

**Methodology for Development of Geologic Storage Estimates for Carbon
Dioxide**

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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 used to produce the geologic resource estimates for carbon dioxide (CO₂) storage in the *2008 Carbon Sequestration Atlas of the United States and Canada (Atlas II)*. The rationales presented were used to simplify assumptions for estimating the amount of CO₂ that can be stored in subsurface geologic environments of the United States and parts of Canada. The primary focus of *Atlas II* is to add additional basins and formations to the CO₂ storage portfolio, update information on the DOE’s Carbon Sequestration Program as well as the Regional Carbon Sequestration Partnerships (RCSPs), and provide definitions of CO₂ resource versus CO₂ capacity that reflect the uncertainty of geologic storage estimates for CO₂ across the RCSPs.

The RCSPs are charged with providing a quantitative estimate of the geologic storage resource for CO₂ 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 CO₂ 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 were 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 made 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 CO₂ storage potential in *Atlas I* were inventoried and reviewed to generate consistent assumptions for estimating the geologic resource for CO₂ in *Atlas II*. 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.

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Introduction

The purpose of this document is to outline procedures for estimating the geologic storage potential for carbon dioxide (CO₂) in the United States and Canada for three types of geologic formations: saline formations, unmineable coal seams, and oil and gas reservoirs. This document was used as part of the updated 2008 *Carbon Sequestration Atlas of the United States and Canada (Atlas II)*. The primary focus of *Atlas II* is to add additional basins and formations to the CO₂ storage portfolio, update information on the DOE's Carbon Sequestration Program as well as the Regional Carbon Sequestration Partnerships (RCSPs), and provide definitions of CO₂ resource versus CO₂ capacity that reflect the uncertainty of geologic storage estimates for CO₂ across the RCSP.

The methodologies presented for estimating geologic storage potential for CO₂ 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 petroleum and ground water science fields. Data collected by the RCSPs were used to estimate the CO₂ 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 CO₂ storage potential. Methodologies for calculating shale and basalt formations' storage potential are currently under development and are not discussed in this methodology document.

Atlas II provides CO₂ **resource** estimates by state/province and RCSP. Methodologies presented in this document describe calculations and assumptions used for CO₂ **resource** estimates. A CO₂ **resource** estimate is defined as the volume of porous and permeable sedimentary rocks available for CO₂ storage and accessible to injected CO₂ via drilled and completed wellbores. Carbon dioxide **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 CO₂ **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 CO₂ resource that is available under various development scenarios. Under the most favorable economic and regulatory scenarios, 100 percent of the estimated CO₂ **resource** may be considered CO₂ **capacity**.

Methods for estimating subsurface volumes are widely and routinely applied in petroleum, groundwater, underground natural gas storage, and Underground Injection Control disposal-related estimations. Therefore, the volumetric method is the basis for CO₂ resource calculations in *Atlas II*. 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 CO₂

Atlas II's assessment is intended to identify the geographical distribution of CO₂ 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 CO₂ storage in specific formations in sedimentary basins without consideration of injection rates, regulations, economics, or surface land usage.

CO₂ Resource Estimates

A CO₂ **resource** estimate includes all volumetric estimates of geologic CO₂ storage reflecting physical and chemical constraints or limitations (including potable water protection), but does not include current or projected economic constraints, regulations, or well and/or surface facility operations. Examples of physical constraints include isolation from potable waters, solubility of CO₂ in water, gravity segregation, injection formation fracture propagation pressure, caprock (or seal) capillary entry pressure, fracture propagation pressure, and displacement efficiency. Potable waters, for the purposes of *Atlas II's* assessment, represent waters protected by the Safe Drinking Water Act (SDWA). Additional geologic-based physical constraints include vertical thickness, proportion of porosity available for CO₂ storage, and fraction of the total area accessible to injected CO₂. Examples of chemical constraints are CO₂-brine solubility, brine concentration with depth, dissolution rates of CO₂ into brine, and precipitation (or mineralization) effects.

CO₂ Capacity Estimates

Carbon dioxide **capacity** is the estimate of geologic storage with the highest degree of certainty with present economic and regulatory considerations included. Economic considerations include CO₂ injection rate and pressure, the number of wells drilled into the formation, types of wells (horizontal versus vertical), the number of injection zones completed in each well, operating expenses, and injection site proximity to a CO₂ source. In most cases, an indication of injectivity must be available from an existing well with adequate tests to indicate CO₂ 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 CO₂ storage with enhanced oil recovery (EOR) and enhanced gas recovery (EGR) can be made when calculating CO₂ 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.

