United States Environmental Protection Agency

Geologic CO_2 Sequestration Technology and Cost Analysis

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1 Introduction

The Environmental Protection Agency (EPA) has developed new minimum Federal requirements under the Safe Drinking Water Act (SDWA) for underground injection of carbon dioxide (CO_2) for the purpose of geologic sequestration (GS). The elements of this rulemaking are based on the existing Underground Injection Control (UIC) Program regulatory framework, creating a Class VI well classification that addresses the unique nature of CO_2 injection for GS. This rule will help to ensure consistency in permitting underground injection of CO_2 at GS operations across the United States. The requirements are designed to prevent endangerment of underground sources of drinking water (USDWs) in anticipation of the eventual use of GS to reduce CO_2 emissions to the atmosphere.

This Geologic CO_2 Sequestration Technology and Cost Analysis document (Technology and Cost document) describes the unit costs of specific technologies and operating practices that are expected to apply to GS activities. It does not discuss in any detail the development of overall costs for the final rule, which is presented in Chapter 5 of the Cost Analysis for the final rule[1]. As described in that chapter, EPA believes that projects will deploy in primarily two types of geologic settings during the period of analysis: saline formations and oil and gas reservoirs (enhanced recovery (ER) sites).[2,3] The costs and risk assessments for these two project types were developed under the five different regulatory alternatives considered in the Cost Analysis, including one baseline alternative that represents EPA's understanding of the costs and risks if it were to deploy under current UIC regulation (absent a Class VI regulation). Each of the unit costs presented in this Technology and Cost document applies to at least one and usually more of the regulatory alternatives considered to varying degrees. A cost that is incurred under a given regulatory alternative and also under the existing Class I non-hazardous injection well regulations (the regulatory baseline for this analysis) is not attributable to the regulatory alternative but are presented in the analysis for completeness.

The SDWA provides EPA with the authority to develop regulations to protect USDWs from endangerment; however, it does not provide authority to develop regulations for all areas related to GS. This document includes all unit costs associated with GS, not just those specific to preventing

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[1] Cost Analysis for the Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells (Final GS Rule), EPA 816-R-10-013. The Cost Analysis presents development of the final rule costs, taking into account the unit costs presented in the Technology and Cost document, the schedule (periodicity) of cost incurrence, the baseline number of projects estimated to deploy, the types of projects (saline and ER) anticipated and the geological and engineering parameters associated with them.

[2] EPA understands that the primary purpose of most CO_2 injection operations located in depleting oil and gas reservoirs will be to enhance recovery of oil and gas until it is no longer economically feasible. Under this scenario, these operations would be covered under the existing Class II injection well regulations. An exception is the conversion of an operation whose primary purpose changes from enhanced recovery to the long term storage of CO_2 in an effort to reduce emissions to the atmosphere. In such a case, the new rule would apply.

[3] There are other possible target formations for GS, including but not limited to coal seams, basalts, salt domes, and shales, as described further in the Preamble to the Final GS Rule. The GS rule does not categorically preclude or prohibit injection into any type of formation, but expects that the majority of GS projects will involve saline reservoirs and converted ER projects.

endangerment to USDWs. GS costs are incurred in the pre-injection, or construction and permitting phase, throughout the injection phase, and during post-injection site care (PISC). However, GS components do not include carbon capture and CO_2 transportation to the GS site. The GS component is estimated to be approximately 2.7 percent of the total cost of an integrated capture and sequestration project, as described in the Preamble to the Final GS Rule.

The major cost categories included in the Cost Analysis for the final rule are: site characterization, well construction and operation, monitoring during operations, area of review and corrective action, and financial responsibility. The sections of this document that follow describe the unit costs specific to each category.

EPA applied a unit cost multiplier to existing unit costs (e.g. monitoring) to account for the few potential cases where a waiver of the required injection depth would be permitted. These and other applicability factors are presented in Appendix B (Project Algorithms) of the Cost Analysis.[4]

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[4] Cost Analysis for the Final GS Rule, EPA 816-R-10-008.

2 General Costing Methodology, Data Sources, and Cost Trends

Costing Methodology

This Technology and Cost document evaluates the individual cost components for GS. These are termed unit costs and are categorized as follows:

- Site Characterization
- Area of Review and Corrective Action
- Injection Well Construction
- Mechanical Integrity Tests
- Monitoring
- Injection Well Operation
- Well Plugging and Post-Injection Site Care (PISC)
- Financial Responsibility

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 pro forma projects presented in the Cost Analysis for this rule.[5] The pro forma descriptions include specifications for total surface area, drilling depth, reservoir thickness, well injectivity, number of wells through time, and other parameters.

In the cost analysis, costs are estimated for a baseline regulatory case, assumed to be equivalent to a Class I Non-Hazardous Industrial Injection Well, and four proposed regulatory alternatives. Each cost item has been evaluated as to whether it is required under each regulatory alternative, and whether the cost will 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 alternative 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 unit costs included in this analysis are attributable to a particular regulatory alternative.

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 United States. and Canada.[6,7,8,9] The cost of drilling and equipping wells represents a large component of

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5 Cost Analysis for the Final GS Rule, EPA 816-R-10-008.

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

7 *PSAC Well Cost Study – 2009,* Petroleum Services Association of Canada, April 30, 2009 and later editions.

Table 1: Major Sources of GS Cost Information

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
2009 Petroleum Services of Canada Well Cost Study (PSAC)	Canada drilling costs, plugging costs, logging costs
Oil and Gas Journal Report on Pipeline Cost Data Reported to FERC	Pipeline costs per inch-mile
Land Rig Newsletter	Onshore day rates/ well cost algorithms
New Orleans Sequestration Technology Meeting, January, 2008	Monitor station costs in several categories; seismic costs
FutureGen Sequestration Site Materials	Monitoring station layout/number of stations
Preston Pipe Report	Casing and tubing costs
U.S. Bureau of Labor Statistics, American Association of Petroleum Geologists, Society of Petroleum Engineers	Hourly labor rates
Selected presentations and papers (see below)	Sensor costs, monitoring costs, number of stations, seismic costs

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.

GS 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 and from surveys of oil and gas professionals performed by the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Engineers (SPE). Labor rates include a "load factor" from EPA guidance. The number of hours estimated for implementation of the various characterization or monitoring activities represent EPA's best professional judgment, informed by and modified in response to public comment.

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[8] *Oil and Gas Lease Equipment and Operating Costs*, U.S. Energy Information Administration, 2007 and later editions, http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html
[9] *Oil and Gas Journal Pipeline Cost Survey*, Oil and Gas Journal Magazine, September, 2009.

Because some GS technologies are still under development, no comprehensive source is available that provides detailed summaries of the full range of GS 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 an industry meeting sponsored by the Groundwater Protection Council.[10]

Cost Year Basis and Trends in Major Costs

The costs reported here and used in the cost analysis represent price levels in late 2007, inflated to 2008 using the Consumer Price Index inflationary factor. Use of the 2007 price level avoids some of the extreme cost fluctuations seen in the 2008-2009 period. For the purpose of providing context for discussion, recent historical cost trends are presented in the figures below in nominal 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 cryogenic applications such as LNG liquefaction plants and LNG storage tanks). Steel prices have declined since peaking in 2008, but are higher than in the early 2000s. 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 Technology and Cost document.

