Quarterly Technical Report

Reactive Multiphase behavior of CO₂ in Saline Aquifers beneath the Colorado Plateau

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ABSTRACT

The six coal-fired power plants located in the Colorado Plateau and southern Rocky Mountain region of the U.S. produce 100 million tons of CO₂ per year. Thick sequences of collocated sedimentary rocks represent potential sites for sequestration of the CO₂. Field and laboratory investigations of naturally occurring CO₂-reservoirs are being conducted to determine the characteristics of potential seal and reservoir units and the extent of the interactions that occur between the host rocks and the CO₂ charged fluids. The results are being incorporated into a series of two-dimensional numerical models that represent the major chemical and physical processes induced by injection.

During reporting period covered here (March 30 to June 30, 2003), the main achievements were:

- Presentation of three papers at the Second Annual Conference on Carbon Sequestration (May 5-8, Alexandria, Virginia)
- Presentation of a poster at the American Association of Petroleum Geologists meeting (Salt Lake City, Utah; see bullet below)
- Co-PI organized and chaired a special session on Geologic Carbon Dioxide Sequestration at the American Association of Petroleum Geologists annual convention in Salt Lake City (May 12-15)

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EXECUTIVE SUMMARY

Three papers were presented at the Second Annual Conference On Carbon Sequestration, held in Alexandria VA on May 5-9. One paper describes the potential for CO₂ sequestration beneath the Colorado Plateau and Southern Rocky Mountain Region. This region contains six major power plants that generate 13000 MW of electricity and produce 100 million tons of CO₂ per year. Thick sequences of co-located sedimentary rocks represent potential sites for the produced CO₂. The characteristics and distributions of potential reservoir and seal units are discussed. The second paper describes the geology, hydrology, geochemistry, and extent of water-rock interactions occurring in the natural CO₂ at Springerville-St. Johns, Arizona. Evidence of interactions between naturally occurring CO₂-charged fluids and the reservoir rocks is presented. The third paper presents a two-dimensional numerical model describing the mobility of CO₂ during injection into an unconfined aquifer that is not domed shape. The major physical and chemical processes induced by injection are represented by the model. The model predicts that at least 70% of the injected CO₂ will be permanently sequestered.

EXPERIMENTAL

Not applicable

RESULTS AND DISCUSSION

The papers presented at the Second Annual Conference on Carbon Sequestration (May 5-8, Alexandria, Virginia) are reproduced sequentially in this section of the report. All three papers will appear in the Conference Proceedings, and

Investigations of CO₂ Mobility in Natural Reservoirs Beneath the Colorado Plateau and Southern Rocky Mountains

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CO₂ Injection Potential Beneath Large Power Plants in the Colorado Plateau-Southern Rocky Mountain Region, USA.

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Injection of CO₂ into an Unconfined Aquifer Located Beneath the Colorado Plateau, Central Utah, USA.

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CO₂ sequestration potential beneath large power plants in the Colorado Plateau-Southern Rocky Mountain region, USA.

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Abstract

Six coal-fired power plant sites in the Colorado Plateau-Southern Rocky Mountains region generate close to 13,000 MW of electricity and represent point sources for 100 million tons of CO₂ per year. The geologic settings of these sites are investigated for potential sequestration of CO₂ separated from flue gas. Five of the sites are located on thick (~ 3 km) sedimentary sequences with simple, near-horizontal, layer-cake stratigraphy and few faults. Multiple potential reservoir and overlying seal units exist at these five sites. Because of the broad, low-amplitude structures, large storage potential exists. Nearby oil and gas fields offer both opportunities for enhanced recovery and challenges from unwanted invasion of migrating CO₂.