For a given CO₂ storage resource estimate for a specific site, different development scenarios affect the estimate of CO₂ storage capacity. Wellbore type, transportation, and injection pressure are just a few examples of different site considerations that may increase or decrease the CO₂ storage capacity of a geologic formation.

CO₂ 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 CO₂ resource and capacity and related market value in the future. If a CO₂ 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 CO₂ capacity owners (pore space and/or adsorptive capacity)

Improving the accuracy of a CO₂ 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 “CO₂ resource estimates” and “CO₂ 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 CO₂ storage industry is in its infancy, there are very few active CO₂ injection wells providing site-specific information needed for reclassifying a “CO₂ resource” as “CO₂ capacity.” However, it is expected that the needed data will evolve as the CO₂ storage industry matures.

Results and conclusions for Phase II Field Validation Tests being conducted by the RCSPs are not 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.

CO₂ Storage Calculation

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

While all methods are applicable after active injection, only the static methods 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 CO₂ injection, dynamic models are applicable. For a description of static and dynamic models for calculating CO₂ 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.

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) were reported. In the database, a low and a high estimate of saline formation and coal CO₂ resource in metric tons

of CO₂ were 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. Variability of E includes uncertainty in geologic parameters such as areal extent, thickness, and porosity. For storage in oil and gas reservoirs, a resource estimate in metric tons of CO₂ is calculated for each formation, play, or region, with individual or total oil and gas reservoir CO₂ storage potential displayed in a polygon. Data that support the calculated volumes are noted and archived by each RCSP.

Each RCSP provided a list of assumptions and calculation criteria that were used in their Region, as well as CO₂ resource estimates at the granularity level available. The criteria outlined in this document are considered the default settings; if a RCSP used other criteria, these are explicitly stated along with the rationale. In addition to basin totals, CO₂ resource estimates by geographic information system (GIS) grid cell were reported.

CO₂ Resource Map

A CO₂ resource map covering the United States and parts of Canada for each formation type was developed by the NATCARB for *Atlas II* from the information provided by the RCSPs.

These maps illustrate areas of potential CO₂ storage. For oil and gas reservoirs and saline formations, the maps illustrate reservoirs or formations with CO₂ storage potential that have had some degree of assessment. For coal seams, the maps illustrate (1) coal seams with CO₂ storage potential that have had some degree of assessment, and (2) coal seams that have been identified but not yet assessed for CO₂ storage potential.

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 reservoirs, shale, and basalt formations. Each of these is defined and input parameters for CO₂ resource calculations are described below. Where possible, CO₂ resource has been quantified for saline, coal, oil, and gas, whereas shale and basalt formations are presented as future opportunities and not assessed in this document.

SALINE FORMATION CO₂ RESOURCE ESTIMATING

Background: Saline formations are composed of porous rock saturated with brine and capped by one or more regionally extensive impermeable rock formations enabling trapping of injected CO₂. 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 CO₂. A saline formation can include more than one named geologic formation or be defined as only part of a formation.

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 CO₂; 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*, CO₂ resource estimates for saline formations were 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 its portion of the basin.

Screening Criteria: Saline formations assessed for storage are restricted to those meeting the following basic criteria for the storage: (1) pressure and temperature conditions in the saline formation are adequate to keep the CO₂ in dense phase (liquid or supercritical); (2) a suitable seal is present to limit vertical flow of the CO₂ to the surface (caprock); and (3) a combination of hydrogeologic conditions isolates the CO₂ within the saline formation. These criteria also apply to existing UIC and other regulations, and are relevant to capacity assessment as well, but the criteria are first incorporated into resource assessments.

