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Comments: Attached is the committee report prepared by Dawn Deal, NETL. Dawn assumed leadership of this element; GCCC staff provided committee and review services. In addition, GCCC provided leadership in MMV tool assessment.

Methodology for Development of Geologic Storage Estimates for Carbon Dioxide

Prepared for
US Department of Energy
National Energy Technology Laboratory
Carbon Sequestration Program

Prepared by
Capacity and Fairways Subgroup
Of the Geologic Working Group
Of the DOE Regional Carbon Sequestration Partnerships

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Foreword

This document is an update to the 2006 "Methodology for Development of Carbon Sequestration Capacity Estimates" published in the *2007 Carbon Sequestration Atlas of the United States and Canada (Atlas I)*. This document describes the methodologies being used to produce the geologic resource estimates for carbon dioxide (CO_2) storage in the *2008 Carbon Sequestration Atlas of the United States and Canada (Atlas II)* – in development. The rationales presented are used to simplify assumptions for estimating the amount of CO_2 that can be stored in subsurface geologic environments of the United States and parts of Canada. The primary focus of this update is to add additional basins and formations to the CO_2 storage portfolio, document procedures completely, and provide definitions of CO_2 resource that reflect the uncertainty of geologic resource estimates for CO_2.

The Regional Carbon Sequestration Partnerships (RCSPs) are charged with providing a quantitative estimate of the geologic storage resource for CO_2 in the subsurface environments of their regions. These estimates are required to indicate the extent to which carbon capture and storage (CCS) technologies could contribute to the reduction of CO_2 emissions into the atmosphere. This assessment is a high-level overview and is not intended as a substitute for site-specific assessment and testing. The methodologies described in this document are designed to integrate results of data compiled by the seven RCSPs for three types of geologic formations: saline formations, unmineable coal seams, and oil and gas reservoirs. These methodologies are developed to be consistent across North America for a wide range of available data. Results of this assessment are intended to be distributed by a geographic information system (GIS) and available as hard-copy results in *Atlas II*.

This document is a consensus product resulting from discussions among researchers representing all seven RCSPs. A subcommittee, the Capacity and Fairways Subgroup, convened by the Geologic Working Group of the RCSPs in May of 2006 for development of *Atlas I*, provided leadership for this effort. Methods used by the RCSPs for estimating CO_2 storage potential in Atlas I were inventoried and reviewed to generate consistent assumptions for estimating the geologic resource for CO_2. A workshop in Pittsburgh, Pennsylvania, on June 21, 2007, provided a venue for broader discussion within the Capacity and Fairways Subgroup, and additional discussions, via phone conference and e-mail, have led to development of consensus on the updated approach presented here.

Contents

Introduction

The purpose of this document is to outline procedures for estimating the geologic storage potential for carbon dioxide (CO_2) in the United States and Canada for three types of geologic formations: saline formations, unmineable coal seams, and oil and gas reservoirs. This document will be used as part of the updated *2008 Carbon Sequestration Atlas of the United States and Canada (Atlas II)*. The primary focus of this update is to add additional basins and formations to the CO_2 storage portfolio, document procedures completely, and provide definitions of CO_2 resource versus CO_2 capacity that reflect the uncertainty of geologic storage estimates for CO_2 across the Regional Carbon Sequestration Partnership (RCSP) Regions.

The methodologies presented for estimating geologic storage potential for CO_2 for this 2008 assessment consist of widely accepted assumptions about in-situ fluid distribution in porous media and fluid displacement processes commonly applied in the oil and gas and ground water science and engineering practices. Data collected by the RCSPs beginning in 2003 and continuing today during their Phase II efforts are used to estimate the CO_2 storage quantities for Atlas II. Diverse data from three types of geologic formations in the subsurface are summarized, interpolated, averaged, or generalized by each of the seven RCSPs to calculate CO_2 storage potential. Methodologies for calculating shale and basalt formations' storage potential are currently under development and are not discussed in this methodology document.

Methodologies presented describe calculations and assumptions used for CO_2 storage resource estimates. A CO_2 storage ***resource*** estimate is defined as the volume of porous and permeable sedimentary rocks that is most likely accessible to injected CO_2 via drilled and completed wellbores. CO_2 storage resource assessments do not include economic or regulatory constraints; only physical constraints to define the accessible part of the subsurface are applied. Economic or regulatory constraints are included in geologic ***capacity*** estimates. It should also be noted that for the development of specific commercial scale geologic storage sites, economic and regulatory constraints must be considered to determine the portion of the CO_2 resource that is available under various development scenarios. Under the most favorable economic and regulatory scenarios, 100 percent of the estimated CO_2 resource may be considered CO_2 capacity.

CO_2 Resource Estimates

A CO_2 resource estimate includes all volumetric estimates of geologic storage reflecting physical and chemical constraints or limitations, but does not include current or projected economic constraints, regulations, or well and/or surface facility operations. Examples of physical constraints include trapped (or residual)

CO_2 saturation to water, irreducible water saturation to CO_2, gravity segregation, injection formation fracture propagation pressure, caprock (or seal) capillary entry pressure, fracture propagation pressure, and displacement efficiency. Additional geologic-based physical constraints include net-to-gross (vertical) thickness, effective-to-total porosity, and net-to-total area. Examples of chemical constraints are CO_2-brine solubility, brine concentration with depth, dissolution rates of CO_2 into brine, and precipitation (or mineralization) effects.

CO_2 Capacity Estimates

Carbon dioxide capacity is the highest degree of certainty of geologic storage with present economic and regulatory considerations included. Economic considerations include CO_2 injection rate and pressure, number of wells drilled into the formation, types of wells (horizontal versus vertical), number of injection zones completed in each well, operating expenses, and injection site proximity to CO_2 source. In most cases, an indication of injectivity must be available from an existing well with adequate tests to indicate CO_2 injection rate directly or, at a minimum, in-situ permeability. In addition, sophisticated analysis of the potential for use of oil and gas reservoirs for CO_2 storage with enhanced oil recovery (EOR) and enhanced gas recovery (EGR) can be made when calculating CO_2 capacity. Examples of regulatory constraints include protection of potable water, minimum well spacing, maximum injection rates, prescribed completion methods (cased vs. open-hole), proximity to existing wells, and surface usage considerations. Appendices 1 and 2 include additional discussion of scenarios where economic and regulatory criteria may impact storage capacity estimates.

CO_2 Storage Classification

Classification of storage is not only necessary to understand the storage estimates in *Atlas II* but also to be able to establish terminology that can be used for making regulatory and business decisions. Furthermore, a classification system provides a comparable basis for assessing CO_2 resource and capacity and related market value in the future. If a CO_2 storage industry or market evolves, a classification system would assist in the following:

- Verifying tradable credits
- Advising government agencies on storage estimates
- Developing confidence in an open market for capacity
- Protecting correlative rights of the CO_2 capacity owners (pore space and/or adsorptive capacity)

Improving the accuracy of a CO_2 resource estimate does not necessarily mean changing the estimate but reclassifying the estimate to signify the increased confidence or lowered risk in the resource estimate. *Atlas II* has started this process by defining “CO_2 resource estimates” and “CO_2 capacity estimates.”