Introduction

The sedimentary basins of the Colorado Plateau and Southern Rocky Mountains region contain large resources of natural gas, oil and coal. Some of the coal is used locally to generate electricity, and these power plants dominate the point sources of CO₂ in the region (Fig. 1). The six largest power plant sites are the basis of this study (Table 1). Two sites (Hunter/Huntington and Four Corners/San Juan) have two power plants in close proximity and are treated as one site. The six power plant sites generate 13,000 MW of electricity and emit 100 million tons/year of CO₂. Natural CO₂ fields in the same region produce close to 30 million tons/year of CO₂ (Fig. 1). Most of this is piped to enhanced oil recovery projects in West Texas (Permian Basin), Rangely oil field (Piceance Basin, Colorado), and Lost Soldier-Wertz oil field (Southern Wyoming). At the moment, 4 million tons/year of CO₂ is vented from the La Barge CO₂ field in southwest Wyoming, but a proposed pipeline extension into the Powder River Basin (northeast Wyoming) for enhanced oil recovery is expected to use most of this surplus production.

This study investigates the possibilities and issues associated with geologic sequestration of CO₂ near the largest power plant sites, assuming the CO₂ can be separated from the flue gas. At least two of these are close to existing CO₂ pipelines, so alternative scenarios such as using the CO₂ for other sequestration projects remote from the site are possible. The Jim Bridger plant is 25 km from the southern Wyoming pipeline, and the Four Corners/San Juan plants are 30 - 40 km from the McElmo Dome – West Texas pipeline. This paper reviews only subsurface sequestration possibilities close to the plant (e.g. < 10 km).

The geological section beneath each power plant site is examined for the presence of high permeability formations (“reservoirs”) potentially capable of receiving large volumes of CO₂, the adequacy of overlying, low permeability units (“seals”) that will prevent vertical migration of the CO₂ plume, and the structural trends which will influence lateral plume migration directions. The presence of major faults that could be leakage zones will be noted, as will the existence of nearby oil and gas reservoirs or coal seams. CO₂ can be used for enhanced oil recovery, enhanced gas recovery through pressure support, enhanced coal bed gas recovery, or could also be considered an undesirable diluent of a gas reservoir.

Although saline aquifers are relatively common at 2 – 3 km depth beneath this region (Freethy and Cordy, 1991, Allis et al., 2001), water quality issues may be important where minimum injection depths are

considered. Because of the likelihood of injection pressures of at least 80 bar (8 MPa, 1160 psi) to keep the CO₂ as a relatively dense, supercritical fluid (700 kg/m³) for efficient transport, injection pressure safety margins mean that the depth will have to be at least 1 km. The injection depth is unlikely to be greater than 2 km depth because of the economic implications for added wellhead pressure needed for injection, and the additional well drilling costs. Migration of injected CO₂ to much shallower depths would raise serious environmental issues from both a safety perspective and if potable aquifers are present. In this paper we focus on the geological characteristics in the likely injection depth window of 1 – 2 km, close to these six power plant sites.

The following section of the paper is divided according to power plant. Each power plant is reviewed under the headings Geologic Setting, Opportunities for CO₂ Sequestration, and Potential Problems or Issues Needing Study. A bulleted format is used for the sake of brevity. In each case the material represents an overview of the main characteristics of the site, and it is designed to be a starting point if geologic sequestration of flue gas CO₂ considered for a particular plant site. In such cases a more thorough geologic investigation is recommended.

Power Plant Name	Approx. Capacity (MW)	2001 Generation (million MW-h)	2001- 02 Coal Consumption (mill. tons/y)	2001 CO₂ Emissions (mill. tons/y)
Hunter/Huntington (Utah)	2000	14.5	6.7	14.7
Intermountain Power Project (Utah)	1500	13.4	5.4	15.2
Jim Bridger (Wyoming)	2034	15.3	8.5	18.5
Navajo (Arizona)	2400	17.4	8.1	19.7
Four Corners/San Juan (New Mexico)	3650	26.8	15	31.0
Craig (Colorado)	1200	9.4	4.8	10.7

Table 1. Generation and emission characteristics for the six power plant sites considered in this paper. The sites are located on Figure 1.

Hunter/Huntington site

Two power plants, Hunter (1200 MW capacity) and Huntington (800 MW) are located about 15 km apart in Emery County, central Utah (Fig. 2a). Both are operated by PacifiCorp (Scottish Power). The power plants are adjacent to the eastern margin of the Wasatch Plateau and the western periphery of the San Rafael Swell. This geologic structure has been used for numerical simulation of the reactive fate of injected CO₂ (White et al., 2003).