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

Figure 1: U.S. Carbon Steel Plate Prices

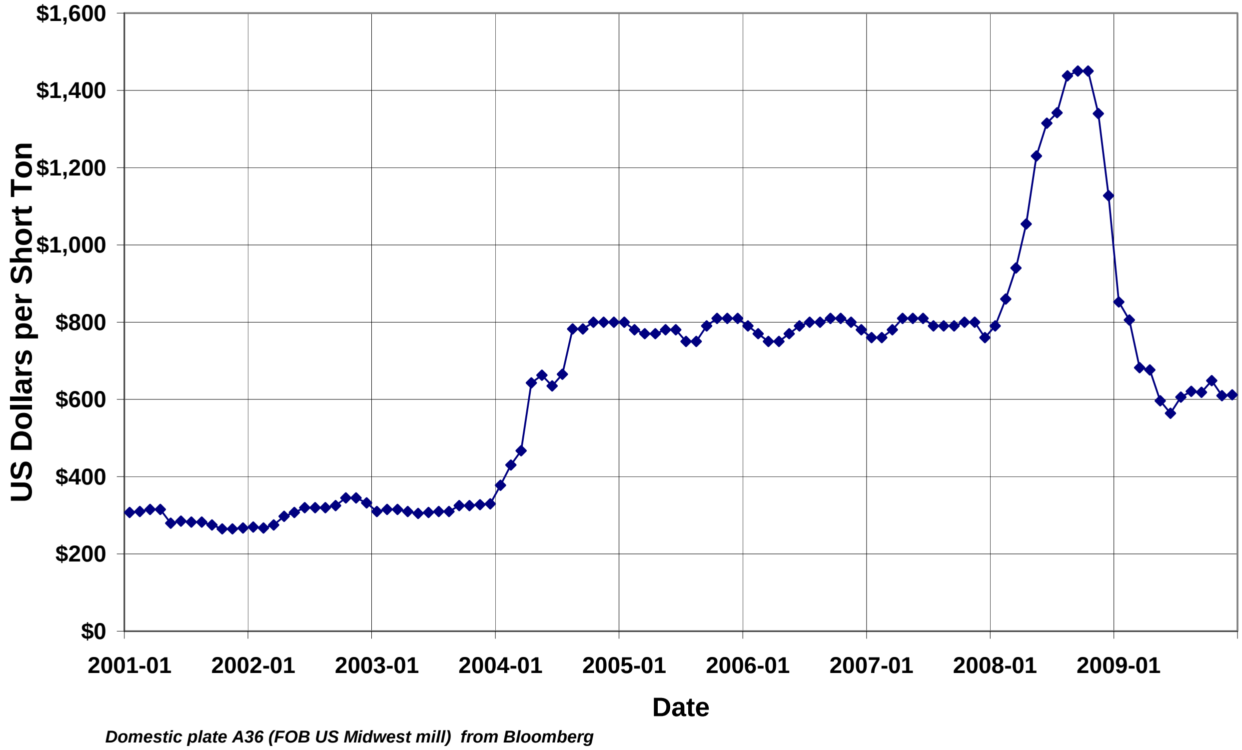


Figure 2: Nickel Prices

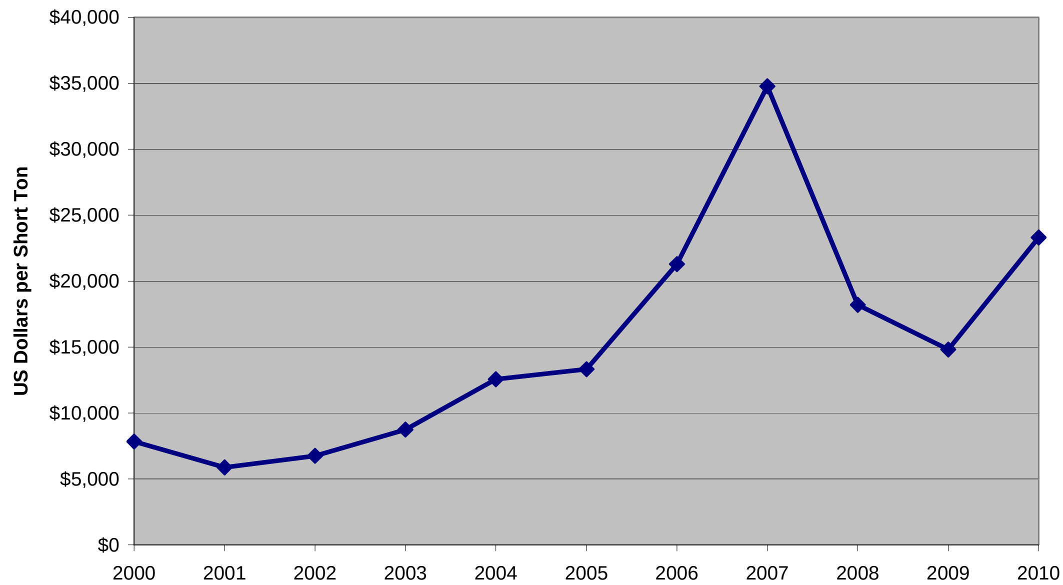
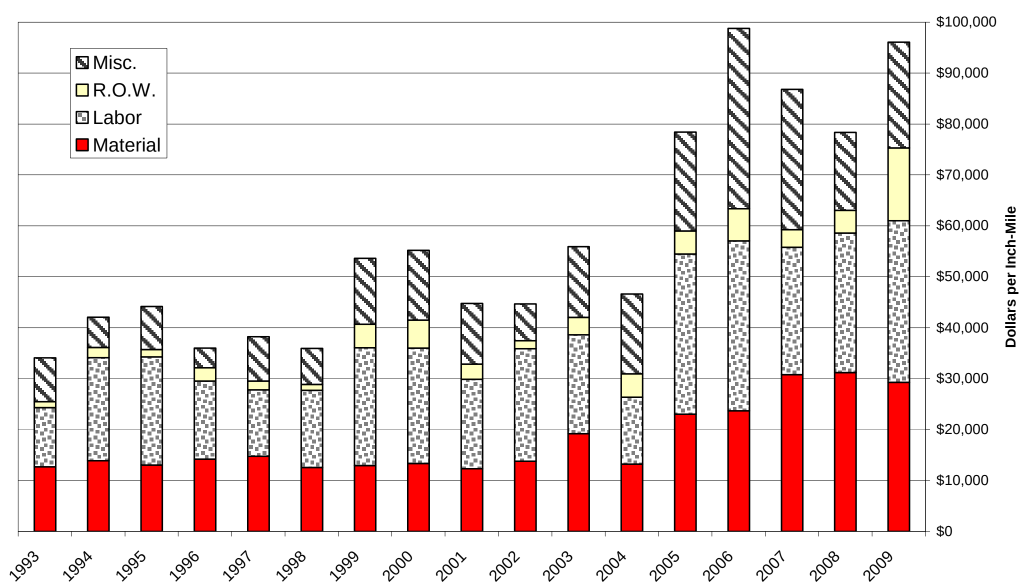
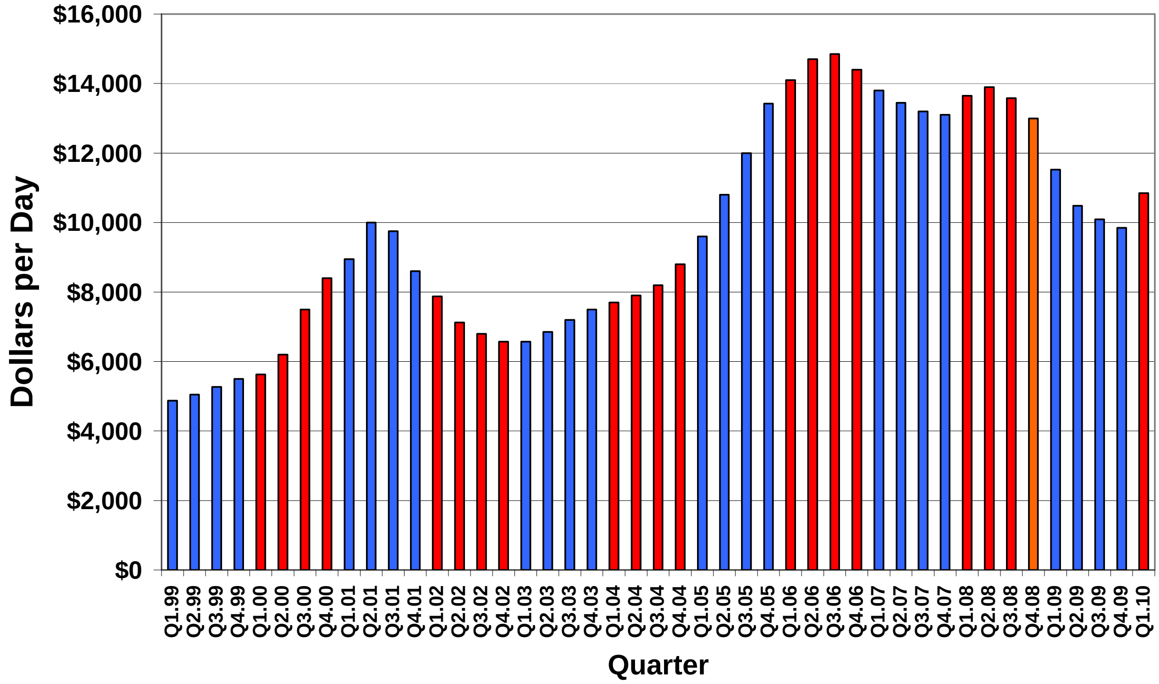


Figure 3: Gas Pipeline Costs by Component



Average of large-diameter gas pipelines 30 to 36 inches FERC data compiled by Oil & Gas Journal

Figure 4: U.S. Drilling Rig Day Rates



3 Technologies and Costs

3.1 Site Characterization

Site characterization is a fundamental component of the UIC program. Owners or operators must identify the presence of suitable geologic characteristics at a site to ensure the protection of USDWs from endangerment associated with injection activities. To accomplish this, site characterization includes an assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site. Characterization is designed to provide the geologic and hydrologic data and needed to design the infrastructure, develop computational models, determine appropriate operation parameters, and design the monitoring program. In this phase of site development, a determination is made of whether the formation has adequate porosity, permeability, and continuity for long term injection. An assessment is also made about the ability of overlying units to restrict upward movement of the injected CO_2 and prevent the endangerment of USDWs. 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 injection zone and overlying formation.

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 information for this analysis is well log data, which allows the geologist to map the depth to various formation tops, thickness variations (i.e., with isopach maps), and lithologies (e.g., sandstone, 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 will be acquired either on the surface, or in a well. Borehole techniques require one or more wells for sources and receivers. Surface seismic data can be either two-dimensional (2-D) or three-dimensional (3-D), with the latter providing a higher degree of resolution but being much more data intensive and costly to obtain and interpret. Seismic data may also be used for monitoring during operations and PISC.[11]

3-D seismic techniques use man-made source signals and a receiver array to image the subsurface. In the site characterization phase, 3-D seismic surveys may be used to evaluate the detailed

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

structural geology and stratigraphy of the site. 3-D seismic data may also be used in the site characterization phase to inform computational models to estimate the volume of CO_2 that can be stored at a potential site.[12] The technology is mature and has been used in the oil and gas exploration and development for decades.

The cost of 3-D seismic acquisition varies widely, ranging from $40,000 to $160,000 per square mile.[13] [14] [15] Factors other than area affecting cost include acquisition parameters, terrain, geology, reservoir depth, and remoteness of location. A recent large seismic survey by a major operator in Louisiana averaged $85,000 per square mile.[16] A Canadian study indicated a range in cost of $21,000 to $104,000 per square mile.[17] A cost of $100,000 per square mile has been cited in industry articles as an average for the United States onshore.

Seismic (Earthquake) History

The natural long-term seismic history of a potential GS site must be evaluated to gain a picture of potential failure risks, including the inherent potential for a seismic event and for induced seismicity. Historic data on seismic activity can be obtained from the U.S. Geological Survey. Evaluation will 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 may be carried out to locate and identify dwellings and other manmade structures affected within the area of review. The AoR is defined in the final rule as "the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream and is based on available site characterization, monitoring, and operational data as set forth in §146.84" of the rule.

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 injection zone interval. In order to develop the analysis, it is necessary to obtain regional well log, well history, pressure test, and other subsurface data.

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[12] Doughty, Christine, Barry Freifeld, and Robert Trautz, 2007, "Site Characterization for CO_2 Geologic Storage," Environmental Geology, vol. 54, no. 8, June 2008.
[13] McFarland, John, 2009, "How Do Seismic Surveys Work?" http://www.oilandgaslawyerblog.com/2009/04/how-do-seismic-surveys-work.html
[14] Dix, Manfred and Greg Albrecht, 2008, "An Economic Impact Analysis of the Haynesville Shale Natural Gas Exploration, Drilling, and Production," Louisiana Department of Natural Resources report, August, 2008 http://dnr.louisiana.gov/haynesvilleshale/manfred-dix-impact-analysis.pdf
[15] Percival, Pamela, 2008, "Chesapeake Exec Discusses 3D Seismic in Major Shale Plays," Basin Oil and Gas Magazine, May 2010.
[16] Hill, Kevin. B., 2010?, "A Seismic Oil and Gas Primer," Hill Geophysical Consulting, Shreveport, LA. http://www.loga.la/flash/HS/kevinhillLSUS.pdf
[17] Cooper, N.M, 2010, "The Value of 3D Seismic in Today's Exploration Environment – In Canada and Around the World," Mustagh Resources, Calgary, Alberta. www.mustagh.com/abstract/opi_3D.doc

Included is the acquisition of core data, drill stem test data, production test data, and other engineering data on wells in the AoR. The geologist uses this information to map the thickness, structure, and injection zone characteristics in the subsurface. The goal is to fully evaluate storage capacity and injectivity, and the expected variability in these parameters. Some sites, such as depleting oil or gas fields, will have a large amount of existing subsurface data in a specific area. In saline formations, 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 injection zone or confining rock, resulting in fracturing and potential leakage that may endanger USDWs. [18] [19] 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 include well logs, seismic, pressure fall-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 must determine the distribution and depth of all potentially affected USDWs.