The petroleum and coal industries have classification protocols that indicate level of certainty and reduced risks that require application of objective and subjective rules. For example, the petroleum industry uses “resource” and “reserve.” Resource is much more uncertain than reserve and as such the petroleum industry has two divisions within resource: “speculative” and “contingent.” Speculative is higher risk or lesser certainty, while contingent is relatively lesser risk or greater certainty. Contingent illustrates a degree of certainty in which plans and budgets are designated to drill wells and test a specific geologic formation. Speculative illustrates a degree of certainty where risk is too high to consider site development.

The petroleum industry’s use of reserve also has two divisions: “proved” and “unproved”. Reserves are considered commercial at current economic conditions by the owner company. Commerciality includes the ability to transport the oil to a market, e.g., the availability of a pipeline. Proved is the highest degree of certainty and requires actively producing wells that have either produced oil or have very strong test results showing that they will produce oil.

Because the CO_2 storage industry is in its infancy, there are very few active CO_2 injection wells providing site specific information needed for reclassifying a “CO_2 resource” as “CO_2 capacity”. However, it is expected that the needed data will evolve as the CO_2 storage industry matures.

Results and conclusions for Phase II Field Validation Tests being conducted by the RCSPs are not anticipated to be completed for inclusion in *Atlas II*. The primary purpose of the Phase II Field Validation Tests is to improve understanding of regional and local considerations for deployment of commercial scale geologic carbon capture and storage (CCS). Consequently, the size of the Phase II pilots relative to a basin may be too small to have any impact on changing the approximations or methodology for formation resource estimates for an entire basin that appears in a national atlas.

CO_2 Storage Calculation

Methods available for estimating subsurface volumes are widely and routinely applied in oil and gas, ground water, underground natural gas storage, and Underground Injection Control (UIC) disposal related estimations. In general, these methods can be divided into two categories: static and dynamic. The static models are volumetric and compressibility; the dynamic models are decline curve analysis, material balance, and reservoir simulation.

While all methods are applicable after active injection, only the static models are applicable prior to injection or collection of field-measured injection rates. These models rely on parameters that are directly related to the geologic description of the area for injection, e.g., thickness, porosity, and compressibility. After CO_2

injection, dynamic models are applicable. For a description of static and dynamic models for calculating CO_2 storage potential see Appendix 3.

It is beyond the scope of this assessment to adequately compare and contrast these methods, but as with other methodologies, some approaches are simple and require only a few parameters, while others methods require numerous input parameters.

The volumetric method is the basis for storage calculations in this assessment.

Reporting

The RCSPs began by compiling data that were collected in their respective regions and submitting it to the National Carbon Sequestration Database and Geographical Information System (NATCARB). Polygons enclosing each area assessed with an attached database file (.dbf) are the preferred method of reporting. In the database, a low and a high estimate of saline formation and coal CO_2 resource in metric tons of CO_2 are recorded for each polygon, with a low value and a high value generated using the low and high values of storage efficiency (E) provided in this document. For storage in oil and gas reservoirs, a resource estimate in metric tons of CO_2 is calculated for each formation, play, or region, with individual or total oil and gas reservoir CO_2 storage potential displayed in a polygon. Data that support the calculated volumes are noted and archived by each RCSP.

Each RCSP is providing a list of assumptions and calculation criteria that are used in their Region, as well as CO_2 resource estimates at the granularity level available. The criteria outlined in this document are considered the default settings; if RCSPs opt to use other criteria, these must be explicitly stated along with the rationale. In addition to basin totals, resource estimates by geographic information system (GIS) grid cell are required. This information, written by each RCSP, will be provided to the National Energy Technology Laboratory (NETL) and included as an Appendix in *Atlas II*.

Types of Geologic Environments

For the purposes of this assessment, the subsurface is categorized into five major geologic formations: saline formations, coal seams, oil and gas formations, shale, and basalt formations. Each of these is defined and input parameters for CO_2 resource calculations are described below. Carbon dioxide resource has been quantified where possible for saline, coal, oil, and gas, whereas shale and basalt formations are presented as future opportunities and not assessed in this document.

<u>SALINE FORMATION CO_2 RESOURCE ESTIMATING</u>

Background: A saline formation assessed for storage is defined as a porous and permeable body of rock containing water with total dissolved solids (TDS) greater than 10,000 parts per million (ppm), which can store large volumes of CO_2. A saline formation can include more than one named geologic formation or be defined as only part of a formation. More than one saline formation can be assessed within a vertical sequence of sedimentary rocks. Many formations are part of the total CO_2 volume that occupies structurally-defined basins, and in this case, the name of the basin is commonly used to describe multiple formations. However, in some cases, the conceptualization and terminology are not appropriate, and the customary local terminology is accepted instead.

This saline formation storage assessment includes the following assumptions: (1) saline formations are heterogeneous and therefore under multiphase conditions; (2) only 20 to 80 percent of the area inventoried and 25 to 75 percent of the formation thickness assessed would be occupied by CO_2; and (3) the efficiency factor accounts for net-to-effective porosity, areal displacement efficiency, vertical displacement efficiency, gravity effects, and microscopic displacement efficiency.

Reporting: For *Atlas II*, CO_2 resource estimates for saline are reported at the geologic basin level. Where basins straddle more than one region, one RCSP assumed primary responsibility for the basin, while the other RCSP provided the needed data in their portion of the basin.

Each RCSP is providing a list of assumptions and calculation criteria that are used in their Region, as well as CO_2 resource estimates at the granularity level available. The criteria outlined in this document are considered the default settings; if RCSPs opt to use other criteria, these must be explicitly stated along with the rationale.

Screening Criteria: Saline formations assessed for storage are restricted to those where the following basic criteria for the storage are met: (1) pressure and temperature conditions in the saline formation are adequate to keep the CO_2 in dense phase (liquid or supercritical); (2) a suitable seal is present to limit vertical flow of the CO_2 to the surface (caprock); and (3) salinity in the saline formation is such that injection is acceptable under provisions of the UIC Program. While the salinity limitation is a regulatory criteria, and therefore a consideration for capacity assessments (but not resource assessments), the authors believe that regulations will always be in place to protect potable waters. Therefore, this criterion is being applied to this resource assessment.

Depths: The storage of CO_2 in saline formations is limited to sedimentary basins with vertical flow barriers and depth exceeding 800 meters. Sedimentary basins include porous and permeable sandstone and carbonate rocks. The continental United States, its internationally recognized waters, and portions of Canada are the boundary of this CO_2 storage assessment. The 800-meter cutoff is an attempt to select a depth that reflects pressure and temperature that yields high density liquid or supercritical CO_2. This is arbitrary and does not necessarily designate a lower limit of depth conducive to CO_2 storage. Several natural gas reservoirs exist at shallower depths; this infers that CO_2-gas may be stored at shallower depths but only at pressure and temperatures most likely to sustain gas-phase CO_2 density. Because of the large difference in density between dense-phase and gas-phase CO_2, the additional storage of shallow saline formations is not anticipated to provide any substantial increase in resource estimates for a national atlas, but this could be considered in a site specific assessment.

