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Geologic CO_2 Sequestration Technology and Cost Analysis

TECHNICAL SUPPORT DOCUMENT

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1 Introduction

The Environmental Protection Agency is developing a set of regulatory alternatives for the geological sequestration (GS) of carbon dioxide. EPA's rule, which will be part of EPA's Underground Injection Control regulations, will provide federal requirements for owners and operators of sequestration operations. It is intended to protect underground sources of drinking water and provide regulatory certainty and permitting consistency for industry.

This Technology and Cost (T&C) Document describes the costs of specific technologies and operating practices that could be applied to underground geologic sequestration of CO_2. The costs are estimated for specific technologies, and then are applied to examples of saline reservoirs, depleted gas reservoirs, and depleted oil reservoirs to estimate total project costs. Examples are provided for both "commercial scale" and "pilot scale" geologic sequestration projects.

While characteristics vary according to geologic site characteristics, for the purposes of this analysis we have developed examples that are representative of different types of geologic sites. The "commercial scale" examples represent typical geologic conditions for sequestration and are based upon sequestering the CO_2 emissions from a 275 MW power plant with an injection period for each sequestration site of 20 years. The "pilot scale" examples are smaller in scale and have characteristics similar to what is planned by the Department of Energy at several sites around the U.S.

In a separate Cost Analysis document prepared for this study, the cost of a base case and four proposed regulatory alternatives is evaluated. This is accomplished through the development of specifications for which technologies or technology categories are required by each regulatory alternative. Base case costs are assumed to be the costs incurred under the current Underground Injection Control regulations for Class I non-hazardous waste injection.

The cost elements described in this document are either attributable to Class I non-hazardous projects, or are under consideration in the regulatory alternatives. It should be emphasized that this document includes all cost elements for GS, not just those costs that incurred only under the new rule. Some of the cost elements described here are attributable to regulatory options 1 through 4, but some costs are baseline costs that would be incurred anyway under Class 1 non-hazardous waste rules.

Only the geologic sequestration component (including pre-injection, injection, and post injection) of the overall capture, transport, and storage system is evaluated here. Excluded are carbon capture and CO_2 transportation to the sequestration site. The sequestration component is expected to be only a fraction of the total cost of an integrated capture and sequestration project, typically in the range of 10 to 20 percent.

The major areas covered by the cost study include geologic characterization of the injection site, well construction and operation, monitoring during operations, post-injection operations, and financial responsibility. Specific costs are developed for site characterization, remediation of existing wells, land permitting, drilling and equipping wells, installation of monitoring equipment, operating costs, and monitoring.

CO_2 sequestration can take place in seven reservoir or operational settings:

- Saline reservoirs (non-basalt)
- Depleted and abandoned gas fields
- Depleted and abandoned oil fields
- Enhanced oil recovery (EOR) conversion to sequestration
- Enhanced coal-bed methane recovery
- Enhanced shale gas recovery
- Basalt reservoirs

Various studies of the CO_2 sequestration capacity of the U.S. have documented that it is dominated by non-basalt saline reservoirs, typically in sandstone lithologies. This study develops cost information for the three following settings:

- Saline reservoirs (non-basalt)
- Depleted and abandoned gas fields
- Depleted and abandoned oil fields

Saline reservoirs are expected to represent the great majority of long-term storage, due to their assessed potential and other factors, including location, availability, access, and injectability. [1] Large regions of the U.S. are underlain by saline-bearing reservoirs extending to depths of 10,000 – 20,000 feet. These formations contain total dissolved solid concentrations of greater than 10,000 mg/ML, differentiating them from underground drinking water sources.

Depleted gas reservoirs and depleted oil reservoirs represent a small percentage of currently assessed U.S. storage capacity. However it is considered important to characterize costs in such "conversion" scenarios because these costs may vary significantly from those of saline reservoir development. In addition, some depleted oil and depleted gas fields also will likely be considered good candidates for sequestration because they have proven traps and seals and a great deal of existing subsurface data. These types of settings have also been used extensively for methane gas injection and storage. It is anticipated that depleted oil and gas reservoirs will be a focus of early GS projects due to existing operational experience with these formations.

Three other potential geologic settings presented above are not covered by the proposed regulations and are not included in the cost study. These are:

- Enhanced oil recovery (EOR)
- Enhanced coalbed methane recovery
- Enhanced shale gas recovery

Because these settings represent CO_2 injection to increase recovery of oil and gas, they are already covered under the EPA Class II injection well designation. An exception is the conversion of and existing EOR operation to only sequestration. In such a case, the new rule would apply. The basalt setting is not included here in the cost examples because its role in sequestration over the forecast period is expected to be very minor.

[1] U.S. Department of Energy, 2007, "Carbon Sequestration Atlas of the United States and Canada," DOE/NETL. March, 2007, http://www.netl.doe.gov

2 General Costing Methodology, Data Sources, and Cost Trends

2.1 Costing Methodology

This report evaluates the costs for geologic sequestration. All of the individual cost components are evaluated. These are termed unit costs and include the following categories:

- Geologic Site Characterization
- Monitoring
- Injection Well Construction
- Area of Review and Corrective Action
- Well Operation
- Mechanical Integrity Tests
- Post Injection Well Plugging and Site Care
- Financial Responsibility
- General and Administrative

Unit costs are specified in terms of cost per site, per well, per square mile, or other appropriate parameter depending on the characteristics of the cost item. Unit costs are applied to type cases in a separate study to estimate total project costs. The type cases include specifications for total area, depth, thickness, well injectivity, number of wells through time, and other parameters.

In the separate Cost Analysis report, costs are estimated for a base case and the four proposed regulatory alternatives. Each cost item has been evaluated as to whether it is included in the regulatory option, and whether the cost would apply to all future projects or to a fraction of projects. In many cases, specific cost components and technologies will be applied to the GS project regardless of which regulatory scenario is chosen. For these cost components, there is no cost difference among the regulations. Other cost components may be applicable only under particular regulatory alternatives. Thus, not all of the cost components examined in this report are attributable to a particular regulatory alternative.

2.2 Primary Data Sources for Costs

Table 1 summarizes the major data sources for costs in the analysis. A wide range of cost data are available from industry survey publications for costs typically incurred in oil and gas drilling and production operations. This includes drilling and completion costs by region and depth interval, equipment and operating costs, and pipeline costs. Data are available for both the U.S. and Canada. [2] [3] [4] [5]The cost of

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[2] *Joint Association Survey of Drilling Costs*, American Petroleum Institute, Washington, DC. http://www.api.org/statistics/accessapi/api-reports.cfm

[3] *PSAC Well Cost Study – 2008,* Petroleum Services Association of Canada, October 30, 2007.

[4] *Oil and Gas Lease Equipment and Operating Costs*, U.S. Energy Information Administration, 2006, http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html

[5] *Oil and Gas Journal Pipeline Cost Survey*, Oil and Gas Journal Magazine, September 3, 2007.

drilling and equipping wells represents a large component of sequestration costs. The costs of additional equipment or material specifications for CO_2 injection wells are based in part upon various sources for corrosion resistant materials and specific well components.

Cost estimates for seismic data acquisition are also available from industry publications and presentations.

Labor rates are obtained from the U.S. Bureau of Labor Statistics. The number of hours required to carry out the various characterization or monitoring activities are ICF estimates that have been reviewed by the EPA workgroup.

No comprehensive source has been identified that provides detailed summaries of the full range of sequestration project cost components. Estimates of the costs of monitoring equipment, the number of stations required, and the cost of ongoing monitoring are based upon analysis of available literature and recent presentations by government and academic research groups. Some specific monitoring costs were obtained at a recent industry meeting sponsored by the Groundwater Protection Council.[6]

Table 1: Major Sources of Geologic Sequestration Cost Information

Source	Cost Categories
API Joint Association Survey of Drilling Costs	Drilling costs in the U.S. for oil, gas, and dry holes by depth interval
EIA Oil and Gas Lease Equipment and Operating Cost Survey	Surface equipment costs, annual operating costs, pump costs
Pipeline Prime Mover and Compressor Costs (FERC)	Pumps
2008 Petroleum Services of Canada Well Cost Study (PSAC)	Drilling costs, plugging costs, logging costs
Oil and Gas Journal Report on Pipeline and Cost Data Reported to FERC	Pipeline costs per inch-mile
Land Rig Newsletter	Onshore rig day rates/ well cost algorithms
New Orleans Sequestration Technology Meeting, January, 2008	Monitor station costs in several categories; seismic costs
FutureGen Sequestration Site Submittals	Monitoring station layout/number of stations
Preston Pipe Report	Casing and tubing costs
Hourly Labor Rates	U.S. Bureau of Labor Statistics
Selected Presentations and Papers (see below)	Sensor costs, monitoring costs, number of stations, seismic costs

Significant Papers and Presentations With Cost Data

Benson, "Monitoring Protocols and Life Cycle Costs for Geologic Storage of Carbon Dioxide", Sept., 2004
IEA Greenhouse Gas Programme Report PH4/29, "Overview of Monitoring Requirements for Geologic Storage Projects, Nov., 2004.
Hoversten, "Investigation of Novel Geophysical Techniques for Monitoring CO2 Movement During Sequestration," Oct., 2003.
Dahowski, et al, " The Costs of Applying Carbon Dioxide Capture and Geologic Storage Technologies to Two Hypothetical Coal to Liquids Production Configurations: A Preliminary Estimation," Pacific NW National Laboratory, September, 2007.

2.3 Cost Year Basis and Trends in Major Costs

The costs reported here represent price levels in late 2007 and early 2008 in the U.S. and are presented in 2007 dollars. There have been very steep increases in the cost of materials and labor used in the construction of all types of energy infrastructure including power plants, pipelines and oil and gas wells. Figure 1 shows the recent history of cost per ton of carbon steel plate (used in line pipe, casing, pressure vessels, etc.) and Figure 2 shows similar data for nickel (used in corrosion resistant tubing and casing and

[6] Ground Water Protection Council Meeting, New Orleans, LA, January, 16, 2008.

cryogenic applications such as LNG liquefaction plants and LNG storage tanks). Figure 3 shows the cost of natural gas pipeline construction and Figure 4 shows the average day rate for onshore drilling rigs in the US.

A discussion of uncertainty in cost estimation for this study is presented as Section 5 of this report.

Figure 1: U.S. Carbon Steel Plate Prices

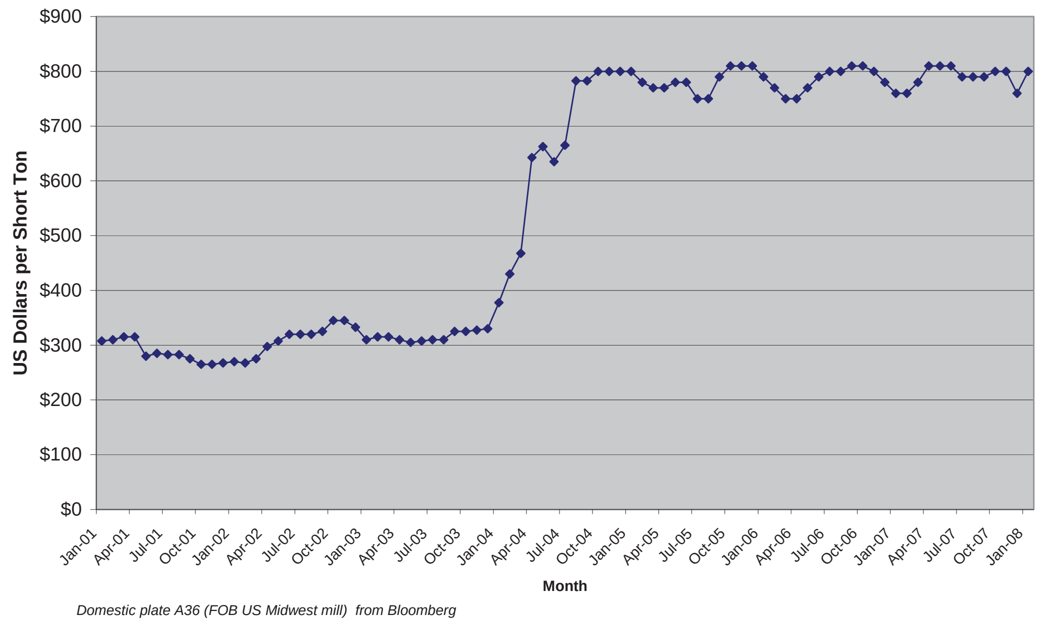


Figure 2: Nickel Prices

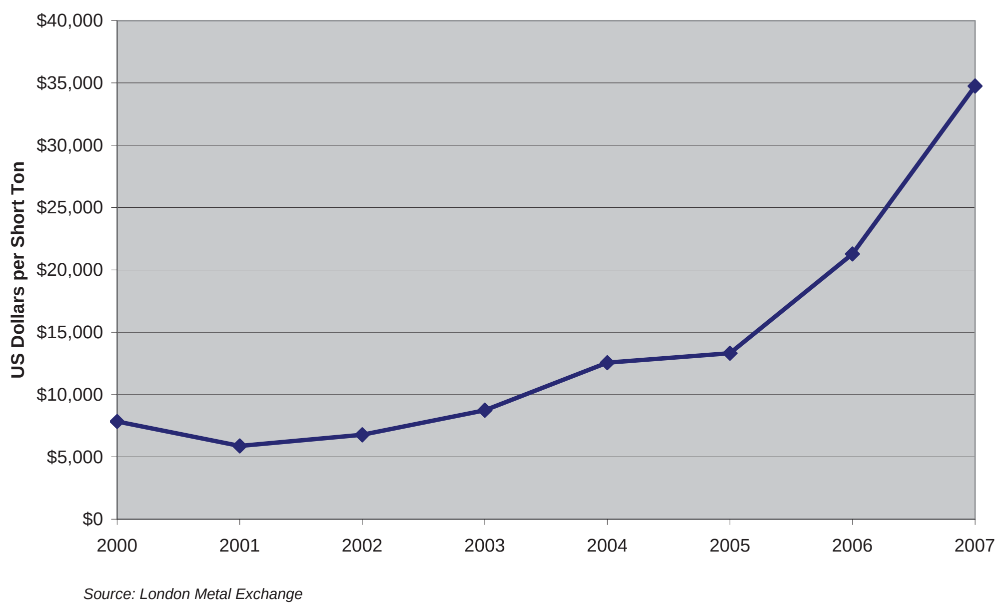
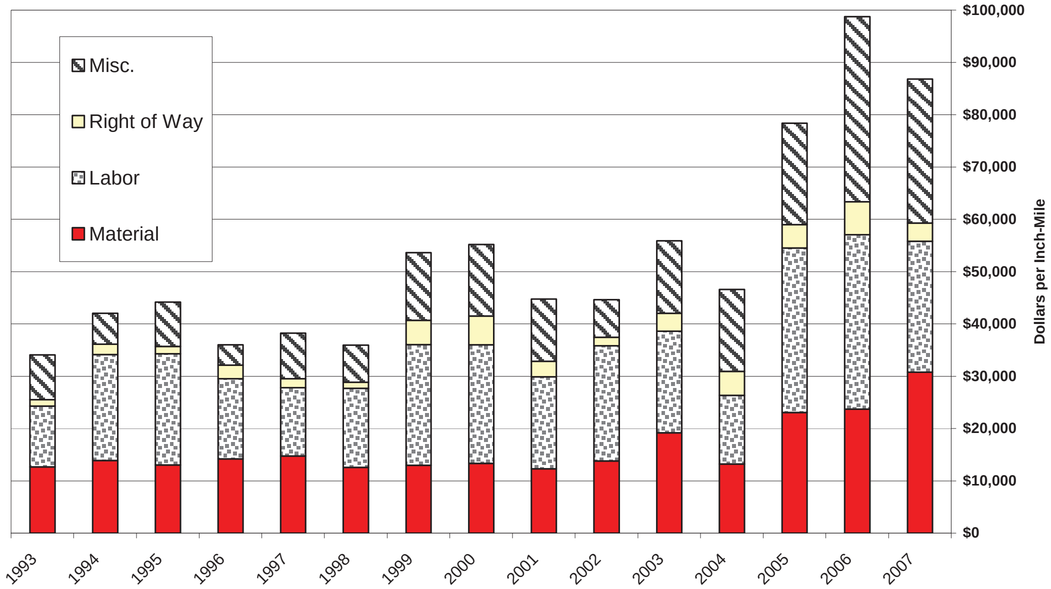
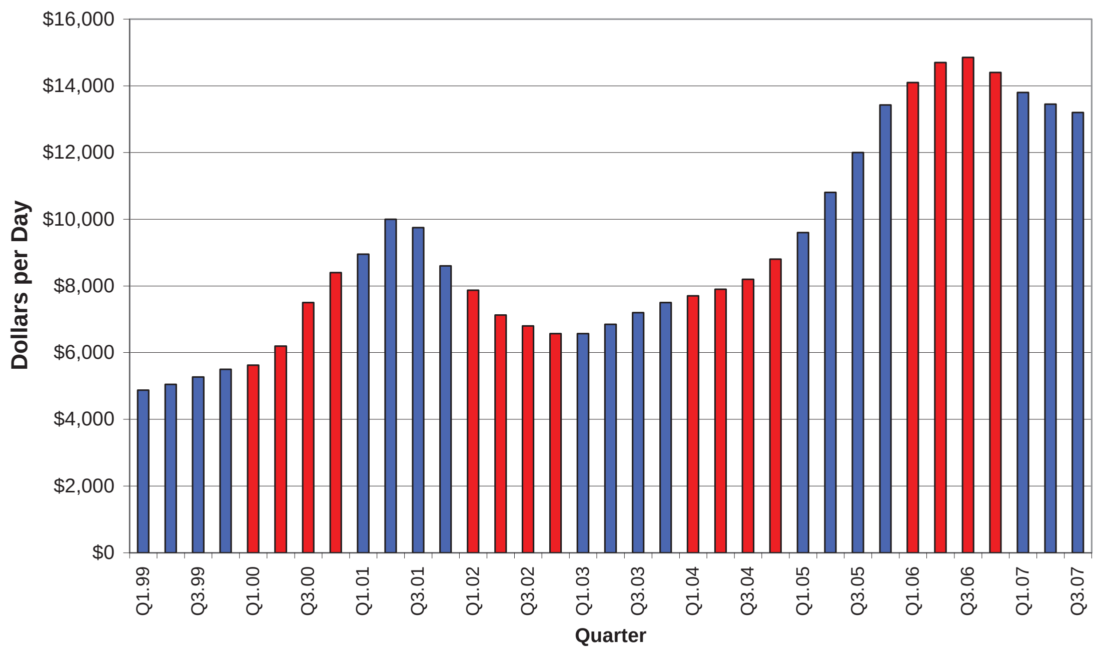


Figure 3: Gas Pipeline Costs by Component



Source: Oil and Gas Journal annual surveys; Average of large-diameter gas pipelines 30 to 36 inches; Miscellaneous category includes surveys, engineering, administration, interest, and overhead.