EPA defines USDWs as follows:

> An aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/l total dissolved solids and is not an exempted aquifer.[20]

This cost element is based upon the cost of researching information on the distribution of USDWs in the vicinity of the GS site. Such information can be found in the literature or in public well logs.

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[18] *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.

[19] *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.

[20] US EPA website, Office of Water, Underground Injection Control: http://www.epa.gov/safewater/uic/glossary.html#t.

Geochemical and Other Information on Formations

In addition to determining the distribution of USDWs at the proposed site, owners and operators must obtain data on the geochemical water properties of regional formations, as well as an overall understanding of their regional thickness and structure. Information on formation water in the potential injection zone may be obtained from nearby well logs or from water samples from nearby wells. This cost element is based upon the time required to research and evaluate this information from public data sources in unit cost A-6 and from new cores and tests in unit cost A-7 in Table 2 below.

Information on Water-Rock Geochemistry

The geochemistry of subsurface fluids can affect whether a site is suitable for GS. Injection of CO_2 can result in the presence of carbonic acid, which can react with injection zone 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. Therefore, another requirement during site characterization is the analysis of the chemical characteristics of the formation water and the potential reactivity of the injection zone rock with CO_2. Information on formation water characteristics may be obtained from nearby well logs or from water samples from nearby wells. Information on injection zone mineralogy may be obtained from whole or sidewall cores, well cuttings or well logs in nearby wells. Analysis will likely include petrographic studies of thin sections of injection zone rock to determine mineralogy. EPA expects that laboratory tests will be conducted to evaluate chemical reactivity to carbonic acid under injection zone conditions.

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 GS economically infeasible or pose undue risk of endangerment to USDWs.

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. Such costs are included in item D-4 (AoR review). The cost of locating and evaluating existing penetrations into the injection zone is expected to vary widely based on the quality and coverage of available well data, the assumption in the current analysis is that well database coverage is good and that magnetic tests are not needed in the site characterization phase. Costs are based on EPA’s best professional judgment regarding the number of hours needed to conduct the research and evaluate the findings.

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 injection zone because these wells could also represent potential leakage pathways. As with the previous item, the source of information is primarily commercially available well history databases. EPA expects that the coverage in well history databases is good and that magnetic tests will generally not be needed.

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. Site inspections would include activities such as land surveys and seismic surveys.

Geologic Characterization Report

Approval of a specific site for GS 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 must 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

Tracking Number	Cost Item	Cost Algorithm	Data Sources
A-1	Develop maps and cross sections of local geologic structure	60 hours of geologists @$107.23/hr = $6,434 per site	AAPG 2009 salary survey of petroleum geologists
A-2	Conduct 3D seismic survey to identify faults and fractures in primary and secondary containment units	$104,000/square mile for good resolution	Several published reports are in range of this cost. Cost depends on resolution (number of lines shot) of survey.
A-3	Obtain and analyze seismic (earthquake) history.	60 hours of geologists @$107.23/hr = $6,434 per site	AAPG 2009 salary survey of petroleum geologists
A-4	Remote (aerial) survey of land, land uses, structures etc.. Should assume survey is twice the project's actual CO2 footprint due to uncertainty during site characterization phase of exact location of facilities and plume.	$3,100/site + $415/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).
A-5	Obtain data on areal extent, thickness, capacity, porosity and permeability of receiving formations and confining systems	24 hours of geologists @$107.23/hr = $2,574 per site	AAPG 2009 salary survey of petroleum geologists
A-6	Obtain geomechanical information on fractures, stress, rock strength, in situ fluid pressures (from existing data and literature)	120 hours of geologists @$107.23/hr = $12,868 per site	AAPG 2009 salary survey of petroleum geologists
A-7	Obtain geomechanical information on fractures, stress, rock strength, in situ fluid pressures (new cores and tests)	$78/foot for stratigraphic test well + $3,100/core	Drilling cost is estimated from drilling cost equations developed from JAS and PSAC data. Core analysis cost is best professional judgement.
A-8	List names and depth of all potentially affected USDWs	24 hours of geologists @$107.23/hr = $2,574 per site	AAPG 2009 salary survey of petroleum geologists
A-9	Provide geochemical information and maps/cross section on subsurface aquifers.	60 hours of geologists @$107.23/hr = $6,434 per site	AAPG 2009 salary survey of petroleum geologists
A-10	Provide information on water-rock-CO2 geochemistry and mineral reactions.	240 hours of geologists @$107.23/hr +$10,300 lab fees = $36,035 per site	Best professional judgement of time required and lab fee.
A-11	Develop list of penetrations into injection zone within AoR (from well history data bases)	12 hours @$107.23/hr = $1,287 per square mile	Best professional judgement of time required. Hourly rate derived from AAPG 2009 salary survey of petroleum geologists. Cost expected to vary widely based on well ages and quality of record keeping.
A-12	Develop list of penetrations into containment systems within AoR (from well history data bases)	12 hours @$107.23/hr = $1,287 per square mile	Best professional judgement of time required. Hourly rate derived from AAPG 2009 salary survey of petroleum geologists. Cost expected to vary widely based on well ages and quality of record keeping.
A-13	Develop list of water wells within AoR (from public data)	36 hours @$107.23/hr = $3,860 per square mile	Best professional judgement of time required. Hourly rate derived from AAPG 2009 salary survey of petroleum geologists. Cost expected to vary widely based on well ages and quality of record keeping.
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 @$107.23/hr = $25,735 per site	Best professional judgement of time required. Hourly rate derived from AAPG 2009 salary survey of petroleum geologists.
A-15	Operating G&A	20% of annual operating costs	Best professional judgement based on oil and gas industry factors.

3.2 Monitoring

Once injection begins, a program for monitoring of conditions in the injection zone and CO_2 distribution is required.[21] 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 computational models
- Provide early warnings of failure

Per the GS rule, monitoring components must, at a minimum, include the following:

- Analysis of the carbon dioxide stream
- Installation and use of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added
- Corrosion monitoring
- Monitoring of ground water quality and geochemical changes above the confining zone(s)
- A demonstration of mechanical integrity
- A pressure fall-off test
- Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure
- Any additional monitoring required by the UIC Director

The GS rule provides more detailed and specific monitoring requirements. 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.

As mentioned in the Introduction to this Technology and Cost document, to cost the potential few cases where a waiver of the required injection depth would be permitted, EPA applied a unit cost multiplier to existing unit costs to account for the additional requirements, in particular for monitoring. These and other applicability factors are presented in Appendix B (Project Algorithms) of the Cost Analysis.[22]

Develop Geochemical Baseline of Formation Water

Prior to injection of CO_2, owners and operators must develop a baseline of geochemical properties and characteristics of water in the injection zones, confining zones, and USDWs. 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,

[21] *The Future of Coal, Options for a Carbon-constrained World*, An Interdisciplinary MIT Study, Massachusetts Institute of Technology, 2007.
[22] Cost Analysis for the Final GS Rule, EPA 816-R-10-013.

N_2), carbonate, and total alkalinity, metals (Na, K, Ca), salinity (total dissolved solids, or TDS), and stable isotopes (C, O).[23] [24]

Downhole fluid samples can be collected for surface analysis using wireline formation testers and U-Tube sampling devices. The Schlumberger Modular Formation Dynamics Tester (MDT) is a wireline tool that is used to collect multiple subsurface samples at formation pressure and temperature (PVT samples) for surface analysis.[25] U-Tube technology was developed for the DOE Frio Brine project and allows sample extraction at injection zone pressure and temperature.[26] 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 is 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 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. Discrete 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.[27]

In depleted/depleting oil and gas formations, there may is a need to monitor for petroleum escaping from an oil field structure that is being filled with CO_2. This could occur as injected CO_2 forces oily fluids down below the lowermost "spill-point" of an ER site or a CO_2 flood project that is converted to GS. Petroleum leaks could be detected by bringing up water samples using a U-tube or other sampling system. A third option is a fiber optic device which can monitor downhole concentrations of hydrocarbons in aquifers. The near-infra-red light source (1.0-1.7 micrometers) and matching optical sensor are kept at the surface, linked by a fiber optic cable bundle to the IR absorption path deep in the well. APS Technology, Inc. has developed such a system under the name PetroMax system.[28] The PetroMax system has completed all laboratory tests and a field prototype has been designed. The PetroMax system provides real-time monitoring of downhole fluid composition and provides continuous oil, water and gas concentrations from multiple downhole locations. The PetroMax system distinguishes among chemicals passing the downhole

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[23] *Matoon Site Environmental Information Volume*, FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.
[24] *Monitoring to Ensure Safe and Effective Geological Sequestration of Carbon Dioxide*, S. Benson and L. Myer, Lawrence Berkeley Laboratory, Berkeley, California, 2002.
[25] *Matoon Site Environmental Information Volume*, FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.
[26] *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).
[27] *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.
[28] Bill Turner, APS Technology, "Downhole Fluid Analyzer Development, Phase I Final Report," DOE Award DE-AC26-98FT40481, U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA, March, 2004. See also: http://www.aps-tech.com/other/petromax.htm; and PetroMax brochure: http://www.aps-tech.com/tds/APS-PetroMax.pdf.

sensor by directly measuring the composition of the downhole fluid. The light that is not absorbed in the sample volume returns to the surface and is analyzed and presented in real time.

Standard sampling and analysis is done by personnel at the well site supplemented as needed with analyses at commercial labs. There is the possibility of continuous automated monitoring of geochemical data using downhole sensors. Although downhole pH and optical sensors for wells exist, additional R&D and commercial operations are needed in this area. Thus, geochemical data acquisition may rely partially upon surface testing of water samples.

Eddy Covariance Air Monitoring

Direct measurement and testing of CO_2 concentrations above a GS 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). This type of monitoring may be required at the discretion of the UIC Director. 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, light detection and ranging (LIDAR), soil gas sampling with ground-surface accumulation chambers, and direct vadose zone sampling using subsurface probes.

The eddy covariance technique is used to measure CO_2 concentration in the air above a GS 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 data.[29,30] 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 GS site provides information regardless of wind direction.

Capital costs for eddy covariance monitoring are based upon cost per station and specifications of number of monitoring stations. Annual costs are estimated separately.

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[29] *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.

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

Front-End Engineering and Design- Monitoring Wells

This encompasses front-end engineering and design of the monitoring wells only. The monitoring wells may be completed above the injection zone or into the injection zone. These items have separate costs in the model.

Rights of Way for Surface Use – Monitoring Wells and Air Monitoring Sites

Owners or operators must obtain rights-of-way for surface use to set up and operate monitoring facilities. In the cost model for this analysis, the costs for right-of-way are estimated separately for monitoring wells above the injection zone, monitoring wells into the injection zone, and for air monitoring sites.