Caprocks: All sedimentary rocks included in the saline formation resource estimate must have caprocks (vertical seals) which include shale, anhydrite, and evaporites. Thickness of these seals is not considered in this assessment. For increasing confidence in a storage estimate (determining CO_2 capacity) other criteria including seal effectiveness (e.g. salinity and pressure above and below the caprock), minimum permeability, minimum threshold capillary pressure, and fracture propagation pressure of a caprock should be considered.

Computing CO_2 Resource: The volumetric method is the basis for CO_2 resource calculations in saline formations. The formula requires the injection total area (A_t), formation thickness (h), and porosity (Φ). A storage efficiency factor (E) is applied to this formula to reflect the accessible volume to injected CO_2. Monte Carlo simulations estimated a range of E between 1 and 4 percent of the total pore volume of saline formations for a 15 to 85 percent confidence range (Appendix 4).

The volumetric equation for CO_2 resource calculation in saline formations with consistent units assumed is as follows:

$$G_{CO2} = A_t \, h_g \, \phi_{tot} \, \rho \, E$$

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of saline formation CO_2 resource.
A_t	L^2	Geographical area that defines the basin or region being assessed for CO_2 storage calculation.
h_g	L	Gross thickness of saline formations for which CO_2 storage is assessed within the basin or region defined by A.
ϕ_{tot}	L^3/L^3	Average porosity of entire saline formation over thickness h_g or total porosity of saline formations within each geologic unit's gross thickness divided by h_g.
ρ	M/L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over h_g.

E	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled by CO_2.

* L is length; M is mass.

Details of this calculation are determined by each RCSP.

OIL AND GAS RESERVOIR CO_2 RESOURCE ESTIMATING

Background: Typical mature oil and gas reservoirs in North America have held crude oil and natural gas over millions of years. They consist of a layer of permeable rock with a layer of nonpermeable rock (caprock) above, such that the nonpermeable layer forms a trap that holds the oil and gas in place. Oil and gas fields have many characteristics that make them excellent target locations for geologic storage of CO_2. The geologic conditions that trap oil and gas are also the conditions that are conducive to long-term CO_2 storage.

As a value-added benefit, CO_2 injected into a mature oil reservoir can enable incremental oil to be recovered. A small amount of CO_2 will dissolve in the oil, increasing its bulk volume and decreasing its viscosity, thereby facilitating flow to the wellbore. Typically, primary oil recovery and secondary recovery via a water flood produce 30-40 percent of a reservoir's original oil-in-place (OOIP). EOR via a CO_2 flood allows recovery of an additional 10-15 percent of the OOIP.

Reporting*:* In *Atlas II*, CO_2 resource estimates for oil and gas reservoirs are reported at the oil or gas field level. An oil or gas field can contain numerous reservoirs, leases, and wells, but field level is a scale that is well defined both on a technical and regulatory basis. In addition, at the field level, data manipulation, storage, and access are surmountable tasks. The field level can easily be summed to provide estimates at the state or RCSP scales. It is also possible to cross-check storage estimates against readily available state/province and national production figures (e.g., Energy Information Administration [EIA] and state oil and gas commissions).

Each RCSP is providing a list of assumptions and calculation criteria that are used in their Region, as well as CO_2 resource estimates at the granularity level available. The criteria outlined in this document are considered the default settings; if RCSPs opt to use other criteria, these must be explicitly stated along with the rationale.

Screening Criteria: Carbon dioxide storage resource for oil or gas reservoirs for this assessment is defined as volumes of the subsurface that have hosted natural accumulations of oil and/or gas and could be used to store CO_2 in the future. Mapping of the seal to oil and gas formations is not required because the entrapment of oil or gas is considered evidence that a CO_2 containment seal is present, and the associated water is normally not potable. Production of oil and gas has demonstrated that pores within the produced area are interconnected and therefore can be accessed by CO_2. In some cases, pressure is depleted significantly as a result of production, which can be conceptualized as volumes that can be replaced by repressurizing these formations with CO_2. In addition, no distinction is made in this assessment for maturity of the field (i.e., fields that are or will soon become depleted or abandoned).

Depths: Because oil and gas fields can be productive across a wide variety of depths, no minimum or maximum depth is proposed. However, RCSPs are cognizant of the Safe Drinking Water Act (SDWA) definitions of water quality and will work to ensure that potentially freshwater-bearing intervals are not included. It is proposed that only oil and gas fields with a water TDS concentration of 10,000 ppm and higher are included, unless specifically noted and justified. The number of fields that do not meet the SDWA minimum cut off is expected to be a very small number. In addition, the water quality is very likely to be classified as non-potable due to oil and gas contamination. SDWA considerations are regulatory and therefore appropriate for capacity estimates (but not resource estimates). However, regulations will always be in place to protect potable waters, therefore, where appropriate, potable water considerations are taken into account for this resource assessment.

Computing CO_2 Resource: Storage volume methodology for oil and gas fields is simplified to provide a nationwide-base case. The calculation is based on quantifying the volume of oil and gas that could be produced and assuming that they could be replaced by an equivalent volume of CO_2, where both oil and gas and CO_2 volumes are calculated at initial formation pressure or a pressure that is considered a maximum CO_2 storage pressure. Two main methods are used to estimate the CO_2 storage volume: (1) a volumetrics-based CO_2 storage estimate and (2) a production-based CO_2 storage estimate. The method used for this assessment is selected by each RSCP based on available data and will be documented in *Atlas II*. It is assumed that either method will provide a similar estimate of potential storage volumes. The two methods have storage efficiency factors built into their respective methodologies. No range of CO_2 storage values is proposed for oil and gas fields, indicating a relatively good understanding of volumetrics of these systems.

Volumetrics-based CO_2 storage estimate for oil and gas formations: The volumetrics-based CO_2 storage estimate is a standard industry method to calculate OOIP or original gas in place (OGIP). OOIP is calculated by multiplying formation area (A), net oil column height (h_n), average effective porosity (ϕ_e), and oil saturation (1 - water saturation as a fraction [S_w]). A formation-specific fraction of OOIP is estimated to be accessible to CO_2; the fraction can include multiple mechanisms, such as dissolution of CO_2 in situ into oil and water. This fraction is defined as the CO_2 storage efficiency factor (E) and can be derived from local experience or reservoir simulation. For site-specific studies, formation volumetrics involving gas require consideration of pressure and formation drive mechanism. Because of previous extensive experience in estimating volumetrics of formations, regional, play, or formation-specific values supplied by each RCSP are used.

The general form of the volumetric equation being used in this assessment is similar to that used from saline formations, except that E involves original oil or gas in place:

$$G_{CO2} = A\ h_n\ \phi_e\ (1-S_w) B\ \rho\ E$$

Parameter	Units*	Description
G_{CO2}	M	Mass estimate of oil and gas formation CO_2 resource.
A	L^2	Area that defines the oil or gas formation that is being assessed for CO_2 storage calculation.
h_n	L	Oil and gas column height in the formation.
ϕ_e	L^3/L^3	Average porosity over net thickness h_n or effective porosity of formation divided by h_n.
S_w	L^3/L^3	Average water saturation within the total area (A) and net thickness (h_n).
B	L^3/L^3	Formation volume factor; converts standard oil or gas volume to subsurface volume (at formation pressure and temperature). B = 1.0 if CO_2 density is evaluated at anticipated reservoir pressure and temperature
ρ	M/L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions in the formation averaged over h_n.
E	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total pore volume from which oil and/or gas has been produced and that can be filled by CO_2.