Depths: The storage of CO₂ 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 800-meter cutoff is an attempt to select a depth that reflects pressure and temperature that yields high density liquid or supercritical CO₂. This is arbitrary and does not necessarily designate a lower limit of depth conducive to CO₂ storage. Several natural gas reservoirs exist at shallower depths; this infers that CO₂ gas may be stored at shallower depths but only at pressure and temperatures most likely to sustain gas-phase CO₂ density. Because of the large difference in density between liquid-phase and gas-phase CO₂, the additional storage of shallow saline formations is not anticipated to provide any substantial increase in resource estimates for *Atlas II*, 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) consisting of shale, anhydrite, and evaporites. Thickness of these seals is not considered in this assessment. For increasing confidence in a storage estimate (determining CO₂ 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 CO₂ Resource: The volumetric method is the basis for CO₂ resource calculations in saline formations. The volumetric 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 volume accessible to injected CO₂. 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 (for more information on E and Monte Carlo simulations see Appendix 4).

The volumetric equation for CO₂ resource calculation in saline formations with consistent units assumed is as follows:

$$G_{CO_2} = A_t h_g \phi_{tot} \rho E$$

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.

**For details on E, please refer to Appendix 4.

Details of this calculation are determined by each RCSP.

OIL AND GAS RESERVOIR CO₂ 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 CO₂. The geologic conditions that trap oil and gas are also the conditions that are conducive to long-term CO₂ storage.

As a value-added benefit, CO₂ injected into a mature oil reservoir can enable incremental oil to be recovered. A small amount of CO₂ 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 CO₂ flood allows recovery of an additional 10–15 percent of the OOIP.

Reporting: In *Atlas II*, CO₂ 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).

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 CO₂ 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 CO₂ 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 CO₂. 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 CO₂. 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 was used for *Atlas II* CO₂ resource estimates. Only oil and gas fields with a water TDS concentration of 10,000 ppm and higher were included, unless specifically noted and justified. The water quality in oil and gas fields is very likely to be classified as non-potable due to oil and gas contamination.

Computing CO₂ Resource: Storage volume methodology for oil and gas fields was simplified for *Atlas II*. The calculation was based on quantifying the volume of oil and gas that could be produced and assuming that it could be replaced by an equivalent volume of CO₂, where both oil and gas and CO₂ volumes are calculated at initial formation pressure or a pressure that is considered a maximum CO₂ storage pressure. Two main methods were used to estimate the CO₂ storage volume: (1) a volumetrics-based CO₂ storage estimate and (2) a production-based CO₂ storage estimate. The method used for *Atlas II* was selected by each RCSP based on available data. The two methods have storage

efficiency factors built into their respective methodologies. No range of CO₂ storage values is proposed for oil and gas fields, indicating a relatively good understanding of volumetrics of these systems.

Volumetrics-based CO₂ Storage Estimate for Oil and Gas Formations: The volumetrics-based CO₂ 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 CO₂; the fraction can include multiple mechanisms, such as dissolution of CO₂ in situ into oil and water. This fraction is defined as the CO₂ 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:

$$G_{CO_2} = A h_n \phi_e (1-S_w) B \rho E$$

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 CO₂ storage estimate for oil and gas formations: A production-based CO₂ 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.

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 CO₂ 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 CO₂ storage volumes; otherwise replacement of produced oil and gas by CO₂ 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 CO₂ storage volume that could be stored include miscibility of CO₂ into oil, dissolution of CO₂ into residual and associated water, mineral trapping, and pressure decline as a result of production. Parameters not considered that may limit the CO₂ volume that can be stored include imperfect inversion of processes that occurred during production—for example, replacement of produced oil or gas by water (CO₂ 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 CO₂ 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 CO₂ as to the oil and gas originally in place.

COAL SEAM CO₂ 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 CO₂. Depending on coal rank, as few as three to as many as thirteen molecules of CO₂ may be adsorbed for each molecule of methane released, thereby providing an excellent storage site for

CO₂, along with the additional benefit of enhanced coalbed methane (ECBM) recovery.

Reporting: For *Atlas II*, CO₂ 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, while the other RCSP provided the needed data in their portion of the basin.

Screening Criteria:

Depths: The vertical intervals included are between a minimum and maximum depth. The minimum depth was dictated by a water-quality standard to ensure that potentially potable water-bearing coals are not included; only coal seams with a water TDS concentration of 10,000 ppm and higher can be included. Where water quality data are scarce or unavailable, analogy to other basins was used to estimate the minimum depth criteria.

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 CO₂. 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 CO₂ resource estimate. If such data are available, any coal reserve is also excluded.