Figure 4: U.S. Drilling Rig Day Rates



3 Technologies and Costs

3.1 Geologic Site Characterization

The purpose of site characterization is to determine whether a site is suitable and safe for sequestration, and to compile the necessary data for the permit application. The process includes geologic, geophysical, and engineering evaluation. Characterization is designed to provide the geologic and hydrologic data needed to design the infrastructure, develop reservoir models, and design the monitoring program. In this phase of site development, a determination is made of whether the reservoir has adequate porosity, permeability, and continuity for long term injection. A determination is also made about the ability of overlying units to confine the injected CO_2 and prevent vertical movement. This includes evaluation for the presence of non-sealing faults or other potential pathways for migration. Other types of evaluation include geomechanical data on the mechanical properties of the reservoir, information on the occurrence and characteristics of USDWs, and information on past drilling into the proposed reservoir and overlying strata.

Maps and Cross Sections

The basic element of geologic analysis and characterization is the development of regional and site-specific geologic maps and cross sections to provide an understanding of stratigraphy and structure. The primary source of data for this analysis is well log data, which allows the geologist to map the depth to various formation tops, thickness variations (isopach maps), and lithologies (sand, shale, or carbonates). Where available, seismic or other geophysical and engineering data are also used to aid the development of the subsurface interpretation.

Seismic Surveys

Seismic data acquisition and interpretation is an important aspect of site characterization. Seismic data may be acquired either on the surface, which is typical, or in a well. Borehole techniques require one or more wells for source or receivers. Surface seismic data may be either 2-dimensional (2-D) or 3-dimentional (3-D), with the latter being much more data intensive and costly to obtain and interpret, but providing a higher degree of resolution. Seismic data may be used also for monitoring during operations and post-injection. [7]

3-D seismic uses man-made source signals and a receiver array to image the subsurface. In the site characterization phase, 3-D may be used to evaluate the detailed structural geology and stratigraphy of the site. Seismic data may in some settings allow the imaging of CO_2 in the reservoir since CO_2 is less dense than formation water, resulting in an acoustic contrast and seismic signature. When 3-D surveys are conducted periodically, a time-lapse analysis can be conducted (termed 4-D seismic).

[7] *Matoon Site Environmental Information Volume,* FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

3-D seismic data may be used in the site characterization phase as input into reservoir models to estimate the volume of CO_2 that can be stored at a potential site. [8] The technology is mature and has been used in the oil and gas exploration and development for decades.

Seismic History

The natural long-term seismic history of a potential sequestration site may be evaluated to gain a picture of potential failure risks. Historic data on seismic activity can be obtained from the U.S. Geological Survey. Evaluation would include the frequency and intensity of historic activity, and its relationship to known geology. The presence of regional faults and the activity on those faults is of significance in assessing site suitability.

Remote Land Survey

An airborne survey of the potential site should be carried out to locate and identify dwellings and other manmade structures affected within the area of review. The size of the survey should be such that it covers an area significantly larger than the expected ultimate dimensions of the subsurface plume and pressure front.

Data on Extent, Thickness, Capacity, Porosity of Receiving Formations

Perhaps the most fundamental aspect of site characterization is the determination of the receiving and storage properties of the proposed reservoir interval. In order to develop the analysis, it is necessary to obtain regional well log, well history, pressure test, and other subsurface data. Included is the acquisition of core data, drill stem test data, production test data, and other engineering data on area wells. The geologist uses this information to map the thickness, structure, and reservoir characteristics in the subsurface. The goal is to fully evaluate storage capacity and injectability, and the expected variability in these parameters. Some sites, such as abandoned oil or gas fields, will have a large amount of subsurface data in a specific area. In saline reservoirs, the amount of subsurface data may be limited or more regional in distribution.

Geomechanical Information

The mechanical properties of a potential storage reservoir play an important role in its ability to withstand injection pressures. If not designed properly, CO_2 injection could lead to deformation of the reservoir or seal rock, resulting in fracturing and potential leakage that may endanger USDWs. [9] [10] The maximum injection pressure for CO_2 must be less than the formation fracture pressure at the depth of injection. If the injection pressure exceeds the fracture pressure, failure and leakage can occur.

Geomechanical information on in-situ stress state, rock strength, and in-situ fluid pressures may be obtained from existing databases and literature as well as from new cores and tests. Sources of geomechanical data

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[8] Doughty, Christine, Barry Freifeld, and Robert Trautz, 2007, "Site Characterization for CO2 Geologic Storage," Environmental Geology, vol. 54, no. 8, June 2008.

[9] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage*, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

[10] *Measuring and Modeling for Site Characterization: A Global Approach*, D. Vu-Hoang, L. Jammes, O. Faivre, and T.S. Ramakrishnan, Schlumberger Carbon Services, March, 2006.

include well logs, seismic, pressure leak-off tests, and direct physical measurements of rock strength in the laboratory. Data parameters include pore pressure, overburden stress, horizontal stress and orientation, elastic strength, and expected failure mechanisms.

Potentially Affected Underground Sources of Drinking Water (USDWs)

A major consideration in site selection and design is the protection of USDWs. As part of the site permitting process, the operator would determine the distribution and depth of all potentially affected USDWs.

Geochemical and Other Information on Formations

In addition to determining the distribution of USDWs at the proposed site, it is desirable to obtain data on water properties of regional formations, as well as an overall understanding of their regional thickness and structure.

Information on Water-Rock Geochemistry

The geochemistry of subsurface fluids can affect whether a site is suitable for sequestration. Injection of CO_2 can result in the presence of carbonic acid, which may react with reservoir rock to liberate heavy metals. Another consideration is whether certain minerals may be precipitated that would plug the pore space, reducing permeability and reducing the ability to inject CO_2.

List of Penetrations of Injection Zone

The location and evaluation of existing penetrations into the injection zone within the area of review is a key component of site characterization. Some older wells may have either been constructed using substandard methods or their condition may have deteriorated significantly through time. Any well penetrating the potential storage reservoir may provide a leakage pathway into overlying strata. Therefore, all well penetrations must be located and the condition of the wells and casing cement evaluated. It may be possible to correct issues with problematic existing wells. In some cases, the presence of such wells can make the use of a particular site for sequestration uneconomic.

Existing commercial oil and gas well history databases contain information on the location, depth, and other characteristics of most historic wells. Because some wells may not be in the database, an operator could also carry out a physical survey using airborne or ground-based magnetic methods to locate abandoned wells.

List of Penetrations of Containment System

It is also important to determine the location, depth, and characteristics of wells that have penetrated the containment system within the area of review, but reached total depth before penetrating the storage reservoir. These wells could also represent potential leakage pathways.

List of Water Wells within Area of Review

Determination of the location and depth of existing water wells is an aspect of site characterization. Information may be obtained from databases of well locations or by site inspection.

Geologic Characterization Report

Approval of a specific site for sequestration involves a thorough understanding of all of the geological characteristics, including the suitability of the receiving zone, storage capacity and injectivity, and that there is a competent confining system. The report will incorporate aspects of the site characterization studies, including geologic, geochemical, geomechanical, hydrological, and geophysical studies. It summarizes the results of any pre-injection modeling studies to evaluate the size and location of the expected CO_2 plume through time.

Geologic Site Characterization Unit Costs

Table 2 specifies the estimated costs and data sources for site characterization.

Table 2: Geologic Site Characterization Unit Costs

Cost Reporting Heading	Unit Cost Heading	Tracking Number	Cost Item	Cost Algorithm	Data Sources
Geologic Site Characterization	Site Selection and Evaluation	A-1	Develop maps and cross sections of local geologic structure	60 hours of geologists @$106.31/hr = $6379 per site	ICF estimate of time required. Hourly rate may change based on labor survey data.
Geologic Site Characterization	Site Selection and Evaluation	A-2	Conduct 3D seismic survey to identify faults and fractures in primary and secondary containment units	$75,000/square mile for good resolution	Several published reports are in range of this cost. Estimates givwn at N.O. meeting were $15,000 to $30,000 per square kilometer ($39,000 to $78,000 per square mile).
Geologic Site Characterization	Site Selection and Evaluation	A-3	Obtain and analyze seismic (earthquake) history.	60 hours of geologists @$106.31/hr = $6379 per site	ICF estimate of time required. Hourly rate may change based on labor survey data.
Geologic Site Characterization	Site Selection and Evaluation	A-4	Remote (aerial) survey of land, land uses, structures etc.	$3,000/site + $400/square mile surveyed. (Should assume survey is twice project's actual footprint.)	Advertised cost of an aerial survey company for high-resolution (1/2 meter).
Geologic Site Characterization	Site Selection and Evaluation	A-5	Obtain data on areal extent, thickness, capacity, porosty and permeability of receiving formations and confining systems	24 hours of geologists @$106.31/hr = $2551 per site	ICF estimate of time required. Hourly rate may change based on labor survey data.
Geologic Site Characterization	Site Selection and Evaluation	A-6	Obtain geomechanical information on fractures, stress, rock strength, in situ fluid pressures (**from existing data and literature**)	120 hours of geologists @$106.31/hr = $12757 per site	ICF estimate of time required. Hourly rate may change based on labor survey data.
Geologic Site Characterization	Site Selection and Evaluation	A-7	Obtain geomechanical information on fractures, stress, rock strength, in situ fluid pressures (**new cores and tests**)	$75/foot for stratigraphic test well + $3,000/core	Drilling cost is estimated fom drilling cost equations developed from JAS and PSAC data. Core analysis cost is a placeholder until more data are obtained.
Geologic Site Characterization	Site Selection and Evaluation	A-8	List names and depth of all potentially affected USDWs	24 hours of geologists @$106.31/hr = $2551 per site	ICF estimate of time required. Hourly rate may change based on labor survey data.
Geologic Site Characterization	Site Selection and Evaluation	A-9	Provide geochemical information and maps/cross section on subsurface aquifers.	60 hours of geologists @$106.31/hr = $6379 per site	ICF estimate of time required. Hourly rate may change based on labor survey data.
Geologic Site Characterization	Site Selection and Evaluation	A-10	Provide information on water-rock-CO2 geochemistry and mineral reactions.	240 hours of geologists @$106.31/hr +$10,000 labe fees = $35514 per site	ICF estimate of time required. Lab fee is a placeholder until more data are obtained.
Geologic Site Characterization	Site Selection and Evaluation	A-11	Develop list of penetrations into injection zone within AoR (from well history data bases)	12 hours @$106.31/hr = $1276 per square mile	ICF estimate of time required. Hourly rate may change based on labor survey data. Cost expected to vary widely based on well ages and quality of record keeping.
Geologic Site Characterization	Site Selection and Evaluation	A-12	Develop list of penetrations into containment systems within AoR (from well history data bases)	12 hours @$106.31/hr = $1276 per square mile	ICF estimate of time required. Hourly rate may change based on labor survey data. Cost expected to vary widely based on well ages and quality of record keeping.
Geologic Site Characterization	Site Selection and Evaluation	A-13	Develop list of water wells within AoR (from public data)	36 hours @$106.31/hr = $3827 per square mile	ICF estimate of time required. Hourly rate may change based on labor survey data. Cost expected to vary widely based on well ages and quality of record keeping.
Geologic Site Characterization	Site Selection and Evaluation	A-14	Prepare geologic characterization report demonstrating: suitability of receiving zone, storage capacity and injectivity, trapping mechanism free of nonsealing faults, competent confining system, etc.	240 hours of geologists @$106.31/hr = $25514 per site	ICF estimate of time required. Hourly rate may change based on labor survey data.

3.2 Monitoring

Once injection begins, a program for monitoring of CO_2 distribution is required. [11] This is needed in order to:

- Manage the injection process
- Delineate and identify leakage risk or actual leakage that may endanger USDWs
- Verify and provide input into reservoir models
- Provide early warnings of failure

Monitoring components may include the following[12]:

- Measurements to determine the mass of CO_2 injected, principally derived from the fluid pressure, temperature, flow rate and gas composition at the wellhead
- Monitoring of pressure during the injection process
- Monitoring of the migration and distribution of the CO_2 in the deep subsurface, focusing on the intended storage reservoir, but including any unintended migration out of the storage reservoir
- Monitoring of the shallow subsurface to detect and quantify any CO_2 migrating out of the storage reservoir towards the ground surface
- Monitoring of the ground surface and atmosphere to detect and quantify CO_2 leaking into the biosphere

Monitoring of the wells, deep subsurface, shallow subsurface and ground surface is expected to continue for long periods after the injection is terminated for safety and to confirm predictions of storage behavior.

Fluid Geochemical Analysis

Prior to injection of CO_2, it may be necessary to develop a baseline of geochemical properties and characteristics of reservoir fluids in the injection zones, confining zones, and groundwater. During injection or in the post-injection monitoring phase, regular sampling continues. In this way, changes in geochemistry through time can be interpreted, allowing analysis of plume movement or leakage. Geochemical analysis of water samples includes the quantification of gases (methane, ethane, CO_2, N_2), carbonate, and total alkalinity, metals (Na, K, Ca), salinity, and stable isotopes (C, O). [13] [14]

Downhole fluid samples can be collected for surface analysis using wireline formation testers and U-Tubes. The Schlumberger Modular Formation Dynamics Tester (MDT) is a wireline tool that is used to collect

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[11] *The Future of Coal, Options for a Carbon-constrained World*, An Interdisciplinary MIT Study, Massachusetts Institute of Technology, 2007.

[12] *Discussion Paper: Identifying Gaps in CO_2 Monitoring and Verification of Storage*, by B. Reynen, M. Wilson, N. Riley, T. Manai, O. M. Mathiassen, and S. Holloway, A Task Force under the Technical Group of the Carbon Sequestration Leadership Foru, (CSLF), Paper No. CSLF-T-2005-3, Presented at the Technical Group Meeting, April 30, 2005.

[13] *Matoon Site Environmental Information Volume*, FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

[14] *Monitoring to Ensure Safe and Effective Geological Sequestration of Carbon Dioxide*, S. Benson and L. Myer, Lawrence Berkeley Laboratory, Berkeley, California, 2002.

multiple subsurface samples at formation pressure and temperature (PVT samples) for surface analysis.[15] U-Tube technology was developed for the DOE Frio Brine project and allows sample extraction at reservoir pressure and temperature. [16] As its name implies, it is a U-shaped tube device inserted in the well. A valve is opened to collect samples from the interval of interest at pressure and transport them to the surface for analysis.

It may be necessary to establish a baseline of existing groundwater properties. After injection begins, periodic testing of groundwater can detect leakage. In many areas, local and regional groundwater wells will be present and are a source of data on chemical properties. New wells may also be needed for sampling. Geochemical analysis of water samples for parameters such as resistivity and pH are routine. For groundwater zone samples, Schlumberger has developed the Westbay sampling system. This is a sampling assembly that is lowered into a groundwater well of generally less than 3,300 feet in depth. Discreet samples can be taken from multiple intervals. The hardware can be left in place for subsequent testing.