* L is length; M is mass.

Production-based CO_2 storage estimate for oil and gas formations: A production-based CO_2 storage estimate is possible if acceptable records are available on volumes of oil and gas produced. Produced water is not considered in the estimates, nor is injected water (waterflooding), although these volumes may be useful in site-specific calculations. In cases where a field has not reached a super-mature stage, it is beneficial to apply decline curve analysis (described in Appendix 3) to generate a better estimate of estimated ultimate recovery (EUR), which represents the expected volume of produced oil and gas (Li and Home, 2003).

It is necessary to apply an appropriate formation volume factor (B) to convert surface oil and gas volumes (reported as production) to subsurface volumes, including correction of solution gas volumes if gas production in an oil formation is included. No area, column height, porosity, residual water saturation, or estimation of the fraction of OOIP that is accessible to CO_2 is required because production reflected these formation characteristics. If data are available, it is possible to apply efficiency to production data to convert it to CO_2 storage volumes; otherwise replacement of produced oil and gas by CO_2 on a volume-for-volume basis (at formation pressure and temperature) is accepted.

Simplifying assumptions for oil and gas fields: Examples of factors not explicitly considered in the production-based method that might increase the potential CO_2 storage volume that could be stored include miscibility of CO_2 into oil, dissolution of CO_2 into residual and associated water, mineral trapping, and pressure decline as a result of production. Parameters not considered that may limit the CO_2 volume that can be stored include imperfect inversion of processes that occurred during production—for example, replacement of produced oil or gas by water (CO_2 may not completely replace this imbibed water), production of gas by solution gas drive, and waterflooding. In addition, it may not be realistic to assume that the volume of CO_2 stored is equivalent to the volume of originally trapped oil and gas because of pressure perturbations of the formation during production (for example, compromise to the seal by well penetration or by deformation during production). It is also not realistic to assume the seal will respond in the same manner to trapped CO_2 as to the oil and gas originally in place.

COAL SEAM CO_2 RESOURCE ESTIMATING

Background: Carbon dioxide storage opportunities exist within coal seams. All coals have varying amounts of methane adsorbed onto pore surfaces, and wells can be drilled into unmineable coalbeds to recover this coalbed methane (CBM). Initial CBM recovery methods, such as dewatering and depressurization, leave a considerable amount of methane in the formation. Additional recovery can be achieved by sweeping the coalbed with CO_2. Depending on coal rank, as few as three to as many as thirteen molecules of CO_2 may be adsorbed for each molecule of methane released, thereby providing an excellent storage site for CO_2 along with the additional benefit of enhanced coalbed methane (ECBM) recovery.

Reporting: For *Atlas II*, CO_2 resource estimates for coal are reported at the geologic basin level. Where basins straddle more than one region, one RCSP assumed primary responsibility for the basin, with the other RCSP providing the needed data in their portion of the basin.

Each RCSP is providing a list of assumptions and calculation criteria that are used in their Region, as well as CO_2 resource estimates at the granularity level available. The criteria outlined in this document are considered the default settings; if RCSPs opt to use other criteria, these must be explicitly stated along with the rationale.

Screening Criteria:
Depths: The vertical intervals included are between a minimum and maximum depth. It is suggested that the minimum depth be dictated by a water-quality standard to ensure that potentially freshwater-bearing coals are not included; only coal seams with a water TDS concentration of 10,000 ppm and higher be included. Where water quality data are scarce or unavailable, analogy to other basins should be used to estimate the minimum depth criteria. While the TDS cutoff is related to regulatory considerations to protect potable water and therefore a consideration for capacity assessments (but not resource assessments), it is believed that regulations will always be in place to protect potable waters. Therefore, this criterion is being applied to this resource assessment.

Mineability: Within the depth intervals selected for a particular basin, a determination is being made as to which coals are unmineable, based upon today's standards of technology and profitability. This criteria implies the use of economic constraints for this coal storage assessment; however, use of this constraint is necessary because of safety and regulatory concerns for mining coal that has been used to store CO_2. While there will clearly be advancements in mining technology and changes in the value of the commodity in the future, which will enable some of the coal seams deemed unmineable today to be mineable in the future, it is beyond the scope of this effort to forecast those developments and their impact. Depth, thickness, and coal quality (e.g., coal rank, sulphur content, etc.) criteria are established for each basin for this purpose. Only those coals deemed unmineable (with today's technology) are included in this CO_2 resource estimate. If such data are available, any coal reserve is also excluded.

Computing CO_2 Resource: Carbon dioxide resource estimates are using a GIS approach with a minimum grid cell size of 10 km x 10 km (a congressional township). A volumetric approach is applied, using the prevailing pressure gradient for each basin (or 0.433 psi/ft if it is unknown), and a (dry, ash-free) CO_2 isotherm at an "average" formation temperature. In-situ storage volumes are computed after correcting for ash content. If data are available, different isotherms for different coal ranks are used. If no CO_2 isotherm is available, isotherms from similar coal ranks in analog basins are used. No accounting for decreasing CO_2 storage potential at increasing temperatures (depths) is taken.

The volumetric equation with consistent units applied for coal CO_2 storage potential follows:

$$G_{CO2} = A\ h_g\ C\ \rho_s\ E$$

Parameter	Units*	Description

G_{CO2}	M	Mass estimate of CO_2 resource of one or more coal beds.
A	L^2	Geographical area that outlines the coal basin or region for CO_2 storage calculation.
h_g	L	Gross thickness of coal seam(s) for which CO_2 storage is assessed within the basin or region defined by A.
C	L^3/ L^3	Concentration of CO_2 standard volume per unit of coal volume (Langmuir or alternative); assumes 100% CO_2 saturated coal conditions; if on dry-ash-free (daf) basis, A and h must be corrected for daf.
ρ_s	M/ L^3	Standard density of CO_2.
E	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total coal bulk volume that is contacted by CO_2.

* L is length; M is mass.

The CO_2 storage efficiency factor has several components that reflect different physical barriers that inhibit CO_2 from contacting 100 percent of the coal bulk volume of a given basin or region. Depending on the definitions of area, thickness, and CO_2 concentration (from Langmuir isotherms), the CO_2 storage efficiency factor may also reflect the volumetric difference between bulk volume and coal volume. For example, if *A* and *h* are based on dry-ash-free (daf) conditions, *C* must have a *daf* basis too. Additionally, because gross thickness is used in the equation above, E includes a term that adjusts gross thickness to net thickness. Appendix 5 provides the assumptions used to estimate E for coal. Monte Carlo simulations estimated a range of E between 28 and 40 percent; these values provide a 15 to 85 percent confidence range. Details are provided in Appendix 5.

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Appendices

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Appendix 1: Storage Development Scenarios Affecting CO_2 Storage Estimates

For a given CO_2 storage resource estimate for a specific site, different development scenarios affect the estimate of CO_2 storage capacity. Wellbore type, transportation, and injection pressure are just a few examples of different site considerations that may increase or decrease the CO_2 storage capacity of a geologic formation.