Downhole Safety Valve or Check Valve

Injection wells must be equipped with alarms and automatic downhole shutoff systems (or, at the discretion of the UIC Director, other mechanical devices that provide equivalent protection). Downhole safety valves will be installed to automatically shut in the well if surface equipment fails so that no surface release occurs and backflow into surface facilities is prevented.

Costs for this item are input as a base cost and an incremental cost as a function of installation depth.

Standard Monitoring Well Costs

To ensure the protection of USDWs, multiple monitoring wells will be required to monitor the movement of CO_2 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:[31]

- Injection Zone Monitoring Wells – monitoring wells that are perforated across the injection zone.
- Above the Confining Zone 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 injection zone and a potential increase in leakage risk. Monitoring wells completed in intervals above the injection zone do not carry this risk. In the current cost study, it is assumed that monitoring wells are completed just above the primary seal.

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

The drilling and completion of CO_2 monitoring wells represents a large component of overall monitoring costs. For example, a 5,000 foot well with an average cost per foot of $180 will cost $900,000. The overall cost is a function of depth and well design and characteristics.

In the Cost Analysis[32] for this rule, monitoring well costs are determined for wells completed either above the injection zone or into the injection zone.

Pressure and Temperature Gauges and Equipment for Monitoring Wells

Monitoring wells may have permanently installed downhole equipment to continuously measure pressure and temperature in the injection and containment zone. Measurements of subsurface pressure are routine in oil and gas field operations. [33] 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 sensors are available. Fiber optic cables from the surface to the formation can provide real-time formation pressure measurements.

These items in the cost model are for the capital costs of such equipment. The annual operating costs for monitoring wells are input separately.

Salinity, CO_2, and Tracer Equipment for Monitoring Wells

Salinity and fluid characteristics may be measured downhole in a monitoring well to help determine composition of fluids and to monitor CO_2 movement. Samples can also be analyzed for injected chemical tracers. At the discretion of the UIC Director, owners and operators may be required to add tracers to the injected CO_2 and conduct subsequent monitoring with monitoring wells to detect the tracers, indicating CO_2 leakage.

Samples can be collected directly from the formation using a U-tube downhole sampler, which was developed by the Lawrence Berkeley National Laboratory (LBNL). 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.[34]

At the Texas Frio Brine Pilot Tests, a U-tube downhole sampler was used to collect high-frequency samples at the monitoring well.[35] 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.

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[32] Cost Analysis for the Final GS Rule, EPA 816-R-10-013.
[33] *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.
[34] *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.
[35] *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.

There are three components in this category for equipment costs only:

- Monitoring equipment for wells above the injection zone
- Monitoring equipment for wells into the injection zone
- U-tube monitoring equipment for sensing oil movement away from the bottom of the formation (Enhanced Recovery only)

Develop Plan and Implement Eddy Covariance Air Monitoring

Eddy covariance is an established technology for potentially monitoring the CO_2 concentration in the air above a GS site. It combines an open path infra-red gas analyzer (IRGA) on a tower alongside a sensitive, high-speed, three-dimensional anemometer, a device used for measuring instantaneous wind speed and direction. Time series data are recorded and evaluated using computer methods. Eddy covariance systems are research tools that are assembled from a variety of commercially available components. The size and shape of the sampling footprint (the surface area that is sampled by the instrument) is derived mathematically from the anemometer data. A typical station consists of sensors mounted on a tower from several meters to 30 meters or more 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 an area provides information regardless of wind direction. CO_2 concentration data are integrated with meteorological data including wind speed and direction, relative humidity, and temperature. Such methods have the ability to measure CO_2 concentration in the atmosphere over relatively large areas.

This cost component incorporates the expenditures for planning and equipment costs for air monitoring using Eddy Covariance technology. Annual operating costs are included as a separate data item.

Costs are broken out into a planning component and a capital expenditure component.

Develop Plan and Implement Digital Color Infrared Ortho-imagery and Hyper-spectral Imaging

Digital color ortho-imagery and hyper-spectral imaging are airborne remote sensing technologies used to detect changes in vegetation resulting from CO_2 leakage. Hyper-spectral sensors are used to image changes in the electromagnetic spectrum from vegetation. The object is to detect a specific spectral signature that is known to result from CO_2 uptake. The advantage of these methods is that they can efficiently cover a large surface area.

This cost component incorporates the expenditures for planning and quality assurance. Annual operating costs are included as a subsequent data item.

Develop Plan and Implement LIDAR Airborne Survey

LIDAR is an optical remote sensing technology that can be used to detect CO_2 concentration in the air above a GS site.[36] Another technology for measurement of CO_2 in air is Raman LIDAR. LIDAR is the optical analog of radar, and it is based upon the use of laser radiation to measure various compounds in the air, including CO_2. The Raman LIDAR method involves transmitting laser light into the atmosphere and then detecting the scattered laser radiation that has been shifted in wavelength due to interaction with the target scattering molecules (e.g., CO_2) along the resolved path length. By comparing the Raman signal of the CO_2 to the Raman signal of N_2 or O_2, a direct measurement of CO_2 concentration can be obtained.

A similar method, Differential Absorption LIDAR (DIAL), uses two wavelengths of laser light to measure the CO_2 concentration in the atmosphere. The wavelengths used are specific to CO_2. One wavelength is selected to correspond to a CO_2 spectral absorption line, while the other is a non-absorbing wavelength. The average CO_2 concentration over the path length can be determined from the ratio of the backscatter signals for the two laser wavelengths. The instrumentation for both methods (Raman LIDAR and DIAL) can be truck or airplane mounted and can provide similar precision at similar cost. Truck methods can cover up to tens of square kilometers per day. Plane mounted platforms can cover a much larger area.

Airborne DIAL methods are currently in use for methane leakage detection along gas pipelines. Instrumentation includes the LIDAR, a digital mapping camera, a color video system, and an optical guidance system. The airplane flies a survey over the pipeline at an altitude of about 1,000 feet, approximately perpendicular to the wind direction. The LIDAR instrumentation measures the concentration of methane by measuring how much of the reflected laser pulse has been absorbed. These data are integrated with real time wind direction and velocity to define the leakage footprint and estimate a leakage rate.

This cost component incorporates the expenditures for planning and quality assurance. Annual operating costs are included as a subsequent data item.

Develop Plan and Implement Soil Zone Monitoring

The soil zone is generally present within the first few inches to possibly tens of feet beneath the Earth's surface. A monitoring program to detect the vertical CO_2 flux in the soil zone can be established. Background levels (which vary with time of day and season) must be determined to provide a baseline against which statistically significant anomalies can be detected. This may consist of a grid of accumulation chambers in which the CO_2 flux is periodically measured.[37]

Commercially available accumulation chamber instrument packages are used to evaluate seasonal variations in CO_2 flux. The accumulation chamber is a method of measuring soil CO_2 flux that

[36] U.S. Department of Energy NETL http://www.netl.doe.gov/publications/factsheets/project/Project642.pdf.
[37] Oldenberg, C.M., Jennifer L. Lewicki, and Robert P. Hepple, 2003, "Near-Surface Monitoring Strategies for Carbon Dioxide Storage Verification," Earth Sciences Division, Lawrence Berkeley National Laboratory, publication LBNL-54089.

involves the placement of a collection chamber directly on or into the soil surface, with the rate of CO_2 accumulation measured periodically with an IRGA.

This cost component incorporates the expenditures for planning and equipment installation. Annual operating costs are included as a subsequent data item.

Develop Plan and Implement Vadose Zone Monitoring

The vadose zone is the relatively shallow zone beneath the surface that is not saturated with groundwater. Due to absence of water, monitoring in this zone therefore is limited to testing the chemistry of the air contained within the pore space. The CO_2 concentration of air samples taken in this zone can be measured using commercially available *infrared gas analyzers* (IRGAs), which measure the absorption of specific portions of the infrared spectrum to determine the concentration of CO_2 (or other gases) in the air sample.

This cost component incorporates the expenditures for planning and equipment installation. Annual operating costs are included as a subsequent data item.

Develop Plan and Implement Water Table Monitoring

The water table is the subsurface zone that lies beneath the vadose zone. The water table can be monitored in shallow water wells to detect CO_2 leakage at a GS site. This cost component incorporates the expenditures for planning and equipment installation. Annual operating costs are included as a subsequent data item.

Periodic Monitoring of Groundwater Quality and Geochemistry

As discussed above, the ground water must be monitored periodically to detect leakage. This cost component details the costs of periodic testing of water wells. Water samples are obtained from the well and tested at the laboratory.

Surface Microseismic Equipment

Microseisms are very small earthquakes that are assumed to be caused naturally or by the pressure front of the injected CO_2. [38] 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 zone.[39,40,41]

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[38] *Matoon Site Environmental Information Volume*, FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.
[39] Monitoring of Sequestered CO2: Meeting the Challenge with Emerging Geophysical Technologies, S.N. Dasgupta, Saudi Aramco, 2005.
[40] *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

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.[42]

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

This cost item includes the installation of microseismic detection equipment. Annual costs are itemized separately.

Monitoring Well O&M Costs - Above Injection Zone

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

Costs are specified as a base cost per year plus a depth based cost.

Monitoring Well O&M Costs - Into Injection Zone

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

Costs are specified as a base cost per year plus a depth based cost.

U-Tube Sampling O&M – Enhanced Recovery

This includes the annual costs of U-tube sampling for enhanced recovery operations. The U-tube technology was described previously.

Annual Costs of Air and Soil Surveys – Eddy Covariance

This component is the annual cost of continuous air sampling using eddy covariance equipment. This technology was described previously.

Survey, Coordinator of the European Network of Excellence on Underground CO2 Storage (CO2GeoNet), Keyworth, Nottingham, UK, March 2005.

[41] *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.

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

Annual Costs of Air and Soil Surveys – Digital Color Infrared Orthoimagery or Hyperspectral Imaging

This component is the annual cost of digital imagery for monitoring of the site. The technologies were described previously.

Annual Costs of Air and Soil Surveys –LIDAR

This component is the annual cost of a LIDAR airborne survey to detect surface CO_2 leaks. This technology was described previously.

Annual Costs of Air and Soil Surveys –Soil Zone Monitoring

This component is the annual cost of soil zone monitoring. The technologies were described previously. The costs are based upon labor and a fee for lab testing.

Annual Costs of Air and Soil Surveys –Vadose Zone Monitoring

This component is the annual cost of vadose zone monitoring. The technologies were described previously. The costs are based upon labor and a fee for lab testing.

Annual Costs of Air and Soil Surveys – Samples from Water Table

This component is the annual cost of water table monitoring. The costs are based upon labor and a fee for lab testing.

Annual Cost of Passive Seismic Equipment

This component is the annual cost of passive seismic detection. The technologies were described previously. The cost is based upon an annual cost for each detection station.