Geological Setting (Fig 2b)

- The San Rafael Swell is a major physiographic feature in east-central Utah. It represents a broad, basement-involved, asymmetrical anticline that trends north-northeast to south-southwest. The San Rafael Swell is one of numerous Laramide-age (middle to late Paleocene to early Oligocene) uplifts on the Colorado Plateau. The west flank is a gently dipping cuesta while the east flank is steeply dipping to near vertical in some locations. There are numerous subsidiary structures along the San Rafael Swell. Many of these structures have been drilled for and produced oil and gas including CO₂. Examples are Farnham dome, Woodside dome, Last Chance anticline, Salt Wash anticline, and

Ferron anticline. Rocks exposed on the uplift include the Cretaceous Mancos through Permian Pakoon Dolomite. The region also includes extensive Tertiary sandstone and Quaternary surficial deposits. Tertiary dikes and sills cut the sedimentary rocks in the southwest corner of the Swell. Minor high-angle, generally east-west-trending, normal faults are also mapped on the crest of the structure; extensive fracturing and joints are present in the White Rim Sandstone and other sandstone formations.

- Over 3,600 m of sedimentary rock ranging in age from Cretaceous to Cambrian including marine, fluvial, eolian, and continental deposits are in the San Rafael Swell. Precambrian granite and schist underlie the basal Cambrian Tintic Quartzite.
- **Potential reservoirs:** (1) **Jurassic Navajo Sandstone** is 137 to 183 m thick, and is a classic example of an eolian deposit containing large-scale cross-beds, frosted quartz grains, and other diagnostic sedimentary eolian features. The Navajo generally has excellent porosity and permeability. It has produced CO₂ at Farnham Dome on the north plunging nose of the San Rafael uplift. (2) **Jurassic Wingate Sandstone** is 91 to 122 m thick in the uplift and relatively homogeneous. It was also deposited in an eolian environment and although little petrophysical work is available, it likely has good porosity and permeability. (3) **Permian White Rim Sandstone** is 61 to 244 m thick, and contains cross-beds in clean, fine-grained sandstone. The eolian White Rim may be the best candidate for CO₂ injection. It has excellent porosity and permeability, and is the main CO₂ reservoir at Gordon Creek field. (4) **Mississippian Redwall Limestone** is 183 to 305 m thick, and was deposited in a shallow marine environment. The Redwall is the deepest candidate for CO₂ injection and is not exposed in the San Rafael Swell. It has moderate porosity and permeability, and is a major producer of oil and gas in structural traps (faulted anticlines) to the southeast in the Paradox Basin. It has also tested significant flow rates of CO₂ from several wells in the basin though never produced. The Redwall in the San Rafael uplift likely has a fair amount of heterogeneity due to changes in depositional facies and carbonate diagenetic effects.
- **Potential shale seals:** (1) **Cretaceous Mancos Shale** is greater than 700 m in thickness, consisting mostly of marine shales deposited in the Cretaceous Interior Seaway. It is divided into several members (Blue Gate Shale, Ferron Sandstone, Tununk Shale) and is exposed on the periphery of the San Rafael Swell forming strike valleys. (2) **Triassic Chinle Formation** is 100 m thick, consisting mostly of varicolored, bentonitic, and non-resistant mudstone and claystone with some locally interbedded resistant channel sandstone. The Chinle Formation was deposited under continental conditions by streams and in lakes. (3) **Triassic Moenkopi Formation** is 288 m thick, consisting mostly of siltstone, sandstone, and mudstone. However, the Sinbad Limestone Member of the Moenkopi has tested significant amounts of CO₂ at the Gordon Creek field to the northwest of the Swell. It is not considered a candidate because it is relatively thin, 15 to 46 m, with low permeability and porosity. What permeability and porosity are present in the Sinbad is the result of fracturing. The Moenkopi was deposited on a broad continental plain that was periodically flooded by an ocean during Early Triassic time. (4) **Permian Black Box Dolomite** ranges in thickness from 0 to 61 m in thickness, and was deposited in a shallow sea. Flow paths would likely be along major fracture or joint systems and minor high angle normal faults present in the region. (5) **Devonian Elbert Formation** is about 100 m thick, and contains dolomite and shale deposited in environments ranging from shallow marine/intertidal to delta front. (6) **Cambrian Ophir Formation** is about 60 m thick, consisting of mainly shale with a few limestone units. The Ophir was deposited in the deeper water environments of the Middle Cambrian epi-continental sea.
- **Potential evaporite seals:** (1) **Jurassic Carmel Formation** is 73 to 91 m thick and consists of marine shale, limestone and anhydrite beds unconformably overlying Navajo Sandstone. (2) **Pennsylvanian Honaker Trail/Paradox Formations** are 30 to 152 m and 91 to 305 m thick, respectively, composed of marine shale and anhydrite deposited in a restricted shallow sea of the Paradox Basin.