<u>Wellbore Type</u>

Horizontal and vertical wells are two types of injection wells that could be considered for a storage site. In general, horizontal wells are expected to have a higher injection rate (tons per day) capability, especially in geologic formations with relatively small vertical thickness. Consequently, for a given CO_2 injection rate, fewer horizontal wells would be required as compared to the number of vertical wells. Fewer drilled wells also result in less impact at the surface.

For geologic formations that are compartmentalized horizontally, a horizontal well is more likely to attain a higher CO_2 storage capacity compared to a vertical well. Similarly, a geologic formation with vertical flow barriers is more likely to have relatively higher CO_2 storage capacity from injecting into vertical wells.

The decision to use horizontal or vertical wells has economic tradeoffs in terms of the number of wells, injection rate, and acquisition of surface acreage for well locations. Moreover, the effect of wellbore type on CO_2 capacity will vary based on the geologic formation. The storage capacity estimate in this example will be different for the well type, but the storage resource available would be the same (unless the drilled wells provided information that increased or decreased the resource estimate).

<u>Transportation of CO_2</u>

In most cases, a pipeline of some distance will be required to link the emission source and the injection site. Pipelines may be on the order of $1 million per mile. A tradeoff between a closer injection site with lesser subsurface CO_2 storage capacity may be economically acceptable compared to the increased capital investment of a longer pipeline to a storage site with higher storage capacity. Likewise, a closer site that requires a greater number of wells, more expensive wells, or deeper wells may be much more economical compared to a geologic formation with fewer, less expensive wells that requires a 10-mile pipeline.

An estimate of CO_2 resource is not affected by the distance between source and sink and gives an estimate of the accessible pore volume regardless of the proximity to an existing or proposed CO_2 emission source.

Injection Pressure

All geologic formations have a threshold pore pressure that will begin to propagate a fracture within the injection formation if exceeded. Some caprocks withstand this pressure and the fracture terminates at the caprock. Many relatively thick shales constrain the growth of a fracture; however, in addition to a threshold fracture pressure, shales have a capillary pressure threshold that if exceeded, will breech and allow an injected fluid to pass through it.

Every formation (reservoirs and caprocks) has a pressure threshold that must be included in site-specific CO_2 capacity estimates. However, this pressure constraint can be managed during the planning and operation stages of development and should not influence the CO_2 resource estimate. A storage site with limited injection and/or pore pressure may reduce the CO_2 capacity, but due to number of injection wells required or length of pipeline, it may be economically the best choice. Moreover, drilling more wells can reduce the injection pressure into each well and keep reservoir pressure lower. Horizontal wells tend to have lower injection pressure as compared to vertical wells. Additionally, similar to natural gas storage, if regulations and economics are favorable, water production wells can be used to reduce pressure and increase capacity at a particular storage site.

All of these seemingly technical considerations all have economic or regulatory components that must be considered. For a site-specific capacity assessment, technical, economic, and regulatory aspects must be considered collectively for the time and duration of the storage project. It is important to note that capacity estimates are dynamic and may change with new regulations, storage technology, or economic conditions. Additionally, new and different information found from characterization of new wells of application of new technology to existing wells can change resource and capacity estimates.

Appendix 2: Injectivity, Regulations, and Economics for CO_2 Storage Estimates

This Atlas's assessment is intended to identify the geographical distribution of CO_2 resource for use in energy-related government policy and business decisions. It is not intended to provide site-specific information for a company to select a site to build a new power plant or to drill a well. This assessment does not include the criteria that are required to make these types of decisions. Similar to a natural resource assessment such as petroleum accumulations, this resource estimation is volumetrically based on physically accessible CO_2 storage in specific formations in sedimentary basins without consideration of injection rates, regulations, economics, or surface land usage. The following are examples of scenarios for considering these criteria in CO_2 capacity assessments:

<u>Injectivity</u>

The daily or annual rate of CO_2 that can be injected into a specific geologic formation is described or inferred by the term "injectivity." Relatively low or high injectivity for a formation is determined by the flow characteristics of the formation (e.g., pressure, permeability, and thickness), the type and size of wellbore drilled, the type of completion, and the number of wells.

No injectivity (zero) means there is no injection rate under any circumstances and as such a geologic formation without injectivity cannot be considered a CO_2 resource. However, a geologic formation with low injectivity that provides a CO_2 injection rate greater than zero does provide the opportunity to store CO_2 and is considered a CO_2 resource.

For selecting and designing specific storage sites, a minimum acceptable injection rate for a well is required to meet the capture rate of CO_2 emitted by the industrial site or utility. For example, if injectivity and storage for 1 million tons per year from an industrial plant is desired for 30 years, the first step in selecting an injection site is to find a geologic unit or group of units as close to the emission site as feasible (to minimize transportation costs) that has adequate CO_2 resource of at least 30 million tons. This industrial plant would likely have a budget (or economic limits) for capturing and storing CO_2 on a per-ton basis (e.g, $15/ton). One of the next steps is to establish the most affordable means of injecting CO_2 that does not exceed the $15/ton economic limit. One single well that could inject at least 1 million tons per year would be the least-cost option. However, if one well cannot provide this high rate of injectivity, additional wells or more expensive well types and completions will be considered. If the number of wells required to meet the 1 million tons per year has expenses that exceed $15/ton, then the site will not be selected and a different storage site further from the source may be considered.

For this example, the resource exists, but under the current economic conditions for this company at this emission site, the resource is not affordable. A different industrial plant with less CO_2 volume to store may find the same geologic unit acceptable with lower injection rate requirements or a higher economic limit than $15/ton. Moreover, the same plant, some time in the future, may have different economic drivers that can afford more wells or type of wells making the same site economical. Injection rate and the geologic parameters that determine injection rate do not affect the resource estimate, and only affect the use of the geologic unit at the present time. If the storage resource evaluated against a set of economic criteria is considered uneconomic, the storage capacity of the site is zero; however, the storage resource estimate remains unchanged.

By analogy, a producing oil well can be produced to the time that not a single drop of additional oil is produced; however, long before this time, the oil rate will be low enough that the income from the sale of oil from this well is not high enough to pay for the daily expense of operating this well. At this time the well is abandoned even though additional oil can be produced. If the price of oil increases or the operating expenses decrease, oil can continue to be produced. For either of these cases, the oil resource is the same and its availability as a resource is not changed by economic conditions.

<u>Regulations</u>

The use of any resource is governed by regulations; CO_2 storage will likely be similar. Some types of regulations may be similar to the oil and gas industry and underground gas storage. Examples of regulations are maximum injection pressure and rates, minimum formation water salinity, and monitoring and reporting requirements. In other industries, regulations have historically changed for technical and environmental reasons. Additionally, many regulations have exemption clauses. For example, the injection of water into an oil reservoir will have a regulated maximum pressure, but on a well-by-well, lease, or field case, a specific test can be conducted to allow injection pressure above the regulated maximum. Exemptions are added to regulations as new information or technology is available. Because of the dynamics of regulations, the use of regulations should not be imposed on the estimate of CO_2 resource.