Computing CO₂ Resource: Carbon dioxide resource estimates for coal use 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) CO₂ 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 CO₂ isotherm is available, isotherms from similar coal ranks in analog basins are used. No accounting for decreasing CO₂ storage potential at increasing temperatures (depths) is taken.

The volumetric equation with consistent units applied for coal CO₂ storage potential follows:

$$G_{CO_2} = A h_g C \rho_s E$$

Parameter	Units [*]	Description
G_{CO_2}	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.

**For details on E, please refer to Appendix 5.

The CO₂ storage efficiency factor has several components that reflect different physical barriers that inhibit CO₂ from contacting 100 percent of the coal bulk volume of a given basin or region. Depending on the definitions of area, thickness, and CO₂ concentration (from Langmuir isotherms), the CO₂ 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. (Additional information on E for coal seams appears in Appendix 5.)

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Appendices

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Appendix 1: Storage Development Scenarios Affecting CO₂ Storage Estimates – by Scott Frailey

For a given CO₂ storage resource estimate for a specific site, different development scenarios affect the estimate of CO₂ storage capacity. Wellbore type, transportation, and injection pressure are just a few examples of different site considerations that may increase or decrease the CO₂ storage capacity of a geologic formation.

Wellbore Type

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 CO₂ 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 CO₂ storage capacity compared to a vertical well. Similarly, a geologic formation with vertical flow barriers is more likely to have relatively higher CO₂ 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 CO₂ 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).

Transportation of CO₂

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 CO₂ 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 CO₂ 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 CO₂ 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 breach 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 CO₂ capacity estimates. However, this pressure constraint can be managed during the planning and operation stages of development and should not influence the CO₂ resource estimate. A storage site with limited injection and/or pore pressure may reduce the CO₂ capacity, but due to the 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 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 or application of new technology to existing wells can change resource and capacity estimates.

Appendix 2: Injectivity, Regulations, and Economics for CO₂ Storage Estimates - by Scott Frailey

Atlas II's assessment is intended to identify the geographical distribution of CO₂ 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 CO₂ 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 CO₂ capacity assessments:

Injectivity

The daily or annual rate of CO₂ 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 CO₂ resource. However, a geologic formation with low injectivity that provides a CO₂ injection rate greater than zero does provide the opportunity to store CO₂ and is considered a CO₂ resource.

For selecting and designing specific storage sites, a minimum acceptable injection rate for a well is required to meet the capture rate of CO₂ 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 CO₂ resource of at least 30 million tons. This industrial plant would likely have a budget (or economic limits) for capturing and storing CO₂ on a per-ton basis (e.g., \$15/ton). One of the next steps is to establish the most affordable means of injecting CO₂ that does not exceed the \$15/ton economic limit. One single well that could inject at least 1 million tons per year might 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 CO₂ 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 will be 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.

Regulations

The use of any resource is governed by regulations; CO₂ 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 CO₂ 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, possibly transitioning the same geologic unit from uneconomical to economical for this industrial site.

Economics

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 CO₂ resource assessment. In addition to project economic considerations, every company storing CO₂ 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 CO₂ 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 CO₂ storage as one of their business units.

Regardless of how the storage industry evolves, the assessment of CO₂ 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.

Land usage clearly impacts capacity. An example is lack of access to some lands such as national parks and wilderness areas, or restricted access to military facilities. Another example is a large holding of unwilling landowners.

Appendix 3: Static and Dynamic Methods for Estimating CO₂ Storage - by Scott Frailey

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.

Volumetric

The volumetric method is the basis for CO₂ 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 CO₂.

Compressibility

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 CO₂ 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_{wo}) due to an increase in pressure (p) above the initial pressure (p_o). The compressed volume (ΔV_w or G_{co2}) is the volume that CO₂ 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 area (A), thickness (h), and porosity (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 CO₂ 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.

Decline Curve Analyses

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 CO₂ 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.

Material Balance

The compressibility formula is a special case of the material balance equation. The complete material balance equation includes the cumulative CO₂ injection and the corresponding pore pressure (p) at various times. Fluid properties that

reflect CO₂ 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 CO₂ injection ($G_{inj-co2}$) versus p/z where z is the z-factor of CO₂ evaluated at pressure p.

