td>Prefer higher voltage lines; provide ratings of lines within 15 miles of power plant site</td>
</tr>
<tr>
<td>Rights-of-way</td>
<td>Provide length of proposed corridor and percentage where have obtained or can obtain right-of-way</td>
</tr>
<tr>
<td>Material and Fuel Delivery</td>
<td></td>
</tr>
<tr>
<td>Distance to rail or barge delivery</td>
<td>Map nearest lines and steps to build lines if needed</td>
</tr>
<tr>
<td>Delivery mode flexibility</td>
<td>Prefer delivery options</td>
</tr>
<tr>
<td>Access to natural gas pipeline</td>
<td>Prefer 30,000 standard cubic feet per minute (SCFM) at 450 psi; provide map of nearest gas lines or proposed lines</td>
</tr>
<tr>
<td>Availability of Workforce</td>
<td></td>
</tr>
<tr>
<td>Construction labor availability</td>
<td>Need adequate workers</td>
</tr>
<tr>
<td>Construction cost</td>
<td>Prefer lower costs</td>
</tr>
<tr>
<td>Monitoring, Mitigation, and Verification</td>
<td></td>
</tr>
<tr>
<td>Physical access</td>
<td>Prefer &gt;60% of land accessible over expected plume area after injection of 50 MT CO₂</td>
</tr>
<tr>
<td>Legal access</td>
<td>Prefer periodic access to project Site for 15 years after start-up</td>
</tr>
<tr>
<td>Subsurface access</td>
<td>Prefer suitable formations for monitoring wells</td>
</tr>
</tbody>
</table>

The two primary leakage pathways from storage reservoirs are wells and transmissive faults. The injection well can be constructed and operated to minimize the potential for leakage, either along the annulus due to cement damage or due to overpressurizing the
formation. The latter effect can occur when a formation has low injectivity, which is more accurately determined from injection tests rather than in a screening evaluation with little site-specific information on injection zone properties. The presence of deep oil or gas wells, particularly older wells that reach below the primary seal should be determined for several miles around the expected plume area. The depths and age of any deep disposal wells should also be identified. The likelihood of abandoned or unknown oil and gas wells should also be estimated.

Faults are not always transmissive due to fault gouge or later mineralization. The presence of deep faults that cut across the primary and secondary seals is the main concern, but any surface faults should also be identified and mapped in the general vicinity of the injection site.

Once site screening is completed, then detailed characterization of the geologic and surficial conditions of the selected sites is conducted. The pre-screened sites are more likely to be acceptable to the stakeholders and less costly to implement than if no prescreening had been done.

The detailed site investigations and risk assessments that would follow the initial screening would be much more detailed in order to determine distributions of the values of the variables that are needed to characterize important site features such as storage capacity over a specified injection lifetime of 30 to 50 years, injectivities which would dictate whether the storage capacity could even be attained, and locations and characteristics of each deep well that could provide conduits to upward migration of carbon dioxide to the biosphere. Screening level approaches will not answer these questions, but more quantitative analysis (such as use of numerical models) utilizing appropriate site-specific data would likely be required. Additionally, extensive site monitoring over extended periods of time (including the post-operational time period) will need to be a part of any detailed site characterization plan because complete characterization of sites and predictions of future risks will always be subject to uncertainties.

4.6.3 Risk Communication

Although the awareness of the role that CCS can play in achieving reductions in atmospheric CO$_2$ emissions is increasing, the general public is generally unaware of technologies like CCS or has limited understanding of the concept. Moreover, public perception of CCS projects represents a potential barrier to geologic sequestration projects. For example, Germany is at the vanguard of CCS technologies, but grass-roots protests are threatening to block the operation of a 30 MW oxyfuel combustion facility that will capture and store the CO$_2$ emissions at a geologic sequestration site (Chazan, 2009). Opponents expressed concern about the safety risks of a CO$_2$ leak and incorrectly cite the sudden discharge of CO$_2$ from Lake Nyos in Cameroon in 1986 that asphyxiated more than 1,700 people as an example.

The lack of awareness and the need for accurate information has become an increasing focus of policy makers internationally and a number of efforts are underway to develop
communication strategies to raise awareness of CCS and to help promote social acceptance of these technologies. Many of the initial communication efforts have been focused on identifying public perceptions and concerns that might affect acceptance. Table 4-22 identifies a number of concerns and perceived benefits about CCS that might affect CCS acceptance (Ashworth et al., 2009).

Table 4-22. Common Concerns and Benefits about CCS (Ashworth et al., 2009)

<table>
<thead>
<tr>
<th>Benefits</th>
<th>Concerns</th>
</tr>
</thead>
<tbody>
<tr>
<td>It could provide a good bridge to the future for low-carbon renewable energy sources</td>
<td>Safety risks of a CO₂ leak</td>
</tr>
<tr>
<td>If successful, can avoid large quantities of CO₂ from release to the atmosphere</td>
<td>The risk of contamination of groundwater</td>
</tr>
<tr>
<td>Allows continued use of fossil fuels, which provides an economic advantage for some countries</td>
<td>Will it harm plants and animals near storage sites?</td>
</tr>
<tr>
<td>Energy security around the world</td>
<td>Assumption that CO₂ is explosive</td>
</tr>
<tr>
<td>Helps to clean up coal-fired power plants for developing countries who need access to energy</td>
<td>Is it the wrong solution for climate change, a Band-Aid?</td>
</tr>
<tr>
<td>Allows emissions to be reduced without having to change lifestyle too much</td>
<td>Are there enough available storage sites?</td>
</tr>
<tr>
<td></td>
<td>It appears to require a large infrastructure which does not necessarily exist today</td>
</tr>
<tr>
<td></td>
<td>Long term viability issue</td>
</tr>
<tr>
<td></td>
<td>Cost—economic efficiency</td>
</tr>
<tr>
<td></td>
<td>Scale required for successful CO₂ mitigation</td>
</tr>
<tr>
<td></td>
<td>It is an unknown technology</td>
</tr>
<tr>
<td></td>
<td>Should not be pursued at the expense of renewable energy sources</td>
</tr>
</tbody>
</table>

Several communication efforts are also underway to addresses the public’s issues and concerns and to promote greater acceptance of CCS technology. For example, the Midwest Geological Sequestration Consortium (MGSC) has developed a communications plan that incorporates outreach and educational programs and identifies target audiences, key messages, and industrial partners (Greenberg et al., 2009). For each of the five audiences, specific communication tools, presentation styles, and venues are identified to facilitate increased public awareness and acceptance of geologic sequestration (Table 4-23). The MGSC efforts have also shown that the risk assessment process facilitated communication and preparation of the communication team members for the outreach tasks (Greenberg et al., 2009).
Table 4-23. Stakeholder Communication Methods (Greenberg et al., 2009)

<table>
<thead>
<tr>
<th>Stakeholder Group</th>
<th>Information Created</th>
<th>Information Presentation Style</th>
<th>Venue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government</td>
<td>Project summaries, presentations</td>
<td>Print, PowerPoint presentations, Workshops, Regional Meetings</td>
<td>Task force meetings, briefings, information sessions, regional workshops</td>
</tr>
<tr>
<td>Industry</td>
<td>Project brochures, posters, website</td>
<td>Print, PowerPoint presentations</td>
<td>Luncheons, meetings</td>
</tr>
<tr>
<td>General Public</td>
<td>Project brochures, factsheets, posters, physical models, rock sample sets, website</td>
<td>Print, Physical samples/models, Presentations</td>
<td>Public meetings, club meetings</td>
</tr>
<tr>
<td>Education</td>
<td>Physical models, rock sample sets, curriculum activities, website</td>
<td>Physical samples/models, Presentations, Workshops</td>
<td>School programs, workshops, colloquia, science fairs</td>
</tr>
<tr>
<td>Technical</td>
<td>Presentations, abstracts, journal articles, website</td>
<td>Presentation at meetings</td>
<td>Conferences, meetings</td>
</tr>
</tbody>
</table>

The success of the required outreach efforts at a regional level has been demonstrated in the FutureGen project, a public-private partnership to demonstrate the availability of technologies to integrate energy production, carbon capture and geologic sequestration. The project is designed as a 275 MW coal-fueled IGCC facility that produces electricity and hydrogen fuel and captures and stores 1 MT CO\textsubscript{2}/yr. The public response to FutureGen in Mattoon, Illinois, the site ultimately selected, was very positive. The project was viewed as a positive economic opportunity to benefit from the native geology, an opportunity to revitalize the Commonwealth coal industry, and a showcase for innovative technology and a world-class research facility. The project was also generally portrayed positively in the local media (Bielicki and Stephens, 2008).

As the CCS program moves forward, an effective communication plan is essential. The following are key elements of the proposed plan (Ashworth et al., 2009; Greenberg et al., 2009; Terwel et al., 2009):

- **Increased public awareness.** The more accurately informed individuals are about CCS the more likely the technology is to be accepted. It is also essential to initiate the communication efforts early in the planning process and to establish positive perceptions towards the technology early. Once formed, opinions can be slow or difficult to change.

- **Effective communication materials.** Communication materials must clearly outline the benefits of CCS and address the major concerns of the stakeholders. Specific materials need to address the information requirements and level of interest of the different stakeholder groups. The overall presentation of the CCS
technology is also important. For example, presenting CCS as one of several important potential climate-change mitigation solutions, alongside increased renewable energies and energy efficiency, has been shown to be effective.

- **Public trust.** Public trust in the organizations communicating the benefits and risk of CCS technology is essential. Partnerships involving industry government, environmental NGOs and independent experts can facilitate effective communication and greater acceptance of CCS.

4.6.4 Measurement, Monitoring and Verification

The risk assessment for individual storage sites provides a snapshot of the potential risks associated with the system. As shown in Figure 4-22, the risk profile can vary over the pre-injection, injection, and post-injection/closure phases of the project. For example, changes to the system due to aging or other factors can affect the risk of failure of individual components. In addition to the use of models to predict the likelihood and modes of system failures, the MMV plan described in Section 4.5 specifies measurements that can be made to update information on system capacities, material strengths and system demands. The implementation of the MMV plan is essential to ensure the safety of the individual operating components of the CCS system and to maintain public trust.
5.0 INSURANCE ASSESSMENT/FINANCIAL MODELS

The purpose of this section is to discuss the mitigation of financial risk for CCS projects by obtaining and maintaining appropriate insurance vehicles. This section discusses current insurance industry perspective with regard to CCS projects and presents analogs (i.e. technologies analogous to component of a CCS project) and examples that may be used to develop appropriate financial models for mitigating risk.

5.1 Overview

To address CCS project risk and to structure insurance needs for the associated large industrial projects and their operations, technical and business acumen is required. The process starts with the following two fundamental questions:

- What is to be protected?
- What threshold of risk mitigation is required or desired by the client?

To answer these fundamental questions, it is essential to identify where the risk resides in a project and to determine whether the risk can or should be modified by technical improvement, or if the risk exposure is supportable by having the addition of a financial or insurance product in the event of a loss.

Insurance is typically structured, priced, and conditioned along two basic tenets: (a) frequency of potential loss and (b) severity of potential loss. Starting from these fundamental tenets, insurance companies assess the risk they perceive in a project or and derive their policy terms, deductibles, premiums, and limits. The insurance industry typically looks for past experience in operating entities of the same or similar risk classes to determine loss history and loss expectations. CCS is not perceived by many insurance firms, however, as having a sufficient “past history” from which the frequency and severity of loss can be deduced. This represents the primary challenge for a CCS project in attracting the necessary capacity and risk-sharing arrangements.

CCS, as an emerging technology, may not be readily recognized and embraced in the collective experience of the insurance industry as having a sufficient track record to qualify as proven or mature. However, this should not impede attracting sufficient insurance capacity because nearly every portion of a CCS project has existing industry analogs that would provide sufficient data for frequency and severity data for loss projections. In fact, a policy for a CCS project has recently been underwritten in the United States (some of the participants involved in that underwriting are included as part of this report). Therefore, it can be concluded, with one very important exception, that CCS projects can attract and maintain sufficient insurance coverage and capacity. The notable exception is long-term liability coverage.

To attract the available capacity and coverage (long-term liability excluded), project developers of early CCS projects will need to educate the public and other stakeholders, including some in the insurance industry, regarding the processes and related technologies required to implement a CCS project. It should be made clear during this
process that these processes/technologies exist widely in our country today, are well understood, and have been afforded ample insurance coverage. An education program will have to review losses and failures incurred in some of the analogs presented to demonstrate the commercial and technical viability of CCS. Events such as the Lake Nyos tragedy and the Hutchinson, Kansas underground gas storage failure are examples that will need to be addressed.

Unlike the analogs that can be used to construct a technically and commercially justifiable premise for why CCS should have consideration as an insurable process, there does not currently exist a commercially viable insurance solution sufficient for covering the long-term liability required for CCS. Although the analogs used for comparison to, and justification for, treating CCS as fundamentally insurable exist, the need for post-closure liability coverage for a term well beyond what is commercially possible is dramatically different. Some firms indicated a willingness to offer post-closure policies that exceed one year, but these will likely have language to allow the insurer to amend terms, coverage, prices and deductibles each year. For these reasons, it is believed that only a governmental solution is possible for addressing the long-term liability issue. There exists at least one governmental model for this long-term catastrophic loss coverage (The Price Anderson Act) and although its intent and application is fairly different from what is required for CCS, it can be used as a derivative for structuring a possible solution to the long-term liability issue. The Price Anderson Act will be discussed in Section 5.6.1

5.2 Education

The following section describes the challenges, current state, and approaches to education of the insurance industry with regard to CCS projects. The following two issues are paramount in the development of CCS as an insurable technology for the Commonwealth of Pennsylvania:

- Education on CCS technology.
- Creation/adoption of best practices for the design, building, operation, maintenance, monitoring, and closeout of a project.

Education on the principles, basic technology, and risk associated with CCS is imperative in positioning the technology for successful acceptance with the public and the insurance industry. Educating the insurance industry should become increasingly easier because a growing number of large carriers and brokerage firms are developing specialty approaches to address emerging energy/climate-related risks and are conversant with CCS issues and risks.

An educational thrust will be needed to describe CO₂-related catastrophic events such as Lake Nyos or underground gas storage failures as in Hutchinson, Kansas. These events could be portrayed as representatives of failures and risks that could occur with CCS. They are discussed in Section 5.4.5, which explains why these examples are not comparable to CCS projects. It is important to note that although there are some risks in
CCS, as there are in all industrial endeavors, these can be attenuated by adherence to industry and government accepted best practices.

5.3 Insurance Policies

The following sections discuss the various components of insurance policies that would be required for a CCS project. A number of stakeholders who could be involved in the eventual process of providing insurance and risk management solutions for a CCS project were contacted for input for this project. Although the list of firms capable of providing such input and ultimately providing risk management solutions for CCS is fairly extensive, the firms that were contacted have significant risk management experience and the capability to technically understand and potentially underwrite CCS risks.

5.3.1 Frequency and Severity of Loss

As stated above, insurance is constructed around two main risk classes, frequency of loss and severity of loss. With few exceptions, insurance policies incorporate information about the frequency and severity of loss to determine the following for each policy holder:

- Deductible or amount of self insurance that is absorbed by the owner before the insurance company begins to pay on any loss.

- Price or premium.

- Terms (the actual language that describes what is covered, excluded, or sub-limited, what constitutes a claim, how a claim will be adjudicated, etc).

- Limit or maximum amount that an insurance company is at risk for in the policy.

For CCS in Pennsylvania, it is premature to speculate on what these would be without having identified a specific site; insurers require location- and project-specific information to generate these items through their underwriting process.

5.3.2 Policy Language

A policy has been written for a CCS project in the United States (West Virginia) and although the specifics of that policy may not be currently available for public disclosure, it is a major positive development in influencing future insurance market responses to any future solicitations for CCS coverage. The insurance industry tends to operate carefully and cautiously, but individual providers tend to follow the examples of their peers, and when a policy is written for the first time in a new occupancy, it may strongly influence the responsiveness of other firms to subsequent solicitations.

Chartis Insurance has provided a copy of their “specimen” insurance policy form for environmental pollution. A carrier’s specimen policy includes basic policy language for the CSS environmental liability market and is an indication of their availability and desire to provide coverage for a certain class of risk. The specimen policy does not indicate
deductibles, limits, premiums, or other critical factors because it is not related to a specific risk. This form has been included in Attachment 5-A.

5.3.3 Classes of Coverage

Each CCS project will need to secure a series of coverages. For the design and construction of the facility, a class of insurance typically referred to as Construction All Risk (CAR) or Engineering All Risk (EAR) will be required by the financing entity. This coverage has a number of components but generally responds to losses during construction, startup, and commissioning.

Completed works coverage is often obtained to cover maintenance related losses during the period of initial operation. EAR/CAR policies cover losses related to natural disasters or elemental perils (e.g., earthquakes, floods, windstorms, etc.), fire, mechanical breakdown, and project delays. It will not, however, cover failure of the design to work effectively or efficiently. Such coverage is referred to as performance guarantee or efficacy cover and is not available in the market today. Errors or oversights that are either inadvertently designed into a project or installed in error during construction often do not manifest themselves until the project is well underway. Thus, implementation of a set of technically proven and accepted best practices for the design and construction phase is imperative. Best practices will be a key for all phases of a CCS project, design, building, operation, maintenance, and closure.

Following the completion of a project, the next classes of insurance required are Property and Casualty coverage, which cover equipment breakdown, fire, elemental peril, pollution, and liability. Structuring liability provisions for CCS projects will be the critical challenge. Specifically, accommodating long-term liability implications by either indemnification or having the government step in to absorb this aspect will be key to ensuring that CCS has a reasonable prospect of attracting all other insurance capacity. Governmental involvement in this process will be discussed in Section 5.6.3.

The need will exist for insurance coverage for time element disruptions, or business interruption as it is commonly referred, during normal operations. To accomplish this, there must be an agreed process, clearly indicating the policy, wherein the insurance company and the client can mutually determine the value of such a delay. For example, if an injection site is shut down for 10 days due to a forced outage as a result of compressor problems, the transport (pipeline) entity can no longer ship product to the site and is impacted as it must curtail its receipt of product from the CO\textsubscript{2} extraction/separation entity at the source. Each operation presumably has an impact to their revenue stream, either directly or as a consequence to the disruption of the process (contingent business interruption). To effectively construct coverage for such an event, there must be advanced agreement on the daily or hourly value of such an interruption. Establishing this in the covenant of insurance obviates problems of adjudicating the impact of a business interruption or time element type loss and affords all parties more certainty in the process. After these values are identified and agreed to, insurance companies can price this time element risk into their premium and establish deductibles to try to balance what a client should pay before an insurance company has the obligation to begin paying for
losses. Clients will also be compelled to prepare their business pro formas (including mandatory insurance coverage and deductibles) and therefore structure their operational activities consistent with what their financing partner is willing to accept. For example, if their financing partner stipulates that as part of the financing, they will not accept any time element exposure for disruptions beyond 15 days, then the client will be compelled to seek a deductible of 15 days for time element and also ensure that the operation and maintenance activities support such a strategy.