Periodic Seismic Surveys – 3D

Seismic methods and costs were described above in the section on site characterization. Seismic data may also be used as a monitoring technology 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 PISC monitoring phase.[43] Three dimensional (3D) data are much more useful but are more costly to obtain and interpret than 2D data. Both velocity and amplitude anomalies may result from CO_2 movement.

Seismic data sources (the energy 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 in shallow holes may also be used. Both of these methods have been used for decades in petroleum exploration.

[43] *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 injection zone 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) will be less amenable to seismic monitoring. Some geological settings may preclude the use of seismic because of near surface factors as well. Such factors may include irregular topography, unusual lithologies, surface water, manmade structures or impediments or other access factors. Where conditions are right, however, it is possible to detect plume movement and it can be possible to detect injected CO_2 volumes of as little as 1,000 tons.[44]

In addition to surface seismic, vertical seismic profiling (VSP) and cross-well seismic may be used for subsurface monitoring to obtain very high resolution data over a small area. VSP is a technique in which surface sources are arrayed around a well that is in close proximity to a CO_2 plume.[45] 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.[46] Both wells must penetrate to the base of the storage injection zone under investigation. This method results in a two-dimensional vertical slice of the subsurface with high resolution at the injection zone level. The method has been successfully tested at the Frio site in Texas.

The VSP and cross-well approaches are not included in the cost model. The cost of 3D seismic is specified in terms of square mile area. A discussion of costs was presented in section 3.1 (site characterization) of this Technology and Cost document.

Complex Modeling of Fluid Flows and Migration

Reservoir modeling methods are numerical methods that employ a representation of a reservoir to evaluate and predict fluid pressures and flows. They can be used in an injection project to forecast the movement of CO_2 in the reservoir. Modeling of subsurface CO_2 flow must be used to define the area of review. Modeling is also 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 injection zone capacity can be estimated with basic engineering methods. However, complex numerical models providing multi-phase and multi-component reservoir simulation may be used to understand the injection project and its

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[44] *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.

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

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

impacts in much greater detail.[47] Different models are needed to analyze the well-bore flow and to simulate the large-scale flow processes in the reservoir. Models may be designed to evaluate flow over periods of tens of years to thousands of years into the future.

Reservoir modeling costs are specified in the cost model in terms of labor hours for the site plus additional labor hours per injection well.

Reports to Regulators

This cost item includes the labor costs to complete periodic reports to regulatory bodies. The cost is based upon an estimate of the number of hours of labor required.

Monitoring Unit Costs

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

[47] *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.

Table 3: Monitoring Unit Costs

Tracking Number	Cost Item	Cost Algorithm	Data Sources
B-1	Develop geochemical baseline for injection zones and confining zone.	\$207 per sample. Assume 4 samples per injection well = \$828 per injection well	Lab analysis fee of \$100 to \$200 discussed in N.O. meeting.
B-2	Develop baseline of surface air CO2 flux for Eddy Covariance leakage monitoring.	\$36,200 per station	Range of costs discussed at N.O. meeting Jan 2008 was \$20,000 to \$50,000 per station.
B-3a	Conduct front-end engineering and design (monitoring wells ABOVE injection zone)	\$20,700 + \$5,200/shallow monitoring well	Best professional judgement.
B-3b	Conduct front-end engineering and design (monitoring wells INTO injection zone)	\$5,200/deep monitoring well	Best professional judgement.
B-4a	Obtain rights-of-way for surface uses. (monitoring wells ABOVE injection zone)	\$10,400 per monitoring well site	Best judgement. Cost of land rights are highly variable.
B-4b	Obtain rights-of-way for surface uses. (monitoring wells INTO injection zone)	\$10,400 per monitoring well site	Best judgement. Cost of land rights are highly variable.
B-5	Obtain rights-of-way for surface uses. (monitoring sites)	\$5,200 per air monitoring station site (microseismic is done inside montoring well and has no extra land costs)	Best judgement. Cost of land rights are highly variable.
B-6a	Downhole safety shut-off valve	\$15,500 + \$2.10/ft depth. Would be placed 100 or more feet above packer	Best professional judgement.
B-6b	Downhole check valve	\$500	Best professional judgement.
B-7	Standard monitoring well stopping above the injection zone (used lookup table). Standard monitoring wells for ER projects stop below the injection zone.	Use look-up table. \$/foot = \$155 to \$207 per foot typical down to 9,000 ft.	Drilling cost is estimated from drilling cost equations developed from JAS and PSAC data.
B-8	Standard monitoring well drilled into the injection zone (used lookup table); applies to RA 3-4 only).	Use look-up table. \$/foot = \$155 to \$207 per foot typical down to 9,000 ft.	Drilling cost is estimated from drilling cost equations developed from JAS and PSAC data.
B-9a	Pressure, temperature, and resistivity gauges and related equipment for monitoring wells ABOVE injection zone	\$10,400/well	Best professional judgement.
B-9b	Pressure, temperature, and resistivity gauges and related equipment for monitoring wells INTO injection zone	\$10,400/well	Best professional judgement.
B-10a	Salinity, CO2, tracer, etc. monitoring equipment for wells ABOVE injection zone (portion of equipment may be at surface such as for in situ sampling using U-tubes)	\$10,400/well	Best professional judgement.
B-10b	Salinity, CO2, tracer, etc. monitoring equipment for wells INTO injection zone (portion of equipment may be at surface such as for in situ sampling using U-tubes)	\$10,400/well	Best professional judgement.
B-10c	ER Only. U-tube for sensing oil movement away from bottom of formation. Applies to 2 of 8 EOR wells.	\$16/ft + \$30,000 per well	Best professional judgement.
B-11a	Develop plan and implement Eddy Covariance air monitoring.	40 hours @\$107.23/hr = \$4,289 for plan plus \$75,000/monitoring site	Best professional judgment of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists. Monitoring station cost estimate from Benson 2004.
B-11b	Develop plan and implement Digital Color Infrared Orthoimagery (CIR) or Hyperspectral Imaging to detect changes to vegetation.	No construction costs, but planning and quality assurance costs would add \$10,000 per square mile.	Best professional judgement.
B-11c	Develop plan and implement LIDAR airborne survey to detect surface leaks. Works best where vegetation is sparse.	No construction costs, but planning and quality assurance costs would add \$10,000 per square mile.	Best professional judgement.
B-11d	Develop plan and implement soil zone monitoring	40 hours @\$107.23/hr = \$4,289 for plan plus \$6,000/monitoring site	Best professional judgement.
B-11e	Develop plan and implement vadose zone monitoring wells to sample gas above water table.	40 hours @\$107.23/hr = \$4,289 for plan plus \$8,000/monitoring site	Best professional judgement.
B-11f	Develop plan and implement monitoring wells for samples from water table.	40 hours @\$107.23/hr = \$4,289 for plan plus \$80,000/monitoring site	Best professional judgement.
B-12	Conduct periodic monitoring of groundwater quality and geochemistry. (146.90(d) of GS Rule).	\$200/sample and 4 samples per well = \$800 per well plus 0.5 hours of engineer labor for sampling per well per month.	Lab analysis fee of \$100 to \$200 discussed in New Orleans mtg.

Table 3 (continued): Monitoring Unit Costs

Tracking Number	Cost Item	Cost Algorithm	Data Sources
B-13	Surface microseismic detection equipment	$52,000/ site (geophone arrays go into monitoring wells)	Best professional judgement.
B-14a	Monitoring well O&M (ABOVE injection zone)	Annual O&M costs are $25,900 + $3.10/ft per well per year	Operating and maintenance costs adapted from EIA Oil and Gas Lease Equipment and Operating Cost estimates.
B-14b	Monitoring well O&M (INTO injection zone)	Annual O&M costs are $25,900 + $3.10/ft per well per year	Operating and maintenance costs adapted from EIA Oil and Gas Lease Equipment and Operating Cost estimates.
B-14c	ER Only; U-tube O&M; for 2 of 8 wells drilled 200 feet below injection zone	$10,000 per year base O&M costs plus monthly sampling (=12*8 hrs/sample * $110.62/hr + 12* $200 (chromatograph cost) per sample = $10,000 plus $13,019 for 12 samples annually per well.	Best professional judgement with reference to Benson, 2004
B-15a	Annual cost of air and soil surveys: Eddy Covariance	$10,000 per station per year	Best professional judgement with reference to Benson, 2004
B-15b	Annual cost of air and soil surveys: Digital Color Infrared Orthoimagery (CIR) or Hyperspectral Imaging to detect changes to vegetation.	Airborne survey costs of $6,250 per square mile plus mobilization costs of $5,000 per site.	Best professional judgement with reference to Benson, 2004
B-15c	Annual cost of air and soil surveys: LIDAR airborne survey to detect surface leaks. Works best where vegetation is sparse.	Airborne survey costs of $6,250 per square mile plus mobilization costs of $5,000 per site.	Best professional judgement with reference to Benson, 2004
B-15d	Annual cost of air and soil surveys: Soil zone monitoring	$200 lab fee per sample plus $100 to collect.	Best professional judgement with reference to Benson, 2004
B-15e	Annual cost of air and soil surveys: Vadose zone monitoring wells to sample gas above water table.	$200 lab fee per sample plus $100 to collect.	Best professional judgement with reference to Benson, 2004
B-15f	Annual cost of air and soil surveys: Monitoring wells for samples from water table.	$200 lab fee per sample plus $1,000 to collect.	Best professional judgement with reference to Benson, 2004
B-16	Annual cost of passive seismic equipment	$10,500 per station per year	Best professional judgement with reference to cited Mattoon site report
B-17	Periodic seismic surveys: 3D	$104,000/square mile for good resolution	Several published reports are in range of this cost. Cost depends on resolution (number of lines shot) of survey.
B-18	Complex modeling of fluid flows and migration (reservoir simulations) over 100 years (RA0-3) or 10,000 years (RA4).	180 hours of engineers @$110.62/hr = $19,912 per site + 64 hours of engineers @$110.62/hr = $7,080 per injection well	Best judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
B-19	Annual reports to regulators and recordkeeping for all data gathering activities.	20 hours of engineers @$110.62/hr = $2,212 per report plus 24 hours annually of engineer labor @110.62 per hour = $2,655 for recordkeeping	Best judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
B-20	Semi-Annual (RA3) or quartery (RA4) reports to regulators and recordkeeping for all data gathering activities and recordkeeping.	15 hours of engineers @$110.62/hr = $1,659 per report plus 36 hours of engineer labor @$110.62/hr for recordkeeping = $3,982	Best judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
B-21	Monthly reports to regulators and recordkeeping for all data gathering activities and recordkeeping.	8 hours of engineers @$110.62/hr = $885 per report	Best judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
B-22	Operating G&A	20% of annual operating costs	Best professional judgement based on oil and gas industry factors.