Reservoir Simulation

Numerical modeling of geologic units that include 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 CO₂ 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 - by Scott Frailey

Efficiency is the multiplicative combination of volumetric parameters that reflect the portion of a basin's or region's total pore volume that CO₂ is expected to actually contact. The CO₂ storage efficiency factor for saline formations has several components that reflect different physical barriers that inhibit CO₂ from contacting 100 percent of the pore volume of a given basin or region. Depending on the definitions of area, thickness, and porosity, the CO₂ 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 CO₂ resource equation, efficiency must include terms that adjust gross thickness to net thickness and total porosity to effective porosity (see definitions in table below).

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 CO₂ 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 equation was used to estimate the CO₂ storage efficiency factor (E) for saline formations:

$$E_{\text{saline}} = (A_n/A_t) (h_n/h_g) (\phi_e/\phi_{\text{tot}}) E_A E_l E_g E_d$$

The following terms are included in the CO₂ 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_I (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 P₅₀ case seems less sensitive to choice of distribution. P₁₅ and P₈₅ 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 P₅₀ E of approximately 1.8 to 2.2 percent.

Case	Parameter	Range	Distribution	P ₁₅	P ₅₀	P ₈₅	Comment
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Case	Parameter	Range	Distribution	P ₁₅	P ₅₀	P ₈₅	Comment
Base-uniform	A_n/A_t	0.2–0.8	Uniform	1.6	2.7	4.2	
	h_n/h_g	0.25–0.75	Uniform				
	ϕ_e/ϕ_{tot}	0.6–0.95	Uniform				
	E_A	0.5–0.8	Uniform				
	E_l	0.6–0.9	Uniform				
	E_g	0.2–0.6	Uniform				
	E_d	0.5–0.8	Uniform				
Base-normal with variance 1.0 max-min difference	A_n/A_t	0.2–0.8	Normal	0.44	1.8	4.1	Median given as midpoint of range; variance given as max less median (broad flat normal distribution).
	h_n/h_g	0.25–0.75	Normal				
	ϕ_e/ϕ_{tot}	0.6–0.95	Normal				
	E_A	0.5–0.8	Normal				
	E_l	0.6–0.9	Normal				
	E_g	0.2–0.6	Normal				
	E_d	0.5–0.8	Normal				
Base-normal with variance ½ max-min difference	A_n/A_t	0.2–0.8	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).
	h_n/h_g	0.25–0.75	Normal				
	ϕ_e/ϕ_{tot}	0.6–0.95	Normal				
	E_A	0.5–0.8	Normal				
	E_l	0.6–0.9	Normal				
	E_g	0.2–0.6	Normal				
	E_d	0.5–0.8	Normal				
Base-normal with variance 2.0 max-min difference	A_n/A_t	0.2–0.8	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.
	h_n/h_g	0.25–0.75	Normal				
	ϕ_e/ϕ_{tot}	0.6–0.95	Normal				
	E_A	0.5–0.8	Normal				
	E_l	0.6–0.9	Normal				
	E_g	0.2–0.6	Normal				
	E_d	0.5–0.8	Normal				

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	0.2–0.8	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.
	h_n/h_g	0.25–0.75	Normal				
	ϕ_e/ϕ_{tot}	0.6–0.95	Normal				
	E_A	0.5–0.8	Normal				
	E_l	0.6–0.9	Normal				
	E_d	0.5–0.8	Normal				
Base-mixed distribution	A_n/A_t	0.2–0.8	Uniform	0.65	1.9	4.4	Change in distribution based on possible petrophysical distribution.
	h_n/h_g	0.25–0.75	Normal				
	ϕ_e/ϕ_{tot}	0.6–0.95	Uniform				
	E_A	0.5–0.8	Normal				
	E_l	0.6–0.9	Log				
	E_d	0.5–0.8	Normal				

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 - by Scott Frailey

Efficiency is the multiplicative combination of volumetric parameters that reflect the portion of a basin’s or region’s coal bulk volume that CO₂ 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 CO₂ 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 CO₂ swelling will most likely have a "correcting" mechanism, which reduces the velocity of CO₂ as the coal swells and redirects CO₂ 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 equation was used to estimate the CO₂ storage efficiency factor (E) for coal seams:

$$E_{\text{coal}} = (A_n/A_t) (h_n/h_g) E_A E_l E_g E_d$$

The following terms are included in the CO₂ 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 CO₂ 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_v (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 P₅₀ case seems less sensitive to choice of distribution. P₁₅ and P₈₅ 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 P₅₀ E of 33 percent.