5.3.4 Summary of Risk

Risk information, as presented in the following tables, was provided by participants and illustrates perceptions of experienced brokers in this industry as to what will be required for CCS projects to be insured and whether CCS will encounter difficulty in acquiring insurance.
Insurance Coverage Overview

The tables below contain brief descriptions of the types of insurance policies expected to be required during construction and commercial operation of a coal-fired power generation project designed to incorporate CCS technology. Blue text indicates that sufficient capacity exists for CCS projects while red text indicates a significant adverse impact for obtaining coverage for CCS.

**Part I – Insurance Maintained by Contractor During Construction Phase**

<table>
<thead>
<tr>
<th>Insurance</th>
<th>Summary</th>
<th>Coverage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Workers’ Compensation and Employer’s Liability</td>
<td>Provides statutory protection for workplace injuries suffered by the Contractor’s employees along with employer’s liability protection. Coverage and premiums should not be adversely impacted due to CCS activities during the construction phase.</td>
<td>• Statutory benefits&lt;br&gt;• Coverage for liability arising out of or in the course of employment for all states&lt;br&gt;• US Longshoremen and Harbor Workers (USL&amp;H) Act coverage, if any work near or over water&lt;br&gt;• Jones Act, if any&lt;br&gt;• No occupational disease exclusions&lt;br&gt;• Voluntary Compensation&lt;br&gt;• Broad Form Named Insured&lt;br&gt;• Waiver of Subrogation&lt;br&gt;• Alternate Employer Endorsement&lt;br&gt;• Notice of Cancellation – 60 Days</td>
</tr>
<tr>
<td>Insurance</td>
<td>Summary</td>
<td>Coverage</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
</tbody>
</table>
| Commercial General Liability  | Project liability policy providing protection to the Insureds for their legal liability to third parties for bodily injury or property damage resulting from claims arising from the activities of the Contractor.  *Coverage and premiums should not be adversely impacted due to CCS activities during the construction phase.* | • Occurrence form  
• Bodily injury and death, property damage  
• Covers premises, operations, products/completed operations, explosion, collapse, underground hazards, blanket contractual (oral and written), broad form property damage, independent contractors coverage, personal injury  
• Broad Form Named Insured  
• Blanket Waiver of Subrogation  
• Blanket Additional Insured, including completed operations  
• Employees as Insureds  
• Unintentional Errors and Omissions  
• Severability of interest/cross liability provision  
• Defense in addition to limits of liability  
• Knowledge/Notice of Occurrence  
• Notice of Cancellation – 60 Days |
| Automobile Liability          | Provides protection to the Insureds for their legal liability to third parties for bodily injury or property damage resulting from the ownership, maintenance, and/or use of vehicles.  *Coverage and premiums should not be adversely impacted due to CCS activities during the construction phase.* | • All owned, non-owned, hired, leased, or borrowed vehicles  
• Covers bodily injury, property damage, and death  
• Broad Form Named Insured  
• Blanket Additional Insured  
• Blanket Waiver of Subrogation  
• Unintentional Omission  
• Employees as Insureds  
• Fellow Employee Coverage  
• Notice of Cancellation – 60 Days |
| Umbrella/Excess Liability      | Provides additional limits of insurance in excess of the underlying policies (e.g., commercial general liability, automobile liability, employers’ liability).  *Coverage and premiums should not be adversely impacted due to CCS activities during the construction phase.* | • Follow form with applicable underlying policies  
• Notice of Cancellation – 60 Days |
<table>
<thead>
<tr>
<th>Insurance</th>
<th>Summary</th>
<th>Coverage</th>
</tr>
</thead>
</table>
| Professional Liability          | Provides coverage for professional liability arising out of project design and construction management services. Coverage and premiums may be adversely impacted due to CCS activities. It would be prudent to require engineers, constructors, and/or geologists responsible for the design and construction of the capture, transport and storage components of the process to procure Professional Liability insurance. Although it is anticipated that coverage will be available, premiums may be relatively high and capacity may be limited. | • Project specific  
  • Coverage to begin at the commencement of design through construction plus from 3 up to 10 years following completion of construction  
  • Non-cancellable, limits dedicated to project  
  • All professional consultants included plus design work delegated to contractors  
  • Owner named as an additional insured (this item needs to be carefully considered - may not be available or advisable)  
  • Notice of Cancellation – 60 Days |
| Pollution Legal Liability       | Provides coverage for pollution events arising during the course of construction. This can include both on- and off-site cleanup. Coverage and premiums may be adversely impacted due to CCS activities. Underwriters providing coverage for the contractor may exclude coverage for CO₂ pollution events. | • Sudden and accidental pollution  
  • On-site and off-site cleanup, including third-party bodily injury and property damage  
  • Notice of Cancellation – 60 Days |
| Aviation and Watercraft Liability (including Non-Owned) | Provides protection to the Insureds for their legal liability to third parties for bodily injury or property damage resulting from the ownership and/or use of aircraft or watercraft that are used in or related to the construction Coverage and premiums will not be adversely impacted due to CCS activities. | • All owned, non-owned, and hired aircraft and/or watercraft  
  • Covers bodily injury, property damage, and death  
  • Notice of Cancellation – 60 Days |
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<th>Insurance</th>
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<th>Coverage</th>
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<tr>
<td>Marine (and Air) Transit (Ocean Cargo)</td>
<td>Coverage is in force from the commencement of loading for shipment through final off-loading at the project site. Provides coverage for physical loss or damage to equipment intended for the project (exclusive of fuel) during the course of loading, unloading, and transportation, including by ocean and air.</td>
<td>• All conveyances, vessels, barges, road, aircraft, parcel post, by land, sea, air, or connection</td>
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<td>• Coverage “warehouse to warehouse” basis from manufacturer/vendor to project site including deviations</td>
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<td>• Coverage limit per occurrence for 110% the highest value of a single shipment</td>
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<td>• Specific Loss Payable clauses</td>
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<td>• Includes shipments for return or repair</td>
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<td>• Coverage on all risks basis from external cause subject American Institute Clauses 32B-10</td>
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<td>• Covers for all risks including war risks and Strikes, Riots, Civil Commotion (SRCC)</td>
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<td>• Includes taxes, fees, duties, interest, advances, insurance, and charges</td>
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<td>• 50/50 clause with Builder’s Risk policy</td>
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<td>• 180 days concealed damage</td>
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<td>• General Average</td>
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<td>• Governmental Action</td>
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## Part II – Insurance Maintained by Owner During Construction and Operations

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<th>Summary</th>
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<tr>
<td>Builders’ All Risks (BAR) including Inland Transit</td>
<td>Coverage is in force from the Notice to Proceed through to the anticipated completion date of the project (recommend extension for additional time to complete construction) and provides coverage for physical loss or damage, including loss from natural catastrophe perils, to the project during the course of construction including during testing. When a project has achieved substantial completion per the terms of the applicable construction contracts, the BAR coverages cease and an Operational All Risks (OAR) property policy is placed. The coverage is substantially the same as the BAR policy and includes mechanical/machinery breakdown coverage. <strong>Coverage for both the BAR and OAR policies will not be adversely impacted due to CCS activities.</strong> Coverage terms and conditions are expected to be consistent with any other similar power-generation project using the same fuel source.</td>
<td>• All real and personal property, material, supplies, machinery, equipment, fixtures, storage facilities applicable to, necessary to, or incidental to design, fabrication, construction, erection, installation, supply, testing, commissioning, handover, and incidental operation of the project • All real and personal property of the client in the care, custody, or control of others and/or real and personal property of others in the care, custody, or control of the Insured • Includes manufacturers’ sites for major components as insured construction sites • Repair or replacement valuation • Includes cost of opening and closing in valuation • “All risks” coverage including natural catastrophe perils (e.g., flood, earth movement, windstorm, sinkhole, subsidence) • Testing and Commissioning, including operational testing - actual number of testing days to be agreed • Limits of Liability at full replacement value or amount agreed as sublimits and aggregate amounts • Debris removal • Demolition and undamaged property • Increased cost of construction • Expediting Expense • Extra Expense – Material Damage • Fire brigade and extinguishing expenses • Off-site storage • Pollution cleanup and removal including decontamination costs • Professional fees • Protection of Property • Public Authorities clause</td>
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<td>Insurance</td>
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|           |         | • Temporary removal of property  
|           |         | • Inland Transit limit per occurrence for the highest value of a single shipment  
|           |         | • Include Valuable Papers and Records at reconstruction value  
|           |         | • Contractors’ Extra Expense (“soft costs”) – if required  
|           |         | • Damage to existing property  
|           |         | • Excludes contractors’ and subcontractors’ construction plant, tools, equipment, temporary buildings, and contents unless reported  
|           |         | • Excludes underground property, dams, earthworks, and land improvements unless reported  
|           |         | • Excludes transmission and distribution equipment beyond 1,000 feet  
|           |         | • Design defects exclusion – MRA wording or LEG3/96 or equivalent  
|           |         | • Severability of Interest (non-vitiation cover)  
|           |         | • Cancellation for non-payment of premium only  
|           |         | • Lender Loss Payable Clause  
|           |         | • Waiver of Subrogation  
<p>|           |         | • 50/50 Clause with Marine Cargo |</p>
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<th><strong>Insurance</strong></th>
<th><strong>Summary</strong></th>
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| Construction Delay in Start-Up (DSU) [also known as Advance Loss of Profits (ALOP)] including Inland Transit DSU | Covers loss of or reduction in earnings (gross revenues less variable/non-continuing expenses) and extra expense including cost of replacement power resulting from a delay beyond the anticipated completion date as scheduled where such delay is a direct result of physical loss or damage covered under the BAR policy above including during inland transit. *When a project has achieved substantial completion, per the terms of the applicable construction contracts, the BAR coverages cease and an OAR property policy is placed. Business Interruption coverage is placed as a part of the OAR policy, if desired, because DSU coverage is no longer applicable.*  

*Coverage applicable to DSU under the BAR policy and Business Interruption under the OAR policy will not be adversely impacted due to CCS activities.*  

*Coverage terms and conditions are expected to be consistent with any other similar power-generation project using the same fuel source.* | • Coverage tailored to exposure  
• Expenses to Reduce/Avert loss  
• Interruption by civil/military authorities  
• Impounded Water  
• Ingress/Egress  
• Contingent Delay in Start-Up (Suppliers’ Extension)  
• Includes Delay from loss of/loss to contractors’ plant and equipment |
| Marine Delay in Start-Up (MDSU) | Covers loss of or reduction in earnings (gross revenues less variable/non-continuing expenses) and extra expense including cost of replacement power resulting from a delay beyond the anticipated completion date as scheduled where such delay is a direct result of physical loss or damage covered under the Marine Transit physical damage policy.  

*Coverage will not be adversely impacted due to CCS activities.*  

*When the project achieves commercial operation, MDSU coverage is no longer required.* | • Coverage tailored to exposure  
• Includes mechanical breakdown of vessel |
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<td>Workers’ Compensation and Employer’s Liability</td>
<td>Provides statutory protection for workplace injuries suffered by the Owner’s employees along with employer’s liability protection. Coverage should not be adversely impacted due to CCS activities. Although there may be some concern about increased exposure for injury to employees arising from a CO\textsubscript{2} release, that exposure is not expected to be any greater than chemical or refining operations. Insurance should be readily available.</td>
<td>• Statutory benefits • Coverage for liability arising out of or in the course of employment for all states • USL&amp;H Act coverage, if any work near or over water • Jones Act, if any • No occupational disease exclusions • Voluntary Compensation • Broad Form Named Insured • Waiver of Subrogation • Alternate Employer Endorsement • Notice of Cancellation – 60 Days</td>
</tr>
<tr>
<td>Automobile Liability</td>
<td>Provides protection to the Insureds for their legal liability to third parties for bodily injury or property damage resulting from the ownership, maintenance, and/or use of vehicles. Coverage will not be adversely impacted due to CCS activities.</td>
<td>• All owned, non-owned, hired, leased, or borrowed vehicles • Covers bodily injury, property damage, and death • Broad Form Named Insured • Blanket Additional Insured • Blanket Waiver of Subrogation • Unintentional Omission • Employees as Insureds • Fellow Employee Coverage • Notice of Cancellation – 60 Days</td>
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<td>Insurance</td>
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| Commercial General Liability (and Excess Liability) | Policy providing protection to the Insureds for their legal liability to third parties for bodily injury or property damage resulting from claims arising from the activities of the Owner. Coverage may be adversely impacted due to CCS activities. Care should be taken to assure that coverage is provided for “Underground Resources and Equipment Hazard” during both the construction phase and subsequent operational period. (Refer to Footnote Number One for coverage description) | • Occurrence form  
• Bodily injury and death, property damage  
• Covers premises, operations, products/completed operations, explosion, collapse, underground hazards, blanket contractual (oral and written), broad form property damage, personal injury  
• Broad Form Named Insured  
• Blanket Waiver of Subrogation  
• Blanket Additional Insured, including completed operations  
• Employees as Insureds  
• Unintentional Errors and Omissions  
• Severability of interest/cross liability provision  
• Defense in addition to limits of liability  
• Knowledge/Notice of Occurrence  
• Notice of Cancellation – 60 Days |
| Umbrella/Excess Liability                      | Provides additional limits of insurance in excess of the underlying policies (e.g., commercial general liability, automobile liability, employers’ liability). Coverage should not be adversely impacted due to CCS activities; however, care should be taken to ensure that the policy follows form with the “Underground Resources and Equipment Hazard” coverage provided in the primary Commercial General Liability policy. | • Follow form with applicable underlying policies  
• Notice of Cancellation – 60 Days |
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| Pollution Legal Liability | Provides coverage for liability arising from Pollution Conditions (as defined in the policy) on or under the Insured Property. At a minimum, coverage should be structured to provide the following:  
  - On-Site Cleanup of New Conditions  
  - Third-Party Claims for On-Site Bodily Injury and Property Damage  
  - Third-Party Claims for Off-Site Cleanup Resulting from New Conditions  
  - Third-Party Claims for Off-Site Bodily Injury and Property Damage  
  Pollution Legal Liability insurance protecting the Insured against liability arising from the escape, release, or dispersal of CO\textsubscript{2} will be the most difficult coverage to procure and maintain. (Refer to Footnote Number Two for Additional Information) | - Coverage is normally written on a Claims-Made basis  
- The anticipated policy terms is 12 months; however, a 36-month term may be available  
- Limits of Liability will be per occurrence and in the aggregate for the policy term  
- Available Limits of Liability - $50,000,000 per occurrence and in the annual aggregate |
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<tr>
<td>Control of Well Insurance (Blowout Insurance)</td>
<td>Provides coverage the actual costs and expenses incurred by the Insured related to (a) bringing a well under control, (b) redrilling and (c) cleanup expenses and seepage, pollution, and contamination costs, as further explained in the coverage description in the next column. Coverage can be arranged for during the drilling and completion stage, as well as the producing and/or operational phase. Coverage is readily available in the petroleum industry for wells of every type and description. However, care must be taken to ensure that pollution-related coverages found in Section C of the policy do not contain any exclusion related to CO$_2$ releases resulting from a Section A loss. Furthermore, pollution-related claims covered under the Control of Well policy should take precedence over and be primary to the coverage provided in the Pollution Legal Liability policy outlined above.</td>
<td>• Section A (Control of Well): Regaining control of a well(s) that becomes out of control, per the definition of a “well out of control” contained in the policy  • Section B (Redrilling Expense): Redrilling, recompletion, snubbing, washover, fishing, and/or any other salvage operations as may be necessary to recover or restore any well that may be lost or damaged as a result of an occurrence insured against in Section A (Control of Well)  • Section C (Cleanup Expense and Seepage, Pollution, and Contamination)  • All sums that the Insured shall be liable to pay as damages caused by or alleged to have been caused directly or indirectly by seepage, pollution, or contamination arising from, or caused by, a well insured under Section A that becomes out of control as defined in the policy, and  • The cost of removing, nullifying or cleaning up seeping, polluting, or contaminating substances emanating from, or caused by, a well insured under Section A that becomes out of control as defined in the policy.</td>
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**Footnote One:**

Underground Resources and Equipment Hazard coverage, described below, is often endorsed onto a Commercial General Liability policy for Oil and Gas drilling and/or operational risks.

**UNDERGROUND RESOURCES AND EQUIPMENT HAZARD**

Notwithstanding any other provisions contained in this policy, it is understood and agreed that coverage provided herein is amended to add the “Underground Resources and Equipment Hazard” as defined below: For the purpose of this insurance, “Underground resources and equipment hazard” shall mean "property damage" to any of the following:

- a. Oil, gas, water, or other mineral substances that have not been reduced to physical possession above the surface of the earth or above the surface of any body of water.
- b. Any well, hole, formation, strata, or area in or through which exploration for or production of any substance is carried on.
- c. Any casing, pipe, bit, tool, pump, or other drilling or well servicing machinery or equipment located beneath the surface of the earth in any such well or hole or beneath the surface of any body of water.
Footnote Two:

Adequately insuring the environmental risks associated with the capture, injection, and long-term underground storage of CO\textsubscript{2} during the operational phase is clearly one of the most problematic and challenging tasks for any risk manager or broker. It could be argued that because of the novelty of CO\textsubscript{2} capture and sequestration, the underwriter’s perception of the danger and potential liability associated with the risk are, in fact, greater than the reality. This perception is certainly fueled by the 1986 natural volcanic eruption of carbon dioxide from a lake in Cameroon wherein nearly 2,000 people died of asphyxiation from being in close vicinity to the release of CO\textsubscript{2}. However, one can also point to the fact that CO\textsubscript{2} is commonly transported via pipeline and injected into formations productive of oil and gas to enhance oil recovery. As of 2006, there were over 1,500 miles of CO\textsubscript{2} pipelines in the United States used for EOR. From 1986 to 2006, only 12 CO\textsubscript{2} pipeline leaks occurred, with no human injuries reported. Contrast that with natural gas and hazardous liquid pipelines, which had more than 5,000 accidents and 107 fatalities in the same period (Parfomak, 2007). Given a detailed and exhaustive geological study to determine the optimum underground formations for CO\textsubscript{2} sequestration, a properly engineered well casing design, and an aggressive predictive and preventative maintenance program applicable to the CO\textsubscript{2} capture, injection, and storage programs, it is anticipated that the Pollution Legal Liability insurance markets will respond favorably and provide adequate coverage, as they have for the oil and gas industry.