Opportunities for CO₂ Sequestration

- + Numerous thick shale and anhydrite deposits provide excellent seals.

- + Thick sandstone and carbonate deposits with good porosity provide excellent reservoir potential.
- + The San Rafael Swell represents a huge area for potential storage and includes numerous subsidiary structures that have both reservoirs and seals as well.
- + Injection targets are relatively shallow in the vicinity of the power plants (about 2,000 meters to the Redwall Limestone).
- + Fractures and jointing in sandstone-dominated formations appear not to continue into overlying shales (seals).

Potential Problems or Issues Needing Study

- The potential reservoirs in the Navajo, Wingate, and White Rim Sandstones are exposed and deeply incised by canyons on the flanks or crest of the San Rafael Swell. If the CO₂ plume moves quickly to the east from the injection points at the power plants, leakage to atmosphere may occur.
- Flow paths would likely be along major fracture or joint systems. Minor high angle normal faults present in the region may contribute to CO₂ leakage.
- The presence of tufa deposits east of the region (Doelling, 1994; Shipton et al., 2003) suggests surface leakage of CO₂-rich deep basin fluids has occurred.
- Constructing CO₂ pipelines to subsidiary structures would involve distances of tens of kilometers and significant financial investments.
- The Redwall Limestone may potentially already contain significant quantities of CO₂, hence storage capacity is uncertain.

Navajo Power Plant site

This 2400 MW coal-fired plant is located near to Page, near the Arizona-Utah state line (Coconino County and Navajo Nation (Fig. 3a). It is operated by the Salt River Project Ag. I & P District and is the largest coal-fired power plant in the study region. The following references have been used to assist the geologic setting discussion: Chidsey (1997), Chidsey et al. (1998), Doelling (1997), Hintze (1993), Utah Geological Survey (1998), Wilson and Moore (1969).

Geological Setting (Fig. 3b)

- Boundary between the Monument upwarp and the Kaiparowits basin, both Laramide features. Gentle north- to northwest-trending anticlines and synclines, secondary folds of the Kaiparowits basin extend into the area and are recognized best along Lake Powell where the lake surface serves as a perfect datum. The folds developed over deep faults in Precambrian basement rocks. Jurassic strata are the oldest rocks exposed on the crests of anticlines. Dips on the flanks of the structures are up to 7°, and plunge is generally to the north. These folds are tens of kilometers in length and many have been targets for petroleum exploration. A few minor normal faults developed parallel to the axes of some of the structures. These faults are typically high angle, down to the west, and have less than 30 meters of displacement.
- Over 4,000 m of sedimentary rock ranging in age from Cretaceous to Cambrian including marine, fluvial, eolian, and continental deposits in the Glen Canyon National Recreation Area and Navajo Nation, Utah and Arizona.
- Potential reservoirs: (1) **Permian Cedar Mesa Sandstone** is 350 m thick, and contains large-scale cross-beds, frosted quartz grains, and other sedimentary features that are typical of eolian deposits. However, the Cedar Mesa also contains some horizontal bedding and algal limestone and gypsum beds that suggest deposition in a sabkha. Thus, the Cedar Mesa Sandstone was deposited in eolian to coastal environment. Porosity ranges from 12 to 16 % (permeability is unknown), and includes intergranular and fracture porosity. The Cedar Mesa tested 96.1 to 93.1% CO₂ in 1983, from the