3.3 Injection Well Construction

Front End Engineering and Design

Front-end engineering and design are carried out for the overall site and for the injection wells. Design of the monitoring wells is included under the monitoring section. Injection well construction costs include development of standard plans associated with current UIC regulations (e.g., the drilling and casing plan, wellhead equipment plan, and downhole equipment selection), as well as pre-operational logging, sampling, and testing.

Costs are specified as a base cost per site and a cost per injection well.

Rights of Way for Surface Uses

This element includes costs of the right-of-way for surface use for injection 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.[48] 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 GS. Pore space costs are outside the scope of SDWA and are not attributable to the GS rule. In the Cost Analysis, pore space costs for the final rule, in incremental terms, are zero because they occur under both the baseline alternative and the final rule (pore space costs in incremental terms are zero for each of the regulatory alternatives in comparison to the regulatory baseline). These costs are presented in the analysis for completeness only.

Costs are specified as a fixed cost per injection well. It is assumed that half of the cost is legal fees for the developer and the other half is a bonus payment to the landowner. Pipeline right-of-ways are specified as pipeline costs.

Lease Rights for Subsurface Pore Space

This includes the upfront costs only for use of pore space. The ongoing pore space costs during the project are specified separately under the discussion of well operation.

Costs are specified on the basis of pore space area in acres.

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.

Costs are specified as a base cost plus cost per impacted square mile.

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[48] *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.

UIC Permit Filing

This unit cost item covers the estimated labor cost to prepare a UIC injection permit. Each well will require its own UIC permit (EPA will not issue area permits), but there will be economies of scale in compiling the group of permits submitted for each project site.

Costs are specified as a base cost per site and a cost per injection well.

Standard Injection Well Drilling 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 (or other) injection well or a gas storage well, with the exception that much of the downhole equipment (e.g. casing and tubing, safety valves, cements, blowout preventers) must be upgraded for high pressure and corrosion resistance.[49] 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.

Injection wells typically consist 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.[50] The innermost, deepest casing string is cemented in place across the storage injection zone and then perforated to allow movement of the CO_2 into the well. Then a small diameter 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” that 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 blowouts due to unexpected pressure (downhole devices are now required). A Supervisory Control and Data Acquisition (SCADA) is used to monitor the data. The system is set up to automatically shut down the injection if needed.

Basic injection well drilling costs are specified on a per-foot of total depth basis. Cost per foot is typically in the range of $220 to $290 per foot. Additional costs such as the use of specialized tubing and casing, cementing, and wellhead equipment are evaluated separately (see below). Operating and maintenance costs are also not included here.

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[49] *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.
[50] *Matoon Site Environmental Information Volume*, FutureGen Alliance,www.futuregenalliance.org, December 1, 2006.

Well Stimulation

In some cases, it may be necessary to artificially fracture the injection well to allow for efficient CO_2 injection. This is accomplished by injecting a mixture of water and sand or other proppant material. This type of well stimulation is now carried out on a large percentage of gas wells drilled in the U.S. Cost information was modified from the PSAC well cost study. For the current study, any such costs included in the model would be based upon the pounds of proppant injected. The expected range is 25,000 to 200,000 pounds of proppant for the stimulation.

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. As discussed in the Preamble of the final GS Rule, supercritical CO_2 in the absence of water will not be corrosive. Corrosiveness of CO_2 in the presence of water is well documented. An API report on injection technology lays out a set of guidelines that were developed to address this corrosivity:[51]

> 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:

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

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

Component	Materials
Tubing	Glass Reinforced Epoxy (GRE) - lined carbon steel; IPC carbon steel, Corrosion Resistant Alloys (CRA)
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

The nickel content of steel can be varied, with higher nickel content resulting in more corrosion resistance but higher costs.

Corrosion Resistant Tubing
The tubing is the injection well tubular component through which the CO_2 is injected into the formation. Cost assumptions for corrosion resistant tubing include glass reinforced epoxy (GRE). Costs are specified on the basis of tubing footage and diameter.

Corrosion Resistant Casing
The casing is the injection well steel tubular component that is inserted in each section of drillhole after drilling and is subsequently cemented in place to prevent fluid movement. Cost assumptions are specified for corrosion resistant materials on the basis of casing diameter and footage.

Cementing of the Injection Well Casing

This cost item includes the cost of cementing the well from the surface through the base of the lowermost USDW and throughout the injection zone. Costs are specified on the basis of casing diameter and footage. Costs specified are for standard Portland cement. (Wells having waivers of the injection depth requirement will be cemented through the base of the USDW immediately above the injection zone.)

Use of CO_2-Resistant Cement

The type of cement that is used in well cementing operations may be subject to chemical reactions in a CO_2 injection zone. Casing and cement or other materials used in the construction of a GS well must have sufficient structural strength and be designed for the life of the geologic sequestration project. In addition, the GS rule specifies that all well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the UIC Director. 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:[52]

> 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.

Costs are specified on the basis of an incremental cost over standard cementing operations.

Pumps

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. Installation of electrical service also adds a cost component.

Wellhead Control Equipment

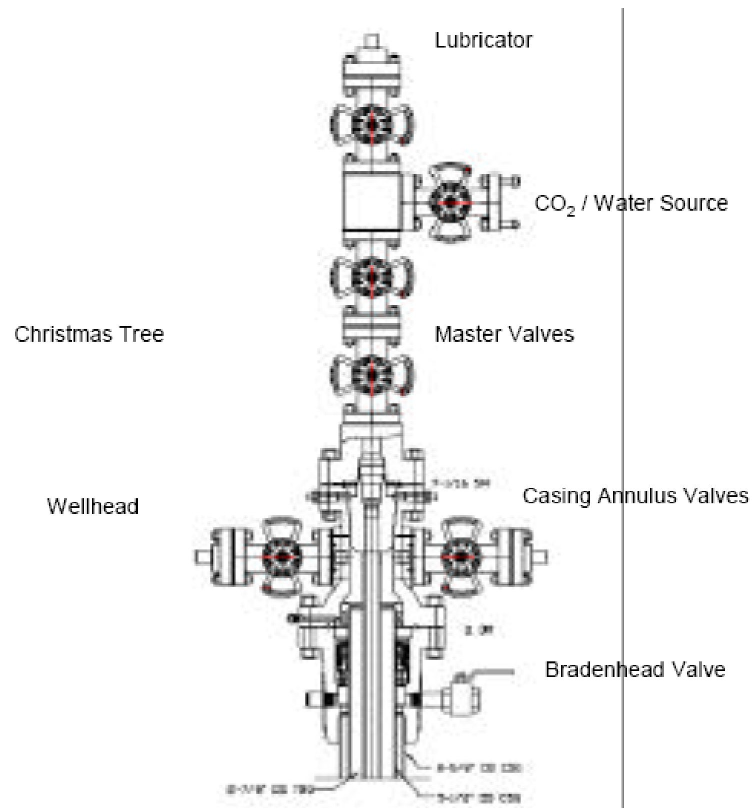
A diagram of typical injection well wellhead and control equipment is shown in Figure 5. The cost of injection equipment is a function of injectivity and the intended rate of injection. Injection well monitoring equipment is described in the 2007 API report and includes a lubricator valve for

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

running wireline tools, master valves to isolatethe 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 monitor the pressure between the production casing and surface casing.[53]

Figure 5: Diagram of Typical CO_2 Injection Wellhead

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



Costs are specified on the basis of the maximum number tons injected per day per well. Operating costs are not included here.

Pipeline Costs

Included in the cost analysis is the cost for a CO_2 pipeline for the immediate GS site. As described previously in this Technology and Cost document, costs to transport the CO_2 to the GS site are

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[53] *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.

outside the scope of the rule and 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

Tracking Number	Cost Item	Cost Algorithm	Data Sources
C-1	Conduct front-end engineering and design (general and injection wells), pre-op logging, sampling, and testing.	$207,000/site + $41,400/injection well	Best professional judgement.
C-2	Obtain rights-of-way for surface uses. (equipment, injection wells)	$20,700 per injection (pipeline right of ways included in pipeline costs) Half of cost is legal fees for developer, other half is bonus to landowner.	Best professional judgement. Cost of land rights are highly variable.
C-3	Lease rights for subsurface (pore space) use.	Upfront payment of $52/acre (additional injection fees under O&M costs)	Best professional judgement. Cost of land rights are highly variable.
C-4	Land use, air emissions, water discharge permits	$103,400/site + $20,700/square mile	Best professional judgement.
C-5	UIC permit filing, including preparation of attachments	$10,400/site + $6,000/injection well for first 5 wells at a site, then $2,000 thereafter	Best professional judgement.
C-6a	Standard injection well cost	Use look-up table. $/foot = $220 to $290 per foot typically down to 9,000 ft.	Drilling cost is estimated from drilling cost equations developed from JAS and PSAC data.
C-6b	Well stimulation	Total cost of stimulation based on cost per pound of proppant injected (coated sand); $1.25 /lb. of sand; 25,000 to 200,000 lbs per frac	Modified from PSAC cost study
C-7	Corrosion resistant tubing	Additional $1.15/foot length - inch diameter for glass reinforced epoxy (GRE) lining	Based on SPE article on economics of GRE tubing.
C-8	Corrosion resistant casing	Additional $1.81/foot length inch diameter (low alloy) or $2.70/ft (higher alloy) - for corrosion resistant casing	PSAC and Preston Pipe Report
C-9	Cement well from surface through base of lowermost USDW and througout injection zone.	$1.20/foot length - inch diameter	Cementing cost based on 2008 PSAC Well Cost Study.
C-10	Use CO2-resistant cement	Adds 25% to total cementing costs	Best professional judgement.
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.
C-14	Pumps	$1550/HP. Installation of electrical service adds $20,700 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.
C-15	Wellhead and Control Equipment	Cost per well is $520*(maximum tons per day injected per well)^0.6	Based on 2008 PSAC Well Cost Study.
C-16	All elements of pipeline costs	$83,000/inch-mile	From pipeline cost data reported to FERC. Published annually in Oil and Gas Journal.
C-17	Operating G&A	20% of annual operating costs	Best professional judgement based on oil and gas industry factors.

3.4 Area of Review 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 it can be extremely involved and use sophisticated numerical reservoir simulation models. Two basic types of analysis are included in the cost analysis, one simple approach using basic reservoir parameters, and the other based upon advanced reservoir simulation.

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

Complex Modeling of CO_2 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. Cost items are included for a 100 year simulation model and a 10,000 year simulation model.

Aerial Survey to Find Old Wells

This cost item involves an airborne magnetic survey using a helicopter that flies over the area of review to detect well casings from all cased wells. This may identify 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.