When taken as a whole, the prospect for CCS to attract insurance coverage will require different insurance carriers (AKA markets) to be identified for participation. The following are the carriers that are anticipated to be fairly motivated to provide capacity for CCS risks: Potential Insurance markets:

CHARTIS (formerly AIU Holdings)
Zurich
ACE
Chubb
XL
Ironshore
The following are the four key phases generally included in a CCS project, each with its inherent risks and insurance requirements:

- **Design and Construction** - including installation of carbon-capture equipment, well drilling and pipeline laying, and commissioning of the plant, pipeline, and reservoir injection equipment.

- **Operation** - including injection of CO₂ into the reservoir.

- **Closure and Decommissioning** – the engineering phase after injection operations have ceased and carbon-capture and well injection equipment have been decommissioned and injection wells plugged.

- **Post-closure** – including continuing monitoring of the integrity of the CO₂ storage after the cessation of injection to the reservoir.

In the above project phases, there exists the possibility of operation failures that may potentially threaten the health and safety of different people or environments, resulting in losses.

CCS is considered by many as an emerging rather than proven technology; however, the engineering components of such a project are all well-established technologies. As such, the risk transfer options are comparable with those applicable to other energy and chemical industry risks with which the insurance industry is familiar and have historically been willing to underwrite. Of these, the most novel is the environmental risk associated with the injection and subsurface storage of CO₂.

Expected risks associated with these four phases are discussed below.

**Design and Construction:** The risks of this phase will be comparable to those of any conventional on-shore exploration project including drilling, pipeline construction, and installation. The novel risks will arise with the inception of project commissioning that will require the introduction of pressurized CO₂ into the system. It will be appropriate to consider the potential risks of delays in the project start-up and the impact on potential loss of earnings (consider Advanced Loss of Profit coverage).

Expected areas of potential risk transfer to be considered are as follows:

- **Damage to existing property** – damage to an existing plant during the construction and commissioning phase.

- **Third-Party Liability** – consideration of the normal third-party liability of a construction project in addition to potential exposures due to loss of containment of CO₂ from the capture equipment at the facility, from the pipeline, or from the reservoir injection during the construction and commissioning phase. The routing of the pipeline will be key in this regard.
• **Advanced Loss of Profits** – implications of permitting and licensing, especially environmental licenses and permits, for the facility, or any carbon trading credits expected to be earned by the commissioning of the CCS project.

• **Control of Well(s)** – the construction project will include drilling into the designated subsurface reservoir; therefore, there is a residual risk of well blow-out and loss of control of well(s) that would potentially result in considerable additional costs and project delay.

**Operation:** This is the main operational phase of the CCS project, introducing CO₂ into the reservoir. The risks are generally comparable to other energy and chemical industry risks, with comparable opportunities for risk transfer. The range of potential third-party exposures during the operational phase of the CCS project can include the following:

- Loss of containment of high-pressure CO₂ at the CO₂ capture site – exposure of workers on site (employees, contractors, other on site) and third parties adjacent to the CO₂ capture site to dangerous concentrations of CO₂.
- Pipeline failures resulting in the loss of containment of CO₂.
- Loss of containment of CO₂ from the reservoir.
- Risk from catastrophic loss of containment to population and environment.
- Potential long-term exposures of a higher-concentration CO₂ environment – impacts to people, industry, community, environment, and property values.
- Contamination of subsurface aquifers and drinking water supplies.

Based on these potential exposures, the areas for potential for risk transfer to be considered during the operation phase are as follows:

- Property damage
- Machinery breakdown
- Operational continuity – business interruption
- Well control/loss of well control
- Third-party liability
- Environmental liability (both subsurface and surface releases)

The possibility of contamination of the CO₂ stream, during pipeline transfer and injection into the reservoir, must be considered along with the additional risk potential in the event of catastrophic or chronic release from the pipeline or reservoir.

**Closure and Decommissioning:** The risks arising during the closure and decommissioning phase are comparable to those during decommissioning of an energy or
chemical plant. There can be potential property damage, third-party liability risks, and potential project delays. The funding structure of the project will need to be examined to determine if there are any implications to earnings due to delays at this stage in the project. In addition, plugging of CO$_2$ injection wells and potential risks associated with this work needs to be considered.

**Post-Closure:** It is expected that there will be ongoing monitoring of the integrity of the reservoir to confirm continuing safe containment of the CO$_2$, with financial assurance provided by the owner. The length of the post-closure period is still being debated but will likely be a lengthy period, possibly up to 50 years, and therefore would preclude use of conventional insurance products.

Funds should be available for maintenance of reservoir monitoring equipment, along with resources for emergency response to deal with any developing hazards associated with the stored CO$_2$, and funds for any third-party liabilities due to loss of containment from the reservoir. It is likely that the owner will have to consider some combination of trust funds, maintenance or forfeiture bonds, and/or prefunded insurance programs.

The environmental insurance markets have provided coverage designed to respond in the event of a release of CO$_2$ at the surface, in the subsurface, or both. The environmental markets most actively involved at this time are Zurich, Chubb, and AIU Holdings (now called Chartis), and to lesser extent XL and ACE. Chubb has written environmental coverage for CO$_2$ sequestration. The environmental policy is triggered by pollution due to release as defined in the policy.

Zurich has developed a policy designed to provide coverage for CCS projects and includes environmental, transmission lines, control of well, business interruption, and geomechanical failure. Zurich has also provided a geologic sequestration financial assurance (GSFA) form designed to provide the framework for a post-closure financial assurance program. In the case of the other carriers, a similar program may likely be put together working with both their environmental and energy underwriting groups.

### 5.4 Analogs for Assessing CCS Risk

The common impression among insurers that there is a lack of sufficient past experience with CCS is a challenge with regard to education and perspective. Developers need to point to the occupancies presently underwritten (successfully) by insurance carriers that emulate (as an analog) many of the same risks that would be associated with CCS. Some of the risks for CCS are significantly less than for other present-day analogs. For example, injection and storage of natural gas in underground geologic formations are widely used practices. Risks and consequences of foreseeable losses associated with injection and storage of CO$_2$ compare very favorably to that of injection and storage of natural gas.

Breaking down the contemplated CCS project into its components of capture, transport, and storage is the method by which logical analogs of existing industrial operations can be presented and compared for insurability. These analogs are critical to demonstrate that
insurance is already available and being provided to these types of operations. It is also the mechanism by which education about CCS should be initiated.

Currently, the perception of risk in CCS is significantly greater than the reality of risk. The insurance industry seeks to insure for fortuitous (accidental or unplanned) events, and the analogs are essential to demonstrate that, in general, CCS represents a collection of analog related risks that are essentially well known to the industry and are therefore insurable.

5.4.1 The Capture Analog for Insurance

The first analog to determine the prospect of insurance for CCS is the capture or purification and concentration (CO\textsubscript{2} absorption and stripping) process. Air separation technology and plants exist today, are covered by insurance, and pose no appreciable unknown risk. These existing facilities would be analogs to the CO\textsubscript{2} removal regimen contemplated in the CCS process.

![Air separation plant (photograph courtesy of Air Product and Chemicals)](image)

Three main CO\textsubscript{2} removal processes - pre-combustion capture, post-combustion capture, and oxy-fuel combustion - are currently contemplated for the CCS industry, and these technologies are reasonably well understood and most have had the benefit of insurance coverage as part of the risk capacity extended to other industries utilizing the same technologies today.
5.4.2 The Transport Analog for Insurance

The second analog for assessing insurability of CCS is that of transport. Approximately 5,800 kilometers (3,600 miles) of CO$_2$ pipelines operate today in the United States, with traditional insurance coverage readily available (Parfomak, 2007). Kinder Morgan has a number of pipelines of this nature in successful operation (and with insurance coverage) and a graphic of one such network is presented below.

![Pipeline network layout](modified after Kinder Morgan)

5.4.3 The Injection/Underground Storage Analog for Insurance

The next analog for assessing insurability of CCS risk is that of injecting gas underground and storing it. The United States has a large number of underground storage locations already in existence, typically for natural gas, and these are all under commercially available insurance coverage. Figure 5-3 represents a map of such locations.
operating across the country and with standard insurance coverage. Please note the density of operations in Pennsylvania. Four categories of geological reservoirs are considered important carbon sequestration targets in Pennsylvania: a) deep saline formations; b) depleted and producing oil and gas fields; c) unmineable coal beds; and d) organic-rich (carbonaceous) shales.

For these facilities to obtain insurance coverage, the subsurface and geotechnical characteristics had to be detailed for suitability. Along with the need for best practices, this is perhaps the single most critical element for CCS. The technology employed to research, evaluate, select, and monitor suitable sites will be an essential consideration for the insurance industry to accept the risk of the projects contemplated and to extend coverage. Accomplishing the geotechnical characterization for acceptability of the risk present in subsurface conditions is critical to having CCS projects accepted as normalized risks, and the technology for this type of characterization for CCS exists today.

5.4.4 The Enhanced Oil Recovery Analog for Insurance

One additional analog that further supports the notion that CCS is not a totally new technology with regard to insurance considerations is the utilization of CO₂ in extracting oil from mature oil fields, known as EOR. Although the CO₂ typically utilized is not anthropogenic but that which is naturally occurring in the field, the lessons learned from geotechnical characterization of the field, observing field pressures, monitoring feed rates of CO₂, evaluating recapture of CO₂ for economic purposes, and determining the dynamics involved with pressurizing a subsurface structure can be considered for CCS insurability considerations. These EOR projects receive broad insurance coverage supplied by the commercial insurance industry.
The oil and gas industry has over 35 years of continuously developing experience in transporting and injecting CO₂ for EOR, and these operations are under commercially provided insurance coverages. Although constantly evolving, this technology’s operating experience and regulatory requirements developed for EOR are extensive. In the United States alone, the oil and gas industry operates over 13,000 CO₂ EOR wells (Meyer, undated).

5.4.5 Analogs for Disaster and the Response for Insurance Purposes

The following are examples of disasters that may be raised as part of arguments that CCS is unsafe, what implication this may have on insurance coverage.

The 1986 Lake Nyos Event in Cameroon, West Africa

Lake Nyos is an active crater lake that contains large amounts of CO₂ produced from volcanic activity. On the evening of August 21, 1986, CO₂ in solution at depth in the lake was released (it is not known precisely what caused this release) and resulted in the death of nearly 1,700 people within a radius of approximately 15 miles.

This example can be raised to indicate that the risk associated with CCS technologies and processes is as uncontrolled as the natural forces that created the conditions for this particular event, and that a sudden and catastrophic release of CO₂ in a populated area can kill many people. The informed response to assure stakeholders and insurance carriers of the non-applicability of such a risk for CCS projects involves pointing out that exhaustive geotechnical assessments would be required, under a set of CCS approved best practices, to ensure that subsurface conditions represent suitable integrity. These assessments will confirm that conditions are appropriate to maintain the CO₂ in place and to indicate that extensive pore-space plume and pressure monitoring and emergency procedures would be designed to stabilize subsurface conditions and prevent such a release. Emergency procedures will also be designed to relieve pressure and stabilize subsurface dynamics via distributed control mechanisms. In addition, the response should include the fact that the pipelines that will carry the CO₂ will have redundant safety systems and isolation valves automatically activated in any emergency condition (such as a loss of pressure if pipeline integrity is breached). Moreover, it should be pointed out that such CO₂ pipelines exist and currently operate successfully and safely without incident and are proven risks for the insurance industry.

The Hutchinson Kansas Incident

As one of the more compelling analogs for disaster, the Hutchinson, Kansas, natural gas explosion offers several lessons to be learned for the insurance related to the implications of CCS. Information reported by Allison, (2001):

On January 17, 2001, a sudden release of natural gas underground in and near Hutchinson, Kansas, created numerous fires in the town, and fountains of natural gas and brine began bubbling up two to three miles east of the downtown fires. The geyser,
some reaching 30 feet high, came from abandoned brine wells that had been drilled as long ago as the 1880s for salt production. The next day, natural gas coming up from a long-forgotten brine well exploded under a mobile home, killing two people. The city ordered hundreds of residences and businesses evacuated. Many people could not return to their homes and businesses for more than two months. On the same day, technicians at an underground natural gas storage field eight miles northwest of Hutchinson saw a dramatic drop in pressure in one underground manmade salt cavern or “jug” that they had been filling with natural gas. The underground field that was 650 to 900 feet deep had developed a leak; gas moved vertically up to a laterally continuous gypsiferous zone that perhaps served as a seal and then spread in all directions due to the pressure and found its way through several miles of underground “conduit” to Hutchinson, where it encountered the vertical conduit through old brine wells.

Research presented by Hopper (2004) described that salt caverns for CCS projects and may have difficulty in obtaining insurance coverage:

“According to the Energy Information Administration, there were 407 underground natural gas storage facilities in operation in the United States in 2002, of which 340, or 84%, were depleted reservoir facilities; 38, or 9%, were aquifer facilities and 29, or 7%, were salt cavern facilities. Market and investor confidence in the U.S. gas storage infrastructure—as well as the blessings of government regulators—are essential to the stability and success of the natural gas storage business. Statistically, the odds are remote that single-point failures involving natural gas storage facilities can produce the kind of catastrophic losses such as what occurred at Moss Bluff (Liberty County, Texas) Be that as it may, they have happened before. In every case, however, a salt cavern storage facility was the culprit, not a depleted reservoir or aquifer gas storage facility (emphasis added). This is an important distinction and underscores the fact that most underground gas storage facilities in the United States—93% of which are either depleted reservoir or aquifer storage facilities—are not susceptible to the kind of catastrophic failure that occurred at Moss Bluff.”

This scenario presents a striking example of why geotechnical due diligence and monitoring are critical elements in insurance considerations of CCS operations and why salt caverns could be considered risky for CCS insurability purposes. According to the article cited above, 100 percent of the failures of underground gas storage occurred in salt caverns, so underwriters may seek exclusions in policy language for covering CCS projects using salt caverns.

The creation of best practices for CCS would ensure that pipelines and compressor stations are designed and constructed to operate with public safety in mind. Best practices employed for CCS injection and sequestration would also ensure that the geotechnical conditions for an injection site and the expected plume area (including but not limited to seismic data, location of abandoned wells to ensure they are properly plugged, location of aquifers, etc.) are very well understood and that the CCS facility is designed and installed to obviate such catastrophic events.
5.5 Feasibility Considerations

CCS, although viewed as a nascent industry, has sufficient present-day analogs to encourage the insurance industry to view the process as insurable. Certain technological improvements and developments are necessary to ensure that the state of the art/science and best practices associated with subsurface characterization, field pressure dynamics, plume monitoring, etc. become more precise. However, the key factors and analogs that already exist will be critical in structuring reasonable risk sharing arrangements for this industry. The basic technology of CCS, when disaggregated to the analogs presented above, should have a reasonable reception for attracting insurance capacity.

In reviewing the overall input regarding CCS, the participants in this current study have validated the general proposition that CCS is insurable with normalized insurance rates, terms, and deductibles drawn from an amalgam of current day analogs through all phases, with one exception, long-term liability, as discussed below.

5.5.1 Long-Term Liability

The main challenge in obtaining insurance for CCS projects that are not necessarily addressed by present day analogs is the issue of long-term sequestration and attendant liability. It is not realistic to expect any firm to expose their company to losses far into the future for which it is impossible to project the conditions, laws, and developments in science that will influence this liability. When the CCS industry speaks in terms of sequestering CO\textsubscript{2} for 1,000 years, there is no responsible insurance carrier in the industry that will meet this challenge.

Liability coverage will likely be available through the design, construction, and injection phases. There may even be a short time wherein some liability coverage is extended into what will be described as post-closure stabilization. However, such insurance will be offered in a manner that its terms, conditions, premium, deductible, exclusions, etc. will be able to be modified on each renewal period, which will likely be one year. The process of being able to re-underwrite the liability risk as new conditions are encountered is known as writing insurance on a “claims made” versus an “occurred” basis. Utilizing a “claims made” approach to underwriting allows the insurance company the opportunity to honor claims made during the active policy period, while affording it the opportunity to re-underwrite the risk going forward as new information is uncovered about the risk.

Such a process would presumably, in the face of new adverse information and impending or actual claims, compel the insurer to seek a more favorable price, terms, deductibles, etc. at each renewal as they learn more. The problem for clients subjected to this type of coverage is the potential for losing reasonable pricing and availability of liability coverage required if loss experience is significant.

In addition, it is not reasonable to expect any carrier to expose their firm beyond a modest amount of time for liability coverage they would be willing to underwrite. The prospect,
therefore, of obtaining such long-term liability coverage through traditional carriers is not realistically achievable at this point, and the participants to this study have validated this.

Quantifying “long-term” liability for the insurance industry with respect to CCS is problematic. Although most carrier participants indicated a strong preference for one year insurance contracts on a claims made basis, the possibility of obtaining three to 10-year liability agreements, if achieved, will come with significant conditions limiting the conditions to which the policies might respond. Because such coverage is expected to be significantly burdened with exceptions and exclusions, the added value actually being provided in such a transaction would be questionable. Thus, the reality is that long-term liability will require a governmental presence for indemnifying and absorbing such risk. This aspect remains the fundamental challenge for CCS. Meeting this challenge may be accomplished by creating some unique arrangements for post-closure liability, and these are covered in Sections 5.6.1, 5.6.2, and 5.6.3.

Although some measure of liability coverage may be expected to be obtained from the insurance industry, it is expected that it will be capped or sub-limited and will be restricted to a point wherein the full measure of a catastrophic event (with massive liability) will require either legal indemnity for the participants and/or a governmental standing in as accountable for such long-term and extensive liabilities. It is therefore anticipated that a governmental role, defined for long-term catastrophic liability exposure, will be necessary for stakeholders in the process (engineering firms, construction firms, equipment manufacturers, operators, insurance firms, etc.) to participate in CCS projects. Indeed, the implementation of CCS technology may require the introduction of new laws affecting tort and liability exposure for participants as necessary in the country’s common good in to initiate these projects. The examination in Section 5.6.1 of using lessons learned in structuring coverage for catastrophic events from the nuclear industry via the Price Anderson Act is one of the more compelling prospects for addressing this.