In sampling for CO_2 concentrations, care must be taken to account for rapid degassing of CO_2 from the water. Misleadingly low values can be obtained unless precautions are taken. [17]

Standard sampling and analysis is done by personnel at the wellsite. There is the possibility of continuous automated monitoring of geochemical data using downhole sensors. Although downhole pH sensors for wells exist, additional R&D is needed in this area. Thus, geochemical data acquisition will generally rely upon surface testing of water samples.

Surface CO_2 and Soil Flux Baseline

Direct measurement and testing of CO_2 concentrations above a sequestration site can be made in the air or vadose zone (the vadose zone is the unsaturated zone between the ground surface and the water table). If this type of monitoring is to be part of the monitoring program, it will be necessary to develop a baseline of ambient conditions as part of the site characterization. Establishment of a representative baseline of the concentration of CO_2 in the air or soil may be somewhat problematic in many instances, due to the potential for a relatively large amount of natural variability. The background variability may be high relative to what is of interest for site monitoring.

Basic technologies include Eddy Covariance, soil gas sampling with ground-surface accumulation chambers, and direct vadose zone sampling using subsurface probes.

Eddy Covariance is used to measure CO_2 concentration in the air above a sequestration site. It combines an open path infra-red gas analyzer on a tower alongside a sensitive anemometer that measures wind speed and direction. The size and shape of the sampling footprint is derived mathematically from the anemometer

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[15] *Matoon Site Environmental Information Volume,* FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

[16] *The U-Tube – Novel System for Sampling and Analyzing Mulit-Phase Borehole Fluid Samples*, by Barry M. Freifeld, et al, Lawrence Berkeley National Laboratory, Berkeley, CA. (publication date unknown).

[17] *Technology Status Review – Monitoring Technologies for the Geological Storage of CO2*, Report No. COAL R285 DTI/Pub URN 05/1033, by J. Pearce, A. Chadwick, M. Bentham, S. Holloway, and G. Kirby, British Geological Survey, Coordinator of the European Network of Excellence on Underground CO2 Storage (CO2GeoNet), Keyworth, Nottingham, UK, March 2005.

data.[18] [19] A typical station consists of sensors mounted on a tower from 10 to 30 feet high. The stations can be operated with solar power and can be set up for data telemetry for transmission to a central facility. Deployment of a grid of such detectors over a sequestration site provides information regardless of wind direction.

Surface CO_2 flux monitoring is used to measure the amount of CO_2 moving across the earth's surface and is used as a leak detection technology. Surface flux is measured using an accumulation chamber. One type of accumulation chamber is made of stainless steel and is placed at the sample location. In some cases, pits are dug and are used for accumulation. Samples are taken from the air inside the chamber and are analyzed in the laboratory. If CO_2 is the only sample of interest, an open path infrared analyzer can be used. However, additional analysis is needed to detect tracers and other chemicals. [20]

Vadose zone sampling and monitoring can be carried out using one-inch diameter probes. Samples are collected with a vacuum pump and are evaluated at the surface for CO_2 content. Correct installation would allow sampling at various depths in the vadose zone. [21]

Gravity Data

Gravity surveys measure subsurface density contrasts. Such contrasts may result from structure, lithology, or pore content. During injection, a density contrast change through time may occur where CO_2 moves into pore space previously occupied by water. Thus, in some cases gravity data can be used to monitor plume movement.

Surface gravity data are obtained through a survey with measurement stations spaced a uniform distance apart across an area. Gravity data may also be taken from the air. A baseline gravity survey may be carried out above a planned sequestration site to establish pre-injection conditions. The ability of gravity to detect and map CO_2 movement is much less precise than that of seismic. It has been estimated that a minimum of several hundred thousand tons of CO_2 would be injected before a significant effect was observed. [22] This volume of CO_2 would be an order of magnitude greater than the detection limits of seismic.

Establishment of a gravity baseline is not included in the cost analysis because of uncertainty that it would be used in monitoring.

Topographic Information

One method of monitoring an injection site is to evaluate ground surface distortion through time. Underground injection can cause measurable surface distortion over time due to volumetric effects. The overall approach is to establish a baseline prior to injection, and then use various techniques to monitor deformation after injection begins. A space-borne geodetic tool called INSAR (Interferometric Synthetic

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[18] *Technology Status Review – Monitoring Technologies for the Geological Storage of CO2*, Report No. COAL R285 DTI/Pub URN 05/1033, by J. Pearce, A. Chadwick, M. Bentham, S. Holloway, and G. Kirby, British Geological Survey, Coordinator of the European Network of Excellence on Underground CO2 Storage (CO2GeoNet), Keyworth, Nottingham, UK, March 2005.

[19] *Monitoring to Ensure Safe and Effective Geological Sequestration of Carbon Dioxide*, S. Benson and L. Myer, Lawrence Berkeley Laboratory, Berkeley, California, 2002.

[20] *Matoon Site Environmental Information Volume*, FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

[21] *Matoon Site Environmental Information Volume*, FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

[22] *IPCC*, ibid.

Aperture Radar) allows development of a detailed spatial picture of land topography. When combined with surface and downhole tiltmeters, there is the potential to monitor extremely small topographic changes over time during injection. [23] [24]

Tiltmeters are instruments that measure very minute changes in the land surface, with detection limits of micro-or nano-radians. The sensors themselves are installed in shallow boreholes, typically less than 10 meters in depth because they are sensitive to temperature changes. [25] The shallow boreholes are arrayed around the injector wells and are installed prior to injection as part of the baseline topographic analysis.

As with gravity methods, topographic distortion methods have much lower resolution that seismic, in terms of plume monitoring, despite the extreme accuracy of the surface measurement. A greater depth of injection would result in less resolution, due to much smaller surface movement. Topographic detection methods are only applicable in areas where natural variations are not present. Natural movement can result from frost heave or surface water conditions. These technologies are relatively new, although they have been used for groundwater investigation.

Establishment of a topographic baseline is not included in the cost analysis because of uncertainty that it would be used in monitoring.

Front-End Engineering and Design

This encompasses front-end engineering and design of the project. Included are site layout and engineering design of surface structures, piping, and pumping equipment. It also includes injection well design, monitoring well design, the drilling plan, casing plan, wellhead equipment design, downhole equipment selection, and monitoring equipment selection.

Rights of Way for Surface Use

It will be necessary to obtain rights of way for surface use to set up and operate monitoring facilities. An example of such a monitoring site would be an eddy covariance station.

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[23] *Monitoring of Sequestered CO2: Meeting the Challenge with Emergng Geophysical Technologies*, S.N. Dasgupta, Saudi Aramco, 2005.

[24] *CO2 Storage in Saline Aquifers,* by M. Bentham and G. Kirby, Oil and Gas Science and Technology, vol. 60, no. 3, 2005.

[25] *Measurement, Monitoring, and Verification*, L. H. Spangler, Zero Emission Research and Technology Center, Carbon Sequestration Leadership Forum, date unknown.

Downhole Safety Valve

Injection wells may be equipped with one or two well control valves, one at the surface and an optimal second one in the tubing string down hole. [26] The downhole safety valve can be installed to automatically shut in the well if surface equipment fails so that no surface release occurs and to prevent back flow into surface facilities.

Standard Monitoring Well Costs

It may be necessary as part of an overall monitoring system to drill and complete one or more monitoring wells to monitor the movement of CO2 in the subsurface. Various types of sensor technologies and fluid sampling methods can be used to provide such information. A 2006 FutureGen report listed the various categories of monitoring wells: [27]

- Injection Reservoir Monitoring Wells – monitoring wells that are perforated across the injection zone.
- Primary Seal Monitoring Wells – monitoring wells that are perforated just above the primary seal. They are used for fluid sampling and in situ pressure and temperature.
- Drinking Water Monitoring Wells – wells that are completed in the deepest drinking water interval and are monitored with fluid sampling to detect CO_2 or salinity.
- Microseismic Wells – wells extending to the top of the primary seal and are used for microseismic monitoring.

With injection zone monitoring wells there is a tradeoff between improved ability to monitor the reservoir and a potential increase in leakage risk. Monitoring wells completed in intervals above the reservoir do not carry this risk. In the current cost study, it is assumed that monitoring wells are completed just above the primary seal.

The drilling and completion of CO_2 monitoring wells, should they be needed or required represents a large component of overall monitoring costs. For example, a 5,000 foot well with an average cost per foot of $100 would cost $500,000. The overall cost is a function of depth and well design and characteristics.

Pressure and Temperature Gauges and Equipment for Monitoring Wells

Monitoring wells may have permanently installed downhole equipment to continuously measure pressure, temperature, resistivity, salinity, and pH. Measurements of subsurface pressure are routine in oil and gas field operations. [28] A wide variety of pressure sensors are available, including piezo-electric transducers, strain gauges, diaphragm gauges, capacitance gauges, and the newer fiber optic pressure and temperature

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[26] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage*, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp
[27] *Matoon Site Environmental Information Volume*, FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

[28] *Overview of Monitoring Techniques and Protocols for Geological Storage Projects*, S. M. Benson, E. Gasperikova, and G. M. Hoversten, IEA Greenhouse Gas R&D Program report, Report Number PH4/29, November 2004.

sensors are available. Fiber optic cables from the surface to the formation can provide real-time formation pressure measurements.

Salinity and Other Monitoring Equipment

Salinity and fluid characteristics may be measured downhole to determine composition and to monitor CO_2 movement. Fluid and gas samples can be collected directly from the formation using a U-tube downhole sampler. Once collected and brought to the surface, the samples can be analyzed for major ions, pH, alkalinity, stable isotopes of carbon, oxygen, and hydrogen, and gases such as hydrocarbon vapors, CO_2, and its associated isotopes. [29]

At the Texas Frio Brine Pilot Tests, a U-tube downhole sampler was used to collect high-frequency samples at the monitoring well.[30] A 'U' shaped tube was equipped with a series of one-way check valves at the cusp of the 'U' bend in the tube and was inserted to the sampling depth. The pressure in the U-tube was decreased below formation pressure to allow sample fluids to enter the tube through the check valves. The U-tube pressure was then increased using compressed nitrogen gas, and the sample was rapidly transported to the surface for analysis.

Surface Monitoring Program

Surface and near surface monitoring equipment includes CO_2 concentration equipment for air or soil sampling and microseismic equipment for monitoring plume movement. Some surface monitoring technologies require specific equipment be installed. Most surface monitoring costs will be non-equipment or labor costs to conduct the surveys and analyze the data. The actual monitoring costs are described in section 3.10.

The proposed regulations for sequestration include varying specifications for surface and near surface monitoring. It may be necessary to implement a monitoring program that includes not only the expected plume area but also the monitoring of all wells within the area of review and other sensitive areas such as buildings to ensure that CO_2 has not migrated in this manner.

The surface monitoring program of each site is customized for the geologic, engineering, and surface characteristics of the site.

Surface Microseismic Equipment

Microseismic sensors are used to continuously detect the microseismic activity that may be associated with injection and movement of CO_2. Such a monitoring array includes both surface and subsurface equipment. The subsurface component is installed in monitoring wells.

Monitoring Well O&M Costs

This includes the annual costs of operating and maintaining the monitoring wells including operating labor and system maintenance.

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[29] *Overview of Monitoring Techniques and Protocols for Geological Storage Projects*, S. M. Benson, E. Gasperikova, and G. M. Hoversten, IEA Greenhouse Gas R&D Program report, Report Number PH4/29, November 2004.

[30] *Monitoring Geologically Sequestered CO2 during the Frio Brine Pilot Test using Perfluorocarbon Tracers*, by S. D. McCallum, D. E. Reistenberg, D. R. Cole, B. M. Freifeld, R. C. Trautz, S. D. Hovorka, and T. J. Phelps, Conference Proceedings, Fourth Annual Conference on Carbon Capture and Sequestration, DOE/NETL, May 2-5, 2005.

Annual Costs of Air and Soil Surveys

The annualized cost of air and soil monitoring surveys includes the cost of continuous air sampling using eddy covariance equipment and soil zone surveys for CO_2 and tracers.

Annual Cost of Passive Seismic Surveys

Microseisms are very small earthquakes that are assumed to be caused by the pressure front of the injected CO_2 or other fluids. [31] Technologies that allow the determination of the location of microseisms in three dimensions through time are used to monitor plume movement.

Passive seismic methods detect seismic signals other than those created by "active" sources. In this technology, sensors (geophones) are deployed downhole. Downhole receivers are cemented in a monitoring well and continuously record a signal from microseismic activity in the injection reservoir.[32] [33] [34]

Passive seismic is used to detect microfractures created during injection. The microfractures result from the change in pressure brought about by injection. Passive seismic is used to monitor CO_2 plume movement, and to help determine the risk of developing through-going fractures that may impact migration or seal integrity. A series of surveys through time results in a time-lapse picture of CO_2 movement. An advantage of microseismic monitoring is that, once the sensors are in place, there is little maintenance needed, and the data can be collected remotely.[35]

Not all storage reservoirs are amenable to passive seismic methods. Factors that play a role include rock mechanics, lithology, and natural seismic activity.

Periodic Seismic Surveys

Seismic data are used in the monitoring phase to evaluate CO_2 plume movement during and after injection. Seismic data can detect plume movement by evaluating changes in fluid properties due to displacement of brine with CO_2. Surveys may be repeated during injection and through the post injection monitoring phase. [36] 3D data are much more useful but are more costly to obtain and interpret than 2D Both velocity and amplitude anomalies may result from CO_2 movement.

Seismic data sources may be either vibroseis or dynamite. A vibroseis truck is a mobile source that shakes to put energy into the ground. Small dynamite shots may also be used as a seismic source, and the charges placed in shallow boreholes holes.

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[31] *Matoon Site Environmental Information Volume,* FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

[32] Monitoring of Sequestered CO2: Meeting the Challenge with Emerging Geophysical Technologies, S.N. Dasgupta, Saudi Aramco, 2005.

[33] *Technology Status Review – Monitoring Technologies for the Geological Storage of CO2*, Report No. COAL R285 DTI/Pub URN 05/1033, by J. Pearce, A. Chadwick, M. Bentham, S. Holloway, and G. Kirby, British Geological Survey, Coordinator of the European Network of Excellence on Underground CO2 Storage (CO2GeoNet), Keyworth, Nottingham, UK, March 2005.

[34] *SACS – 2, Work Package 4, Monitoring Well Scenarios*, by I. M. Carlsen, S. Mjaaland, and F. Nyhavn, SINTEF Petroleum Research, Trondheim, Norway, for SACS group, April 6, 2001.

[35] *Matoon Site Environmental Information Volume,* FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

[36] *Matoon Site Environmental Information Volume,* FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

The ability to monitor CO_2 in the subsurface using seismic depends upon numerous factors, and not all sites or reservoir formations will be amenable to seismic monitoring. For example, a storage formation that has low porosity or is very deep (certainly below 10,000 feet, and in some cases less) would be less amenable to seismic monitoring. Some geological settings may preclude the use of seismic because of near surface factors as well. Near surface factors may include irregular topography, unusual lithologies, surface water, man made structures or impediments or other access factors. Where conditions are right, however, it may be possible to detect injected CO_2 volumes of as little as 1,000 tons.[37]

There are two major subsurface seismic methods for monitoring, Vertical Seismic Profiling and Cross-Well Seismic. Vertical Seismic Profiling (VSP) is a technique in which surface sources are arrayed around a well that is in close proximity to a CO_2 plume.[38] The sensors are deployed downhole. The advantage of VSP is that it offers high quality resolution in the vicinity of the test well. It can also be used to detect upward migration of CO_2.

In Cross-Well seismic methods, seismic sources suspended on a cable are lowered into one well, and the receivers are lowered into an adjacent well.[39] Both wells must penetrate to the base of the storage reservoir under investigation. This method results in a two-dimensional vertical slice of the subsurface with high resolution at the reservoir level. The method has been successfully tested at the Frio site in Texas.

Fluid Flow Calculations and Modeling

Modeling of subsurface CO_2 flow can be used to define the area of review and area within which existing wells need to be evaluated for possible remediation. It is used to help determine the location, number, and specifications for the injection and monitoring wells.

CO_2 flow from injection wells can be modeled and the reservoir capacity can be estimated with basic engineering methods. However, complex, numerical methods providing multi-phase and multi-component reservoir simulations may be used to understand the injection project and its impacts in much greater detail.[40]

Different models are needed to analyze the well-bore flow and to simulate the large-scale flow processes in the reservoir.

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[37] *Technology Status Review – Monitoring Technologies for the Geological Storage of CO2*, Report No. COAL R285 DTI/Pub URN 05/1033, by J. Pearce, A. Chadwick, M. Bentham, S. Holloway, and G. Kirby, British Geological Survey, Coordinator of the European Network of Excellence on Underground CO2 Storage (CO2GeoNet), Keyworth, Nottingham, UK, March 2005.

[38] *Measurement, Monitoring, and Verification*, L. H. Spangler, Zero Emission Research and Technology Center, Carbon Sequestration Leadership Forum, date unknown.