The use of current regulations is very pertinent to a specific site assessment with projected start-up time and duration. To continue the example of the 1 million ton per year emission site, part of the $15/ton economic limit included a regulated monitoring technique that was relatively expensive. If later technology found a less expensive and equally effective method to monitor, the regulatory agency could be petitioned to consider the new technology and lower the storage cost to $14/ton, and the same geologic unit could be economical to this industrial site.

<u>Economics</u>

Similar to the resource assessment of other natural resources such as petroleum accumulations and coal beds, the inclusion of economic considerations is inappropriate for a CO_2 resource assessment. In addition to project economic considerations, every company storing CO_2 will have different economic criteria to impose such as rate of return, payout, and profit/investment ratio that will affect the capacity of a geologic formation. In any storage industry scenario (e.g. carbon credits), each business will be making final estimates of available CO_2 capacity based on economic criteria. At this time it is unclear if a storage industry will emerge that has companies that provide dedicated storage services, or if corporations within existing industries, such as coal-burning power plants and ethanol-generating plants, will take on CO_2 storage as one of their business units.

Regardless of how the storage industry evolves, the assessment of CO_2 resources is unaffected by the projection of a new industry, and capacity of a site will be estimated by individual companies using their own economic criteria.

Land Usage

Current or projected use of surface land is not included in the estimate of storage resource of this Atlas and likely would not adversely affect most of the storage currently assessed under lands used for other purposes. This is primarily because horizontal-well technology can be used to access this type of area and would be determined by specific economic conditions on a site-by-site basis.

Appendix 3: Static and Dynamic Methods for Estimating CO_2 Storage

Methods available for estimating subsurface volumes are widely and routinely applied in oil and gas, ground water, underground natural gas storage, and UIC disposal-related estimations. In general, these methods can be divided into two categories: static and dynamic. The static models are volumetric and compressibility; the dynamic models are decline curve analyses, material balance, and reservoir simulation.

<u>Volumetric</u>

The volumetric method is the basis for CO_2 resource calculations in the Atlas, and is described in detail in the previous three formation sections. The volumetric formula uses porosity, area, and thickness in a Monte Carlo simulation approach with various efficiency terms included to account for ranges of variations in the geologic volumetric properties and the fraction of the accessible pore volume that is most likely to be contacted by injected CO_2.

<u>Compressibility</u>

The compressibility approach is generally applied to fluids with nearly constant total compressibility (c_t) over some increase or decrease to pressure (p) from an initial pressure (p_o). As such, single-phase oil reservoirs and confined saline-water filled formations are typical applications.

The injection of CO_2 into a saline formation suggests two phases, but if the formula is applied to the water phase only, it is applicable. The equation below shows the compression of the original water volume (V_o) due to an increase in pressure (p) above the initial pressure (p_o). The compressed volume (ΔV_w) is the volume that CO_2 can occupy as a consequence of increasing the pressure from p_o to p via the injection process.

$$G_{co2} = \Delta V_w = V_{wo}\, c_t\, (p - p_o)$$

The original water volume V_{wo} is determined by the volumetric equation using A, h, and ϕ. The c_t is the sum of the pore compressibility of the formation (c_p) and the in-situ water saturating the formation (c_w).

$$c_t = c_p + c_w$$

In a closed system, where water cannot be displaced from the area around the injector, the V_{wo} is calculated based on the area defined by the boundaries of the formation.

In an open system, water is displaced from around the injector and the V_{wo} term cannot be clearly defined. Theoretically, V_{wo} is infinite for an open system and the equation is not applicable.

For an estimate of the CO_2 storage capacity of a site, p could be defined as the maximum capillary pressure of the sealing rock or a maximum pressure that may cause a boundary (e.g., a fault) to leak. This pressure is not the injection pressure of a well that may initiate or propagate a fracture due to relatively high pressure injection, but is the average water pressure of the entire V_{wo}. Because the pressure could be controlled by the production of water, this example would not be used to calculate the storage resource.

<u>Decline Curve Analyses</u>

The basis for estimating subsurface storage volumes using active injection assumes a type of injection rate – time relationship. The most common relationship is exponential primarily because of its simplicity. Injection rate (q_{co2}) is expected to be an exponential function of time based on an initial injection rate (q_{co2i}) and a decline coefficient (D) that reflects various flow characteristics of the formation. The general form of this equation follows:

$$q_{co2} = q_{co2i}\, e^{-Dt}$$

This formula is only applicable if injection rate varies with time due to pseudo-state conditions of pressure increasing in the formation with time and injection rate decreasing. Another variation of this formula exists for constant rate injection and variable injection pressure.

The exponential decline equation is used to determine the decline coefficient, D, given an injection rate history. The projected CO_2 capacity (G_{co2}) is based on the following equation:

$$G_{co2} = (q_{co2i} - q_{co2}) / D$$

The formula is generally applicable to individual wells or entire fields as long as the exponential trend exists between injection rate and time. Because this formula is based on injection rates only, it reflects the storage volume that is likely to be attained with continued injection; therefore, this is storage capacity. Use of the storage efficiency factor (E) could be used to estimate the storage resource that might be available.

<u>Material Balance</u>

The compressibility formula is a special case of the material balance equation. The complete material balance equation includes the cumulative CO_2 injection and the corresponding pore pressure (p) at various times. Fluid properties that reflect CO_2 compressibility are required. This formula can be derived very similarly to the p/z plot used in gas reservoir and underground gas storage reservoirs. (An aquifer influx or efflux term can be included based on specific site applications; in this case, aquifer properties such as water and formation compressibility are required.) This formula can be written so that a straight line appears on a cumulative CO_2 injection ($G_{inj-co2}$) versus p/z where z is the z-factor of CO_2 evaluated at pressure, p.

Reservoir Simulation

Numerical modeling of geologic units that includes volumetric and geologic flow properties, as well as fluid properties, is the most advanced method for estimating storage. Advanced technology does not necessarily mean improved accuracy unless the representative data are available.

Reservoir simulation includes the material balance, compressibility, and volumetrics formulas on a cell-by-cell representation of the geologic unit. It is considered an advanced methodology because it is designed to include a more realistic geologic description, fluid properties, and injection/production wells. Various development scenarios can be simulated, too.

Simulation can be used to make projections or to study actual field or pilot performance. If simulation is used in design only, the basic equations may give similar results for storage estimate; for use with actual field or pilot injection and pressure data, a more improved estimate for CO_2 resource can be made.

It should be noted that the reservoir simulation method is the most resource-consuming. It needs data at a scale and resolution that make it applicable at the reservoir scale but not at the formation and basin scales.

Appendix 4: Estimation of the Storage Efficiency Factor for Saline Formations

Efficiency is the multiplicative combination of volumetric parameters that reflect the portion of a basin's or region's total pore volume that CO_2 is expected to actually contact. The CO_2 storage efficiency factor for saline formations has several components that reflect different physical barriers that inhibit CO_2 from contacting 100 percent of the pore volume of a given basin or region. Depending on the definitions of area, thickness, and porosity, the CO_2 storage efficiency factor may also reflect the volumetric difference between bulk volume, total pore volume, and effective pore volume.

Because formation thickness and total porosity are used in the saline CO_2 resource equation, efficiency must include terms that adjust gross thickness to net thickness and total porosity to effective porosity (interconnected).