5.5.2 Best Practices for Insurance Acceptability

The need to support CCS also will require a set of best practices to which project developers and other stakeholders must ascribe. The insurance stakeholders (as a minimum) will seek to examine these best practices and will extend their insurance capacity only to projects that have agreed to follow these best practices in the design, construction, operation, and maintenance of the facilities. Best practices also provide a set of commonly accepted and followed standards (subject to constant improvement) that allow the industry and insurance companies (who will be placing their capacity at risk) to accept that the projects are, at a minimum, under technological control and meet consistent standards.

To further reinforce the necessity for CCS to adopt and employ a series of best practices, the International Energy Agency (IEA) Working Party for Fossil Fuels (WPFF), Coal Industry Advisory Board (CIAB), Carbon Sequestration Leadership Forum (CSLF), and Global Carbon Capture and Storage Institute (GCCSI) convened a workshop of experts in 2009 to support IEA’s report to the Group of Eight (G8) on the launch of the 20 first
large-scale CCS demonstration projects by 2010. The following is one of the recommendations provided by the workshop of experts titled “Expanded Recommendations in Support of the IEA’s Report to the G8”:

“Develop and Promote International Best Practices
Governments should work with industry partnerships to develop and promote international best practices and knowledge sharing from publically funded pioneer demonstration projects.

- Governments should work through the IEA, CSLF and GCCSI, to establish a set of site selection, characterization, design and operational standards and best practices that incorporate lessons learned from all aspects of pioneer demonstration projects from carbon capture to transport and storage.

- Regulatory framework development should be linked to pioneer demonstration projects to ensure that project experience and outcomes inform regulatory processes governing subsequent projects.

- Governments should support the establishment of an international CCS training institute to advance best practices and knowledge sharing.”

The lack of standard practices would make projects very difficult to insure because variations in standards (design, construction, monitoring, control, operation, maintenance, safety, etc.) for each project would make it difficult to determine what is prudent.

It should be pointed out that the qualifications for stakeholders to participate should and will be examined by insurance entities to assess risk for a CCS project. An examination of the contracts and subcontracts that constitute the design/construction and operation of the facilities may be undertaken by carriers with exposure to ensure the following:

- That the schedule is reasonable.

- That firms and specific individuals leading the project effort have the responsibility and experience to undertake the tasks.

- That proper quality assurance/quality control (QA/QC) provisions are mandated by contract (and followed).

- That contract incentives and penalties are not inducements to curtail quality or cut corners that might compromise safety and operational integrity.

- That the scope is clearly defined.

- That sufficient qualified manpower is available to execute the scope.
• That the type of contract selected (fixed price or cost plus) is commensurate with the extent of the scope and the extent of the engineering and design being completed or approved for construction.

• That the start-up commissioning and acceptance criteria are well defined.

5.5.3 Commercial Insurance Availability

It is the conclusion of this report, based upon the input from participants that (1) insurance capacity for nearly every phase of the process should be available; (2) projects should receive commercially available rates and premiums for risks commensurate with the analogs to which they relate; and (3) projects likely will find such insurance in sufficient capacity to accommodate the needs of each project site. There are at least two exceptions to this, as summarized below.

One exception, previously discussed, is long-term liability. Every insurance company has seen or learned lessons from exposure they unwittingly absorbed and losses they incurred from asbestos. To rectify this, they have determined that liability under their policies should be structured such that it has a short tail and to attempt to write all policies on a claims-made basis, which affords the opportunity to re-underwrite the risk when new information or losses are uncovered. Although the time frames for short-term versus long-term liability is subject to individual interpretation, it is not realistic in the case of CCS to expect any firm to accept liability for longer than three years on the operation of the facility, and moreover on the storage site, will likely not provide meaningful coverage after the site is closed for further injection.

Another exception involves aggregation of locations. Placing a number of sites in a geographically close proximity presents a significant problem for carriers, which they refer to as aggregation exposure. For example, locations in close proximity could present aggregation problems for carriers with regard to a seismic event in the area that could cause them to suffer a loss at nearly every location where they provided coverage.

5.5.4 Requirements for Obtaining Insurance and Cost

To actually obtain insurance and cost for CCS projects, it is necessary to describe an actual project for the insurance companies to begin their underwriting process and arrive at what they feel they need for such a policy. Nearly every insurer would be able to provide pricing, deductibles, terms, etc. if an actual project could be described including location, operating characteristics, limits and deductibles being sought, etc. However, without such a detailed example, it is not possible to obtain this detailed information. What is clear is that there is a viable market for obtaining insurance and cost data when projects are released. Some generalized examples are discussed below.

5.5.4.1 Requirements for Obtaining Commercial Insurance for CCS

The requirements for obtaining commercial insurance for design through building, start-up commissioning and operations are to: (1) demonstrate that the project has followed best practices; and (2) have the following available for the carriers to review:
• A CCS project site assiduously characterized as exceeding safety parameters from a geotechnical perspective.

• An engineering, procurement, and construction (EPC) contract that has avoided inducements/incentives/penalties for schedule or other factors that might cause contractors or project personnel to cut corners on safety or quality.

• A robust monitoring program for subsurface dynamics, pressure control, and tracking of plume migration.

• A project that has a well-defined scope, schedule, and proper EPC contracts and documents that stress safety, QA/QC, and adherence to CCS best practices.

• A project team that has an indisputable track record of experience in designing and building the analogs to this process.

• A policy that only contractors with experience modification rates less than 0.8 will be employed.

• A mitigation strategy for relieving the subsurface field should it become necessary to extract the CO₂ to stabilize the plume or for any reason.

• A set of operating and maintenance practices that follow best practices.

• A standard for certifying and continually training operating and maintenance staff.

• A control and emergency procedures manual that is well understood by personnel and periodically exercised.

• Use of a simulator to train personnel on operations including proper responses to emergency situations or out of tolerance conditions.

5.5.4.2 Costs of Commercial Insurance for CCS

As previously discussed, without having a defined site, scope, and process from which to obtain pricing, assessing the cost of commercial insurance is problematic; however, the following principles are instructive in assessing general cost ranges. Because of the existence of current-day analogs, costs for nearly every phase of CCS are likely discernable. Carriers will likely bring anywhere from $50 million to $250 million in their available line size. It is important to remember that a carrier’s line size or capacity is not what they will necessarily put forth for a particular project. It is anticipated that a CCS project (depending on the size and other factors yet unknown) will have to be structured with limits of no less than $1 billion. It would not be surprising to have to structure capacity and limits equaling $3 billion.
To accomplish this, an insurance program will have to be structured on a quota share basis with a number of carriers each taking a percentage of the overall limit required. The client may decide to accept a self-insured risk exposure in the overall program at various levels. In addition, there will likely be a primary and excess layers of insurance described for the program. The purpose of primary and excess layers of insurance is to obtain different insurance pricing for those regions of the program that have a different prospect of being affected. For example, the primary insurance layer is the first one that will be affected by any loss that exceeds the deductible. The premium for this insurance layer is going to be more expensive than insurance in any of the excess layers, which have a lower probability of being affected by or having to respond to losses.

Figure 5-4 is a very simplified example of how a program could be structured with the client taking a self-insured retention level (deductible) and various carriers placing their capacity at different levels. In this example, the client decided to absorb risk in the excess layers as well.

<table>
<thead>
<tr>
<th>$500</th>
<th>$1000</th>
<th>$1500</th>
<th>$2000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Client (100%)</td>
<td>Client (25%)</td>
<td>Client (75%)</td>
<td>Client (100%)</td>
</tr>
<tr>
<td>Company X (25%)</td>
<td>Company Y (25%)</td>
<td>Company A (25%)</td>
<td></td>
</tr>
<tr>
<td>Company Z (25%)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Figure 5-4. Simplified insurance cost program structure: quota share coverage.**

If an entire CCS project is to be placed under insurance coverage, the likely rate will be an amalgam of the various rates for risks that the carrier has, with the most severe predominating the price calculation. The price of the property cover is likely going to be relatively modest compared to the casualty and liability costs. This is not different than for most other technological processes.

Table 5-1 is an example of a hypothetical CCS operation of an amalgamated risk profile for all phases (separation, transport, and injection). These figures do not relate to any real site or project; however, they provide estimated range of costs and other factors for insurance considerations.
Additional cost refinement can be conducted for a specific location and overall scope of CCS activities including amount of CO$_2$ to be disposed/processed, selection of capture and injection methods, type of pipeline (size, length, etc.), site-specific geotechnical characteristics, storage capacity and other site-specific information.
Table 5-1. Projected insurance premiums and amalgamated risk profile for separation, transport, and injection phases of CCS

<table>
<thead>
<tr>
<th>Rating Basis Assumptions</th>
<th>$</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Property Damage</td>
<td>500,000,000</td>
<td></td>
</tr>
<tr>
<td>Business Interruption</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Gross Earnings</strong></td>
<td>32,000,000</td>
<td></td>
</tr>
<tr>
<td>Replacement Power Extra Expense</td>
<td>120,000,000</td>
<td></td>
</tr>
<tr>
<td><strong>Total Business Interruption</strong></td>
<td>152,000,000</td>
<td></td>
</tr>
<tr>
<td>Annual kW Hours</td>
<td>3,605,858,000</td>
<td></td>
</tr>
<tr>
<td>Payroll</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td><strong>Automobiles</strong></td>
<td>2.00</td>
<td></td>
</tr>
<tr>
<td><strong>Number of CO₂ Injection Wells</strong></td>
<td>1</td>
<td></td>
</tr>
<tr>
<td><strong>Total Vertical Depth of CO₂ Well</strong></td>
<td>8,500 feet</td>
<td></td>
</tr>
</tbody>
</table>

### Operational Phase Insurances

<table>
<thead>
<tr>
<th>Line of Coverage</th>
<th>Limit of Liability</th>
<th>Rating Basis</th>
<th>Rating Method</th>
<th>Rate</th>
<th>Premium</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operational All Risks (OAR)</td>
<td>$ 500,000,000</td>
<td>$ 500,000,000</td>
<td>Per $100 in values</td>
<td>0.25</td>
<td>1,250,000</td>
</tr>
<tr>
<td>Business Interruption (BI)</td>
<td>$ 152,000,000</td>
<td>$ 152,000,000</td>
<td>Per $100 in values</td>
<td>0.75</td>
<td>1,140,000</td>
</tr>
<tr>
<td>General Liability</td>
<td>$ 1,000,000</td>
<td>3,605,858,000</td>
<td>Per kW hr</td>
<td>0.008</td>
<td>28,847</td>
</tr>
<tr>
<td>Worker's Compensation and Employer's Liability</td>
<td>Statutory/$1,000,000</td>
<td>-</td>
<td>Per $100 in Payroll</td>
<td>4.00</td>
<td>-</td>
</tr>
<tr>
<td>Automobile Liability</td>
<td>$1,000,000</td>
<td>2.00</td>
<td>Per Automobile</td>
<td>2.500</td>
<td>5,000</td>
</tr>
<tr>
<td>Excess Liability</td>
<td>$25,000,000</td>
<td>flat</td>
<td>flat</td>
<td>N/A</td>
<td>40,000</td>
</tr>
<tr>
<td>Blowout Insurance</td>
<td>$20,000,000</td>
<td>8,500 feet</td>
<td>Flat - Minimum Premium</td>
<td>N/A</td>
<td>10,000</td>
</tr>
<tr>
<td>Pollution Legal Liability Insurance (CO₂)</td>
<td>$20,000,000</td>
<td>Subjective</td>
<td>Subjective</td>
<td>N/A</td>
<td>250,000</td>
</tr>
</tbody>
</table>

**Total Estimated Premium excluding fees and taxes, if any**  $ 2,723,847
Notes regarding total estimated costs:
1. OAR deductibles: $500,000 per occurrence, except $1,000,000 for machinery breakdown.
2. Business Interruption Waiting Period: 45 Days.
3. Deductibles applicable to General Liability and Automobile Liability - none.
4. Retention for Blowout Insurance: $150,000.
5. Retention for Pollution Legal Liability: $250,000.

Note: Premiums may vary dramatically based on specific underwriting information and other factors.
5.5.5 Preliminary Risk Management Plan

There is a need for the Commonwealth to ensure that any CCS project authorized is following best practices and establishes a risk management plan. Such a plan would incorporate the following basics elements:

- Monthly reporting of progress on the construction.
- Monthly reporting of progress on a schedule versus actual basis.
- On-site inspections both at the CCS location and at critical component manufacturers to ensure that QA/QC safe practices are being rigidly followed.
- A safety protocol for reporting near misses.
- A management of change process.
- A protocol for ensuring that safety and control devices are designed for the duty/service contemplated and are utilized.
- A communication plan to ensure that all contractors and project participants understand the absolute necessity of following good risk management and safety practices.

5.6 FINANCIAL MODELS

This section describes possible financial models based on analogous situations. Although transmission piping is analogous to situations involving current widespread practices, liability associated with a sequestration site presents a more unique challenge.

For transport components, the amount of insurance depends on the size of the pipe, amount of CO₂ to be transported, length of the pipe, and number of compressor stations, among others. It is not uncommon for owners of existing pipelines to only insure critical sections of the pipeline because the risk of loss and the severity of such a loss may not justify carrying coverage for the entire length. Therefore, it is not unusual to have just compressor stations and other critical operations on a pipeline under cover, with owners preferring to self-insure the remainder of the operation. The deductible for CO₂ pipelines could be approximately $100,000 to $250,000; the premium and terms cannot be determined without specific details.

For a storage-site only, the closure and post-closure periods are the critical points wherein a liability period for an insurance carrier will have to sunset and another entity (possibly the government) or another instrument (Trust Bond, Forfeiture Fund, National Consortium of CCS operators fund, etc.) will have to bridge this gap. The Price-Anderson Act, discussed in the following section, is a possible analog for this.
5.6.1 The Price-Anderson Act

The need for possible risk investment in CCS may have a precursor in regard to establishment of a liability fund for the emerging nuclear industry (while also establishing a liability limit or cap that helped to attract investors to this industry). Although the severity of loss from the consequences of a CO$_2$ incident may not be commensurate with a nuclear accident, such a model is useful for constructing a CCS derivative for structuring long-term liability solutions.

The Price-Anderson Act was designed to ensure that adequate funds would be available to satisfy liability claims of members of the public for personal injury and property damage in the event of a catastrophic nuclear accident. The legislation helped encourage private investment in commercial nuclear power by placing a cap, or ceiling, on the total amount of liability each holder of a nuclear power plant license faced in the event of a catastrophic accident. Over the years, the "limit of liability" for a catastrophic nuclear accident has increased the insurance pool to over $10 billion.

Utilities that operate nuclear power plants pay a premium each year for $300 million in private insurance for off-site liability coverage for each reactor unit. This primary insurance is supplemented by a second policy. In the event that a nuclear accident causes damages in excess of $300 million, each licensed nuclear reactor would be assessed a prorated share of the excess up to $95.8 million. This secondary pool contains about $8.6 billion. After 15 percent of this pool is expended, prioritization of the remaining funds is left to the discretion of local jurisdictions. Responding organizations such as state and local governments can petition Congress for additional disaster relief under the provisions of Price-Anderson.

5.6.2 State Ownership/Private Ownership Options

Contemplating a model whereby the public entity establishes ownership of the insurability of CCS (including liability issues) creates several possible conditions to review:

- One scenario would be the establishment of a group captive within the state; however, the Commonwealth in this case would be assuming the role of the insurer of last resort. To do this, the Commonwealth would establish the governance and the financial controls to ensure a reliable flow of funds from the projects is assured and all the participants should have a reasonable financial interest (risk/reward) commensurate with the positions they occupy. The Commonwealth might assume responsibility for the excess layers of coverage and for defaults by subordinate captives (private entities or insurance companies). It is critical to establish a reliable, consistent, and sustained flow of funds from the various projects in the Commonwealth (perhaps predicated on a toll of $ for each unit volume of CO$_2$ extracted, shipped, and stored). In addition of the pool of funds set aside for unforeseen events, the Commonwealth has to assume governance of the projects from the perspective of asserting best practices that must be followed, reviewing and approving each project’s efficacy and technical
sufficiency. It is important to ensure that sufficient funds are available for post-closure phase of the CCS project.

- Another public ownership/stewardship/custodial role for the Commonwealth is to establish a broad set of partnerships with other CCS operations in a national pool of CCS projects. The legal issues need to be crafted to allow cooperation amongst the states. The reliability of any indemnity, extent and duration of potential liability that is offered from this group is significant compared to a single private entity or one state to absorb the responsibly.

- The models (as discussed elsewhere in this report for commencing a role for the Commonwealth or the nation) to accept the liabilities which are too broad and extensive for private entities to contemplate may be found in a CCS derivative of the Price Anderson Act, whereby the state/government collects funds from all ongoing operations to cover the long term liability and damage that may result from CCS failures.

- Another CCS derivative of an existing program for the Commonwealth could be viewed as a quasi governmental precedent. The Servicemen’s Group Life Insurance (SGLI) program offers term life insurance to members of the armed forces as the conventional life insurance contained exclusions for coverage in the event of armed conflict. Conventional insurance appropriately considers war or armed conflict as a certainty of skewing any actuarial table, thus making the coverage of a class of individuals who are subject to be placed in harms way as adverse selection. In order to ensure that service members had coverage, the government hired a private insurance firm to run the administrative portion of the program, but the fully funded the death benefits that were incurred. Service members paid the premiums under SGLI, private insurance companies were selected on a competitive basis to administer the program, but in the end, the government accepted the full liability for paying all the death benefits, irrespective of the amount. Thus, in the absence of conventional insurance coverage, the government stepped in and created a solution not otherwise available due to the pronounced risk profile.

- Shortcomings can occur when the government steps into absorbing insurance coverages for certain classes of risk when private or conventional insurance is not available. The example is the State of Florida catastrophe reinsurance fund. Despite the projections on loss experience and payouts, this particular structure is not effective to financially respond to a bad hurricane season due to insufficient funds. The citizens of Florida may become the default insurer of last resort via increased taxes or one time charges.

- To provide financial solutions for certain risks during defined phases of CCS projects, the Commonwealth can create a hybrid of the above mentioned conditions coupled with the use bond and trust funds. Involving the Commonwealth as the manager of the pool and the private owners, who have
common understanding of the risks and can adhere to a set of best practices mandated by the Commonwealth, could also help accomplishing the coverage for the construction and operational phases as well as the long-term liability of the post closure.

5.6.3 Pool Opportunities

The Price-Anderson Act could serve as a model applicable to CCS and create opportunities for the Commonwealth of Pennsylvania as follows:

- If multiple sites are contemplated in the Commonwealth, Pennsylvania could establish a fund and compel operators to pay a premium into this fund for off-site liability (in this case, likely to cover subsurface contamination of pore space, formation or aquifer damage, etc.).