[39] *Matoon Site Environmental Information Volume*, FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

[40] *GEO-SEQ Best Practices Manual, Geologic Carbon Dioxide Sequestration: Site Evaluation to Implementation*, by the GEO-SEQ Project Team, Earth Sciences Division, Lawrence Berkeley National Laboratory, Berkeley, California, September 30, 2004.

Reports to Regulators

This includes the labor costs to complete periodic reports to regulatory bodies.

Monitoring Unit Costs

Table 3 specifies the estimated costs and data sources for monitoring.

Table 3: Monitoring Unit Costs

Cost Reporting Heading	Unit Cost Heading	Tracking Number	Cost Item	Cost Algorithm	Data Sources
Monitoring	Site Selection and Evaluation	B-1	Develop geochemical baseline for injection zones and confining zone.	$200 per sample. Assume 4 samples per injection well = $800 per injection well	Lab analysis fee of $100 to $200 discussed in N.O. meeting.
Monitoring	Site Selection and Evaluation	B-2	Develop baseline of surface air CO2 flux for leakage monitoring.	$35,000 per station	Range of costs discussed at N.O. meeting Jan 2008 was $20,000 to $50,000 per station.
Monitoring	Site Selection and Evaluation	B-3	Conduct front-end engineering and design (monitoring wells)	$20,000 + $5,000/shallow monitoring well	ICF estimate.
Monitoring	Land and Land Use Rights	B-4	Obtain rights-of-way for surface uses. (monitoring wells)	$10,000 per monitoring well site	ICF estimate. Cost of land rights are highly variable.
Monitoring	Land and Land Use Rights	B-5	Obtain rights-of-way for surface uses. (monitoring sites)	$5,000 per air monitoring station site (microseismic is done inside montoring well)	ICF estimate. Cost of land rights are highly variable.
Monitoring	Drilling and Equipping Injection Wells	B-6	Downhole safety shut-off valve	$15,000 + $2/ft depth. Would be placed 100 or more feet above packer	Initial cost estimate until more data are obtained.
Monitoring	Drilling and Equipping Monitoring Wells	B-7	Standard monitoring well cost (ABOVE injection zone)	Use look-up table. $/foot = $100 to $130 per foot typical for **slim-hole design** down to 9,000 ft.	Drilling cost is estimated fom drilling cost equations developed from JAS and PSAC data.
Monitoring	Drilling and Equipping Monitoring Wells	B-8	Standard monitoring well cost (INTO injection zone)	Use look-up table. $/foot = $100 to $130 per foot typical for **slim-hole design** down to 9,000 ft.	Drilling cost is estimated fom drilling cost equations developed from JAS and PSAC data.
Monitoring	Downhole Monitoring Equipment (for Monitoring Wells or Injection Wells)	B-9	Pressure and temperature gauges and related equipment for monitoring wells	$10,000/well	Initial cost estimate until more data are obtained.
Monitoring	Downhole Monitoring Equipment (for Monitoring Wells or Injection Wells)	B-10	Salinity, CO2, tracer, etc. monitoring equipment for wells (portion of equipment may be at surface such as for *in situ* sampling using U-tubes)	$10,000/well	Initial cost estimate until more data are obtained.
Monitoring	Surface or Near-Surface Monitoring Equipment	B-11	Develop plan and implement surface air and/or soil monitoring within current plume footprint	40 hours @$106.31/hr = $4252 for plan plus $70,000/monitoring site	ICF estimate of time required. Hourly rate may change based on labor survey data. Monitoring station cost estimate from Benson 2004.
Monitoring	Surface or Near-Surface Monitoring Equipment	B-12	Develop plan and implement surface air and/or soil monitoring within current plume footprint, at artificial penetrations and sensitive locations (human occupancy)	40 hours @$106.31/hr = $4252 for plan plus $70,000/monitoring site	ICF estimate of time required. Hourly rate may change based on labor survey data. Monitoring station cost estimate from Benson 2004.
Monitoring	Surface or Near-Surface Monitoring Equipment	B-13	Surface microseismic detection equipment	$50,000/ site (geophone arrays go into monitoring wells)	Initial cost estimate until more data are obtained.
Monitoring	Operating Costs	B-14	Monitoring well O&M	Annual O&M costs are $25,000 + $3/ft per well per year	Operating and maintenance costs adapted from EIA Oil and Gas Lease Equipment and Operating Cost estimates.
Monitoring	Operating Costs	B-15	Annual cost of air and soil surveys & equipment	$10,000 per station per year	ICF estimate.
Monitoring	Operating Costs	B-16	Annual cost of passive seismic equipment	$10,000 per station per year	ICF estimate.
Monitoring	Operating Costs	B-17	Periodic seismic surveys: 3D	$75,000/square mile for good resolution	Several published reports are in range of this cost.
Monitoring	Operating Costs	B-18	Complex modeling of fluid flows and migration (reservior simulations) every five years	180 hours of engineers @$53.52/hr = $9634 per site + 24 hours of engineers @$53.52/hr = $1284 per injection well	ICF estimate of time required. Hourly rate may change based on labor survey data.
Monitoring	Operating Costs	B-19	Annual reports to regulators	20 hours of engineers @$53.52/hr = $1070 per report	ICF estimate of time required. Hourly rate may change based on labor survey data.
Monitoring	Operating Costs	B-20	Quarterly reports to regulators	15 hours of engineers @$53.52/hr = $803 per report	ICF estimate of time required. Hourly rate may change based on labor survey data.
Monitoring	Operating Costs	B-21	Monthly reports to regulators	8 hours of engineers @$53.52/hr = $428 per report	ICF estimate of time required. Hourly rate may change based on labor survey data.

3.3 Injection Well Construction

Rights of Way for Surface and Subsurface Uses

This includes the right of way for surface use for injection and monitoring wells and for subsurface or pore space use. The issue of subsurface property rights varies by state and is discussed in detail in the IPCC report. [41] Rights to use subsurface pore space could be granted separately from surface ownership. Obtaining the right to use subsurface pore space may represent a significant cost component of sequestration. While pore space costs are included in the analysis, they are not a part of the new rule.

Land Use, Air Emissions, and Water Permits

This unit cost item covers the estimated labor cost to obtain permits for land use, air emissions, and water use.

UIC Permit Filing

This unit cost item covers the estimated labor cost to prepare an Underground Injection Control injection permit.

Standard Injection Well Cost

The technologies for drilling and equipping CO_2 injection wells are well developed. Most aspects of drilling and completing such wells are similar or identical to that of drilling and completing a producing gas well. Many CO_2 enhanced oil recovery projects are active in the U.S., especially in the Permian Basin of West Texas, and technologies have been developed to complete, produce, and maintain CO_2 injection and CO_2 EOR production wells for long periods of time.

The design of a CO_2 injection well is similar to that of a conventional gas injection well or a gas storage well, with the exception that much of the downhole equipment must be upgraded for high pressure and corrosion resistance. [42] Upgrades may include special casing and tubing, safety valves, cements, and blowout preventers. A well program is designed prior to drilling to determine the drilling plan and casing points. This design incorporates what is known about the geology and engineering aspects of the location.

The injection well typically consists of several strings of casing extending to different depths. Multiple casing strings are required to isolate the well from shallow drinking water and to prevent problems with weak sections of the well bore. [43] The innermost, deepest casing string is cemented in place across the storage reservoir and then perforated to allow movement of the CO_2 into the well. Then a small diameter

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[41] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage,* by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp

[42] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage,* by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp

[43] *Matoon Site Environmental Information Volume,* FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

tube is run into the well inside the innermost casing. This injection tubing is sealed off from the casing with a double grip packer.

The well is completed at the surface by installing a wellhead and "Christmas Tree." The Christmas Tree sits on top of the wellhead and is an assembly of valves, pressure gauges and chokes. Devices are connected to the Christmas Tree that allow the monitoring of pressure, temperature, and injection rates. A blowout preventer is used to prevent well blowout due to unexpected pressure. A Supervisory Control and Data Acquisition (SCADA) is typically used to monitor the data. The system is set up to automatically shut down the injection if needed.

Corrosion Resistant Tubing and Casing

Operators of CO_2 EOR projects have developed guidelines for the use of special materials to prevent or minimize corrosion caused by carbonic acid. An API report on injection technology lays out a set of guidelines that were developed. [44]

> "Because of the corrosive effects of carbonic acid, H_2CO_3, on metal components, induced by the alternating water and gas (WAG) injection cycles during CO_2 EOR operation, a significant fraction of scientific and technical work has been devoted to developing robust solutions to corrosion problems. Supplemental work has also been done on identifying and developing elastomeric materials for packers and seals that can withstand the solvent effects of supercritical CO_2 that induce swelling and degradation. Throughout this process, the underlying strategy of the industry has been to select materials based on their durability and corrosion resistance. As a result of these efforts, tubular components can be expected to have a service life of 20 to 25 years before replacement."

The following guidelines were published on page 23 of the report (continued on next page):

Component	Materials
Upstream metering and piping runs	316 Stainless Steel (SS)/ Fiberglass
Christmas Tree (Trim)	316 SS Nickel, Monel
Valve Packing and Seals	Teflon, Nylon
Wellhead (Trim)	316 SS Nickel, Monel
Tubing Hangar	316 SS Incoloy
Tubing	Glass Reinforced Epoxy (GRE) - lined carbon steel; IPC carbon steel, Corrosion Resistant Alloys (CRA)

[44] *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology, J.P. Meyer,, Contek Solutions, for the American Petroleum Institute, 2007.*

Tubing Joint Seals	Seal ring (GRE), Coated threads and collars
ON/OFF Tool, Profile Nipple	Nickel plated wetted parts
Packers	Internally coated hardened rubber, etc. Nickel plated wetted parts
Cements and Cement Additives	API cements and/or acid resistant cements

It should also be noted that the nickel content of steel can be varied, with higher nickel content resulting in more corrosion resistance but higher costs.

Well Cementing

The type of cement that is used in well cementing operations may be subject to chemical reactions in a CO_2 injection zone. Thus, it may in some cases be necessary to use specialty cements in remediation or new well construction. The following text is taken from the API report on injection well technology used in CO_2 EOR operations: [45]

> "Because CO_2 corrosion of cement is thermodynamically favored and cannot be entirely prevented, various solutions have been developed to limit CO_2 attack on the cement sheath. Most of these approaches involve substituting materials such as fly ash, silica fume or other non-affected filler or other cement materials for a portion of the Portland cement. The water ratio of the cement slurry is designed to be low to reduce the permeability of the set cement. The permeability of the set cement may be further lowered through the addition of materials such as latex (styrene butadiene) to the design
>
> Recently, investigators took samples from a 52 year old SACROC well with conventional, Portland-based well cement exposed to CO_2 for 30 years and found limited evidence of cement degradation. Preliminary evaluation suggests that the mixture of gelled and solid-particulate, (CO_2 and cement), reaction products sealed the cement permeability pore throats to significantly delay or prevent further CO_2 migration. While the evidence is limited, significant wellbore failure as indicated by over pressurization of over-lying formations and leakage to the surface has not been observed.
>
> Non-Portland solutions, marketed as specialty cements, have not been widely used in CO_2 EOR applications, most likely due to the observed adequate performance of current formulations, as well as the higher cost and logistic issues associated with such systems. However, in some cases, these systems have been applied to resist very severe acid gas (CO_2 and H_2S) and highly corrosive geothermal brine exposure conditions, in place of conventional systems."

[45] *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology, J.P. Meyer,, Contek Solutions, for the American Petroleum Institute, 2007.*

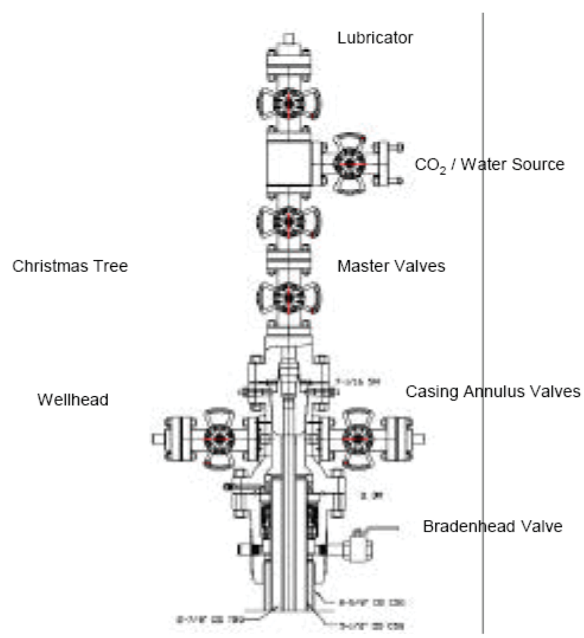
Pumps and Wellhead Control Equipment

Pumps, wellhead and control equipment, and measuring and monitoring equipment are required elements of the injection system. The pumps are those needed to move the CO_2 to the injectors. Pump costs are a function of horsepower and installation of electrical service also adds a cost component.

A diagram of typical injection well wellhead and control equipment is shown in Figure 5. The cost of injection equipment is a function of capacity. Injection well monitoring equipment are described in the 2007 API report and include a lubricator valve for running wireline tools, master valves to permit isolation of the tubing from the CO_2 source, casing head valves to permit monitoring of pressure in the annulus between the production casing and the tubing string to ensure mechanical integrity, and a Bradenhead valve to permit monitoring of the pressure between the production casing and surface casing. [46]

Figure 5: Diagram of Typical CO_2 Injection Wellhead

Source: 2007 API report (cited on previous page).



[46] *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology*, supporting information provided by J. P. Meyer, Contek Solutions, for the American Petroleum Institute, 2007.

Pipeline Costs

Included in the cost analysis is a CO_2 pipeline component of costs. The pipeline costs included here are only for the immediate sequestration site. Costs to transport the CO_2 to the sequestration site are excluded. Pipeline costs are specified in terms of cost per "inch-mile," which is the pipeline diameter in inches times the miles of pipeline.

Injection Well Construction Unit Costs

Table 4 specifies the estimated costs and data sources for injection well construction.

Table 4: Injection Well Construction Unit Costs

Cost Reporting Heading	Unit Cost Heading	Tracking Number	Cost Item	Cost Algorithm	Data Sources
Injection Well Construction	Site Selection and Evaluation	C-1	Conduct front-end engineering and design (general and injection wells)	$200,000/site + $40,000/injection well	ICF estimate.
Injection Well Construction	Land and Land Use Rights	C-2	Obtain rights-of-way for surface uses. (equipment, injection wells)	$20,000 per injection (pipeline right of ways included in pipeline costs) Half of cost is legal fees for developer, other half is bonus to landowner.	ICF estimate. Cost of land rights are highly variable.
Injection Well Construction	Land and Land Use Rights	C-3	Lease rights for subsurface (pore space) use.	Upfront payment of $50/acre (additional injection fees under O&M costs)	ICF estimate. Cost of land rights are highly variable.
Injection Well Construction	Permitting Costs	C-4	Land use, air emissions, water emissions permits	$100,000/site + $20,000/square mile	ICF estimate.
Injection Well Construction	Permitting Costs	C-5	UIC permit filing	$10,000/site + $5,000/injection well	ICF estimate.
Injection Well Construction	Drilling and Equipping Injection Wells	C-6	Standard injection well cost	Use look-up table. $/foot = $210 to $280 per foot typically down to 9,000 ft.	Drilling cost is estimated fom drilling cost equations developed from JAS and PSAC data.
Injection Well Construction	Drilling and Equipping Injection Wells	C-7	Corrosion resistant tubing	Additional $1.10/foot length - inch diameter for glass reinforced epoxy (GRE) lining	Based on SPE article on economics of GRE tubing.
Injection Well Construction	Drilling and Equipping Injection Wells	C-8	Corrosion resistant casing	Additional $1.75/foot length - inch diameter for corrosion resistant casing	PSAC and Preston Pipe Report
Injection Well Construction	Drilling and Equipping Injection Wells	C-9	Cement entire length of well	$1.15/foot length - inch diameter	Cementing cost based on 2008 PSAC Well Cost Study.
Injection Well Construction	Drilling and Equipping Injection Wells	C-10	Use CO2-resistant cement	Adds 25% to total cementing costs	Initial cost estimate until more data are obtained.
Injection Well Construction	Drilling and Equipping Injection Wells	C-11	Set packer no more than 100 ft above highest perforation	Affects tubing length	Assumed to be in standard cost.
Injection Well Construction	Drilling and Equipping Injection Wells	C-12	Set packer no more than 300 ft above highest perforation	Affects tubing length	Reduces feet of tubing used. Standard tubing cost based on 2008 PSAC Well Cost Study.
Injection Well Construction	Drilling and Equipping Injection Wells	C-13	Injection pressure limited to 90% of fracture pressure of injection formation	Affects maximum flow of well, number of wells needed	Due to uncertainty of injectability, this pressure impact is ignored.
Injection Well Construction	Injection Equipment (pumps, valves, measurement equipment)	C-14	Pumps	$1500/HP. Installation of electrical service adds $20,000 per well site.	Electrification cost based on EIA Oil and Gas Lease Equipment and Operating Cost estimates. Pump costs based on pipeline prime mover and compressor cost reported to FERC.
Injection Well Construction	Injection Equipment (pumps, valves, measurement equipment)	C-15	Wellhead and Control Equipment	Cost per well is $500*(maximum tons per day injected per well)^0.6	Based on 2008 PSAC Well Cost Study.
Injection Well Construction	CO2 Pipeline (within storage facility)	C-16	All elements of pipeline costs	$60,000/inch-mile	From pipeline cost data reported to FERC. Publised annually in Oil and Gas Jounal.