These terms can be grouped into a single term that defines the entire basin's or region's pore volume and terms that reflect local formation effects in the injection area of a specific injection well. Assuming that CO_2 injection wells can be placed regularly throughout the basin or region to maximize storage, this group of terms is applied to the entire basin or region. Given this assumption, the resource estimate is the maximum storage available because there is no restriction on the number of wells that could be used for the entire area of the basin or region. Because formation heterogeneity terms are included, this estimate could be considered a "reasonable" maximum storage resource estimate.

The following terms are included in the CO_2 storage efficiency factor:

Term	Symbol (range)	Description
Terms used to define the entire basin or region pore volume		
Net to total area	A_n/A_t (0.2–0.8)	Fraction of total basin or region area that has a suitable formation present.
Net to gross thickness	h_n/h_g (0.25–0.75)	Fraction of total geologic unit that meets minimum porosity and permeability requirements for injection.
Effective to total porosity ratio	ϕ_e/ϕ_{tot} (0.6–0.95)	Fraction of total porosity that is effective, i.e., interconnected.
Terms used to define the pore volume immediately surrounding a single well CO_2 injector		
Areal displacement efficiency	E_A (0.5–0.8)	Fraction of immediate area surrounding an injection well that can be contacted by CO_2; most likely influenced by areal geologic heterogeneity such as faults or permeability anisotropy.

Vertical displacement efficiency	E_l (0.6–0.9)	Fraction of vertical cross section (thickness), with the volume defined by the area (A) that can be contacted by the CO_2 plume from a single well; most likely influenced by variations in porosity and permeability between sublayers in the same geologic unit. If one zone has higher permeability than others, the CO_2 will fill this zone quickly and leave the other zones with less CO_2 or no CO_2 in them.
Gravity	E_g (0.2–0.6)	Fraction of net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and in situ water. In other words, 1-E_g is that portion of the net thickness **not** contacted by CO_2 because the CO_2 rises within the geologic unit.
Microscopic displacement efficiency	E_d (0.5–0.8)	Portion of the CO_2-contacted, water-filled pore volume that can be replaced by CO_2. E_d is directly related to irreducible water saturation in the presence of CO_2.

The range of values for each parameter is an approximation to reflect various lithologies and geologic depositional systems that occur throughout the Nation. The maximum and minimum are meant to be reasonable high and low values for each parameter.

The table below gives results of six Monte Carlo simulations of the distribution of values described. (The Fourth and Fifth cases are run to assess sensitivity to the input parameters and are not considered valid for interpretation of E.) Selection of distributions was to see the effect of choice of distribution on the final answer. The P_{50} case seems less sensitive to choice of distribution. P_{15} and P_{85} cases are more sensitive to the distribution selection and parameters that describe the distribution. No rigor was given to selection of the distribution or the parameters that describe them. The intent of these Monte Carlo simulations was to give some basis or perspective for choice of the magnitude of total storage efficiency (E). In other words, this is an example of a combination of ranges of parameters and distributions that would yield a P_{50} E of approximately 1.8 to 2.2 percent.

Case	Parameter	Range	Distribution	P_{15}	P_{50}	P_{85}	Comment
Base-uniform	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_l E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5-0.8	Uniform Uniform Uniform Uniform Uniform Uniform Uniform	1.6	2.7	4.2	

Case	Parameter	Range	Distribution	P_{15}	P_{50}	P_{85}	Comment
Base-normal with variance 1.0 max-min difference	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	0.44	1.8	4.1	Median given as midpoint of range; variance given as max less median (broad flat normal distribution).
Base-normal with variance ½ max-min difference	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	1.2	2.2	3.7	Median given as midpoint of range; variance given as one-half max less median (narrow, spike normal distribution).
Base-normal with variance 2.0 max-min difference	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	0.22	1.9	10	Median given as midpoint of range; variance given as twice max less median (very broad, flat normal distribution). P85 likely too high as wide distribution makes values of some components over 1.0.
Base-normal with variance 1.0 max-min difference with minimum imposed	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Normal Normal Normal Normal Normal Normal Normal	1.7	3.7	8.0	Median given as midpoint of range; variance given as max less median (broad flat normal distribution); minimum equals low of range.

Case	Parameter	Range	Distribution	P_{15}	P_{50}	P_{85}	Comment
Base-mixed distribution	A_n/A_t h_n/h_g ϕ_e/ϕ_{tot} E_A E_I E_g E_d	0.2–0.8 0.25–0.75 0.6–0.95 0.5–0.8 0.6–0.9 0.2–0.6 0.5–0.8	Uniform Normal Uniform Normal Log Normal Normal Normal	0.65	1.9	4.4	Change in distribution based on possible petrophysical distribution.

Averaging and rounding these values results in a **low value of E of 0.01 and a high value of 0.04**; these values provide a 15 to 85 percent confidence range.

Appendix 5: Estimation of Storage Efficiency Factor for Unmineable Coal Formations

Efficiency is the multiplicative combination of volumetric parameters that reflect the portion of a basin's or region's coal bulk volume that CO_2 is expected to actually contact.

The terms that describe this volume can be grouped into one term that defines the entire basin's or region's coal bulk volume and the local formation effects in the injection area of a specific injection well. Assuming that CO_2 injection wells can be placed regularly throughout the basin or region to maximize the basin's coal storage, this group of terms is applied to the entire basin or region. The capacity estimate is therefore the maximum storage available because there is no restriction in the number of wells that could be used for the entire basin or region area. Because formation heterogeneity terms are included, however, this estimate could be considered a "reasonable" maximum storage estimate.

All of the terms are the same conceptually as with saline, except that the "effective porosity to total porosity" term was dropped. It is not in the coal volumetric equation; it is replaced by "concentration" from the Langmuir isotherm. Definitions in the table on the next page are modified for coal. Because of the lack of extensive enhanced coalbed methane (ECBM) field experience, ranges are based loosely on coalbed methane (CBM) production and computer modeling observations.

The adsorptiveness of coal compared to storage in porous media causes the range of parameters for displacement efficiency terms to be much higher than similar terms for porous media. Although geologic heterogeneity is expected in coal, the permeability reduction expected in coal due to CO_2 swelling will most likely have a "correcting" mechanism, which reduces the velocity of CO_2 as the coal swells and redirects CO_2 to lesser-swept parts of the coal seam. Since coal is thinner than saline formations, gravity effects will likely be very slight, so this term was raised also. The bulk coal terms (A/A and h/h) are increased because most basin coals would be better defined compared with saline formations.