- When the project is closed (post-closure), the pool of money could be turned over fully to the state to manage this over the long term.

- The possibility of arranging risk pools of CCS operators across the nation, such as was accomplished with American Nuclear Insurers (ANI) (see below). This could be an opportunity to create the private ownership option and coverage pool that the state is also seeking. It is anticipated however that such an arrangement will require some changes in law regarding liability.

The fees for extracting, transporting, and injecting CO₂ could have a toll added to contribute to funding the project. When the site is closed and no further CO₂ is injected, no additional money would be added from the tolling arrangement. CCS project participants or the Commonwealth of Pennsylvania may have to partner with other CCS operations in a national pool to accomplish this, analogous to an example described by the Natural Resource Council. An insurance pool, ANI, is comprised of investor-owned stock insurance companies. Approximately one-half of the pool's total liability capacity comes from foreign sources like Lloyd's of London. The average annual premium for a single-unit reactor site is $400,000. The premium for a second or third reactor at the same site is discounted to reflect a sharing of limits.

The structure of Price-Anderson responds to everything, including transportation of the radioactive material (an analog of the CO₂ pipeline). Again from the NRC (2008):

“Because virtually all property and liability insurance policies issued in the U.S. exclude nuclear accidents, claims resulting from nuclear accidents are covered under Price-Anderson. It includes any accident (including those that come about because of theft or sabotage) in the course of transporting nuclear fuel to a reactor site; in the storage of nuclear fuel or waste at a site; in the operation of a reactor, including the discharge of radioactive effluent; and in the transportation of irradiated nuclear fuel and nuclear waste from the reactor.”
The other public act that may be applicable to CCS is the Disaster Relief Funds - Stafford Act, which is designed to provide early assistance to accident victims. Under a cost-sharing provision, state governments pay 25 percent of the cost of temporary housing for up to 18 months, home repair, temporary mortgage or rental payments, and other "unmet needs" of disaster victims; the federal government pays the balance. This presents an interesting complement to the earlier model from Price-Anderson in that it establishes the path for an incident to be judged by the senior executive government official (in the case of the Stafford Act it would be the President; in the case of the state it could be the Governor), and it addresses the needs of victims who may be displaced by such an event. Potential relocation due to aquifer contamination could fall into this category.

5.6.4 Commonwealth Ownership

Based on its complexity and the lack of site-specific information, it was not possible to develop an approach for Commonwealth ownership for this report. Even so, some models are available that could contribute to understanding the possibilities and challenges of structuring such ownership. One of these that might provide such an insight would be the state-backed catastrophe reinsurance fund in Florida. For CCS operations wherein the Commonwealth assumes responsibility, a key question will involve the monetary source during post-closure.

Spreading the risks present in any CCS project across a private ownership captive pool arrangement (among other private owners who have a common understanding of the risks and adhere to a set of best practices) may be the way to accomplish coverage for the construction and operational phase. The use of bonds and trusts can be used as financial solutions for certain risks during these phases. However, long-term liability coverage for the post-closure period is going to require the active and direct involvement of the Commonwealth as the insurer for excess liability, or perhaps more realistically, the federal government will have to ultimately act as the insurer for this long-term liability exposure.

The document contained in Appendix A was provided courtesy of Chartis (formerly AIG insurance), the first company to place a CCS policy in force in the United States (the Mountaineer CCS project in West Virginia). This document, although it is a specimen policy and not representative of an actual in-force policy, is included to illustrate that coverage is available but that the provisions of insurance for this particular line of coverage require a close scrutiny by clients because this form (and others) contains terms that define events precisely, excludes certain conditions and losses, prescribes how coverage incepts, and also stipulates the limits and deductible. Pricing would be dependent on the actual CCS project being presented for coverage. Items such as limits, deductible, etc. would be provided on a declaration page.

5.7 Cost Estimating

Selecting successful geologic CO₂ sequestration projects involves optimizing multiple key objectives, including lowering cost, minimizing environmental impact and risk, and gaining public acceptance. A range of factors needs to be considered in choosing
appropriate mitigation and disposal options, including how soon each option can be expected to be commercially available, the volume of emissions that can be reduced or offset, other environmental, technical, social, and political factors, as well as cost. Because geologic CO₂ sequestration is a relatively new technology, research and development on this topic is ongoing. Hands-on CCS technology experience is limited globally, and therefore cost estimates, technology selection choices, and performance expectations have a high degree of uncertainty.

There are several reports available that describe the best practices for geologic carbon sequestration from site evaluation, implementation, monitoring, verification, and accounting (LBNL, 2004; Gupta et al., 2004; NETL, 2009; Freifeld et al., 2009; Alberta Carbon Capture and Storage Development Council, 2009). There are also various cost models available for geologic sequestration, including GeoCAT (Geosequestration Cost Analysis Tool) (ICF, 2009), Carnegie Mellon’s engineering performance and cost model for geological storage in deep saline formations (McCoy and Rubin, 2009), IEA’s greenhouse gas R&D program (IEA, 2005), and MIT’s model for economic assessment of CCS (Booras, 2008). The EPA’s recently reported unit costs (in terms of cost per site, per well, per square mile, and other appropriate parameters) for the above-mentioned categories from major data sources for cost analysis (2008). EPA has recognized that no single comprehensive source provides the detailed summaries of a full range of sequestration project cost components. Although these cost estimating models provide an appropriate cost range, a cost estimate for a specific project site using project-specific data is needed to account for all of the variables and site conditions that exist.

Although the geologic sequestration component represents only a portion of total CCS costs, evaluation of the costs to develop and monitor these underground injection sites is critical to understanding the cost of CCS (Chattopadhyay et al., 2005). Vidas et al. (2009) conducted a detailed characterization and model of the individual cost components of geologic sequestration of CO₂. These authors reported a life cycle of 75 years for $135.4 million of capital and operating cost expenditures for a typical commercial-scale saline reservoir geologic sequestration project. The expenditures that occur before injection begins (geologic site characterization, area of review [AoR] study and corrective action, and construction) constitute about 21 percent of total project expenditures. About 53 percent of expenditures occur during the injection period for well operation, monitoring, and mechanical integrity tests. This is reflected in the cost curve module for a typical reservoir in the United States over the life cycle of a CCS project (see Figure 5-5) developed by Vidas et al. (2009).
Table 5-2. Comparative range of carbon sequestration costs

<table>
<thead>
<tr>
<th>Activity</th>
<th>Cost Range ($/ton CO₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capture</td>
<td>13 44 74</td>
</tr>
<tr>
<td>Pipeline</td>
<td>0.75 2 4</td>
</tr>
<tr>
<td>Injection</td>
<td>0.5 4 8</td>
</tr>
<tr>
<td>Monitoring</td>
<td>0.05 0.07 0.10</td>
</tr>
<tr>
<td>Pore Space Acq.</td>
<td>0.04 4 9</td>
</tr>
</tbody>
</table>

$/t$ CO₂ – Dollars per ton of CO₂.

Table 5-2 was developed based on information from several different sources to provide a comparative estimate of the costs for various CCS activities (Benson, 2005; IPCC, 2005; McCoy and Rubin, 2008). Interpreting this table shows that CO₂ capture represents 75 to 90 percent of the overall combined costs of the capture, transport, and storage sequence. In addition, it is an area where there is significant cost uncertainty. An example of the uncertainties that exist include The Intergovernmental Panel on Climate Change (IPCC) report that estimated the cost of acquiring the legal right to sequester CO₂. They reported that the operational cost of CCS and can be between $0.5 and $8 per ton of CO₂. In addition, Laumer (2009) reported that researchers at Carnegie Mellon University modeled the cost to use pore space in Pennsylvania and Ohio and reported that pore space acquisition costs could vary between $0.04 and $9 per ton of CO₂. They also suggested that using thin local formations for sequestration may be more expensive than piping CO₂ to thicker formations at distant sites. Various factors are responsible for the differences in cost of CCS: a) some reports considered only partial costs where others
address the full value chain; b) the characteristics of the reference plants differ (for example, capacity, plant lifetime, etc.); c) the significant escalation in fuel and steel costs in the last three years has driven up overall costs compared to older estimates; and d) assumptions in key variables (for example, CCS efficiency penalty, storage characteristics, etc.).

Because the cost of each project has many variables (point source configuration, CCS technology, fuel costs, size of project, location, reservoir depth and plume extent, pipeline route and distance, etc.) it is recommended that a project-specific cost estimate be completed for each targeted site. These estimates would then be considered among the selection criteria during the site selection phase of the project. To take into account the different project phases (site characterization and selection, design and environmental approvals, construction, operation or injection, closure, post-closure monitoring, and site restoration) and the time that each phase occurs, a Net Present Worth (NPW) of each potential project should be estimated. This would allow the project sponsors to account for the time value of money and could also be used to determine the value of each component per ton of CO₂.
ATTACHMENT 5-A

CHARTIS SPECIMEN POLICY
(formerly known as “AMERICAN INTERNATIONAL SPECIALTY LINES INSURANCE COMPANY”)

POLLUTION LEGAL LIABILITY SELECT® POLICY

MANY OF THE COVERAGEs CONTAIN CLAIMS-MADE-AND-REPORTED REQUIREMENTS. PLEASE READ CAREFULLY. ADDITIONALLY, THIS POLICY HAS CERTAIN PROVISIONS AND REQUIREMENTS UNIQUE TO IT AND MAY BE DIFFERENT FROM OTHER POLICIES THE INSURED MAY HAVE PURCHASED. DEFINED TERMS, OTHER THAN HEADINGS, APPEAR IN BOLD FACE TYPE.

NOTICE: THE DESCRIPTIONS IN ANY HEADINGS OR SUB-HEADINGS OF THIS POLICY ARE INSERTED SOLELY FOR CONVENIENCE AND DO NOT CONSTITUTE ANY PART OF THE TERMS OR CONDITIONS HEREOF.

In consideration of the payment of the premium, in reliance upon the statements in the Declarations and the Application annexed hereto and made a part hereof, and pursuant to all of the terms of this Policy, the Company agrees with the Named Insured as follows:

I. INSURING AGREEMENTS

1. COVERAGES:

THE FOLLOWING COVERAGES ARE IN EFFECT ONLY IF SCHEDULED IN THE DECLARATIONS.

COVERAGE A - ON-SITE CLEAN-UP OF PRE-EXISTING CONDITIONS

1. To pay on behalf of the Insured, Clean-Up Costs resulting from Pollution Conditions on or under the Insured Property that commenced prior to the Continuity Date, if such Pollution Conditions are discovered by the Insured during the Policy Period, provided:

   (a) The discovery of such Pollution Conditions is reported to the Company in writing as soon as possible after discovery by the Insured and in any event during the Policy Period in accordance with Section III. of the Policy.

   Discovery of Pollution Conditions happens when a Responsible Insured becomes aware of Pollution Conditions.

   (b) Where required, such Pollution Conditions have been reported to the appropriate governmental agency in substantial compliance with applicable Environmental Laws in effect as of the date of discovery.

2. To pay on behalf of the Insured, Loss that the Insured is legally obligated to pay as a result of Claims for Clean-Up Costs resulting from Pollution Conditions on or under the Insured Property that commenced prior to the Continuity Date, provided such Claims are first made against the Insured and reported to the Company in writing during the Policy Period, or during the Extended Reporting Period if applicable.

COVERAGE B - ON-SITE CLEAN-UP OF NEW CONDITIONS

1. To pay on behalf of the Insured, Clean-Up Costs resulting from Pollution Conditions on or under the Insured Property that commenced on or after the Continuity Date, if such Pollution Conditions are discovered by the Insured during the Policy Period, provided:
(a) The discovery of such Pollution Conditions is reported to the Company in writing as soon as possible after discovery by the Insured and in any event during the Policy Period in accordance with Section III. of the Policy.

Discovery of Pollution Conditions happens when a Responsible Insured becomes aware of Pollution Conditions.

(b) Where required, such Pollution Conditions have been reported to the appropriate governmental agency in substantial compliance with applicable Environmental Laws in effect as of the date of discovery.

2. To pay on behalf of the Insured, Loss that the Insured is legally obligated to pay as a result of Claims for Clean-Up Costs resulting from Pollution Conditions on or under the Insured Property that commenced on or after the Continuity Date, provided such Claims are first made against the Insured and reported to the Company in writing during the Policy Period, or during the Extended Reporting Period if applicable.

COVERAGE C – THIRD - PARTY CLAIMS FOR ON-SITE BODILY INJURY AND PROPERTY DAMAGE

To pay on behalf of the Insured, Loss that the Insured becomes legally obligated to pay as a result of Claims for Bodily Injury or Property Damage resulting from Pollution Conditions on or under the Insured Property, if such Bodily Injury or Property Damage takes place while the person injured or property damaged is on the Insured Property, provided such Claims are first made against the Insured and reported to the Company in writing during the Policy Period, or during the Extended Reporting Period if applicable.

COVERAGE D – THIRD - PARTY CLAIMS FOR OFF-SITE CLEAN-UP RESULTING FROM PRE-EXISTING CONDITIONS

To pay on behalf of the Insured, Loss that the Insured becomes legally obligated to pay as a result of Claims for Clean-Up Costs resulting from Pollution Conditions, beyond the boundaries of the Insured Property, that commenced prior to the Continuity Date, and migrated from the Insured Property, provided such Claims are first made against the Insured and reported to the Company in writing during the Policy Period, or during the Extended Reporting Period if applicable.

COVERAGE E – THIRD - PARTY CLAIMS FOR OFF-SITE CLEAN-UP RESULTING FROM NEW CONDITIONS

To pay on behalf of the Insured, Loss that the Insured becomes legally obligated to pay as a result of Claims for Clean-Up Costs resulting from Pollution Conditions, beyond the boundaries of the Insured Property, that commenced on or after the Continuity Date, and migrated from the Insured Property, provided such Claims are first made against the Insured and reported to the Company in writing during the Policy Period, or during the Extended Reporting Period if applicable.

COVERAGE F – THIRD - PARTY CLAIMS FOR OFF-SITE BODILY INJURY AND PROPERTY DAMAGE

To pay on behalf of the Insured, Loss that the Insured becomes legally obligated to pay as a result of Claims for Bodily Injury or Property Damage resulting from Pollution Conditions, beyond the boundaries of the Insured Property, that migrated from the Insured Property, provided such Claims are first made against the Insured and reported to the Company in writing during the Policy Period, or during the Extended Reporting Period if applicable.

COVERAGE G – THIRD - PARTY CLAIMS FOR ON-SITE BODILY INJURY, PROPERTY DAMAGE OR CLEAN-UP COSTS - NON-OWNED LOCATIONS

To pay on behalf of the Insured, Loss that the Insured becomes legally obligated to pay as a result of Claims for Bodily Injury or Property Damage of parties other than the owners, operators or contractors of the Non-Owned Location, or their employees, or Clean-Up Costs resulting from Pollution Conditions on or under the Non-Owned Location, provided such Claims are first made against the Insured and reported to the Company in writing during the Policy Period, or during the Extended Reporting Period if applicable.
COVERAGE H – THIRD-PARTY CLAIMS FOR OFF-SITE BODILY INJURY, PROPERTY DAMAGE OR CLEAN-UP COSTS - NON-OWNED LOCATIONS

To pay on behalf of the Insured, Loss that the Insured becomes legally obligated to pay as a result of Claims for Bodily Injury, Property Damage or Clean-Up Costs resulting from Pollution Conditions, beyond the boundaries of the Non-Owned Location, that migrated from the Non-Owned Location, provided such Claims are first made against the Insured and reported to the Company in writing during the Policy Period, or during the Extended Reporting Period if applicable.

COVERAGE I - POLLUTION CONDITIONS RESULTING FROM TRANSPORTED CARGO

To pay on behalf of the Insured, Loss that the Insured becomes legally obligated to pay as a result of Claims for Bodily Injury, Property Damage or Clean-Up Costs resulting from Pollution Conditions caused by Transported Cargo, provided such Claims are first made against the Insured and reported to the Company in writing during the Policy Period, or during the Extended Reporting Period if applicable. This coverage shall not be utilized to evidence financial responsibility of any Insured under any federal, state, provincial or local law.

COVERAGE J - BUSINESS INTERRUPTION COVERAGE - ACTUAL LOSS OR RENTAL VALUE (ONLY AVAILABLE IF COVERAGE A, COVERAGE B OR BOTH COVERAGES A AND B ARE PURCHASED)

To pay the Insured’s Actual Loss or loss of Rental Value, and Extra Expense to the extent it reduces Actual Loss or loss of Rental Value otherwise payable under this coverage section, resulting from an Interruption caused directly by Pollution Conditions on or under the Insured Property. If the Interruption is caused by such Pollution Conditions and any other cause, the Company shall pay only for that portion of Actual Loss or loss of Rental Value, and Extra Expense resulting from an Interruption caused solely and directly by such Pollution Conditions.

1. Such Pollution Conditions must:
   (a) (i) commence prior to the Continuity Date, if the Named Insured has purchased Coverage A, under this Policy, or
   (ii) commence on or after the Continuity Date, if the Named Insured has purchased Coverage B, under this Policy; and
   (b) be first discovered by the Insured during the Policy Period. Discovery of Pollution Conditions happens when a Responsible Insured becomes aware of Pollution Conditions.

2. An Interruption must be reported to the Company, no later than thirty (30) days after its commencement. The Insured shall, as soon as practicable, resume normal operation of the business and dispense with Extra Expense.

3. In determining Actual Loss or loss of Rental Value, the Report/Worksheet annexed to this Policy and made a part of it shall be utilized. If the Insured could reduce the Actual Loss or loss of Rental Value, or Extra Expense resulting from an Interruption:
   (a) by complete or partial resumption of operations; or
   (b) by making use of other property at the Insured Property, or elsewhere,

   such reductions shall be taken into account in arriving at Actual Loss or loss of Rental Value or Extra Expense.

2. LEGAL EXPENSE AND DEFENSE

The Company shall have the right and the duty to defend any Claims covered under Coverages A through I provided the Named Insured has purchased such Coverage. The Company’s duty to defend or continue defending any such Claim, and to pay any Loss, shall cease once the applicable limit of liability, as described in Section V. LIMITS OF COVERAGE: DEDUCTIBLE has been exhausted. Defense costs, charges and expenses are included in Loss and reduce the applicable limit of
liability, as described in Section V., and are included within the Deductible amount for the Coverage Section that applies and is shown in Item 3 of the Declarations.