Evaluate Mechanical Integrity of Existing Wells Penetrating Containment System

Existing wells at a planned GS 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 GS. The wells that are most critical in this analysis are those that penetrate the proposed injection zone and confining zone units. Factors that must be evaluated include the condition of the cement and overall well maintenance.[54,55]

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[54] *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.

A description of the process of evaluating and remediating old wells is provided by Meyer in a recent report published by API: [56]

> 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.

This cost item includes the labor costs to evaluate the integrity of wells penetrating the containment system at the site. Costs are specified on the basis of hours of labor costs at specified labor rates.

Evaluate Integrity of Shallow Wells

Existing shallow wells may pose a threat to USDWs. This cost item includes labor costs to evaluate the record of completion and plugging of shallow wells.

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[55] *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.
[56] *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)

Remediate Old Wells in Area of Review

It may be necessary to remediate existing wells at a potential GS 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 formations, there may be few, if any, existing wellbores. However, with older oil and gas fields, remediation costs may be significant, especially with old wells. 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.[57]

<u>Remediate Old Wells that Pose a Risk to USDWs</u>

Owners and operators must remediate wells that are in a condition that poses a risk to a USDW to ensure well integrity. This cost item includes well cleanout, logging, and re-plugging.

<u>Remediate Old Wells in AOR that Lack High Quality Cementing Information</u>

Wells that lack adequate information on cementing must undergo remediation to ensure integrity. This cost item includes well cleanout, logging, and re-plugging.

Area of Review and Corrective Action Unit Costs

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

[57] EPA workgroup, January, 2008.

Table 5: Area of Review and Corrective Action Unit Costs

Tracking Number	Cost Item	Cost Algorithm	Data Sources
D-1	Simple fluid flow calculations to predict CO2 fluid flow.	36 hours of engineers @$110.62/hr = $3982 per site + 12 hours of engineers @$110.62/hr = $1327 per injection well	Best professional judgement of time required. Hourly rate may change based on labor survey data.
D-2	Complex modeling of CO2 fluid flows and migration (reservoir simulations) over 100 years	180 hours of engineers @$110.62/hr = $19,912 per site + 24 hours of engineers @$110.62/hr = $2,655 per injection well	Best professinoal judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
D-3	Complex modeling of CO2 fluid flows and migration (reservoir simulations) over 10,000 years	180 hours of engineers @$110.62/hr = $19,912 per site + 36 hours of engineers @$110.62/hr = $3,982 per injection well	Best professinoal judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
D-4	Areal search for old wells (artificial penetrations)	helicopter magnetic survey requires about 9 hours/square mile @$1,240 per hour. Cost = $5,200 mobilization + $11,160 per square mile. Follow-up ground surveys will add another $2,070 per square mile. (helicopter survey interline spacing is about 80 feet with speed of 10 ft/sec)	Based on DOE sponsored research at Salt Creek WY . Helicopter hourly rate is in range of several published estimates, adjusted for fuel costs.
D-5	Evaluate integrity of construction and record of completion and/or plugging of existing wells that penetrate containment system.	24 hours @$107.23/hr = $2,574 per site + 6 hours @$110.62/hr = $664 per well	Best judgement of time required. Hourly rate derived from AAPG 2009 salary survey of petroleum geologists.
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 @$110.62/hr = $664 per well	Best professinoal judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
D-7	Remediate old wells in AoR that pose a risk to USDWs	$31,200 for clean out, $13,500 to replug and $11,400 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 $20,700.	Plugging and logging cost based on 2008 and 2009 PSAC Well Cost Studies. Clean out cost will vary widely. Cost here is 3 days of rig use @ $10,400 per day. Rig cost from Land Rig Newsletter US Land Rig Rates.
D-8	Remediate old wells in AoR that lack high quality cementing information	$31,200 for clean out, $13,500 to replug and $11,400 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 $20,700.	Plugging and logging cost based on 2008 and 2009 PSAC Well Cost Studies. Clean out cost will vary widely. Cost here is 3 days of rig use @ $10,400 per day. Rig cost from Land Rig Newsletter US Land Rig Rates.
D-9	Operating G&A	20% of annual operating costs	Best professional judgement based on oil and gas industry factors.

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, repair and replacement of wells and equipment, and estimated costs for the possibility of failure at the site and the need to relocate a GS operation. As discussed previously in this Technology and Cost document, pore space costs are included for completeness in the analysis, but are not attributable to this rulemaking.

Corrosion Monitoring and Prevention Program

Because of the potential for CO_2 to be corrosive in the presence of water, owners and operators must develop a corrosion monitoring and prevention program for the operation. The cost is specified as labor hours to develop the program.

Corrosion Monitoring

This cost item includes the labor costs and sample analysis costs for the corrosion monitoring program. Corrosion monitoring includes quarterly analysis of the injectate stream and the measurement of corrosion well material coupons.

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.[58]

This cost item includes the equipment costs for equipment to monitor injection volumes, pressure, flow rates, and annulus pressure. It is specified as a cost per injection well.

Equipment to Add Tracers

Tracer testing is implemented at the Director's discretion, and 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 injection zone and potentially in overlying groundwater or soil zones. A number of tracers with very low detection limits are available and more are under development.

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[58] *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.

The use of tracers for monitoring was investigated under GEO-SEQ[59]. Natural and artificial tracers have the potential to assist in characterizing injection zones, 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). [60] Perfluorocarbon Tracers (PFTs) have many advantages in that they are soluble in water, non-toxic, non-radioactive, and have an extremely small detection limit. [61] 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 injection zone 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.[62] 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.

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. This cost is specified as a cost per injection well.

Electricity Costs for Pumps and Equipment

Electricity costs represent a significant component of overall operating costs. This cost item specifies the electricity costs for pumps and equipment. The cost is specified as dollars per kilowatt hour.

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.

Costs are specified as a base rate per year plus a cost per foot per well.

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[59] *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.
[60] *Monitoring to Ensure Safe and Effective Geological Sequestration of Carbon Dioxide*, S. Benson and L. Myer, Lawrence Berkeley Laboratory, Berkeley, California, 2002.
[61] *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.
[62] *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.

Land Use Rents and Right of Way

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

Costs are specified in terms of dollars per acre per year.

Pore Space Unit Costs

This unit cost includes an estimate of pore space cost per barrel 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 attributable to the final rule.

Property Taxes and Insurance

This unit cost includes the ongoing expense of property tax and liability insurance. It is specified as a cost per dollar of capital expenditures.

Tracers in Injected Fluid

The use of injected tracers to detect leakage is discussed above. This cost item specifies the cost of the tracer material, estimated as a cost per unit volume of CO_2 injected.

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. The cost is based upon an assumption of 1 percent per year of initial well and equipment cost.

General Failure of Containment Site – Remove and Relocate CO_2

There is a small probability that a given GS site will not perform adequately, due to unforeseen subsurface conditions that are not detected during the site characterization and construction phases. This may require in a small percentage of cases the closure of the site and re-location sometime during the operating life or in the post-injection period. The best method of incorporating such a cost is through a risk-based accounting approach, taking the entire cost times the small probability of occurrence. An assumption is made of a 1 percent chance of site failure after it is constructed and begins operations.

Well Operation Unit Costs

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

Table 6: Well Operation Unit Costs

Tracking Number	Cost Item	Cost Algorithm	Data Sources
E-1	Develop a corrosion monitoring and prevention program	24 hours of engineers @$110.62/hr = $2655 per site	Best professional judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
E-2	Corrosion monitoring; quarterly analysis of injectate stream and measurement of corrosion of well material coupons.	6 hours a@ $110.62/hr= $663.72/well plus $25/well (quarterly) plus $300 per sample (4 samples per injection well)	Best professional judgement.
E-3	Continuous measurement / monitoring equipment: injected volumes, pressure, flow rates and annulus pressure	$15,500/well	Best professional judgement.
E-4	Equipment to add tracers	$10,400/well	Best professional judgement.
E-5	Electricity cost for pump, equipment	$0.066/kWh	2007 average industrial sector electricity price reported by EIA.
E-6	Injection well O&M	Annual O&M costs are $77,500 + $3.10/ft per well per year	Operating and maintenance cost based on EIA Oil and Gas Lease Equipment and Operating Cost estimates.
E-7	Land use rent, rights-of-way	$5.20/acre/year	Best professional judgement based on oil & gas industry costs. Cost of land rights are highly variable.
E-8	Pore space use costs	$0.052/barrel or about $0.36 per metric ton	Best professional judgement based on oil & gas industry costs. Cost of land rights are highly variable.
E-9	Property Taxes & Insurance	$0.03/$1CAPEX	Best professional judgement.
E-10	Tracers in injected fluid	$0.05/ton of CO2 injected	Best professional judgement. Cost will depend of type of tracer.
E-12	Repair, replace wells and equipment	Assume 1%/year of initial well and equipment cost	Best professional judgement
E-13	General failure of containment at site: cost to remove and relocate CO2	Assuming a 1% chance of failure over injection life, then approximately 0.083% of total capital costs each year would cover such a contingency	Best professional judgement
E-14	Operating G&A	20% of annual operating costs	Best professional judgement based on oil and gas industry factors.

3.6 Mechanical Integrity Tests

Owners or operators of CO_2 injection wells must periodically evaluate well integrity 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.

Internal Mechanical Integrity Tests

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.

Annular pressure under normal operating conditions will be continuously monitored and recorded as one means of assuring internal mechanical integrity. In addition, periodic internal MITs can be performed. The most common internal periodic MIT is the standard annular pressure test (SAPT). The annulus between the casing and injection tubing is pressured far above normal operating conditions and monitored to see if the pressure holds.[63]

EPA and state regulatory agencies have specific requirements for pressure testing injection wells and for performing other mechanical integrity tests.[64,65] Testing occurs prior to injection and periodically thereafter. Wells that fail the mechanical integrity test must be shut in until repaired, reworked, or plugged.[66] 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.

Casing Inspection Log

Following is a definition of the casing inspection log:

> An in situ record of casing thickness and integrity, to determine whether and to what extent the casing has undergone corrosion. The term refers to an individual measurement, or a combination of measurements using acoustic, electrical and mechanical techniques, to evaluate the casing thickness and other parameters. The log is usually presented with the basic measurements and an estimate of metal loss. It was first introduced in the early 1960s.

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[63] Carbon Dioxide Storage: Geological Security and Environmental Issues – Case Study on the Sleipner Field, Norway, S. Soloman, Bellona Foundation, May, 2007.

[64] *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.

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

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

Today the terms "casing-evaluation log" and "pipe-inspection log" are used synonymously.[67]

Radioactive Tracer Survey of Bottom Hole 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 bond, temperature, noise, and oxygen activation logs.[68] 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.[69] Descriptions of these technologies are available at the EPA Region 5 website [70]

Costs are specified for annual tests or tests every six months.