3.4 Area of Review Study and Corrective Action

This aspect of the cost analysis includes fluid flow and reservoir modeling to predict the movement of the injected CO_2 and pressure changes during and after injection. It also includes those cost elements pertaining to the identification, evaluation, and remediation of existing wells within the area of review.

Simple Fluid Flow Calculations to Predict CO_2 Flow

Modeling of fluid flow in the subsurface can be based on relatively simple, straightforward approaches that are not particularly data intensive, or can be extremely involved using sophisticated numerical reservoir simulation models. It was determined that two basic types of analysis should be included in the cost analysis:, one a simple approach using basic reservoir parameters, and the other based upon advanced reservoir simulation.

This cost element is for a simple flow calculation that would provide basic information on subsurface CO_2 movement.

Complex Modeling of Fluid Flow

This cost element is an estimation of the number of hours of labor required to set up, run, and interpret a sophisticated subsurface reservoir simulation model.

Physical Survey to Find Old Wells

This cost item involves a method in which an airborne magnetic survey is carried out using a helicopter which flies over the area of review to detect well casings from all cased wells. This may turn up old wells that are not in existing databases. Magnetic surveys can also be carried out from ground vehicles, but airborne surveys can cover the large expected survey areas much more efficiently. If such well casings are identified, additional follow-up, research of well records and physical inspection can be used to obtain additional data on the condition of these wells.

Mechanical Integrity of Old Wells

Existing wells at a planned sequestration site are potential conduits for the leakage of CO_2. The goal in evaluating these wells is to assess risk and to develop a plan of corrective action prior to sequestration. The wells that are most critical in this analysis are those that penetrate the proposed injection reservoir and confining zone units. Factors that must be evaluated include the condition of the cement and overall well maintenance. [47] [48]

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[47] I*PCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage,* by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.
[48] *Measuring and Modeling for Site Characterization: A Global Approach*, D. Vu-Hoang, L. Jammes, O. Faivre, and T.S. Ramakrishnan, Schlumberger Carbon Services, March, 2006.

A description of the process of evaluating and remediating old wells is provided by Meyer in a recent report published by API: [49]

> "More recently, the 100 year old Salt Creek Field in Wyoming has been converted to a CO_2 EOR development in which over 4,500 wells were re-completed. To do so, the following re-completion process was used:
>
> 1. Where they existed, cement bond logs were examined to ascertain the condition of individual wellbores with regard to bonding between the casing and the adjoining formation.
>
> 2. For wells that were plugged and abandoned, a pulling unit was set up and the wellbore drilled, from the top of the surface conductor to the bottom of the target formation to remove any accumulated debris (cement, bridge plugs, tree stumps, etc).
>
> 3. For those wells with cement bond logs, if insufficient or inadequate bonding was detected, a squeeze cement procedure was used to place cement behind the casing and the cement bond log rerun to validate successful wellbore remediation.
>
> 4. For every well, a casing mechanical integrity test was run. This required pressurizing the wellbore and monitoring it, to see if any pressure falloff occurred. If not, the wellbore was competent.
>
> 5. When pressure fall off was observed, it was indicative of casing leaks. The leaking section of casing was first identified and then re-sealed by squeeze cementing. In extreme cases, it was necessary to install a liner over the leaking section."

Remediate Old Wells in Area of Review

It may be necessary to remediate existing wells at a potential sequestration site. Existing wells that penetrate the injection zone or overlying seal units may provide conduits for the vertical movement of injected CO_2. Well remediation may involve the removal of existing plugs and casing strings, and re-completing the well. In some cases this may involve the use of CO_2 resistant cements in portions of the well.

In the case of saline reservoirs, there may be few, if any, existing wellbores. However, with old abandoned oil and gas fields, remediation costs may be significant, especially with old wells.

With some marginally deficient wells, it may be determined that a monitoring program alone may be acceptable, rather than remediation. The major difficulty in estimating the scope and nature of remediation is that there is little definitive research on the subject of the need for application of CO_2-resistant cement in acid gas wells.[50]

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[49] *Summary of Carbon Dioxide Enhanced Oil Recovery Injection Well Technology*, by James P. Meyer, API, http://www.gwpc.org/e-library/e-library_documents/e-library_documents_co2/API%20CO2%20Report.pdf (no publication date provided)
[50] EPA workgroup, January, 2008.

Area of Review and Corrective Action Unit Costs

Table 5 specifies the estimated costs and data sources for area of review and corrective action.

Table 5: Area of Review and Corrective Action Unit Costs

Cost Reporting Heading	Unit Cost Heading	Tracking Number	Cost Item	Cost Algorithm	Data Sources
AoR Study & Corrective Action	Site Selection and Evaluation	D-1	Simple fluid flow calculations to predict CO2 fluid flow.	36 hours of engineers @$53.52/hr = $1927 per site + 12 hours of engineers @$53.52/hr = $642 per injection well	ICF estimate of time required. Hourly rate may change based on labor survey data.
AoR Study & Corrective Action	Site Selection and Evaluation	D-2	Complex modeling of CO2 fluid flows and migration (reservoir simulations) over **100 years**	180 hours of engineers @$53.52/hr = $9634 per site + 24 hours of engineers @$53.52/hr = $1284 per injection well	ICF estimate of time required. Hourly rate may change based on labor survey data.
AoR Study & Corrective Action	Site Selection and Evaluation	D-3	Complex modeling of CO2 fluid flows and migration (reservoir simulations) over **10,000 years**	180 hours of engineers @$53.52/hr = $9634 per site + 36 hours of engineers @$53.52/hr = $1927 per injection well	ICF estimate of time required. Hourly rate may change based on labor survey data.
AoR Study & Corrective Action	Site Selection and Evaluation	D-4	Search physically for old wells (artificial penetrations)	helicopter magnetic survey requires about 9 hours/square mile @$1,200 per hour.Cost = $5,000 mobilization + $11,000 per square mile. Follow-up ground surveys will add another $2,000 per square mile. (helicopter survey interline spacing is about 80 feet w	Based on DOE sponsored research at Salt Creek WY . Helicopter hourly rate is in range of several publised estimates, adjustd for higher fuel costs.
AoR Study & Corrective Action	Site Selection and Evaluation	D-5	Evaluate integrity of construction and record of completion and/or plugging of **existing wells that penetrate containment system.**	24 hours @$106.31/hr = $2551 per site + 6 hours @$53.52/hr = $321 per well	ICF estimate of time required. Hourly rate may change based on labor survey data.
AoR Study & Corrective Action	Site Selection and Evaluation	D-6	Evaluate integrity of construction and record of completion and/or plugging of **existing shallow wells that pose a treat to USDWs.**	6 hours @$53.52/hr = $321 per well	ICF estimate of time required. Hourly rate may change based on labor survey data.
AoR Study & Corrective Action	Construction Site Remediation (Old Wells)	D-7	Remediate old wells in AoR that pose a risk to USDWs	$30,000 for clean out, $13,000 to replug and $11,000 to log (two cement plugs - one in producing formation and one for surface to bottom of USDWs, remainder of borehole filled with mud). Water well remediation is $20,000.	Plugging and logging cost based on 2008 PSAC Well Cost Study. Clean out cost will vary widely. Cost here is 3 days of rig use @ $10,000 per day. Rig cost from Land Rig ewsletter US Land Rig Rates, Novemebr 2007.
AoR Study & Corrective Action	Construction Site Remediation (Old Wells)	D-8	Remediate old wells in AoR that lack high quality cementing information	$30,000 for clean out, $13,000 to replug and $11,000 to log (two cement plugs - one in producing formation and one for surface to bottom of USDWs, remainder of borehole filled with mud). Water well remediation is $20,000.	Plugging and logging cost based on 2008 PSAC Well Cost Study. Clean out cost will vary widely. Cost here is 3 days of rig use @ $10,000 per day. Rig cost from Land Rig Newsletter US Land Rig Rates, November 2007.

3.5 Well Operation

This cost category includes those cost elements related to the operation of the injection wells, including measuring and monitoring equipment, electricity costs, O&M costs, pore space costs, contribution to a long term monitoring fund, repair and replacement of wells and equipment, and estimated costs for the possibility of failure at the site and the need to relocate a sequestration operation. While pore space costs are included in the analysis, they are not a part of the new rule.

Corrosion Monitoring and Prevention

Because of the propensity of CO_2 injection for corrosion, it will be necessary to develop a corrosion monitoring and prevention program for the operation.

Measuring and Monitoring Equipment

Measuring and monitoring equipment include a lubricator valve for running wireline tools, master valves to permit isolation of the tubing from the CO_2 source, casing head valves to permit monitoring of pressure in the annulus between the production casing and the tubing string to ensure mechanical integrity, and a Bradenhead valve to permit monitoring of the pressure between the production casing and surface casing. [51]

Equipment to Add Tracers

If chemical tracers are to be injected into the CO_2 stream for monitoring purposes, it will be necessary to incur costs related to the injection equipment.

Electricity Costs for Pumps and Equipment

Electricity costs represent a significant component of overall operating costs.

Injection Well Operating and Maintenance Costs

The annual costs of operating and maintaining the injection wells include operating labor, system maintenance, and CO_2 compression costs (if needed). Not included in this unit cost are the costs for mechanical integrity pressure tests, mechanical integrity logging, and the repercussions from those tests, such as the cost to repair, rework, or plug the injection well.

Land Use Rents and Right of Way

This unit cost includes the ongoing annual costs for land use and right of way. This is distinct from the upfront land use costs associated with site characterization.

Pore Space Unit Costs

This unit cost includes an estimate of pore space cost per metric ton of CO_2 injected. This is distinct from the upfront payment unit cost included under site characterization. While pore space costs are included in the analysis, they are not a part of the new rule.

Property Taxes and Insurance

This unit cost includes the ongoing expense of property tax and liability insurance.

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[51] *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology*, supporting information provided by J. P. Meyer, Contek Solutions, for the American Petroleum Institute, 2007.

Tracers in Injected Fluid

Tracer testing involves the incorporation of trace amounts of chemical compounds into the injected CO_2. The objective is to confirm the migration and location of CO_2 within the reservoir and potentially in overlying groundwater or soil zones. A number of tracers with very low detection limits are available and more are under development.

The use of tracers for monitoring was investigated under GEO-SEQ[52]. Natural and artificial tracers have the potential to assist in characterizing reservoirs, and calibrating models as well as indicating leakage and seepage.

Tracers may consist of natural tracers (isotopes of C, O, H, and noble gases) that are associated with the injected CO_2, and introduced tracers including noble gases, SF6, and perfluorocarbons (PFC's). [53] Perfluorocarbon Tracers (PFTs) have many advantages in that they are soluble in water, non-toxic, non-radioactive, and have an extremely small detection limit. [54] Thus, much smaller amounts are required to be injected compared to other compounds such as sulfur hexafluoride.

Tracers may be detected in monitoring wells either within the storage reservoir or in shallower zones, groundwater, or soil gases. At the Frio Brine pilot in Texas, there were three types of monitoring installations to test for CO_2 in shallow zones.[55] These included capillary absorbent tubes (CATs) and soil gas wells for the soil zone and water wells for groundwater testing. Soil gas wells may be only a few feet deep and are sampled with a syringe. CAT samples are removed and shipped to a laboratory for analysis. Fresh CATs are then installed and the sample tubes sealed. Groundwater wells are sampled for the headspace atmosphere.

One potential problem or uncertainty in the use of chemical tracers is the degree to which the tracers move differently through the reservoir or at different rates than the injected CO_2.

Contribution to Long Term Monitoring, Insurance, and Remediation

This cost component represents those costs potentially incurred to establish a long-term post-injection monitoring program, along with insurance and necessary remediation activity. This cost would be applied only if such a program is required. Because of the focus of the Safe Drinking Water Act on endangerment to USDWs and the absence of provisions to allow transfer of liability no such long term program has yet been proposed and therefore we have not included any potential costs in this report. The IPCC report (page 241) includes a description of aspects of long term stewardship. [56]

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[52] *GEO-SEQ Best Practices Manual, Geologic Carbon Dioxide Sequestration: Site Evaluation to Implementation,* by the GEO-SEQ Project Team, Earth Sciences Division, Lawrence Berkeley National Laboratory, Berkeley, California, September 30, 2004.

[53] *Monitoring to Ensure Safe and Effective Geological Sequestration of Carbon Dioxide*, S. Benson and L. Myer, Lawrence Berkeley Laboratory, Berkeley, California, 2002.

[54] *Surface Environmental Monitoring at the Frio CO2 Sequestration Test Site, Texas*, H.S. Nance, Texas Bureau of Economic Geology, Austin, Texas, DOE/NETL Conference on Carbon Capture and Storage, May, 2005.

[55] *Surface Environmental Monitoring at the Frio CO_2 Sequestration Test Site, Texas,* H.S. Nance, Texas Bureau of Economic Geology, Austin, Texas, DOE/NETL Conference on Carbon Capture and Storage, May, 2005.

[56] *IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage*, by Working Group III of the Intergovernmental Panel on Climate Change [B. Metz, O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp

Repair or Replace Wells and Equipment

This cost component includes remediation of wells and equipment that occurs during the injection phase. This is in addition to the remediation that is completed during the initial site remediation work.

General Failure of Containment Site

There is a small statistical probability that a given sequestration site does not perform adequately, due to unforeseen subsurface conditions. This may in some cases require the abandonment of the site and re-location. The best method of incorporating such a cost is through a risked approach, taking the entire cost times the small probability of occurrence.

Well Operation Unit Costs

Table 6 specifies the estimated costs and data sources for well operation unit costs.

Table 6: Well Operation Unit Costs

Cost Reporting Heading	Unit Cost Heading	Tracking Number	Cost Item	Cost Algorithm	Data Sources
Well Operation	Permitting Costs	E-1	Develop a corrosion monitoring and prevention program	24 hours of engineers @$53.52/hr = $1284 per site	ICF estimate of time required. Hourly rate may change based on labor survey data.
Well Operation	Injection Equipment (pumps, valves, measurement equipment)	E-2	**Standard** measurement / monitoring equipment: injected volumes, pressure, flow rates and annulus pressure	$10,000/well	Initial cost estimate until more data are obtained.
Well Operation	Injection Equipment (pumps, valves, measurement equipment)	E-3	**Continuous** measurement / monitoring equipment: injected volumes, pressure, flow rates and annulus pressure	$15,000/well	Initial cost estimate until more data are obtained.
Well Operation	Injection Equipment (pumps, valves, measurement equipment)	E-4	Equipment to add tracers	$10,000/well	Initial cost estimate until more data are obtained.
Well Operation	Operating Costs	E-5	Electricity cost for pump, equipment	$0.064/kWh	2007 average industrial sector electricity price reported by EIA.
Well Operation	Operating Costs	E-6	Injection well O&M	Annual O&M costs are $75,000 + $3/ft per well per year	Operating and maintenance cost based on EIA Oil and Gas Lease Equipment and Operating Cost estimates.
Well Operation	Operating Costs	E-7	Land use rent, rights-of-way	$5/acre/year	ICF estimate based on oil & gas industry costs. Cost of land rights are highly variable.
Well Operation	Operating Costs	E-8	Pore space use costs	$0.05/barrel or about $0.35 per metric ton	ICF estimate based on oil & gas industry costs. Cost of land rights are highly variable.
Well Operation	Operating Costs	E-9	Property Taxes & Insurance	$0.03/$1CAPEX	ICF estimate.
Well Operation	Operating Costs	E-10	Tracers in injected fluid	$0.05/ton of CO2 injected	Initial cost estimate until more data are obtained.
Well Operation	Operating Costs	E-11	Contribution to Long-term Monitoring, Insurance, Remediation Fund	$0.0/unit CO2 injected	not used
Well Operation	Remediation During Operation	E-12	Repair, replace wells and equipment	Assume 1%/year of initial well and equipment cost	ICF assumption
Well Operation	Remediation During Operation	E-13	General failure of containment at site. Need to build new site, remove and relocate CO2	Assuming a 1% chance of failure over injection life, then something like 0.083% of total capital costs each year would cover such a contingency	ICF assumption

3.6 Mechanical Integrity Tests

A CO_2 injection well will periodically undergo integrity testing to ensure mechanical soundness, lack of corrosion, and ability to sustain pressure. There are several such tests that are typically used, and they include both pressure tests and wireline logs. These technologies are well established and have been used for decades for underground injection operations.