The Company will present any settlement offers to the Insured, and if the Insured refuses to consent to any settlement within the limits of liability of this Policy recommended by the Company and acceptable to the claimant, the Company’s duty to defend the Insured shall then cease and the Insured shall thereafter negotiate or defend such Claim independently of the Company and the Company’s liability shall not exceed the amount, less the Deductible or any outstanding Deductible balance, for which the Claim could have been settled if such recommendation was consented to.

3. INDEPENDENT COUNSEL

In the event the Insured is entitled by law to select independent counsel to defend the Insured at the Company’s expense, the attorney fees and all other litigation expenses the Company must pay to that counsel are limited to the rates the Company would actually pay to counsel that the Company retains in the ordinary course of business in the defense of similar Claims in the community where the Claim arose or is being defended.

Additionally, the Company may exercise the right to require that such counsel have certain minimum qualifications with respect to their competency, including experience in defending Claims similar to the one pending against the Insured, and to require such counsel to have errors and omissions insurance coverage. As respects any such counsel, the Insured agrees that counsel will timely respond to the Company's request for information regarding the Claim. The Insured may at any time, by its signed consent, freely and fully waive its right to select independent counsel.

II. EXCLUSIONS

1. COMMON EXCLUSIONS - APPLICABLE TO ALL COVERAGES

This Policy does not apply to Clean-Up Costs, Claims, Loss, Actual Loss, Extra Expense, or loss of Rental Value:

A. CRIMINAL FINES, PENALTIES, AND ASSESSMENTS:

Due to any criminal fines, penalties or assessments.

B. CONTRACTUAL LIABILITY:

Arising from liability of others assumed by the Insured under any contract or agreement, unless the liability of the Insured would have attached in the absence of such contract or agreement or the contract or agreement is an Insured Contract.

C. TRANSPORTATION:

Except with respect to Coverage I, arising out of Pollution Conditions that result from the maintenance, use, operation, loading or unloading of any conveyance beyond the boundaries of the Insured Property.

D. INTENTIONAL NONCOMPLIANCE:

Arising from Pollution Conditions based upon or attributable to any Responsible Insured’s intentional, willful or deliberate noncompliance with any statute, regulation, ordinance, administrative complaint, notice of violation, notice letter, executive order, or instruction of any governmental agency or body.

E. INTERNAL EXPENSES:

For costs, charges or expenses incurred by the Insured for goods supplied or services performed by the staff or salaried employees of the Insured, or its parent, subsidiary or affiliate, except if in response to an emergency or pursuant to Environmental Laws that require immediate remediation of Pollution Conditions, or unless such costs,
charges or expenses are incurred with the prior written approval of the Company in its sole discretion.

F. INSURED vs. INSURED:

By any Insured against any other person or entity who is also an Insured under this Policy. This exclusion does not apply to Claims initiated by third parties or Claims that arise out of an indemnification given by one Named Insured to another Named Insured in an Insured Contract.

G. ASBESTOS AND LEAD:

Solely with respect to Coverages A, B, D, E, G, H and J, arising from asbestos or any asbestos-containing materials or lead-based paint installed or applied in, on or to any building or other structure. This exclusion does not apply to Clean-Up Costs for the remediation of soil and groundwater.

H. EMPLOYER LIABILITY:

Arising from Bodily Injury to an Insured or its parent, subsidiary or affiliate arising out of and in the course of employment by the Insured or its parent, subsidiary or affiliate. This exclusion applies whether the Insured may be liable as an employer or in any other capacity and to any obligation to share damages with or repay third parties who must pay damages because of the injury.

I. PRIOR KNOWLEDGE/ NON-DISCLOSURE:

Arising from Pollution Conditions existing prior to the Inception Date and known by a Responsible Insured and not disclosed in the application for this Policy, or any previous policy for which this Policy is a renewal thereof.

J. IDENTIFIED UNDERGOUND STORAGE TANK:

Arising from Pollution Conditions resulting from an Underground Storage Tank whose existence is known by a Responsible Insured as of the Inception Date and which is located on the Insured Property unless such Underground Storage Tank is scheduled on the Policy by endorsement.

2. COVERAGE I EXCLUSIONS

The following exclusions apply to Coverage I.

This Policy does not apply to Loss:

A. PROPERTY DAMAGE TO CONVEYANCES:

For Property Damage to any conveyance utilized during the Transportation of Transported Cargo. This exclusion does not apply to Claims made by third-party carriers of the Insured for such Property Damage arising from the Insured’s negligence.

B. POLLUTION CONDITIONS PRIOR OR SUBSEQUENT TO TRANSPORTATION OF CARGO:

Arising from Pollution Conditions:

1. That commence prior to the Transportation of Transported Cargo; or

2. That commence after Transported Cargo reaches its final destination, or while Transported Cargo is in storage off-loaded from the conveyance that was transporting it.

C. THIRD-PARTY CARRIER CLAIMS:

Made by a third-party carrier, its agents or employees, for Bodily Injury, Property Damage or Clean-Up Costs, whether or not the Bodily Injury, Property Damage or
Clean-Up Costs were directly incurred by such third-party carrier. This exclusion does not apply to Claims arising from the Insured's negligence.

III. NOTICE REQUIREMENTS AND CLAIM PROVISIONS

The Insured shall provide the Company with notice of Pollution Conditions, Claims or an Interruption as follows:

A. NOTICE OF POLLUTION CONDITIONS, CLAIMS AND AN INTERRUPTION

1. In the event of Pollution Conditions or Claims under Coverages A through I, or an Interruption under Coverage J, the Insured shall give written notice to:

   Manager, Pollution Insurance Products Dept.
   Chartis Claims, Inc.
   Attn.: CID
   101 Hudson Street, 31st Floor
   Jersey City, NJ 07302
   Fax: 866-260-0104
   Email: severityfnol@chartisinsurance.com

   or other address(es) as substituted by the Company in writing.

2. The Insured shall give written notice of Pollution Conditions as soon as possible. Notice under all coverages shall include, at a minimum, information sufficient to identify the Named Insured, the Insured Property, the names of persons with knowledge of the Pollution Conditions and all known and reasonably obtainable information regarding the time, place, cause, nature of and other circumstances of the Pollution Conditions.

3. The Insured shall give notice of Claims as soon as possible, but in any event during the Policy Period or during the Extended Reporting Period, if applicable. The Insured shall furnish information at the request of the Company. When a Claim has been made, the Insured shall forward the following to the Company as soon as possible:

   (a) All reasonably obtainable information with respect to the time, place and circumstances thereof, and the names and addresses of the claimant(s) and available witnesses.

   (b) All demands, summonses, notices or other process or papers filed with a court of law, administrative agency or an investigative body.

   (c) Other information in the possession of the Insured or its hired experts which the Company reasonably deems necessary.

B. NOTICE OF POSSIBLE CLAIM

1. If during the Policy Period, the Insured first becomes aware of a Possible Claim, the Insured may provide written notice to the Company during the Policy Period containing all the information required under Paragraph 2. below. Any Possible Claim which subsequently becomes a Claim made against the Insured and reported to the Company within five (5) years after the end of the Policy Period of this Policy or any continuous, uninterrupted renewal thereof, shall be deemed to have been first made and reported during the Policy Period of this Policy. Such Claim shall be subject to the terms, conditions and limits of coverage of the policy under which the Possible Claim was reported.

2. It is a condition precedent to the coverage afforded by this Section III. B that written notice under Paragraph 1. above contain all of the following information:

   (a) the cause of the Pollution Conditions; (b) the Insured Property or other location where the Pollution Conditions took place; (c) the Bodily Injury, Property Damage or Clean-Up Costs which has resulted or may result from such Pollution Conditions; (d) the Insured(s) which may be subject to the Claim and
any potential claimant(s); (e) all engineering information available on the Pollution Conditions and any other information that the Company deems reasonably necessary; and (f) the circumstances by which and the date the Insured first became aware of the Possible Claim.

IV. RIGHTS OF THE COMPANY AND DUTIES OF THE INSURED IN THE EVENT OF POLLUTION CONDITIONS

A. The Company’s Rights

The Company shall have the right but not the duty to clean up or mitigate Pollution Conditions upon receiving notice as provided in Section III. of this Policy. Any sums expended in taking such action by the Company will be deemed incurred or expended by the Insured and shall be applied against the limits of coverage and deductible under this Policy.

B. Duties of the Insured

The Named Insured shall have the duty to clean up Pollution Conditions to the extent required by Environmental Laws, by retaining competent professional(s) or contractor(s) mutually acceptable to the Company and the Named Insured. The Company shall have the right but not the duty to review and approve all aspects of any such clean-up. The Named Insured shall notify the Company of actions and measures taken pursuant to this paragraph.

V. LIMITS OF COVERAGE; DEDUCTIBLE

Regardless of the number of Claims, claimants, Pollution Conditions or Insureds under this Policy, the following limits of liability apply:

A. Policy Aggregate Limit

The Company’s total liability for all Loss, under Coverages A through I, and all Actual Loss, loss of Rental Value and Extra Expense under Coverage J, shall not exceed the “Policy Aggregate” stated in Item 4 of the Declarations. The Company’s internal expenses do not erode the limit of liability available for any Loss.

B. Each Incident Limit - Coverages A Through I

1. Subject to Paragraph V.A. above, the most the Company will pay for all Loss under each Coverage in Coverages A through I arising from the same, related or continuous Pollution Conditions is the “Each Incident” limit of coverage for that particular coverage stated in Item 3 of the Declarations.

2. If the Insured first discovers Pollution Conditions during the Policy Period and reports them to the Company in accordance with Section III., all continuous or related Pollution Conditions reported to the Company under a subsequent Pollution Legal Liability Policy issued by the Company or its affiliate providing substantially the same coverage as this Policy shall be deemed to have been first discovered and reported during the Policy Period.

3. If a Claim for Bodily Injury, Property Damage, or Clean-Up Costs is first made against the Insured and reported to the Company during the Policy Period, all Claims for Bodily Injury, Property Damage or Clean-Up Costs, arising from the same, continuous or related Pollution Conditions that are first made against the Insured and reported under a subsequent Pollution Legal Liability Policy issued by the Company or its affiliate providing substantially the same coverage as this Policy, shall be deemed to have been first made and reported during the Policy Period. Coverage under this Policy for such Claims shall not apply, however, unless at the time such Claims are first made and reported, the Insured has maintained with the Company or its affiliate Pollution Legal Liability coverage substantially the same as this coverage on a continuous, uninterrupted basis since the first such Claim was made against the Insured and reported to the Company.
C. Coverage Section Aggregate Limit

Subject to Paragraph V.A. above, the Company’s total liability for all Loss under each Coverage in Coverages A through I, shall not exceed the “Coverage Section Aggregate” limit of coverage for that particular coverage stated in Item 3 of the Declarations.

D. Maximum for All Business Interruption

Subject to Paragraph V.A. above, the maximum amount for which the Company is liable for all Actual Loss or loss of Rental Value, and Extra Expense under Coverage J is 80% of the lesser of:

1. The Actual Loss and Extra Expense, or loss of Rental Value and Extra Expense, whichever is applicable, incurred during the number of days of interruption of business stated in Item 3 of the Declarations; and

2. The amount stated in Item 3 of the Declarations.

It is a condition of Coverage J that the remaining 20% of such amount be borne by the Insured at its own risk and remain uninsured.

E. Multiple Coverages

Subject to Paragraph V.A. above, if the same, related or continuous Pollution Conditions result in coverage under more than one Coverage under Coverages A through J, every applicable “Each Incident,” “Coverage Section Aggregate,” and “Maximum for All Business Interruption” limit of coverage among such coverage sections shall apply to the Clean-Up Costs, Loss, Actual Loss and Extra Expense, or loss of Rental Value and Extra Expense, whichever is applicable, resulting from such Pollution Conditions.

F. Deductible

1. Coverages A through I

Subject to Paragraphs V.A. through V.E. above, this Policy is to pay covered Loss in excess of the Deductible amount stated in Item 3 of the Declarations for the applicable coverage, up to but not exceeding the applicable “Each Incident” limit of coverage.

If the same, related or continuous Pollution Conditions result in coverage under more than one coverage section in Coverages A through I, only the highest Deductible amount stated in Item 3 of the Declarations among all the coverage sections applicable to the Loss will apply.

The Insured shall promptly reimburse the Company for advancing any element of Loss falling within the Deductible.

2. Coverage J

Subject to Paragraphs V.A. through V.E. above, this Policy is to pay the Actual Loss or loss of Rental Value, and Extra Expense under Coverage J in excess of the Actual Loss or loss of Rental Value, and Extra Expense sustained during the first seven (7) days of an Interruption during the Period of Restoration. The seven (7) day period applies to all Actual Loss, or loss of Rental Value, and Extra Expense arising from the same, related or continuous Pollution Conditions.
VI. CONDITIONS

A. Assignment - This Policy may be assigned with the prior written consent of the Company, which consent shall not be unreasonably withheld or delayed. Assignment of interest under this Policy shall not bind the Company until its consent is endorsed thereon.

B. Subrogation - In the event of any payment under this Policy, the Company shall be subrogated to all the Insured's rights of recovery therefor against any person or organization and the Insured shall execute and deliver instruments and papers and do whatever else is necessary to secure such rights including without limitation, assignment of the Insured's rights against any person or organization who caused Pollution Conditions on account of which the Company made any payment under this Policy. The Insured shall do nothing to prejudice the Company's rights under this paragraph subsequent to Loss. Any recovery as a result of subrogation proceedings arising out of the payment of Loss covered under this Policy shall accrue first to the Insured to the extent of any payments in excess of the limit of coverage; then to the Company to the extent of its payment under the Policy; and then to the Insured to the extent of its Deductible. Expenses incurred in such subrogation proceedings shall be apportioned among the interested parties in the recovery in the proportion that each interested party's share in the recovery bears to the total recovery.

C. Cooperation - The Insured shall cooperate with the Company and offer all reasonable assistance in the investigation and defense of Claims under the applicable Coverages purchased. The Company may require that the Insured submit to examination under oath, and attend hearings, depositions and trials. In the course of investigation or defense, the Company may require written statements or the Insured's attendance at meetings with the Company. The Insured must assist the Company in effecting settlement, securing and providing evidence and obtaining the attendance of witnesses.

D. Changes - Notice to any agent or knowledge possessed by any agent or by any other person shall not effect a waiver or a change in any part of this Policy or estop the Company from asserting any rights under the terms of this Policy; nor shall the terms of this Policy be waived or changed, except by endorsement issued by the Company to form a part of this Policy.

E. Voluntary Payments - No Insured shall voluntarily enter into any settlement, or make any payment or assume any obligation unless in response to an emergency or pursuant to Environmental Laws that require immediate remediation of Pollution Conditions, without the Company's consent which shall not be unreasonably withheld, except at the Insured's own cost.

F. Concealment or Fraud - This entire Policy shall be void if, whether before or after Clean-Up Costs are incurred or a Claim is first made, the Named Insured has willfully concealed or misrepresented any fact or circumstance material to the granting of coverage under this Policy, the description of the Insured Property, or the interest of the Insured therein.

G. Cancellation - This Policy may be cancelled by the Named Insured by surrender thereof to the Company or any of its authorized agents or by mailing to the Company written notice stating when thereafter the cancellation shall be effective. This Policy may be cancelled by the Company only for the reasons stated below by mailing to the Named Insured at the address shown in the Policy, written notice stating when not less than 60 days (10 days for nonpayment of premium) thereafter such cancellation shall be effective. Proof of mailing of such notice shall be sufficient proof of notice.
1. Material misrepresentation by the Insured;

2. The Insured’s failure to comply with the material terms, conditions or contractual obligations under this Policy, including failure to pay any premium or Deductible when due;

3. A change in operations at an Insured Property during the Policy Period that materially increases a risk covered under this Policy.

The time of surrender or the effective date and hour of cancellation stated in the notice shall become the end of the Policy Period. Delivery of such written notice either by the Named Insured or by the Company shall be equivalent to mailing. If the Named Insured cancels, earned premium shall be computed in accordance with the customary short rate table and procedure. If the Company cancels, earned premium shall be computed pro-rata. Premium adjustment may be either at the time cancellation is effected or as soon as practicable after cancellation becomes effective, but payment or tender of unearned premium is not a condition of cancellation.

H. Other Insurance - Where other insurance may be available for Loss, Actual Loss or loss of Rental Value, and Extra Expense covered under this Policy, the Insured shall promptly upon request of the Company provide the Company with copies of all such policies. If other valid and collectible insurance is available to the Insured for Loss, Actual Loss or loss of Rental Value, and Extra Expense covered by this Policy, the Company's obligations are limited as follows:

1. This insurance is primary, and the Company's obligations are not affected unless any of the other insurance is also primary. In that case, the Company will share with all such other insurance by the method described in Paragraph 2. below.

2. If all of the other insurance permits contribution by equal shares, the Company will follow this method also. Under this approach each insurer contributes equal amounts until it has paid its applicable limit of insurance or none of the loss remains, whichever comes first. If any of the other insurance does not permit contribution by equal shares, the Company will contribute by limits. Under this method, each insurer's share is based on the ratio of its applicable limit of insurance to the total applicable limits of insurance of all insurers.

I. Right of Access and Inspection – To the extent the Insured has such rights, any of the Company’s authorized representatives shall have the right and opportunity but not the obligation to interview persons employed by the Insured and to inspect at any reasonable time, during the Policy Period or thereafter, the Insured Property. Neither the Company nor its representatives shall assume any responsibility or duty to the Insured or to any other party, person or entity, by reason of such right or inspection. Neither the Company's right to make inspections, sample and monitor, nor the actual undertaking thereof nor any report thereon shall constitute an undertaking on behalf of the Insured or others, to determine or warrant that property or operations are safe, healthful or conform to acceptable engineering practices or are in compliance with any law, rule or regulation. The Named Insured agrees to provide appropriate personnel to assist the Company's representatives during any inspection.

J. Access to Information - The Named Insured agrees to provide the Company with access to any information developed or discovered by the Insured concerning Loss covered under this Policy, whether or not deemed by the Insured to be relevant to such Loss and to provide the Company access to interview any Insured and review any documents of the Insured.

K. Representations - By acceptance of this Policy, the Named Insured agrees that the statements in the Declarations, the Application and the Report/Worksheet are their agreements and representations, that this Policy is issued in reliance upon the truth
of such representations and that this Policy embodies all agreements existing between the Insured and the Company or any of its agents relating to this insurance.

L. Action Against Company - No third-party action shall lie against the Company, unless as a condition precedent thereto there shall have been full compliance with all of the terms of this Policy, nor until the amount of the Insured's obligation to pay shall have been finally determined either by judgment against the Insured after actual trial or by written agreement of the Insured, the claimant and the Company.