Pressure Falloff Tests

A falloff test is a pressure transient test that consists of shutting in an injection well and measuring the pressure falloff. [71] Falloff tests provide injection zone pressure data and are used to characterize both the injection zone 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.

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[67] http://www.glossary.oilfield.slb.com/Display.cfm?Term=casing-inspection%20log

[68] *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.

[69] *Carbon Dioxide Storage: Geological Security and Environmental Issues – Case Study on the Sleipner Field*, Norway, S. Soloman, Bellona Foundation, May, 2007.

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

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

Table 7: Mechanical Integrity Tests Unit Costs

Tracking Number	Cost Item	Cost Algorithm	Data Sources
F-1	Internal mechanical integrity pressure tests	$2,070/test	Best professional judgement.
F-2	Casing inspection log	$2,070 plus $4.15/foot	Based on 2008 and 2009 PSAC Well Cost Studies for wireline log suite. Cost of MIT log could be lower.
F-3	Conduct a tracer survey of the bottom-hole cement using a CO2-soluble isotope	$5,200/test	Best professional judgement.
F-5	External mechanical integrity tests to detect flow adjacent to well using temperature or noise log	$2,070 plus $4.15/foot	Based on 2008 PSAC Well Cost Study for wireline log suite. Cost of external MIT log could be lower.
F-6	External mechanical integrity tests to detect flow adjacent to well using temperature or noise log	$2,070 plus $4.15/foot	Based on 2008 PSAC Well Cost Study for wireline log suite. Cost of external MIT log could be lower.
F-7	Conduct pressure fall-off test	$2,070/test	Best professional judgement.
F-9	Operating G&A	20% of annual operating costs	Best professional judgement based on oil and gas industry factors.

Note: Schedule/periodicity for each unit cost is described in Appendix B (Project Algorithms) of the Cost Analysis of the Final GS Rule.[72]

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

After the injection phase has ended, the owner or operator must close the site in a safe and secure manner that protects USDWs from endangerment and monitor the site during the PISC period. 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 that the CO_2 moved as expected in the subsurface.

Flush Wells with Buffer Fluid before Plugging

Prior to plugging, the well is flushed with a buffer fluid. This cost includes a fixed component and a cost per inch-foot of casing diameter.

Plug Injection Wells

Upon completion of injection operations and PISC, prior to site closure, an owner or operator will plug those injection wells not intended for further use as monitoring wells. Monitoring wells will be plugged following a phase of long-term monitoring. Closure of injection and monitoring wells involves the placement of cement plugs over all or part of the well, with special care taken to seal off USDWs. 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

[72] Cost Analysis for the Final GS Rule, EPA 816-R-10-013.

corrosion resistant cement. (Reference: IPCC report). A guide to the plugging and closure requirements for injection wells is available on the EPA website.[73]

Costs are specified as a cost per well for logging and plugging. Cement plugging involves two plugs – one in the injection zone and one from the surface to the base of the USDWs.

Perform Mechanical Integrity Test Prior to Plugging

An important aspect of proper well closure is mechanical integrity testing. This testing confirms that the casing and cement have integrity and will not provide a pathway for fluid movement. Various types of mechanical integrity tests are described in the previous section. Costs are specified as a base cost per well and cost per foot.

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. Costs are specified for three cases:

- Plug monitoring wells above injection zone
- Plug monitoring wells into injection zone
- Plug monitoring wells below injection zone (for waivered wells)

Remove Surface Equipment, Structures, Restore Vegetation

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

Costs are specified for four cases:

- Injection wells
- Monitoring wells above injection zone
- Monitoring wells into injection zone
- Monitoring wells below injection zone (waivered wells)

Costs are specified as a fixed cost per well and cost per monitoring station.

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, PISC, and site closure plans.

[73] U.S. EPA, http://www.epa.gov/r5water/uic/r5guid/r5_04.htm#iv.

PISC Monitoring Well O&M

The annual costs of operating and maintaining the monitoring wells will extend through the end of the PISC monitoring period.

Costs are specified for three cases:

- Monitoring wells above injection zone
- Monitoring wells into injection zone
- Monitoring wells below injection zone (waivered wells)

Post-Injection Air and Soil Surveys

The annual costs of air and soil surveys will extend through the end of the PISC monitoring period. Costs are specified per station per year.

Post- Injection Seismic Surveys

The annual costs of seismic surveys will extend through the end of the PISC monitoring period. Costs are specified on a square mile basis.

Post- Injection Reports to Regulators

Periodic reports to regulators will continue during PISC monitoring. The frequency and duration of reports is dependent upon the regulatory alternative and is specified in Chapter 5 of the Cost Analysis.[74] Costs are specified as labor costs.

Well Plugging, Equipment Removal, and PISC Unit Costs

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

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[74] Cost Analysis for the Final GS Rule, EPA 816-R-10-013.

Table 8: Well Plugging, Equipment Removal, and PISC Costs

Tracking Number	Cost Item	Cost Algorithm	Data Sources
G-1	Flush wells with a buffer fluid before closing	$1000 + $0.085/inch-foot casing diameter	Best professional judgement.
G-2	Plug injection wells (done to all wells)	$13,500 to plug and $11,400 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.
G-3	Perform a mechanical integrity test prior to plugging to evaluate integrity of casing and cement to remain in ground	$2,070 plus $4.15/foot	Based on 2008 PSAC Well Cost Study for wireline log suite.
G-4a	Plug monitoring wells ABOVE injection zone	$6,700 to plug and $5,700 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.
G-4b	Plug monitoring wells INTO injection zone	$6,700 to plug and $5,700 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.
G-5	Remove surface equipment, structures, restore vegetation (injection wells)	$25,900/injection well	Best professional judgement.
G-6a	Remove surface equipment, structures, restore vegetation (monitoring wells ABOVE injection zone)	$10,400/monitoring well, $5,200 for monitoring stations	Best professional judgement.
G-6b	Remove surface equipment, structures, restore vegetation (monitoring wells INTO injection zone)	$10,400/monitoring well, $5,200 for monitoring stations	Best professional judgement.
G-7	Document plugging and closure process (well plugging, post-injection plans, notification of intent to close, post-closure report)	120 hours of engineers @$110.62/hr = $13,274 per site	Best professional judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
G-8a	Post-closure monitoring well O&M (ABOVE injection zone)	Annual O&M costs are $25,900 + $3.10/ft per well per year	Operating and maintenance costs adapted from EIA Oil and Gas Lease Equipment and Operating Cost estimates.
G-8b	Post-closure monitoring well O&M (INTO injection zone)	Annual O&M costs are $25,900 + $3.10/ft per well per year	Operating and maintenance costs adapted from EIA Oil and Gas Lease Equipment and Operating Cost estimates.
G-9	Post-injection air and soil surveys	$10,400 per station per year	Best professional judgement.
G-10	Post-closure seismic survey	$104,000/square mile for good resolution	Several published reports are in range of this cost. Cost depends on resolution (number of lines shot) of survey.
G-11	Periodic post-injection monitoring reports to regulators	40 hours @$110.62/hr = $4,425 per report	Best professional judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
G-12	Operating G&A	20% of annual operating costs	Best professional judgement based on oil and gas industry factors.

Note: Schedule/periodicity for each unit cost is described in Appendix B (Project Algorithms) of the Cost Analysis of the Final GS Rule.[75]

[75] Cost Analysis for the Final GS Rule, EPA 816-R-10-013.

3.8 Financial Responsibility

To ensure that resources are available to protect USDWs from endangerment, today's rule identifies qualifying financial instruments, the time frames over which financial responsibility must be maintained, procedures for estimating the costs of activities covered by the financial instruments, procedures for notifying the Director of adverse financial conditions, and requirements for adjusting cost estimates to reflect changes to the project plans. Today's rule requires the owner or operator to have a detailed written estimate, in current dollars, of the cost of: 1) performing corrective action on wells in the AoR, 2) plugging the injection well(s), 3) PISC and site closure, and 4) emergency and remedial response. The cost estimate must be prepared separately for each injection activity and be based on the costs to the owner or operator of hiring a third party (who is neither a parent nor a subsidiary of the owner or operator) to perform the activities. The following unit costs were used:

Performance Bond or Demonstration of Financial Ability to Close Site

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

Performance Bond or Demonstration of Financial Ability for PISC

This cost item includes the labor costs to prepare a report demonstrating financial responsibility for post injection monitoring period, including remediation. The duration of the period is dependent upon the regulatory alternative, and is specified in Chapter 2 of the Cost Analysis.[76]

Financial Responsibility Unit Costs

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

Table 9: Financial Responsibility Unit Costs

Tracking Number	Cost Item	Cost Algorithm	Data Sources
H-1	Performance bond or demonstrate financial ability to close site (including an inflation factor)	8 hours @$110.62/hr = $885 per financial report	Best professional judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
H-2	Performance bond or demonstrate financial ability for post-injection monitoring, remediation (including an inflation factor)	4 hours @$110.62/hr = $442 per financial report	Best professional judgement of time required. Hourly rate derived from SPE 2009 salary survey of petroleum geologists.
H-3	Operating G&A	20% of annual operating costs	Best professional judgement based on oil and gas industry factors.

[76] Cost Analysis for the Final GS Rule, EPA 816-R-10-013.

4 Uncertainties in Analysis

As with any technology and cost analysis, there are many sources of uncertainty, including current costs and likely future costs. In this analysis, uncertainty is 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) (presented in the Cost Analysis)
- How many times the costs are applied through the life of the project. (e.g. number of surveys) (presented in the Cost Analysis)
- 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 are known to industry, although there is uncertainty as where this will apply and how much impact it will have.

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 GS technologies are in an early stage of development and are not commercially deployed and because 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. EPA has obtained useful information from the literature and from a UIC Technology Conference in New Orleans [77] for the basis of unit costs such as eddy covariance, geochemical testing, and tracer injection. In addition, unit cost input has been received from the Department of Energy, public comment on the rule, 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, the impact of this uncertainty is expected to be minimal.

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.

Number of Hours and Hourly Rates

Several of the cost categories described in this document 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 will be done in-house by employees or contracted out.

Fluctuation in Unit Costs over Time

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 information is needed and what activities should be implemented, and general labor cost changes.

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

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

Overall Cost Analysis Uncertainty

Chapter 5 of the Cost Analysis[78] discusses uncertainty related to the overall cost analysis. Briefly, EPA used best professional judgment in determining the characteristics of the pro forma projects developed to represent baseline projects for saline and ER sites, the schedule of cost incurrence throughout the period of analysis, and the applicability of each unit cost under each regulatory alternative considered.

Various sources in the literature informed development of the pro forma site characteristics and the number of monitoring stations and frequency of monitoring. However, industry has not yet reached consensus on issues such as the appropriate number of monitoring wells for a GS project.

[78] Cost Analysis for the Final GS Rule, EPA 816-R-10-013.

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