Mechanical Integrity Pressure Tests

The most common internal MIT is the standard annular pressure test (SAPT). The annulus between the casing and injection tubing is pressured and monitored to see if the pressure holds. [57] The EPA and state regulatory agencies have specific requirements for pressure testing injection wells and for performing other mechanical integrity tests. [58] [59] Testing occurs prior to injection and periodically thereafter. Wells which fail the mechanical integrity test must be shut in until repaired, reworked, or plugged. [60] In addition if after a mechanical integrity test is performed, a well operation causes the injection packer to be unseated or if the tubing or packer was pulled, repaired, or replaced, the well must be re-tested for mechanical integrity.

Internal Mechanical Integrity

An injection well has internal mechanical integrity if it can be demonstrated that there is no leakage in the tubing, casing, or packers. This is differentiated from an external mechanical integrity that evaluates the bond between casing and rock.

Radioactive Tracer Survey of Cement

A radioactive tracer survey is a mechanical integrity test in which a slug of radioactive material is injected into the well, and gamma ray detection equipment is used to detect specific movement of the tracer material between the well and the surrounding rock that indicates problems with the cement, in which the injected material moves in vertical channels outside the casing.

External Mechanical Integrity Test

A number of wireline logging tools are used to evaluate external integrity, which is the integrity of the bond between the cement and surrounding rock or between the casing and the cement. These include cement

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[57] Carbon Dioxide Storage: Geological Security and Environmental Issues – Case Study on the Sleipner Field, Norway, S. Soloman, Bellona Foundation, May, 2007.
[58] *UIC Program Mechanical Integrity Testing: Lessons for Carbon Capture and Storage*, Jonathan Koplos, Bruce Kobelski, Anhar Karimjee, and Chi Ho Sham, Fifth Annual Conference on Carbon Capture and Sequestration, DOE/NETL, May, 2006.
[59] *Determination of the Mechanical Integrity of Injection Wells*, EPA Region 5 website, www.epa.gov/region5/water/uic/r5guid/r5_05.htm

[60] *Underground Injection Control Rules*, Montana Board of Oil and Gas Conservation, www.bogc.dnrc.state.mt.us/uicrules.htm.

bond, temperature, noise, and oxygen activation logs.[61] Cement bond logs are used to assess the presence, bond and continuity of cement. Periodic cement bond logs can detect deterioration of the cement through time or any indication of reaction with CO_2.[62] Descriptions of these technologies are available at the EPA Region 5 website [63]

Pressure Falloff Tests

A falloff test is a pressure transient test that consists of shutting in an injection well and measuring the pressure falloff. [64] Falloff tests provide reservoir pressure data and are used to characterize both the reservoir and the completion condition of the injection well. For Class I non-hazardous injection wells, operators are required to perform the test annually.

Mechanical Integrity Test Unit Costs

Table 7 specifies the estimated costs and data sources for mechanical integrity test unit costs.

Table 7: Mechanical Integrity Tests Unit Costs

Cost Reporting Heading	Unit Cost Heading	Tracking Number	Cost Item	Cost Algorithm	Data Sources
Mechanical Integrity Tests	Operating Costs	F-1	Internal mechanical integrity pressure tests	$2,000/test	Initial cost estimate until more data are obtained.
Mechanical Integrity Tests	Operating Costs	F-2	Mechanical integrity internal log and video every 5 years	$2,000 plus $4/foot	Based on 2008 PSAC Well Cost Study for wireline log suite. Cost of MIT log could be lower.
Mechanical Integrity Tests	Operating Costs	F-3	Conduct a radioactive tracer survey of the bottom-hole cement using a CO_2-soluble isotope annually (every 2 years RA2)	$5,000/test	Initial cost estimate until more data are obtained.
Mechanical Integrity Tests	Operating Costs	F-4	Conduct a radioactive tracer survey of the bottom-hole cement using a CO_2-soluble isotope every 6 months	$5,000/test	Initial cost estimate until more data are obtained.
Mechanical Integrity Tests	Operating Costs	F-5	External mechanical integrity tests to detect flow adjacent to well using temperature or noise log at least annually	$2,000 plus $4/foot	Based on 2008 PSAC Well Cost Study for wireline log suite. Cost of external MIT log could be lower.
Mechanical Integrity Tests	Operating Costs	F-6	External mechanical integrity tests to detect flow adjacent to well using temperature or noise log at least every 6 months	$2,000 plus $4/foot	Based on 2008 PSAC Well Cost Study for wireline log suite. Cost of external MIT log could be lower.
Mechanical Integrity Tests	Operating Costs	F-7	Conduct pressure fall-off test every five years	$2,000/test	Initial cost estimate until more data are obtained.
Mechanical Integrity Tests	Operating Costs	F-8	Conduct pressure falloff test every 6 months	$2,000/test	Initial cost estimate until more data are obtained.

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[61] *UIC Program Mechanical Integrity Testing: Lessons for Carbon Capture and Storage*, Jonathan Koplos, Bruce Kobelski, Anhar Karimjee, and Chi Ho Sham, Fifth Annual Conference on Carbon Capture and Sequestration, DOE/NETL, May, 2006.
[62] *Carbon Dioxide Storage: Geological Security and Environmental Issues – Case Study on the Sleipner Field*, Norway, S. Soloman, Bellona Foundation, May, 2007.

[63] *Determination of the Mechanical Integrity of Injection Wells*, EPA Region 5 website, www.epa.gov/region5/water/uic/r5guid/r5_05.htm

[64] *UIC Pressure Falloff Requirements*, USEPA Region 9, August, 2002.

3.7 Post-Injection Well Plugging, Equipment Removal, and Site Care

After the injection phase has ended, it is necessary to prepare the site for long-term monitoring and eventual closure in a safe and secure manner that protects USDWs. This involves the plugging of injection wells, removal of surface equipment, and land restoration. It also includes long term requirements for monitoring the site to ensure safety and to confirm an understanding of the CO_2 distribution in the subsurface.

Plug Injection Wells

Injection wells will be plugged upon completion of injection operations, while monitoring wells will be plugged after long-term monitoring, since they will be part of the long-term monitoring operation. Well abandonment of injection and monitoring wells involves the placement of cement plugs over all or part of the well, with special care taken to seal of drinking water zones. While most aspects of plugging CO_2 injection wells are similar to procedures used in conventional wells, it may be required to plug more of the well and may be necessary to use corrosion resistant cement. (Reference: IPCC report).

Plug Monitoring Wells

Monitoring wells at the site may be conduits for leakage and also will require eventual plugging after the long-term monitoring period.

Remove Surface Equipment

For both injection and monitoring wells, surface equipment will be removed as part of site restoration. Injection well site restoration occurs after the injection period and monitoring well restoration occurs before closing the site.

Document Plugging and Post-Injection Process

This cost item includes the labor costs for notification to regulators of intent to cease injection, including well plugging, post injection site care, and closure plans.

Post-Injection Monitoring Well O&M

The annual costs of operating and maintaining the monitoring wells will extend through the end of the post-injection site care monitoring period.

Post-Injection Air and Soil Surveys

The annual costs of air and soil surveys will extend through the end of the post- injection site care monitoring period.

Post- Injection Seismic Surveys

The annual costs of seismic surveys will extend through the end of the post-injection site care monitoring period.

Post- Injection Reports to Regulators

Periodic reports to regulators will continue during post Injection Site Care monitoring.

Post-Injection Well Plugging, Equipment Removal, and Site Care Unit Costs

Table 8 specifies the estimated costs and data sources for plugging, equipment removal and post-injection care.

Table 8: Post-Injection Well Plugging, Equipment Removal, and Site Care Unit Costs

Cost Reporting Heading	Unit Cost Heading	Tracking Number	Cost Item	Cost Algorithm	Data Sources
Plugging and Post-Injection Site Care	Post-Injection MIT, Plugging, and Remove Surface Equip.	G-1	Flush wells with a buffer fluid before plugging	$500 + $0.10/foot	Initial cost estimate until more data are obtained.
Plugging and Post-Injection Site Care	Post-Injection MIT, Plugging, and Remove Surface Equip.	G-2	Plug injection wells (done to all wells, percents refer to intensity)	$13,000 to plug and $11,000 to log (two cement plugs - one in injection formation and one for surface to bottom of USDWs, remainder of borehole filled with mud)	Plugging and logging cost based on 2008 PSAC Well Cost Study.
Plugging and Post-Injection Site Care	Post-Injection MIT, Plugging, and Remove Surface Equip.	G-3	Perform an MIT prior to plugging to evaluate integrity of casing and cement to remain in ground	$2,000 plus $4/foot	Based on 2008 PSAC Well Cost Study for wireline log suite. Cost of external MIT log could be lower.
Plugging and Post-Injection Site Care	Post-Injection MIT, Plugging, and Remove Surface Equip.	G-4	Plug monitoring wells	$6,500 to plug and $5,500 to log (one cement plugs - surface to bottom of USDWs, remainder of borehole filled with mud)	Plugging and logging cost based on 2008 PSAC Well Cost Study.
Plugging and Post-Injection Site Care	Post-Injection MIT, Plugging, and Remove Surface Equip.	G-5	Remove surface equipment, structures, restore vegetation (injection)	$25,000/injection well	ICF estimate
Plugging and Post-Injection Site Care	Post-Injection MIT, Plugging, and Remove Surface Equip.	G-6	Remove surface equipment, structures, restore vegetation (monitoring wells)	$10,000/monitoring well, $5,000 for monitoring stations	ICF estimate
Plugging and Post-Injection Site Care	Post-Injection MIT, Plugging, and Remove Surface Equip.	G-7	Document plugging and post-injection process (notification of intent, post-injection plan, post-injection report)	120 hours of engineers @$53.52/hr = $6422 per site	ICF estimate of time required. Hourly rate may change based on labor survey data.
Plugging and Post-Injection Site Care	Post-Injection Monitoring and Remediation	G-8	Post-injection monitoring well O&M	Annual O&M costs are $25,000 + $3/ft per well per year	Operating and maintenance costs adapted from EIA Oil and Gas Lease Equipment and Operating Cost estimates.
Plugging and Post-Injection Site Care	Post-Injection Monitoring and Remediation	G-9	Post-injection air and soil surveys	$10,000 per station per year	ICF estimate.
Plugging and Post-Injection Site Care	Post-Injection Monitoring and Remediation	G-10	Post-injection seismic survey (assume every five years)	$75,000/square mile for good resolution	Several published reports are in range of this cost.
Plugging and Post-Injection Site Care	Post-Injection Monitoring and Remediation	G-11	Periodic post-injection reports to regulators (every 5 years)	40 hours @$53.52/hr = $2141 per report	ICF estimate of time required. Hourly rate may change based on labor survey data.

3.8 Financial Responsibility

It will be necessary for the operator to demonstrate and maintain financial responsibility, and have the resources for activities related to closing and remediating GS sites. The rule only specifies a general duty to obtain financial responsibility acceptable to the Director, and EPA will provide guidance to be developed at a later date that describes the recommended types of financial mechanisms that owners or operators can use to meet this requirement. The following unit costs were used:

Performance Bond or Demonstration of Financial Ability for Well Plugging

This unit cost item includes the labor costs to prepare a report demonstrating financial responsibility for well plugging.

Performance Bond or Demonstration of Financial Ability for Post-Injection Site Care Period

This unit cost item includes the labor costs to prepare a report demonstrating financial responsibility for post injection monitoring, including remediation.

Financial Responsibility Unit Costs

Table 9 specifies the estimated costs and data sources for financial responsibility unit costs.

Table 9: Financial Responsibility Unit Costs

Cost Reporting Heading	Unit Cost Heading	Tracking Number	Cost Item	Cost Algorithm	Data Sources
Financial Responsibility	Post-Injection Monitoring and Remediation By Operator	H-1	Performance bond or demonstrate financial ability to close site (including annual inflation factor)	8 hours @$53.52/hr = $428 per financial report	ICF estimate of time required. Hourly rate may change based on labor survey data.
Financial Responsibility	Post-Injection Monitoring and Remediation By Operator	H-2	Performance bond or demonstrate financial ability for post-injection monitoring (including annual inflation factor)	4 hours @$53.52/hr = $214 per financial report	no added cost

3.9 General and Administrative Costs

General and administrative costs are included as unit costs for both the project development and operating phases. The costs are specified as a percentage either capital costs or annual operating costs.

Table 10 specifies the estimated costs and data sources for general and administrative unit costs.

Table 10: General and Administrative Unit Costs

Cost Reporting Heading	Unit Cost Heading	Tracking Number	Cost Item	Cost Algorithm	Data Sources
G&A Costs	General and Administrative Costs for Capex	J-!	Project development G&A	20% of initial capital expenditure	ICF estimate based on oil and gas industry factors.
G&A Costs	General and Administrative Costs for Opex	J-2	Operating G&A	20% of annual operating costs	ICF estimate based on oil and gas industry factors.

4 Characteristics of Example Projects for Costing

4.1 Introduction

While costs could vary significantly on a site-by-site basis, for the current analysis a decision was made to create three example geologic sequestration cases for costing:

- saline reservoir
- depleted gas field
- depleted oil field

The rationale for selecting these three cases is as follows:

Saline Reservoir
Saline reservoir storage capacity represents a large percentage of assessed U.S. capacity and it is widely agreed that this reservoir type will eventually be chosen for most future U.S. CO_2 storage. Saline reservoirs are present in most regions of the country, including areas that have not historically had a great deal of oil and gas production. An additional factor is that in most cases these potential reservoirs have not been penetrated by wells, which can provide leakage pathways. It has also been demonstrated at Sleipner field that CO_2 sequestration in saline reservoirs is effective and the CO_2 plume can generally be monitored effectively with seismic and other forms of monitoring techniques.

In addition, most of the planned major DOE sequestration pilots are in saline reservoir settings.

Depleted Conventional Gas Field and Depleted and Abandoned Oil Field
While the assessed volume of potential U.S. CO_2 storage in depleted gas fields is only a small fraction of the U.S. total, it is expected that industry will choose to sequester some CO_2 in these settings. Among these are the known presence of a trap, known reservoir properties such as porosity, permeability, and flow characteristics, and established field and transportation infrastructure. It was also considered important to develop a set of characterization, monitoring, and other costs in settings other than saline reservoirs, because of presences of existing wells and other infrastructure.

4.2 Lawrence Berkeley Study

ICF has reviewed available literature from other organizations that have developed parameters for "typical" storage scenarios by reservoir type. Review of this information was useful in helping us develop our example projects.

A research team at Lawrence Berkeley National Laboratory investigated a large number of scenarios for carbon sequestration and selected two for detailed evaluation[65]. Table 11 lists their parameters to use for estimating the costs of storage for enhanced oil field recovery and saline aquifer scenarios.

[65] *Monitoring Protocols and Life-Cycle Costs for Geologic Storage of Carbon Dioxide*, by S. M. Benson, M. Hoversten, and E. Gasperikova of Lawrence Berkeley National Laboratory, and M. Haines of EA Greenhouse Gas

Table 11: Lawrence Berkeley Study Parameters for Their Economic Analysis

Scenario Parameters	Oil-Field	Saline Formation
Storage Scenario	CO_2 storage combined with enhanced oil recovery	CO_2 storage in a saline formation
Number of Injection Wells	20 injection, 12 production wells distributed evenly over the foot print of the reservoir, based on the Schader Bluff scenario	10 injection wells located within a 10 sq. km area, based on the injectivity of vertical wells in a Frio-like formation with a permeability of 0.5 Darcy
Reservoir Properties	25 m thick, areal extent of 360 km2	100 m thick, 20% porosity, capacity factor of 10%, density of CO_2 at reservoir conditions 800 kg/m3
Operational Period	30 years	30 years
Post Inj. Period	20 years	50 years
Post-Closure	0 years (assume no leakage from the storage formation)	0 years (assume no leakage from the storage formation)
Mass of CO_2 Injected	258 million metric tons CO_2	258 million metric tons CO_2
Frequency of Geophysical Monitoring	5, 10, 20, 30, 40, and 50 years	1, 2, 5, 10, 15, 20, 25, 30, 40, 50, 60, 70, and 80 years
Project Footprint	360 km2 (area of the oil reservoir)	HRG Plume: 19 km2 after the first year, growing to 216 km2 after 80 years; LRG Plume: 18 km2 after the first year, growing to 348 km2 after 80 years

4.3 Regional DOE Partnership Pilot Projects and FutureGen

ICF has evaluated the characteristics of the DOE pilot sequestration projects and the previously selected FutureGen sequestration site in Illinois. The characteristics of these projects were used in the development of our type examples. Project characteristics that have been compiled are shown in Tables 12 and 13. None of the major projects currently planned for injection pilots is a depleted gas field, but there is information on oil reservoir pilots. As shown in the table, the currently planned projects are only scheduled for about three to four years of injection. The typical injection rate (from one well) is up to one million tons of CO_2 per year. This can be compared to an expected full scale future rate for a power plant of up to several million tons per year, likely involving multiple injection wells over a much longer period of time.

For the FutureGen project, a 2007 report by the FutureGen Alliance lays out the characteristics of all of the proposed sequestration sites (FutureGen Initial Conceptual Design Report, 2007). Included is information on several areas including such as depth, thickness, porosity, expected injectivity and ultimate plume size.