Any person or organization or the legal representative thereof who has secured such judgment or written agreement shall thereafter be entitled to recover under this Policy to the extent of the insurance afforded by the Policy. No person or organization shall have any right under this Policy to join the Company as a party to any action against the Insured to determine the Insured's liability, nor shall the Company be impleaded by the Insured or his legal representative. Bankruptcy or insolvency of the Insured or of the Insured's estate shall not relieve the Company of any of its obligations hereunder.

M. Arbitration - It is hereby understood and agreed that all disputes or differences that may arise under or in connection with this Policy, whether arising before or after termination of this Policy, including any determination of the amount of Loss, may be submitted to the American Arbitration Association under and in accordance with its then prevailing commercial arbitration rules. The arbitrators shall be chosen in the manner and within the time frames provided by such rules. If permitted under such rules, the arbitrators shall be three disinterested individuals having knowledge of the legal, corporate management, or insurance issues relevant to the matters in dispute.

Any party may commence such arbitration proceeding and the arbitration shall be conducted in the Insured's state of domicile. The arbitrators shall give due consideration to the general principles of the law of the Insured's state of domicile in the construction and interpretation of the provisions of this Policy; provided, however, that the terms, conditions, provisions and exclusions of this Policy are to be construed in an evenhanded fashion as between the parties. Where the language of this Policy is alleged to be ambiguous or otherwise unclear, the issue shall be resolved in the manner most consistent with the relevant terms, conditions, provisions or exclusions of the Policy (without regard to the authorship of the language, the doctrine of reasonable expectation of the parties and without any presumption or arbitrary interpretation or construction in favor of either party or parties, and in accordance with the intent of the parties).

The written decision of the arbitrators shall set forth its reasoning, shall be provided simultaneously to both parties and shall be binding on them. The arbitrators' award shall not include attorney fees or other costs. Judgment on the award may be entered in any court of competent jurisdiction. Each party shall bear equally the expenses of the arbitration.

N. Service Of Suit – Subject to Paragraph M. above, it is agreed that in the event of failure of the Company to pay any amount claimed to be due hereunder, the Company, at the request of the Insured, will submit to the jurisdiction of a court of competent jurisdiction within the United States. Nothing in this condition constitutes or should be understood to constitute a waiver of the Company's rights to commence an action in any court of competent jurisdiction in the United States, to remove an action to a United States District Court, or to seek a transfer of a case to another court as permitted by the laws of the United States or of any state in the United States. It is further agreed that service of process in such suit may be made upon Counsel, Legal Department, American International Specialty Lines Insurance Company, 175 Water Street, New York, New York 10038, or his or her representative, and that in any suit
instituted against the Company upon this contract, the Company will abide by the final
decision of such court or of any appellate court in the event of any appeal.

Further, pursuant to any statute of any state, territory, or district of the United States
which makes provision therefor, the Company hereby designates the Superintendent,
Commissioner, Director of Insurance, or other officer specified for that purpose in the
statute, or his or her successor or successors in office as its true and lawful attorney
upon whom may be served any lawful process in any action, suit or proceeding
instituted by or on behalf of the Insured or any beneficiary hereunder arising out of
this contract of insurance, and hereby designates the above named Counsel as the
person to whom the said officer is authorized to mail such process or a true copy
thereof.

O. Acknowledgment of Shared Limits – By acceptance of this Policy, the Named Insureds
understand, agree and acknowledge that the Policy contains a Policy Aggregate Limit
that is applicable to, and will be shared by, all Named Insureds and all other Insureds
who are or may become insured hereunder. In view of the operation and nature of this
shared Policy Aggregate Limit, the Named Insureds and all other Insureds understand
and agree that prior to filing a Claim under the Policy, the Policy Aggregate Limit may
be exhausted or reduced by prior payments for other Claims under the Policy.

P. Separation of Insureds - It is hereby agreed that except with respect to the Limit of
Liability, Section II. F. (Insured vs. Insured exclusion), and any rights and duties
specifically assigned to the first Named Insured, this insurance applies: 1. As if each
Named Insured were the only Named Insured; and 2. Separately to each Named
Insured against whom a Claim is made. Misrepresentation, concealment, breach of a
term or condition, or violation of any duty under this Policy by one Named Insured
shall not prejudice the interest of coverage for another Named Insured under this
Policy. Provided, however, that this Condition shall not apply to any Named Insured
who is a parent, subsidiary or affiliate of the first Named Insured.

VII. EXTENDED REPORTING PERIOD FOR CLAIMS - COVERAGES A THROUGH I

The Named Insured shall be entitled to an Automatic Extended Reporting Period, and (with
certain exceptions as described in Paragraph B. of this Section) be entitled to purchase an
Optional Extended Reporting Period for Coverages A through I collectively, upon termination
of coverage as defined in Paragraph B.3. of this Section. Neither the Automatic nor the
Optional Extended Reporting Period shall reinstate or increase any of the limits of liability of
this Policy.

A. Automatic Extended Reporting Period

Provided that the Named Insured has not purchased any other insurance to replace this
insurance and which applies to a Claim otherwise covered hereunder, the Named Insured
shall have the right to the following: a period of sixty (60) days following the effective
date of such termination of coverage in which to provide written notice to the Company of
Claims first made and reported within the Automatic Extended Reporting Period.

A Claim first made and reported within the Automatic Extended Reporting Period will be
deemed to have been made on the last day of the Policy Period, provided that the Claim
arises from Pollution Conditions that commenced before the end of the Policy Period and
is otherwise covered by this Policy. No part of the Automatic Extended Reporting Period
shall apply if the Optional Extended Reporting Period is purchased.

B. Optional Extended Reporting Period

The Named Insured shall be entitled to purchase an Optional Extended Reporting Period
upon termination of coverage as defined herein (except in the event of nonpayment of
premium), as follows:

1. A Claim first made and reported within the Optional Extended Reporting Period, if
purchased in accordance with the provisions contained in Paragraph 2. below, will be
deemed to have been made on the last day of the Policy Period, provided that the
2. The Company shall issue an endorsement providing an Optional Extended Reporting Period of up to forty (40) months from termination of coverage hereunder for all Insured Properties and Non-Owned Locations, if applicable, or any specific Insured Property or Non-Owned Location, provided that the Named Insured:

(a) makes a written request for such endorsement which the Company receives within thirty (30) days after termination of coverage as defined herein; and

(b) pays the additional premium when due. If that additional premium is paid when due, the Extended Reporting Period may not be cancelled, provided that all other terms and conditions of the Policy are met.

3. Termination of coverage occurs at the time of cancellation or nonrenewal of this Policy by the Named Insured or by the Company, or at the time of the Company's deletion of a location which previously was an Insured Property or Non-Owned Location.

4. The Optional Extended Reporting Period is available to the Named Insured for not more than 200% of the full Policy premium stated in the Declarations.

VIII. DEFINITIONS

A. Actual Loss means the:

1. Net income (net profit or loss before income taxes) the Insured would have earned or incurred had there been no Interruption; and

2. Continuing normal operating expenses incurred, including Ordinary Payroll Expense.

B. Bodily Injury means physical injury, or sickness, disease, mental anguish or emotional distress, sustained by any person, including death resulting therefrom.

C. Claim means a written demand received by the Insured seeking a remedy or alleging liability or responsibility on the part of the Insured for Loss under Coverages A through I. For purposes of this Policy, a Claim does not include a Possible Claim that was reported under a prior policy but which has become a Claim during the Policy Period of this Policy as described in Section III. B.

D. Clean-Up Costs means reasonable and necessary expenses, including legal expenses incurred with the Company's written consent which consent shall not be unreasonably withheld or delayed, for the investigation, removal, remediation including associated monitoring, or disposal of soil, surfacewater, groundwater or other contamination:

1. To the extent required by Environmental Laws; or

2. That have been actually incurred by the government or any political subdivision of the United States of America or any state thereof or Canada or any province thereof, or by third parties.

Clean-Up Costs also include Restoration Costs.

E. Continuity Date means the date stated in Item 8 of the Declarations.
F. **Environmental Laws** means any federal, state, provincial or local laws (including, but not limited to, statutes, rules, regulations, ordinances, guidance documents, and governmental, judicial or administrative orders and directives) that are applicable to Pollution Conditions.

G. **Extended Reporting Period** means either the automatic additional period of time or the optional additional period of time, whichever is applicable, in which to report Claims following termination of coverage, as described in Section VII. of this Policy.

H. **Extra Expense** means necessary expenses the Insured incurs during the **Period of Restoration**:

1. That would not have been incurred if there had not been an Interruption; and
2. That avoid or minimize an Interruption,

but only to the extent such expenses reduce Actual Loss or loss of Rental Value, whichever is applicable, otherwise covered under this Policy.

Extra Expense will be reduced by any salvage value of property obtained for temporary use during the **Period of Restoration** that remains after the resumption of normal operations.

I. **Inception Date** means the first date set forth in Item 2 of the Declarations.

J. **Insured** means the Named Insured, and any past or present director, officer, partner or employee thereof, including a temporary or leased employee, while acting within the scope of his or her duties as such.

K. **Insured Contract** means a contract or agreement submitted to and approved by the Company, and listed on an Endorsement to this Policy.

L. **Insured Property** means each of the locations identified in Item 5 of the Declarations.

M. **Interruption** means the necessary suspension of the Insured’s business operations at an Insured Property during the **Period of Restoration**.

N. **Loss** means, under the applicable Coverages:

1. Monetary awards or settlements of compensatory damages; where allowable by law, punitive, exemplary, or multiple damages; and civil fines, penalties, or assessments for Bodily Injury or Property Damage;
2. Costs, charges and expenses incurred in the defense, investigation or adjustment of Claims for such compensatory damages or punitive, exemplary or multiple damages, and civil fines, penalties or assessments, or for Clean-Up Costs; or
3. Clean-Up Costs.

O. **Named Insured** means the person or entity named in Item 1 of the Declarations acting on behalf of all other Insureds, if any, for the payment or return of any premium, payment of any deductible, receipt and acceptance of any endorsement issued to form a part of this Policy, giving and receiving notice of cancellation or nonrenewal, and the exercise of the rights provided in the **Extended Reporting Period** clause.

P. **Natural Resource Damage** means physical injury to or destruction of, including the resulting loss of value of, land, fish, wildlife, biota, air, water, groundwater, drinking water supplies, and other such resources belonging to, managed by, held in trust by, appertaining to, or otherwise controlled by the United States (including the resources of the fishery conservation zone established by the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. 1801 et seq.)), any state or local...
government, any foreign government, any Indian tribe, or, if such resources are subject to a trust restriction on alienation, any member of an Indian tribe.

Q. Non-Owned Location means a site that is not owned or operated by the Named Insured, and that is identified in a Non-Owned Covered Locations Schedule attached to and made a part of this Policy by endorsement.

R. Ordinary Payroll Expense means the entire payroll expense for all employees of the Insured, except officers, executives, department managers and employees under contract.

S. Period of Restoration means the length of time as would be required with the exercise of due diligence and dispatch to restore the Insured Property to a condition that allows the resumption of normal business operations, commencing with the date operations are interrupted by Pollution Conditions and not limited by the date of expiration of the Policy Period. The Period of Restoration does not include any time caused by the interference by employees or other persons with restoring the property, or with the resumption or continuation of operations.

T. Policy Period means the period set forth in Item 2 of the Declarations, or any shorter period arising as a result of:

1. Cancellation of this Policy; or

2. With respect to particular Insured Property(s) or Non-Owned Location(s) designated in the Declarations, the deletion of such location(s) from this Policy by the Company at the Named Insured’s written request, but solely with respect to that Insured Property or Non-Owned Location.

U. Pollution Conditions means the discharge, dispersal, release or escape of any solid, liquid, gaseous or thermal irritant or contaminant, including, but not limited to, smoke, vapors, soot, fumes, acids, alkalis, toxic chemicals, medical waste and waste materials into or upon land, or any structure on land, the atmosphere or any watercourse or body of water, including groundwater, provided such conditions are not naturally present in the environment in the amounts or concentrations discovered.

V. Possible Claim means Pollution Conditions that commenced on or after the Inception Date that the Insured reasonably expects may result in a Claim.

W. Property Damage means:

1. Except with respect to Coverage C, physical injury to or destruction of tangible property of parties other than the Insured, including the resulting loss of use and diminution in value thereof;

2. Loss of use, but not diminution in value, of tangible property of parties other than the Insured that has not been physically injured or destroyed;

3. Solely with respect to Coverage C, physical injury to or destruction of tangible property of parties other than the Insured, including the resulting loss of use thereof; and


Property Damage does not include Clean-Up Costs.

X. Rental Value means the:

1. Total anticipated rental income from tenant occupancy of the Insured Property as furnished and equipped by the Insured;

2. Amount of all charges that are the legal obligation of the tenant(s) pursuant to a lease and that would otherwise be the Insured’s obligations; and
3. Fair rental value of any portion of the Insured Property that is occupied by the Insured during the Period of Restoration, less any rental income the Insured could earn:

(a) by complete or partial rental of the Insured Property, or

(b) by making use of other property on the Insured Property or elsewhere.

Y. Responsible Insured means the manager or supervisor of the Named Insured responsible for environmental affairs, control or compliance, or any manager of the Insured Property, or any officer, director or partner of the Named Insured.

Z. Restoration Costs means reasonable and necessary costs incurred by the Insured with the Company’s written consent, which consent shall not be unreasonably withheld or delayed, to repair, replace or restore real or personal property to substantially the same condition it was in prior to being damaged during work performed in the course of incurring Clean-Up Costs. However, such Restoration Costs shall not exceed the net present value of such property prior to incurring Clean-Up Costs. Restoration Costs do not include costs associated with improvements or betterments.

AA. Transportation means the movement of Transported Cargo by a conveyance, from the place where it is accepted by a carrier until it is moved:

1. To the place where the carrier finally delivers it; or

2. In the case of waste, to a waste disposal facility to which the carrier delivers it.

Transportation includes the carrier’s loading or unloading of Transported Cargo onto or from a conveyance provided that the loading or unloading is performed by or on behalf of the Named Insured.

BB. Transported Cargo means goods, products, or waste transported for delivery by a carrier properly licensed to transport such goods, products, or waste.

CC. Underground Storage Tank means any tank that has at least ten (10) percent of its volume below ground in existence at the Inception Date, or installed thereafter, including associated underground piping connected to the tank.

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6.0 FINDINGS & RECOMMENDATIONS

6.1 Introduction

This report discusses the viability of a CCS network to reduce GHG emissions in the Commonwealth of Pennsylvania. The information currently available, reviewed and discussed in this report suggests favorable geologic conditions exist for such a network. CCS has quantifiable risks that are currently addressed by the insurance market. However, there is no commercially available insurance solution that will cover the long term liability of the site after closure. The current legal framework in the Commonwealth is problematic but solutions are available. It appears that the CCS network project can achieve the overall goals identified by the Commonwealth of Pennsylvania.

Additional data and information are needed to further refine this conclusion. Although CCS is proposed and considered by many to provide part of the solution to reversing climate change by reducing GHG emissions, further understanding, scrutiny, and optimization of the concept is required to ensure it can be done without risk to human health and the environment.

The next suggested step would be to identify specific geographic areas be evaluated. This will allow development and integration of all of the distinct elements - geology, legal implications, risk analysis, insurance components and cost - discussed in this report. The following sections provide an overview of the findings within the report.

6.2 CO₂ Storage Site Assessments

The Upper Devonian Venango Group sandstones, Oriskany Sandstone Formation, Medina Group/Tuscarora Sandstone and the Salina Group each have potential as viable sequestration targets. Other Upper Devonian sandstones (where present at depths greater than 2,500 ft), Silurian Bass Island Dolomite, Cambrian Gatesburg Formation, and deeper basal Cambrian sandstones also offer significant potential and deserve closer evaluation. In north-central and southwestern Pennsylvania, the Upper Silurian Salina Group contains a thick sequence of salt. The thick net salt area in the southwestern part of the Commonwealth is situated near many of the largest sources of CO₂ and may be a potential for a storage reservoir. Historically, salt caverns have been used to successfully storage natural gas and compressed air. Potential physical limitations with construction of salt caverns and issues dealing with the brine water will require further evaluation for potential and economic use. The Oriskany Sandstone is a target formation based on natural gas plays, several successful industrial waste injection projects and natural gas storage fields in this formation. Overall, a large number of deep (greater than 2500 ft) borings/wells have been drilled in the central Appalachian Plateau area; therefore, the deep formation characteristics, at least through the Oriskany Sandstone interval, are fairly well known. The Medina Group/Tuscarora Sandstone (which can be much thicker than the Oriskany) is another sequestration target which is widespread in this area and has proven to have adequate permeability for significant natural gas production and gas storage. The deeper Cambrian Gatesburg and basal Cambrian sandstones may offer substantial potential as well with great thicknesses possible on downblocks of Precambrian basement faults which occur in this area. The high number of proximal CO₂
point sources in the central portion of the Appalachian Plateau Province reduces the piping network.

Other regions, such as the northeast portion of the Appalachian Plateau in Pennsylvania, much of the Valley and Ridge province and all of Gettysburg Basin and Piedmont Provinces may be viable targets, but insufficient geologic information exists to make a sound determination of their viability at this time. A notable concern with the Ridge and Valley Province is potential for leaking of \( \text{CO}_2 \) via faults which often reach the ground surface. These areas may be suitable for geologic sequestration, but additional data (from new wells and seismic data collection) are needed for a thorough evaluation of potential. If additional data is to be collected, these areas should be prioritized as follows: the Appalachian Plateau and Valley and Ridge, the Gettysburg Basin and finally the Piedmont Provinces.

The following specific recommendations should be considered to identify and further refine the understanding of the candidate areas and formations:

1. To better understand the viability of the Appalachian Plateau, the collection and utilization of the Marcellus Shale drill logs, wireline logs and other data from drilling these wells should be used to the maximum extent possible. These wells penetrate into the Middle Devonian and can provide a better understanding of the Upper Devonian and perhaps the integrity of the Oriskany cap rock. Inclusion of these data in a GIS database of current and former oil and gas wells will help us better understand the subsurface geology with proximity to former oil and gas wells, and thereby help determine the risks associated with \( \text{CO}_2 \) sequestration in the Upper Devonian and Oriskany.

2. For the potential sequestration targets below the Upper Devonian, all available seismic data should be reviewed to identify favorable areas for sequestration related to structural position (and fracturing), integrity of cap rock, thickness of the unit (e.g., basal Cambrian sandstones in Rome Trough area), etc. In areas with significant potential additional seismic data should be collected followed by drilling of wells required to better understand key characteristics of the sequestration and cap rock intervals.