Case	Parameter	Range	Distribution	P ₁₅	P ₅₀	P ₈₅	Comment
Base-uniform	A_n/A_t	0.6–0.8	Uniform	28	33	40	
	h_n/h_g	0.75–0.90	Uniform				
	E_A	0.7–0.95	Uniform				
	E_l	0.8–0.95	Uniform				
	E_g	0.9–1.0	Uniform				
	E_d	0.75–0.95	Uniform				
Base-normal with variance 1.0 max-min difference	A_n/A_t	0.6–0.8	Normal	25	33	43	Median given as midpoint of range; variance given as max less median (broad flat normal distribution).
	h_n/h_g	0.75–0.90	Normal				
	E_A	0.7–0.95	Normal				
	E_l	0.8–0.95	Normal				
	E_g	0.9–1.0	Normal				
	E_d	0.75–0.95	Normal				
Base-normal with variance ½ max-min difference	A_n/A_t	0.6–0.8	Normal	29	33	38	Median given as midpoint of range; variance given as one-half max less median (narrow, spike normal distribution).
	h_n/h_g	0.75–0.90	Normal				
	E_A	0.7–0.95	Normal				
	E_l	0.8–0.95	Normal				
	E_g	0.9–1.0	Normal				
	E_d	0.75–0.95	Normal				
Base-normal with variance 2.0 max-min difference	A_n/A_t	0.6–0.8	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.
	h_n/h_g	0.75–0.90	Normal				
	E_A	0.7–0.95	Normal				
	E_l	0.8–0.95	Normal				
	E_g	0.9–1.0	Normal				
	E_d	0.75–0.95	Normal				

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	0.6–0.8	Normal				Median given as midpoint of range; variance given as max less median (broad flat normal distribution); minimum equals low of range.
	h_n/h_g	0.75–0.90	Normal				
	E_A	0.7–0.95	Normal	32	39	49	
	E_l	0.8–0.95	Normal				
	E_g	0.9–1.0	Normal				
	E_d	0.75–0.95	Normal				

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 CO₂ Dissolution in Saline and Free Phase CO₂ - by Scott Frailey

Because some RCSPs used dissolution of CO₂ in water and other RCSPs used free-phase CO₂ to estimate their respective basins'/regions' storage resource, the total storage efficiency (E) derived for use in one technique is not equivalent or applicable to the other.

The dominant mechanism of CO₂ storage may change from storage of an immiscible free-phase to CO₂ dissolved in water over time, causing the proportion of dissolved CO₂ to a basin's/region's pore volume to be larger than the proportion contacted by free phase CO₂. Several RCSPs focused on dissolved storage for capacity calculation. To avoid any RCSPs repeating a rigorous calculation of capacity with new methodology, a method of converting E for free-phase CO₂ to the equivalent E for dissolved CO₂ 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 permillion (ppm) water. The density of CO₂ is 48.55 pound mass per cubic foot (lbm/ft³), 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 CO₂ 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 ft³ of pore volume, the 48.55 lbm of free-phase CO₂ occupies 1 ft³ of pore space.

For dissolution of CO₂ into water, 1 ft³ of pore space is occupied by water; 118 scf of CO₂ 100% saturates a stb of 100,000 ppm water at 140 °F and 3500 psia. Converting to lbm/ft³

$$\left(\frac{118 \text{ scf} - \text{CO}_2}{\text{stb} - \text{water}} \right) \left(\frac{1 \text{ bbl}}{5.615 \text{ ft}^3} \right) \left(\frac{1 \text{ ton} - \text{CO}_2}{17,140 \text{ scf} - \text{CO}_2} \right) \left(\frac{2000 \text{ lbm}}{\text{ton}} \right) = \frac{2.452 \text{ lbm} - \text{CO}_2}{\text{ft}^3 - \text{pore volume}}$$

There is a slight difference, usually less than 1 percent, 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 ft³ of water volume due to dissolution of CO₂ 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 CO₂ is 2 percent, the equivalent E for dissolution is 2×19.8 , or 39.6 percent. Interestingly if the E-free phase was 5%, the equivalent E-dissolution for this example is 99 percent. So at the assumed salinity, if 5 percent of a basin's pore volume is free-phase CO₂, the equivalent mass distributed via dissolution in water would require 99 percent 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.