R&D Programme, Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), September 5–9, 2004, Vancouver, Canada, v. II, 1259-1266, 2005.

Table 12: DOE CO_2 Sequestration Pilot Projects (DOE Phase III) and FutureGen Project

Regional Organization	Project Name	DOE Funding Status	Tons per Year	Duration Years	Planned Sequestered Tons	Total Cost $MM	CO2 Source	Injection Depth ft	Comments
Main Projects - Announced DOE Phase III									
Big Sky	Green River Basin Nugget Saline Reservoir Moxa Arch, Western Wyoming	Proposed	1,000,000	3	3,000,000	$110	Gas plant	12,000	
MGSC	Illinois Basin Mt. Simon Saline Reservoir	Approved	365,000	3	1,095,000	$84	ADM ethanol plant	5,500	
PCOR	Williston Basin EOR Sequestration; ND	Approved	750,000	6	4,500,000	$300	Existing coal plant	10,000	
SWCARB	Raton Basin Entrada Saline Reservoir; SW Colorado	Approved	700,000	4	2,800,000	$81	La Veta gas plant	?	Strat. below gas field containing CO2
SECARB	Mississippi Tuscaloosa Massive Saline Reservoir; SW Mississippi	Approved	1,000,000	1.5	1,500,000	$94	Jackson Dome	10,000	Downdip of oil reservoir
MRCSP	Cincinnati Arch Mt. Simon Saline Reservoir; Greenville, OH	Proposed	280,000	4	1,120,000	$93	Planned ethanol plt.	3,500	
WESTCARB	San Joaquin Basin, CA Saline Formation; Olcese and Vedder Sands	Proposed	250,000	4	1,000,000	$91	New 49 MW plant	9,000	Timeline shows 8 years of injection
Other Proposed DOE Pilot Projects									
SWCARB	Green River Basin Entrada	Proposed	100,000	1	100,000		Pacificorp power plt.	7,000	
SECARB	"Athropogenic " Test in Tuscaloosa Massive Saline Reservoir	Proposed	250,000	4	1,000,000				CO2 from as yet undecided source/ power plant
FutureGen Project	Matoon, IL Location of FutureGen	Selected	2,000,000	20+	50,000,000	$1,500	IGCC plant		

Table 13: Details of Sequestration Pilot Projects

Regional Organization	Project Name	Formation Name	Lithology	Top Injection Depth ft	Gross Interval ft	Net Sand ft	Porosity %	Perm. md	Press. Grad. psi/ft	Pressure psi	Temp F	TDS mg/L	Gas Stream % CO2	Well Injec-tivity MM t/yr
Main Projects - Announced DOE Phase III														
Big Sky	Green River Basin Nugget Saline Reservoir Moxa Arch, Western Wyoming	Nugget	Sandstone	12,000	700	200	15%		0.35	4200	209	109000	92%	
MGSC	Illinois Basin Mt. Simon Saline Reservoir	Mt. Simon	Sandstone	5,500	1500									
PCOR	Williston Basin EOR Sequestration; ND	Undet.	Carbonate	10,000										
SWCARB	Raton Basin Entrada Saline Reservoir; SE Colorado	Entrada	Sandstone	?									97%	
SECARB	Mississippi Tuscaloosa Massive Saline Reservoir; SW Mississippi	Tuscaloosa	Sandstone	10,000	1300									
MRCSP	Cincinnati Arch Mt. Simon Saline Reservoir; Greenville, OH	Mt. Simon	Sandstone	3,500	300		12%	50-400	0.41	1450	88			
WESTCARB	San Joaquin Basin, CA Saline Formation; Olcese and Vedder Sands	Vedder	Sandstone	9,000	800		10-40%							
Other Proposed DOE Pilot Projects														
SWCARB	Green River Basin Entrada	Entrada	Sandstone	7,000										
SECARB	"Athropogenic " Test in Tuscaloosa Massive Saline Reservoir	Tuscaloosa	Sandstone											
Proposed FutureGen Projects														
	Matoon, IL Location of FutureGen	Mt. Simon	Sandstone	6,750	1,300-1,600	500								2.50
	Tuscola, IL Mt. Simon	Mt. Simon	Sandstone	6,150	1600	600								2.50
	Odessa, TX Delaware Sand	Delaware	Sandstone	3,600	1600	130								0.25-0.33
	Brazos, TX Woodbine Sand	Woodbine	Sandstone	4,800	500		20-30%	high						1.13

4.4 Project Characteristics – Saline Reservoir (Commercial Scale)

Basic properties from the saline reservoir case are based upon typical parameters as evaluated in the DOE pilots. It should be noted that there is a wide range of variation in the properties among the various DOE pilot projects. Generally speaking however, the saline reservoirs are characterized by thick, porous intervals, generally at depths below 5,000 feet. Gross sand intervals are typically hundreds of feet thick and net (porous) sand intervals are also thick.

Table 14 presents the project characteristics for a commercial scale saline reservoir site. The example is based upon sequestration of the CO_2 from a 275 MW power plant. As shown in the first part of the table titled "**Power Plant, Injection Rate, and Monitoring**," with 90 percent capture and 85 percent utilization, this equates 1.8 million tons per year. The injection period is 20 years, representing about 37 million tons of sequestration. The 20 year period represents one half of the full lifetime of a power plant. The injection was split into two 20 year periods under the assumption that the operator will develop half of the sequestration capacity initially and the other half in approximately 20 years. Such a staggered development would reduce the present value of investment and operating cost.

The second portion titled **"Injection Zone Depth, Pressure, and Temperature"** lists the values for those parameters and the calculated CO_2 density.

The next section titled "**Volumetrics and Capacity"** lists the assumptions required to estimate the total potential storage volume within a specified area. In terms of theoretical storage capacity, an initial volume is estimated based upon the pore space and the density of CO_2 in kg/cu. meter. A practical storage volume is calculated using an estimated storage efficiency factor of ten percent. The ten percent assumption has been cited in various literature sources as a good first approximation and is based upon a volumetric analysis carried out by ICF on published storage capacity estimates from the DOE NATCARB project. The practical storage capacity is much lower than the pore space volume because of factors such as the geometry of the plume and other factors relating to geologic complexity.

The section titled **"Old Wells in Area"** shows the assumptions for the number and characteristics of existing wells. Old wells are estimated at one per square mile for deeper wells and two per square mile for shallow wells. The old well assumptions impact well remediation costs.

The section titled "**Injection Wells and Stratigraphic Wells**" shows the assumptions for the number of injection wells and potential stratigraphic test wells. For the commercial scale projects, the number of injection wells is based upon an assumption of 2,000 tons per day per well, plus one additional well. For the pilot scale projects, there is an assumption of one injector. The number of stratigraphic wells is a maximum of one for commercial scale projects, and depends upon the regulatory scenario. There are no stratigraphic wells for the pilot projects.

Under the section titled "**Monitoring Wells**," assumptions are presented on the maximum number of monitoring wells in each case. The actual number of monitoring wells is dependent upon the regulatory scenario. Also shown here are the assumptions for air and soil sampling and microseismic arrays.

The section "**USDWs and Containment Systems**" shows the assumptions for the depths to the top of the deepest USDW and the depths to the top and bottom of containment systems.

The "**CO2 Pipelines and Pumps**" section shows the estimated number of miles of CO2 distribution pipelines, pipeline diameters, and pump horsepower.

Table 14: Saline Reservoir Type Case Characteristics (Commercial Scale Project)

Power Plant, Injection Rate, and Monitoring	
MW Power Plant	**275**
90% Capture (CO2 tonnes/day)	5,940
Capacity Utilization	**0.85**
Tons per Year	1,842,885
Storage facility injection life in years	**20**
Tons for facility	36,857,700
Post-injection monitoring period in years	**10**

Injection Zone Depth, Pressure, and Temperature	
Depth to Top of Injection Interval (ft)	7,900
Depth to Bottom of Injection Interval (ft)	**8,500**
Hydrostatic pressure (psi)	3,681
Temp (F) @1dF/100 ft	147
Hydrostatic pressure (Mpa)	25.4
Temp. (C)	63.9
CO2 density (kg/cu.m)	782.0

Volumetrics and Capacity		
Gross thickness (ft)	**600**	
Net thickness (ft)	**300**	
Porosity (%)	**20%**	
Area (sq. mi.)	**10**	*<< Set square miles so as to make facilities*
Area (sq. ft.)	278,784,000	*capacity large enough for power plant*
Pore space volume (cu. ft)	16,727,040,000	
Pore space volume (cu. m)	473,656,579	
Million tonnes capacity at 100% storage efficiency	370	
Storage efficiency	**10.0%**	
Effective Million tonnes capacity	**37**	

Old Wells in Area	In AoR	Known to Require Remediation	Additional Wells w/o Good Cement Logs	
Deep Artificial Penetrations (exclude any to be used as injectors)	**10**	1.0	1.5	*<< One per square mile*
Shallow Artificial Penetrations	**20**	2.0	3.0	*<< Two per square mile*
Water Wells Artificial Penetrations	**20**	2.0	3.0	*<< Two per square mile*

Table 14. (continued) Saline Reservoir Type Case Characteristics (Commercial Scale Project)

Injection Wells and Stratigraphic Wells			
Injection Wells Required (total)	**4.0**		<< *Based on injection rate*
Injection Wells New Drills	**4.0**		*per well of 2,000 mtpd plus*
Injection Wells Conversions of Old Wells	0		*one extra well.*
Cost of Converted Wells as % of New	**15%**		
Tubing Size (inches)	**6.0**		
Number of Stratigraphic Tests (if required)	**1**		
Depth of Stratigraphic Tests (feet)	9,350		
Cores per Stratigraphic Test	**6**		

Monitoring Wells, etc.	Above Inj Zone	Into Inj Zone	
Max. Number of Monitoring Wells (depends on scenario)	**16**	**16**	<< *Maximum number based*
Depth of Monitoring Wells (feet)	4,700	8,350	*on number of injectors*
Long-string Casing of Monitoring Wells (diam. inches)	**3.5**	**3.5**	
Air/soil Sampling Stations (if required)	3		
Passive seismic arrays (inside monitoring wells if required)	2		

USDW's and Containment Systems		
Deepest USDW	2,000	<< *Depths are estimates*
Second Containment System Depth to Top (ft)	5,800	*based upon relationship*
Second Containment System Depth to Bottom (ft)	6,100	*to reservoir depth.*
First Containment System Depth to Top (ft)	7,000	
First Containment System Depth to Bottom (ft)	7,400	

CO2 Pipelines and Pumps			
	Miles	(inches)	
Distribution Pipeline 1	3.2	6	<< *Calculated from*
Distribution Pipeline 2	3.2	4	*reservoir area*
Total inch-miles	32		
Pump HP	713		<< *Based on inj. rate*

4.5 Project Characteristics – Depleted gas reservoir (Commercial Scale)

For the depleted gas and depleted oil reservoirs, ICF relied upon a statistical analysis of the DOE "GASIS" reservoir database. [66] This is a reservoir level database compiled for DOE in the 1990s and includes properties for most of the significant oil and gas fields in the U.S. Statistics were derived from GASIS through the evaluation of only those reservoirs occurring within a depth range of 3,000 to 10,000 feet. The results of the analysis are shown in Table 15 and the example case for commercial scale depleted gas reservoirs is shown in Table 16. The categories are the same as described above for the commercial scale saline case.

[66] *Gas Information System (GASIS) Project*, U.S. Department of Energy, National Energy Technology Center, Morgantown, WV.

Table 15: Summary of GASIS Reservoir Database Parameters for Depleted Gas Reservoir and Depleted Oil Reservoir Example Cases

Parameter	Units	Saline	Gas	Oil
Depth	feet	8,500	7,500	5,000
Porosity	%	20.0%	15.0%	15.0%
Permeability	md	200	50	50
Gross Pay	feet	600	400	400
Net Pay	feet	300	200	200
Area	acres	*	9,600	12,800
Area	sq. mi.	*	15.0	20.0
Hist. Completions	number	*	30.0	160.0
Completions/Sq.mi.	number		2	8

* = Dependent upon injection scenario

Table 16: Depleted Gas Reservoir Type Case Characteristics (Commercial Scale Project)

Power Plant, Injection Rate, and Monitoring		
MW Power Plant	**210**	<< *Sized to match reservoir storage volume*
90% Capture (CO2 tonnes/day)	4,536	
Capacity Utilization	**0.85**	
Tons per Year	1,407,294	
Storage facility injection life in years	**20**	
Tons for facility	28,145,880	<< *Sized to match reservoir storage volume*
Post-injection monitoring period in years	**10**	

Injection Zone Depth, Pressure, and Temperature	
Depth to Top of Injection Interval (ft)	7,200
Depth to Bottom of Injection Interval (ft)	**7,500**
Hydrostatic pressure (psi)	3,248
Temp (F) @1dF/100 ft	137
Hydrostatic pressure (Mpa)	22.4
Temp. (C)	58.3
CO2 density (kg/cu.m)	789.0

Volumetrics and Capacity		
Gross thickness (ft)	**300**	
Net thickness (ft)	**200**	
Porosity (%)	**15%**	
Area (sq. mi.)	**15.0**	<< *Actual area from database analysis*
Area (sq. ft.)	418,176,000	
Pore space volume (cu. ft)	12,545,280,000	
Pore space volume (cu. m)	355,242,434	
Million tonnes capacity at 100% storage efficiency	280	
Storage efficiency	**10.0%**	
Effective Million tonnes capacity	**28.0**	

Old Wells in Area	In AoR	Known to Require Remediation	Additional Wells w/o Good Cement Logs	
Deep Artificial Penetrations (exclude any to be used as injectors)	**30**	3.0	4.5	<< *One per square mile*
Shallow Artificial Penetrations	**30**	3.0	4.5	<< *Two per square mile*
Water Wells Artificial Penetrations	**30**	3.0	4.5	<< *Two per square mile*

Table 16 (continued) Depleted Gas Reservoir Type Case Characteristics (Commercial Scale Project)

Injection Wells and Stratigraphic Wells			
Injection Wells Required (total)	**4.0**		*<< Based on injection rate per well of 2,000 mtpd plus one extra well.*
Injection Wells New Drills	**4.0**		
Injection Wells Conversions of Old Wells	0		
Cost of Converted Wells as % of New	**15%**		
Tubing Size (inches)	**6.0**		
Number of Stratigraphic Tests (if required)	**1**		
Depth of Stratigraphic Tests (feet)	8,250		
Cores per Stratigraphic Test	**6**		

Monitoring Wells, etc.	Above Inj Zone	Into Inj Zone	
Max. Number of Monitoring Wells (depends on scenario)	**16**	**16**	*<< Maximum number based on number of injectors*
Depth of Monitoring Wells (feet)	4,150	7,425	
Long-string Casing of Monitoring Wells (diam. inches)	**3.5**	**3.5**	
Air/soil Sampling Stations (if required)	4		
Passive seismic arrays (inside monitoring wells if required)	3		

USDW's and Containment Systems		
Deepest USDW	2,000	*<< Depths are estimates based upon relationship to reservoir depth.*
Second Containment System Depth to Top (ft)	5,100	
Second Containment System Depth to Bottom (ft)	5,400	
First Containment System Depth to Top (ft)	6,300	
First Containment System Depth to Bottom (ft)	6,700	

CO2 Pipelines and Pumps			
	Miles	(inches)	
Distribution Pipeline 1	3.9	6	*<< Calculated from reservoir area*
Distribution Pipeline 2	3.9	4	
Total inch-miles	39		
Pump HP	544		*<< Based on inj. rate*

4.6 Current Project Characteristics – Depleted Oil Reservoir (Commercial Scale)

The example case for depleted oil reservoirs is presented in Table 17.