3. A better understanding of the geologic formations and the cap rock in which CCS is viable should be done using three dimensional analysis and illustrations. This can be accomplished with the creation of a three dimensional model using GIS that will incorporate the lithology, extent, thickness and structural information for each formation along with data on other key characteristics (e.g., permeability, fracture pressure, salinity, etc.). This will allow scientists and engineers, and the public, to better understand the extent, depth, structure and other key characteristics of each unit. This tool can also assist in better understanding how the risks of injection in one formation may be influenced by activity (e.g., oil and gas exploration and development) in another formation. Data for the modeling
can be stored and managed utilizing the database referenced in the DCNR 2009 report.

4. Once target areas for CO2 are selected, additional site specific information will be required. The following data are recommended to be collected and analyzed through a test boring program:

   • Testing of potential cap rock intervals by permeability testing of core samples, petrographic analysis and other means to confirm properties are favorable for containment.

   • Develop a database of fracture pressures for each cap rock interval by laboratory testing or by other field-determined means. This data can be utilized to identify maximum pressures for CO\textsubscript{2} injection that will not compromise the integrity of the cap rock.

   • The potential increase in porosity and permeability and hence storage capacity resulting from stimulating the formation (e.g., through hydraulic fracturing and acidizing) should be evaluated. Reviewing such records pertaining to oil and gas production from the target formations can help in this evaluation.

   • Conduct geochemical testing for each target formation to determine whether the reaction with CO\textsubscript{2} may result in reductions in permeability, mobilization of hydrocarbons, etc.

5. It is recommended that at least three specific candidate sites for CO2 injectivity testing considering proximity to large source of CO2, anticipated injectivity and storage capacity (following stimulation if necessary), presence of cap rock of suitable thickness and integrity, lack of pathways for migration out of the injection zone (e.g., poorly plugged wells, faults, etc.), cooperation of landowners and lease owners, etc. Potential injectivity testing sites should be ranked based on criteria discussed in this report and testing performed at the best candidate site(s). Ideally, sites selected for testing will have potential for multiple formations which have good potential for carbon storage.

6. It is also recommended that the feasibility of utilizing abandoned natural gas storage fields be evaluated considering such factors as proximity to major CO2 sources, capacity, integrity of wells, operating results, acquisition costs, etc.

6.3 Legal Liability Assessment

In order to create a CCS network, property rights, liability issues, and regulatory requirements must be addressed.
Development of a GS network faces a number of legal and practical property rights issues. There are legal and practical uncertainties regarding:

- the nature of the right to use subsurface strata;
- who owns the rights;
- how many properties may be affected; and
- the fragmentation of ownership across the landscape and between owners of different estates, how does one assemble the property rights.

There are numerous possible solutions:

- use only contiguous tracts of land owned by a single landowner who owns both surface and mineral rights in fee simple;
- pass legislation that clarifies the nature of the right to sequester CO\textsubscript{2}, vests it in a particular owner
- provide means to acquire that right such as a variant of the unitization programs used for oil and gas in other states;

Because there is no current market for determining the value of pore space, it may be necessary to establish a value by statute in order to facilitate acquisition of the right. These approaches could be incorporated into draft legislation that should be developed as a party of a further study. This study should also investigate tracts of land that will minimize property rights issues and satisfy the conditions described in other sections of this report (e.g., land that overlies suitable CO\textsubscript{2} storage capacities and includes the appropriate proximity to point sources or the pipeline networks while eliminating remote or environmentally sensitive locations).

All parties involved in GS could potentially face liability for personal injury and property damage arising from transportation and sequestration of CO\textsubscript{2}. Specific mechanisms that will fix/limit the financial and legal exposure of those implementing the technology should be evaluated. This can be accomplished by: (1) providing full or partial immunity from liability to some or all of those parties involved in the injection; (2) acquiring commercial insurance; (3) creating an alternative to insurance such as a liability fund; (4) transferring liability to the government statutorily, by having the government assume responsibility for the activity or by providing indemnification; and (5) various combinations of the above. A combination of these mechanisms will likely be most cost effective. Commercial insurance should be required, as should the provision of financial assurance mechanisms for post closure monitoring and care. These requirements can be supplemented by the creation of indemnity funds that are funded with tax dollars, or charges on disposal. These extra funds will pick up where the insurance and financial assurance does not.

Creation of a sound, coordinated and predictable regulatory mechanism is essential to manage the risks of GS. Currently proposed federal UIC regulations represent the best mechanisms to manage risk, including requirements for siting, construction, operation, financial assurance, closure and post-closure care. While Pennsylvania does not have an
approved UIC program, it may have the statutory authority to adopt similar or more protective regulations and to obtain primacy or partial primacy. Adopting regulations that would allow Pennsylvania to implement both the federal and state programs would likely best promote GS by eliminated the need for two permits and two sets of regulations.

The authority to implement these programs within Pennsylvania should reside with Commonwealth. It is unlikely the Commonwealth can fund this process, so creation of a public-private partnership should be evaluated as a potentially more effective vehicle to finance, execute and complete a project. Therefore, the legislation should also include mechanisms that would contemplate private ownership or operation.

Comprehensive legislation should be developed as a part of a further study implementing the recommendations relating to property rights, liability and regulation. Siting criteria developed in future studies should be incorporated in the legislation or regulations. Legislation that has already been introduced in the General Assembly will accomplish some but not all of the necessary elements. There is also model legislation that can be used and tailored to Pennsylvania.

6.4 Safety/Risk Assessment

The safety and risk assessment is divided into three primary parts that correspond to the potential exposure sources: 1) capture technologies to be deployed at point sources (e.g., power plants), 2) the pipelines that will be required to transport CO$_2$ to the sequestration site, and 3) any releases of CO$_2$ from geologic storage sites.

While capture of CO$_2$ can be achieved from numerous point sources, CCS from coal-fired power plants is the most likely. The capture of CO$_2$ from existing pulverized coal power plants and associated risks are fairly well understood. The risk to the public from capture will be minimized as capture will likely be done on the power plant property.

Transport of captured CO$_2$ will likely occur in a network of pipelines. Currently there is an extensive pipeline network for natural gas and refined petroleum products in Pennsylvania; however, there are currently no CO$_2$ pipelines in the Commonwealth. The 37-year history of CO$_2$ pipelines in the US has shown that this gas can be transported safely. Incidents involving CO$_2$ pipelines between 1988 and 2008 have not resulted in any fatalities, and the annual incident frequency is 0.23 per 1,000 km linear pipe distance. This is similar to the incident frequency of natural gas (OPS, 2009). The major cause of pipeline failure is damage (puncture or rupture) during excavation. As the Pennsylvania pipeline network is being developed, release scenarios and exposure analysis should be included during the project design phase.

Determination of storage risk is highly dependent on the site specific conditions. As identification and characterization of a specific candidate site has not yet been done, details of risk associated with an injection and storage site in Pennsylvania is unknown. The primary release mechanisms can be either short-term (catastrophic) or long-term, but the time frame of the risk assessment includes the period from the pilot, thru operation of
CO₂ capture at the plant, to plant closure (estimated to be 30 years to 50 years), and then a much longer time period for the post-injection period [i.e., on the order of 1,000 to 5,000 years]. Without having a specific site(s) to evaluate it is difficult to determine the risk associate with injection and storage. Therefore, it is recommended that specific areas and then sites within that area should be identified to refine these analyses.

Once specific site(s) are identified, release scenarios should be reevaluated to quantify the true injection and storage risk. Risk thresholds must be identified to determine when a site exceeds an acceptable risk level. If the risk for a given site exceeds these risk thresholds, other site(s) will need to be selected and evaluated.

Once the sequestration site is selected, an effective MMV plan must be developed and executed. MMV tools have improved significantly in breadth of application, sensitivity, and resolution during the demonstration phase of the CCS technology. A wide range of methods have been developed and tested to monitor the movement of CO₂ from the capture site, along pipeline corridors, and into and within geologic storage sites. Adequate MMV technology exists today for the ongoing demonstration projects, but new and innovative methods that can be applied in a wide range of conditions are needed to ensure the ability to detect and monitor the movement of CO₂ within storage reservoirs, the ability to detect and respond to changes in the containment of the stored CO₂, and to assess the environmental, safety and health impacts in the event of releases to the atmosphere or groundwater occur.

A Risk Management Plan should be defined for each site(s). The goal of the Risk Management Plan is to build regional and site-specific knowledge that can be used to 1) achieve maximum CO₂ capture potential; 2) facilitate transparent communication between project developers and operators, policy makers and regulators, and the public to develop a fuller appreciation of all the factors involved; and 3) minimize risk and establish a technical basis for activities during the pre-injection, injection, and post-injection/closure phases of the project.

6.5 Insurance Assessment/Financial Models

CCS is not perceived by many insurance firms as having a sufficient “past history” from which coverage can be based. This represents the primary challenge for a CCS project in attracting the necessary capacity and risk-sharing arrangements. To attract the available capacity and coverage, project developers of early CCS projects must attempt to educate the public and other stakeholders, including some in the insurance industry, regarding the processes and related technologies required to implement a CCS project. During this process it should be made clear that, with one exception, the processes/technologies that are used in CCS exist widely in the U.S. today, are well understood, and have been afforded ample insurance coverage. The exception is that no commercially viable insurance solution exists that is sufficient for covering the long-term liability required for CCS.

Liability coverage will likely be available through the design, construction, and injection phases. There may even be a short time wherein some liability coverage is extended into
the post-closure period. However, such insurance will probably be offered in such a manner that its terms, conditions, premium, deductible, exclusions, etc., will be able to be modified on each renewal period, which will likely be one year. Thus, the reality is that long-term liability will require a governmental presence for indemnifying and absorbing such risk. This aspect of the project will have to be considered by the Commonwealth.

For transport components, the amount of insurance depends on such factors as the size of the pipe, amount of CO₂ to be transported, length of the pipe, and number of compressor stations. It is not uncommon for owners of existing pipelines to only insure critical sections of the pipeline because the risk of loss and the severity of such a loss may not justify carrying coverage for the entire length.

For a storage-site only, the closure and post-closure periods are the critical points wherein a liability period for an insurance carrier will have to sunset and another entity (possibly the government) or another instrument (Trust Bond, Forfeiture Fund, National Consortium of CCS operators fund, etc.) will have to bridge this gap. The Price-Anderson Act is a possible analog for this.

The Price-Anderson Act was designed to ensure that adequate funds would be available to satisfy liability claims of members of the public for personal injury and property damage in the event of a catastrophic nuclear accident. The legislation helped encourage private investment in commercial nuclear power by placing a cap, or ceiling, on the total amount of liability each holder of a nuclear power plant license faced in the event of a catastrophic accident.

Contemplating a model whereby the public entity establishes ownership of the insurability of CCS (including liability issues) creates several possible conditions to review. One scenario would be the establishment of a group of CCS operators captive within the state; however, the Commonwealth in this case would be assuming the role of the insurer of last resort. Another public ownership/stewardship/custodial role for the Commonwealth is to establish a broad set of partnerships with other CCS operations in a national pool of CCS projects. The legal issues need to be crafted to allow cooperation amongst the states. The reliability of any indemnity, extent and duration of potential liability that is offered from this group is significant compared to a single private entity or one state to absorb the responsibly. Another CCS derivative of an existing program for the Commonwealth could be viewed as a quasi governmental precedent. The Servicemen’s Group Life Insurance (SGLI) program offers term life insurance to members of the armed forces as the conventional life insurance contained exclusions for coverage in the event of armed conflict.

Some models are available that could contribute to understanding the possibilities and challenges of structuring Commonwealth ownership. One of these that might provide such an insight would be the state-backed catastrophe reinsurance fund in Florida.

Spreading the risks present in any CCS project across a private ownership captive pool arrangement (among other private owners who have a common understanding of the risks
and adhere to a set of best practices) may be the way to accomplish coverage for the construction and operational phase. The use of bonds and trusts can be used as financial solutions for certain risks during these phases. However, long-term liability coverage for the post-closure period is going to require the active and direct involvement of the Commonwealth as the insurer for excess liability, or perhaps more realistically, the federal government will have to ultimately act as the insurer for this long-term liability exposure.

Hands-on CCS technology experience is limited globally, and therefore cost estimates, technology selection choices, and performance expectations have a high degree of uncertainty. Although cost estimating models from published provide an appropriate cost range, a cost estimate for a specific project site using project-specific data is needed to account for all of the variables and site conditions that exist. Because the cost of each project has many variables (point source configuration, CCS technology, fuel costs, size of project, location, reservoir depth and plume extent, pipeline route and distance, etc.) it is recommended that a project-specific cost estimate be completed for each targeted site. These estimates would then be considered among the selection criteria during the site selection phase of the project.

6.6 Summary

The findings in this report suggest that a CCS network can be achieved successfully and safely in the Commonwealth of Pennsylvania. However, there are many potential concerns that must be addressed for a CCS project to be implemented. These concerns include identification of specific sites where CCS can be successfully implemented.
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GLOSSARY

Ancillary Systems – CO₂ compressors, booster pumps, surge tanks, and other equipment are all off-the-shelf technologies that can be considered routine aspects of CCS operations.

Basalt Formation - Basalts are rich in iron and other elements (Al, Ti, Ca, Mg, Si, etc.) that allow for the inclusion and permanent storage of CO₂ in carbonate minerals, so the mineralization potential in these formations tends to be much higher.

Cap and Trade - Market-based policy tool for curbing carbon emissions. Generally, a maximum limit on carbon emission allowance is set. Carbon producers are then allowed to design their own compliance strategy to meet the overall reduction requirement, which may include the sale or purchase of carbon credits, installation of pollution controls, and implementation of efficiency measures, among other options.

Carbon Dioxide - A colorless, odorless, non-poisonous gas that is a normal part of the ambient air. The molecule is made up of one carbon atom and two oxygen atoms. Carbon dioxide is the principal greenhouse gas that contributes to global warming.

Carbon Sequestration - Capturing atmospheric carbon (carbon dioxide) and storing it by one of several mechanisms to reduce this greenhouse gas and its contribution to global warming. Carbon may be stored in living (green vegetation and forests) or non-living reservoirs (soil, geologic formations, oceans, wood products).

Climate Change - The long-term fluctuations in temperature, precipitation, wind, and all other aspects of the Earth's climate.

CO₂ Capture - For some CO₂ emissions mitigation applications, first-generation CO₂ capture systems already exist and can be purchased from commercial vendors. But the cost, performance, and other operating characteristics of these first-generation CO₂ capture systems need to be improved in order to enable CCS systems to deploy to their full market potential. The scale of today’s CO₂ capture systems is also considerably smaller than the scale needed to address climate change concerns.

CO₂ Injection into Deep Geologic Formations - The most likely CO₂ storage sites are deep geologic formations. The technologies to inject CO₂ into these formations exist today and are routinely used in the oil and gas industries. Though CO₂ injection can be considered an established technology, ways to optimize injection, such as using lateral wells and injecting into multiple vertically stacked reservoirs, still need to be better understood. The continued development and field demonstration of these more advanced drilling and CO₂ injection techniques could facilitate the use of CCS, a necessary step if CCS technologies are to deploy on a large scale.

CO₂ Storage – CO₂ can be stored in geological media by various means through a variety of physical and chemical trapping mechanisms. In physical traps, CO₂ retains its
structure and characteristics, while in chemical traps it is adsorbed onto organic material or it dissolves in formation water, with the subsequent potential of precipitating as a mineral carbonate. R&D work related to storage of CO2 storage will be in areas such as capacity, downhole flow, and monitoring techniques. Much of this research is already under way. Several geologic sequestration projects are currently underway or planned: Sleipner (Statoil/North Sea), Weyburn (EnCana/Canada), In Salah (BP and Sonatrach/Algeria), Snohvit (Statoil, Petoro, TotalFinaElf, and others/Barents Sea), Gorgon (Chevron Texaco/Australia) projects have a varied research program addressing geophysical and geochemical monitoring, verification, wellbore integrity and risk assessment – and recommendations that should help advance new storage projects in Pennsylvania.

**CO2 Transport** - A transportation system is needed to connect capture and compression sites with storage sites. Transport can be done via pipeline or by tanker. For economic reasons the CO2 is compressed to either a supercritical or liquid phase. Transporting CO2 is an established practice. Currently, more than 3,000 miles of dedicated CO2 pipeline exist in the United States. The principal issue for CO2 transport is the potential obstacles in the siting and placement of potentially large CO2 pipeline networks that would likely be needed as CCS systems begin to deploy at a significant scale.

**Coalbed Methane** - Methane contained in coal seams, and is often referred to as virgin coalbed methane, or coal seam gas.

**Deep Saline Formation** - Sandstone and carbonate (limestone or dolomite) rocks with void spaces inhabited by salty water.

**Depleted Natural Gas Reservoir** - Once the formation has been stripped of its natural gas, it essentially behaves like a deep saline formation in terms of CO2 storage.

**Depleted Oil Reservoir** - Once the recoverable oil has been produced from the formation, CO2 may be stored in the available pore space and/or CO2 injection can also be used to recover additional oil that was left behind during primary production.

**Geologic Storage** – It means underground storage or sequestration of carbon dioxide or other greenhouse gas in a reservoir, including and EOR reservoir.

**Greenhouse Gas** - Any gas that absorbs infrared radiation in the atmosphere. Greenhouse gases include, but are not limited to, water vapor, carbon dioxide (CO2), methane(CH4), nitrous oxide(N2O), chlorofluorocarbons(CFCs), hydrochlorofluorocarbons (HCFCs), ozone (O3), hydrofluorocarbons(HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6).

**Measurement, Monitoring, and Verification (MMV)** - MMV technologies, crucial elements of a complete CCS system, are not as easily described as established technologies. Some off-the-shelf MMV technologies can be applied to ensure safe and effective storage of injected CO2 in certain classes of formations and under specific.
MMV is, and will continue to be, an active area of intense research; new MMV technologies need to be developed and the cost, performance, and other operating characteristics of existing MMV technologies need to be improved. Prospective industrial users and regulators also need to create a shared vision of what it means in practice to measure, monitor, and verify CO$_2$ that has been injected into the deep subsurface.

**Pore Space** - Space between rock or sediment grains that can contain fluids. Thus far, no court has specifically ruled on who owns pore space needed by a CO$_2$ sequestration project. It is likely that the surface owner generally will be found to own the pore space. The pore space ownership rights may well be limited in accordance with rights to use the pore space held by mineral owners.