The following terms are included in the CO_2 storage efficiency factor for coal:

Term	Symbol (range)	Description
Terms used to define the entire basin or region bulk coal volume		
Net to total area	A_n/A_t (0.6–0.8)	Fraction of total basin or region area that has bulk coal present; used if known or suspected locations are within a basin or region outline where a coal seam may be discontinuous. For example, in the Illinois Basin there are subregions within the basin where sand channels have incised and replaced coal. This situation can be handled through this term.
Net to gross thickness	h_n/h_g (0.75–0.90)	Fraction of total coal seam thickness that has adsorptive capability.
Terms used to define the coal volume immediately surrounding a single well CO_2 injector		
Areal displacement efficiency	E_A (0.7–0.95)	Fraction of the immediate area surrounding an injection well that can be contacted by CO_2; most likely influenced by areal geologic heterogeneity such as faults or permeability anisotropy.
Vertical displacement efficiency	E_I (0.8–0.95)	Fraction of the vertical cross section (thickness), with the volume defined by the area (A) that can be contacted by a single well; most likely influenced by variations in the cleat system within the coal. If one zone has higher permeability than others, the CO_2 will fill it quickly and leave the other zones with less CO_2 or no CO_2 in them.
Gravity	E_g (0.9–1.0)	Fraction of the net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and the in-situ water in the cleats. In other words, 1-E_g is the portion of the net thickness **not** contacted by CO_2 because the CO_2 rises within the coal seam.
Microscopic displacement efficiency	E_d (0.75–0.95)	Reflects the degree of saturation achievable for in situ coal compared with the theoretical maximum predicted by the CO_2 Langmuir Isotherm.

The range of values for each parameter is an approximation to reflect various coals. The maximum and minimum are meant to be reasonable high and low values for each parameter.

The following table gives results of five Monte Carlo simulations of the distribution of points that are given in the previous table. The selection of distributions was to see the effect of choice of distribution on the final answer. The P_{50} case seems less sensitive to choice of distribution. P_{15} and P_{85} cases are more sensitive to distribution selection and parameters that describe the distribution. No rigor was given to the selection of the distribution or the parameters that describe them. The intent of these Monte Carlo simulations was to give some basis or perspective for the choice of magnitude of total efficiency (E). In other words, this is an example of a combination of ranges of parameters and distributions that would yield a P_{50} E of 33 percent.

Case	Parameter	Range	Distribution	P_{15}	P_{50}	P_{85}	Comment
Base-uniform	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Uniform Uniform Uniform Uniform Uniform Uniform	28	33	40	
Base-normal with variance 1.0 max-min difference	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	25	33	43	Median given as midpoint of range; variance given as max less median (broad flat normal distribution).
Base-normal with variance ½ max-min difference	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	29	33	38	Median given as midpoint of range; variance given as one-half max less median (narrow, spike normal distribution).
Base-normal with variance 2.0 max-min difference	A_n/A_t h_n/h_g E_A E_I E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	16	29	53	Median given as midpoint of range; variance given as twice max less median (very broad, flat normal distribution) P85 likely too high as wide distribution makes values of some components over 1.0.

Case	Parameter	Range	Distribution	P_{15}	P_{50}	P_{85}	Comment
Base-normal with variance 1.0 max-min difference with minimum imposed	A_n/A_t h_n/h_g E_A E_l E_g E_d	0.6–0.8 0.75–0.90 0.7–0.95 0.8–0.95 0.9–1.0 0.75–0.95	Normal Normal Normal Normal Normal Normal	32	39	49	Median given as midpoint of range; variance given as max less median (broad flat normal distribution); minimum equals low of range.

Depending on how mapping was conducted, the value for E could reflect the volumetric difference between bulk volume and coal volume, or it could reflect coal-quality factors such as ash content, amount of moisture, heating value, vitrinite reflectance, maceral composition, and total organic content.

Compared with that of coalbed methane recovery, the value of storage efficiency of 33 percent is relatively low. The difference is that 50 to 75 percent storage efficiency may be more likely in a well field where coal is present in 100 percent of the area studied. When applying this efficiency to a basin, two factors (A/A and h/h) reduce this value to account for the volumes of the basin that actually have coal present with adsorptive coal capacity. If these terms are removed or if the volume of coal was known with 100 percent certainty, a storage factor of 57 percent would be predicted with this range of values. This storage factor is in agreement with coalbed methane recovery.

For the National Resource Estimate, Monte Carlo simulations estimate a **range of E of 0.28 to 0.40**; these values provide a 15 to 85 percent confidence range.

Appendix 6: Comparison of Pore Volume Occupied by CO_2 Dissolution in Saline and Free Phase CO_2

Because some RCSPs used dissolution of CO_2 in water and other RCSPs used free-phase CO_2 to estimate their respective basins/regions' storage capacity, the total storage efficiency (E) derived for use in one technique is not equivalent or applicable to the other.

The dominant mechanism of CO_2 storage may change from storage of an immiscible free-phase to CO_2 dissolved in water over time, and the proportion of dissolved CO_2 to a basin's/region's pore volume would be larger than the proportion contacted by free phase CO_2. Several RCSPs focused on dissolved storage for capacity calculation. To avoid any RCSP's repeating a rigorous calculation of capacity with new methodology, a method of converting E for free-phase CO_2 to the equivalent E for dissolved CO_2 is desirable. The example below shows how it can be done.

Example calculation for a formation at 8,000 feet, with temperature of 140 °F and 3,500 pounds per square inch absolute (psia) saturated with 100,000 parts per million (ppm) water. The density of CO_2 is 48.55 pound mass per cubic foot (lbm/ft^3), and dissolution in this saline is 118 standard cubic feet/stock tank barrel (scf/stb). (MIDCARB, 2004, Midcontinent Interactive Digital Carbon Atlas and Relational database (MIDCARB), http://www.midcarb.org/calculators.shtml accessed February 14, 2007; Practical Aspects of CO_2 Flooding, 2002, Perry M. Jarrell, Charles E. Fox, Michael H. Stein and Steve L. Webb Society of Petroleum Engineers (SPE) Monograph 22, 220p.)

Using a common basis of 1 ft^3 of pore volume, the 48.55 lbm of free-phase CO_2 occupies 1 ft^3 of pore space.

For dissolution of CO_2 into water, 1 ft^3 of pore space is occupied by water; 118 scf of CO_2 100% saturates a stb of 100,000 ppm water at 140 °F and 3500 psia. Converting to lbm/ft^3

$$\left(\frac{118\,\text{scf}-CO_2}{\text{stb}-\text{water}}\right)\left(\frac{1\,\text{bbl}}{5.615\,\text{ft}^3}\right)\left(\frac{1\,\text{ton}-CO_2}{17{,}140\,\text{scf}-CO_2}\right)\left(\frac{2000\,\text{lbm}}{\text{ton}}\right)=\frac{2.452\ \text{lbm - }CO_2}{\text{ft}^3\text{ - pore volume}}$$

There is a slight difference, usually less than 1%, between a stock tank barrel of water and a formation barrel of water; for this example it was assumed that they were equal. Any increase or decrease in the 1 ft^3 of water volume due to dissolution of CO_2 was not included in this example.

The ratio of 48.55 to 2.452 is used to convert from the E derived for free phase to the E for dissolution, which is 19.8 in this example. If the E for free-phase CO_2 is 2%, the equivalent E for dissolution is 2 × 19.8, or 39.6%. Interestingly if the E-free phase was 5%, the equivalent E-dissolution for this example, is 99%. So at the assumed salinity, if 5% of a basin's pore volume is free-phase CO_2, the equivalent mass distributed via dissolution in water would require 99% of the basin's pore volume.

Because of variation of pressure, temperature, and salinity as a function of depth across a basin or region, an average value should be used to calculate the conversion factor from free phase to dissolution for the entire region; otherwise a rigorous GIS study would be required to make the conversion at different values of pressure, salinity, and temperature.