Table 17: Depleted Oil Reservoir Type Case Characteristics (Commercial Scale Project)

Power Plant, Injection Rate, and Monitoring		
MW Power Plant	**275**	<< *Sized to match reservoir storage volume*
90% Capture (CO2 tonnes/day)	5,940	
Capacity Utilization	**0.85**	
Tons per Year	1,842,885	
Storage facility injection life in years	**20**	
Tons for facility	36,857,700	
Post-injection monitoring period in years	**10**	

Injection Zone Depth, Pressure, and Temperature	
Depth to Top of Injection Interval (ft)	4,600
Depth to Bottom of Injection Interval (ft)	**5,000**
Hydrostatic pressure (psi)	2,165
Temp (F) @1dF/100 ft	112
Hydrostatic pressure (Mpa)	14.9
Temp. (C)	44.4
CO2 density (kg/cu.m)	758.0

Volumetrics and Capacity		
Gross thickness (ft)	**400**	
Net thickness (ft)	**200**	
Porosity (%)	**15%**	
Area (sq. mi.)	**20**	<< *Actual area from database analysis*
Area (sq. ft.)	557,568,000	
Pore space volume (cu. ft)	16,727,040,000	
Pore space volume (cu. m)	473,656,579	
Million tonnes capacity at 100% storage efficiency	359	
Storage efficiency	**10.0%**	
Effective Million tonnes capacity	**36**	

Old Wells in Area	In AoR	Known to Require Remediation	Additional Wells w/o Good Cement Logs	
Deep Artificial Penetrations (exclude any to be used as injectors)	**160**	16.0	24.0	<< *One per square mile*
Shallow Artificial Penetrations	**40**	4.0	6.0	<< *Two per square mile*
Water Wells Artificial Penetrations	**40**	4.0	6.0	<< *Two per square mile*

Table 17 (continued) Depleted Oil Reservoir Type Case Characteristics (Commercial Scale Project)

Injection Wells and Stratigraphic Wells			
Injection Wells Required (total)	**4.0**		*<< Based on injection rate*
Injection Wells New Drills	**4.0**		*per well of 2,000 mtpd plus*
Injection Wells Conversions of Old Wells	0		*one extra well.*
Cost of Converted Wells as % of New	**15%**		
Tubing Size (inches)	**6.0**		
Number of Stratigraphic Tests (if required)	**1**		
Depth of Stratigraphic Tests (feet)	5,500		
Cores per Stratigraphic Test	**6**		

Monitoring Wells, etc.	Above Inj Zone	Into Inj Zone	
Max. Number of Monitoring Wells (depends on scenario)	**16**	**16**	*<< Maximum number based*
Depth of Monitoring Wells (feet)	2,700	4,900	*on number of injectors*
Long-string Casing of Monitoring Wells (diam. inches)	**3.5**	**3.5**	
Air/soil Sampling Stations (if required)	5		
Passive seismic arrays (inside monitoring wells if required)	4		

USDW's and Containment Systems			
Deepest USDW	1,700		*<< Depths are estimates*
Second Containment System Depth to Top (ft)	2,500		*based upon relationship*
Second Containment System Depth to Bottom (ft)	2,800		*to reservoir depth.*
First Containment System Depth to Top (ft)	3,700		
First Containment System Depth to Bottom (ft)	4,100		

CO2 Pipelines and Pumps			
	Miles	Diam (inches)	
Distribution Pipeline 1	4.5	6	*<< Calculated from*
Distribution Pipeline 2	4.5	4	*reservoir area*
Total inch-miles	45		
Pump HP	713		*<< Based on inj. rate*

4.7 Pilot Scale Example Projects

A set of example projects has also been developed to allow the application of unit costs to pilot scale projects. The pilot projects are characterized to represent the smaller annual and total injection volumes and other aspects of pilot scale projects such as those planned by DOE. These projects are detailed in Appendix A.

5 Uncertainties in Analysis

As with any technology and cost analysis, there are many sources of uncertainty, both in terms of current costs and likely costs in the future. In the current study, these are characterized as follows:

Uncertainties are related to:

- Unit costs of technology (e.g. dollars per foot to drill and complete an injection well)
- Characteristics of the example case which determines how the unit costs are multiplied. (e.g. number of feet to injection zone)
- How many times the costs are applied through the life of the project. (e.g. number of surveys)
- Number of hours and hourly rates for large scale aspects such as geologic characterization
- Costs changes through time due to:
    - Worldwide demand for materials
    - Improved technology
    - Better knowledge of what works and what amount of data needed
    - Availability of workforce and their experience.
    - Labor costs

<u>Uncertainty in Unit Costs</u>
Generally speaking, the unit costs for which there is greater certainty are those directly or indirectly related to conventional drilling and completion practices and geophysical techniques used in exploration and development. This includes drilling costs and day rates, completion costs including tubulars and wellhead equipment, and so forth. The cost of 2D and 3D seismic is well known, although there is considerable variation related to the geology and depth of each site, and the spacing and resolution needed. The cost of pipelines of different diameters and capacity are known to industry but vary based on market forces affecting supply and demand for materials and labor.

In addition to equipment costs, the operating cost component is also well known by region and well characteristics.

Well remediation unit costs are known through conventional oil and gas field development as well as through underground injection and EOR projects.

The costs of specialty cements and corrosion resistant tubulars is known to industry, although there is uncertainty in terms of which situations this would be applied and how much impact it will have.

Unit cost uncertainty on a unit cost basis for specific technologies is larger with site characterization and monitoring technologies that are not generally used in the oil and gas industry or rarely used. Factors include a general paucity of data in the literature, the fact that technologies are in an early stage of development and are not commercially deployed, and the fact that companies do not publicize such individual unit costs due to competitive factors. In addition, the service companies package these technologies and tailor them to specific projects. ICF has obtained useful information from the literature and from a UIC meeting in New Orleans. [67] For example, we obtained information on eddy covariance, geochemical testing, and tracer injection. In addition, unit cost input has been received from the Department of Energy and other sources. The specific unit costs of monitoring equipment, for example, do affect the cost analysis, but since the overall uncertainty includes how often and how much the technology is applied, this uncertainty is only part of the equation.

It is important to note that the cost of drilling and completing injection and monitoring wells represents a large component of sequestration costs, and these costs are relatively well known.

<u>Uncertainty in Characteristics and Cost Repetition Through Time</u>
Much of the overall uncertainty relates not to the specific unit costs but the assumptions related to the characteristics of the example cases which determine the overall cost of applying the technology.

There is uncertainty in the example sequestration projects. For example, the saline reservoir case is based upon the general characteristics of the DOE pilots, but there is a great range of characteristics such as depth, pay thickness, and porosity in those projects. For the depleted gas and depleted oil field example cases, a statistical analysis of existing fields was performed, but because of the general lack of pilot projects in these settings, there is uncertainty in terms of what may become typical in these settings over the coming decades.

Various sources in the literature helped in our determination of the example site characteristics and the number of monitoring stations and frequency of monitoring. However, it can be said that there is no industry consensus on the levels of appropriate monitoring, how many monitor wells are needed, etc.

<u>Number of Hours and Hourly Rates</u>
Several of the cost categories here are labor intensive projects requiring many hours of time at relatively high labor rates. Due to the expected large variability in projects, it is difficult to estimate the number of hours required for activities such as geological site characterization. The hours required for such analysis are estimates, while the labor rates are generally known. Uncertainty in labor rates involves the level of technical expertise required and other factors such as whether the work would be done in-house by employees or contracted out.

<u>Cost Changes Through Time</u>

A significant element of uncertainty is associated with potential changes in technology or labor costs through time. As listed above, these may relate to improved technology, changes in the experience of the technical workforce, better understanding of what is needed, and general labor cost changes.

For example, sequestration projects initiated over the next decade or so may incur higher labor costs than those farther in the future, due to a shortage of experienced technical staff that specialize in injection operations. As more projects become operational, costs may decline due to better knowledge and more efficient site characterization, operation, and monitoring approaches.

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[67] Joint GWPC/EPA CO2 MMV meeting, New Orleans, LA January 16, 2008.

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APPENDIX A – CHARACTERISTICS OF PILOT SCALE EXAMPLE PROJECTS

Table A1 – Saline Pilot Scale Project

Power Plant, Injection Rate, and Monitoring		
MW Power Plant	**112**	<< *Equivalent to 750,000 tons/yr*
90% Capture (CO2 tonnes/day)	2,419	
Capacity Utilization	**0.85**	
Tons per Year	750,557	
Storage facility injection life in years	**7**	
Tons for facility	5,253,898	
Post-injection monitoring period in years	**10**	

Injection Zone Depth, Pressure, and Temperature	
Depth to Top of Injection Interval (ft)	7,900
Depth to Bottom of Injection Interval (ft)	**8,500**
Hydrostatic pressure (psi)	3,681
Temp (F) @1dF/100 ft	147
Hydrostatic pressure (Mpa)	25.4
Temp. (C)	63.9
CO2 density (kg/cu.m)	782.0

Volumetrics and Capacity		
Gross thickness (ft)	**600**	
Net thickness (ft)	**300**	
Porosity (%)	**20%**	
Area (sq. mi.)	**1.4**	<< *Set square miles so as to make facilities*
Area (sq. ft.)	39,029,760	*capacity large enough for power plant*
Pore space volume (cu. ft)	2,341,785,600	
Pore space volume (cu. m)	66,311,921	
Million tonnes capacity at 100% storage efficiency	52	
Storage efficiency	**10.0%**	
Effective Million tonnes capacity	**5.2**	

Old Wells in Area	In AoR	Known to Require Remediation	Additional Wells w/o Good Cement Logs	
Deep Artificial Penetrations (exclude any to be used as injectors)	**1**	0.1	0.2	<< *One per square mile*
Shallow Artificial Penetrations	**3**	0.3	0.4	<< *Two per square mile*
Water Wells Artificial Penetrations	**3**	0.3	0.4	<< *Two per square mile*

Table A1 (Continued) – Saline Pilot Scale Project

Injection Wells and Stratigraphic Wells			
Injection Wells Required (total)	**1.0**		*<< One injector well*
Injection Wells New Drills	**1.0**		*for pilots*
Injection Wells Conversions of Old Wells	0		
Cost of Converted Wells as % of New	**15%**		
Tubing Size (inches)	**6.0**		
Number of Stratigraphic Tests (if required)	**0**		*<< None for pilots*
Depth of Stratigraphic Tests (feet)	9,350		
Cores per Stratigraphic Test	**6**		

Monitoring Wells, etc.	Above Inj Zone	Into Inj Zone	
Max. Number of Monitoring Wells (depends on scenario)	**4**	**4**	*<< Maximum number based*
Depth of Monitoring Wells (feet)	4,500	8,350	*on number of injectors*
Long-string Casing of Monitoring Wells (diam. inches)	**3.5**	**3.5**	
Air/soil Sampling Stations (if required)	0		
Passive seismic arrays (inside monitoring wells if required)	0		

USDW's and Containment Systems		
Deepest USDW	2,000	*<< Depths are estimates*
Second Containment System Depth to Top (ft)	5,800	*based upon relationship*
Second Containment System Depth to Bottom (ft)	6,100	*to reservoir depth.*
First Containment System Depth to Top (ft)	7,000	
First Containment System Depth to Bottom (ft)	7,400	

CO2 Pipelines and Pumps	Miles	(inches)	
Distribution Pipeline 1	1.2	6	*<< Calculated from*
Distribution Pipeline 2	0.0	4	*reservoir area*
Total inch-miles	7		
Pump HP	290		*<< Based on inj. rate*

Table A2 – Depleted Gas Pilot Scale Project

Power Plant, Injection Rate, and Monitoring		
MW Power Plant	**112**	*<< Equivalent to 750,000 tons/yr*
90% Capture (CO2 tonnes/day)	2,419	
Capacity Utilization	**0.85**	
Tons per Year	750,557	
Storage facility injection life in years	**7**	
Tons for facility	5,253,898	
Post-injection monitoring period in years	**10**	

Injection Zone Depth, Pressure, and Temperature	
Depth to Top of Injection Interval (ft)	7,200
Depth to Bottom of Injection Interval (ft)	**7,500**
Hydrostatic pressure (psi)	3,248
Temp (F) @1dF/100 ft	137
Hydrostatic pressure (Mpa)	22.4
Temp. (C)	58.3
CO2 density (kg/cu.m)	789.0

Volumetrics and Capacity		
Gross thickness (ft)	**300**	
Net thickness (ft)	**200**	
Porosity (%)	**15%**	
Area (sq. mi.)	**15.0**	*<< Actual typical area from database analysis*
Area (sq. ft.)	418,176,000	
Pore space volume (cu. ft)	12,545,280,000	
Pore space volume (cu. m)	355,242,434	
Million tonnes capacity at 100% storage efficiency	280	
Storage efficiency	**10.0%**	
Effective Million tonnes capacity	**28.0**	

Old Wells in Area	In AoR	Known to Require Remediation	Additional Wells w/o Good Cement Logs	
Deep Artificial Penetrations (exclude any to be used as injectors)	**30**	3.0	4.5	*<< One per square mile*
Shallow Artificial Penetrations	**30**	3.0	4.5	*<< Two per square mile*
Water Wells Artificial Penetrations	**30**	3.0	4.5	*<< Two per square mile*

Table A2 (Continued) Depleted Gas Pilot Scale Project

Injection Wells and Stratigraphic Wells			
Injection Wells Required (total)	**1.0**		*<< One injector well*
Injection Wells New Drills	**1.0**		*for pilots*
Injection Wells Conversions of Old Wells	0		
Cost of Converted Wells as % of New	**15%**		
Tubing Size (inches)	**6.0**		
Number of Stratigraphic Tests (if required)	**0**		*<< None for pilots*
Depth of Stratigraphic Tests (feet)	8,250		
Cores per Stratigraphic Test	**6**		

Monitoring Wells, etc.	Above Inj Zone	Into Inj Zone	
Max. Number of Monitoring Wells (depends on scenario)	**4**	**4**	*<< Maximum number based*
Depth of Monitoring Wells (feet)	4,150	7,425	*on number of injectors*
Long-string Casing of Monitoring Wells (diam. inches)	**3.5**	**3.5**	
Air/soil Sampling Stations (if required)	4		
Passive seismic arrays (inside monitoring wells if required)	3		

USDW's and Containment Systems		
Deepest USDW	2,000	*<< Depths are estimates*
Second Containment System Depth to Top (ft)	5,100	*based upon relationship*
Second Containment System Depth to Bottom (ft)	5,400	*to reservoir depth.*
First Containment System Depth to Top (ft)	6,300	
First Containment System Depth to Bottom (ft)	6,700	

CO2 Pipelines and Pumps			
	Miles	(inches)	
Distribution Pipeline 1	3.9	6	*<< Calculated from*
Distribution Pipeline 2	0.0	4	*reservoir area*
Total inch-miles	23		
Pump HP	290		*<< Based on inj. rate*

Table A3 – Depleted Oil Pilot Scale Project

Power Plant, Injection Rate, and Monitoring		
MW Power Plant	**112**	<< *Equivalent to 750,000 tons.year*
90% Capture (CO2 tonnes/day)	2,419	
Capacity Utilization	**0.85**	
Tons per Year	750,557	
Storage facility injection life in years	**7**	
Tons for facility	5,253,898	
Post-injection monitoring period in years	**10**	

Injection Zone Depth, Pressure, and Temperature	
Depth to Top of Injection Interval (ft)	4,600
Depth to Bottom of Injection Interval (ft)	**5,000**
Hydrostatic pressure (psi)	2,165
Temp (F) @1dF/100 ft	112
Hydrostatic pressure (Mpa)	14.9
Temp. (C)	44.4
CO2 density (kg/cu.m)	758.0

Volumetrics and Capacity		
Gross thickness (ft)	**400**	
Net thickness (ft)	**200**	
Porosity (%)	**15%**	
Area (sq. mi.)	**20**	<< *Actual area from database analysis*
Area (sq. ft.)	557,568,000	
Pore space volume (cu. ft)	16,727,040,000	
Pore space volume (cu. m)	473,656,579	
Million tonnes capacity at 100% storage efficiency	359	
Storage efficiency	**10.0%**	
Effective Million tonnes capacity	**36**	

Old Wells in Area	In AoR	Known to Require Remediation	Additional Wells w/o Good Cement Logs	
Deep Artificial Penetrations (exclude any to be used as injectors)	**160**	16.0	24.0	<< *One per square mile*
Shallow Artificial Penetrations	**40**	4.0	6.0	<< *Two per square mile*
Water Wells Artificial Penetrations	**40**	4.0	6.0	<< *Two per square mile*

Table A3 (Continued) Depleted Oil Pilot Scale Project

Injection Wells and Stratigraphic Wells			
Injection Wells Required (total)	**1.0**		*<< One injector well*
Injection Wells New Drills	**1.0**		*for pilots*
Injection Wells Conversions of Old Wells	0		
Cost of Converted Wells as % of New	**15%**		
Tubing Size (inches)	**6.0**		
Number of Stratigraphic Tests (if required)	**0**		*<< None for pilots*
Depth of Stratigraphic Tests (feet)	5,500		
Cores per Stratigraphic Test	**6**		

Monitoring Wells, etc.	Above Inj Zone	Into Inj Zone	
Max. Number of Monitoring Wells (depends on scenari	**4**	**4**	*<< Maximum number based*
Depth of Monitoring Wells (feet)	2,700	4,900	*on number of injectors*
Long-string Casing of Monitoring Wells (diam. inches)	**3.5**	**3.5**	
Air/soil Sampling Stations (if required)	5		
Passive seismic arrays (inside monitoring wells if required)	4		

USDW's and Containment Systems		
Deepest USDW	1,700	*<< Depths are estimates*
Second Containment System Depth to Top (ft)	2,500	*based upon relationship*
Second Containment System Depth to Bottom (ft)	2,800	*to reservoir depth.*
First Containment System Depth to Top (ft)	3,700	
First Containment System Depth to Bottom (ft)	4,100	

CO2 Pipelines and Pumps	Miles	Diam (inches)	
Distribution Pipeline 1	4.5	6	*<< Calculated from*
Distribution Pipeline 2	0.0	4	*reservoir area*
Total inch-miles	27		
Pump HP	290		*<< Based on inj. rate*