Mid-Continent Oil and Gas Reserves, Inc. Charger No. 1 well (section 29, T. 32 S. R. 3 E., SLBL&M) 130 kilometers to the northwest on the Escalante anticline. The well test had a total open flow gauged at 3.5 million cubic meters (124 million cubic feet [mmcf]) of gas per day from a net productive Permian and Triassic section of 600 m. (2) **Mississippian Redwall Limestone** is about 200 m thick, and was deposited in a shallow marine environment. Variations in depositional facies and carbonate diagenetic effects likely result in significant reservoir heterogeneity. It is cavernous where exposed in the Grand Canyon. The Redwall has produced oil in the Upper Valley field to the northwest (the only oil field in the Kaiparowits Basin) and tested CO₂ in the southern Paradox Basin to the east. (3) **Cambrian Tapeats Sandstone** is about 100 m thick, and contains fine- to coarse-grained dolomitic and glauconitic sandstone. These sands were deposited initially in a braided stream setting. Later widespread progradation of the sea resulted in shallow marine to shoreface deposition of blanket sands over the underlying coastal plain. Porosity ranges from 7 to 13 % (permeability is unknown), primary intergranular and some solution-enhanced porosity. The Tapeats tested 98 percent CO₂ in 1994 from the BHP Petroleum No. 28-1 well (section 28, T. 33 S. R. 7 E., SLBL&M) 120 km to the north on the giant Circle Cliffs anticline. The drill-stem test had a flow gauged at 141,600 cubic meters (5 mmcf) of gas per day.

- Potential seals: (1) **Triassic Chinle Formation** is 242 m thick, consisting mostly of varicolored, bentonitic and non-resistant mudstone and claystone with some locally interbedded resistant channel sandstone. The Chinle Formation was deposited under continental conditions by streams and in lakes. (2) **Triassic Moenkopi Formation** is 76 m thick, consisting mostly of siltstone, sandstone, and mudstone. The Moenkopi was deposited on a broad continental plain that was periodically flooded by an ocean during Early Triassic time. (3) **Permian Organ Rock Formation** is about 140 m thick, consisting of siltstone, sandstone, and shale. The Organ Rock was deposited in a marginal to shallow marine environment on the edge of a large coastal dune field. (4) **Cambrian Bright Angel Shale** is about 200 m thick, consisting of shale with a few siltstone and limestone units. The Bright Angel was deposited in the deeper water environments of the Middle Cambrian epi-continental sea.
- Carbon dioxide is present in many large anticlines to the north and northwest (Circle Cliffs, Escalante, Upper Valley, and Reese Canyon). The thick sections of Paleozoic carbonate rocks in the region (Cambrian Muav Limestone, Mississippian Redwall Limestone, and Permian Kaibab Limestone) are the probable CO₂ source rocks. One explanation is metamorphism of these marine carbonates by the heat of nearby igneous intrusive rocks including the laccoliths that form Navajo Mountain and the Henry Mountains to the north, and those associated with the volcanic flows of the High Plateaus to the northwest likely generated CO₂. This would require the CO₂ to be trapped for about 30 million years. An alternative explanation is that the CO₂ is more recent and is a product of prograde metamorphism in the lower crust, perhaps related to the uplift of the Colorado Plateau. This implies the CO₂ source to be regional in extent.

Opportunities for CO₂ Sequestration

- + Thick shale deposits provide excellent seals with few mapped faults and no tufa deposits identified
- + Thick sandstone and carbonate deposits with good porosity provide excellent reservoir potential
- + Injection targets are relatively shallow (about 1,500 m to the Cedar Mesa Sandstone; 2400 m to Redwall Limestone, and > 3,000 m to the Tapeats Sandstone)
- + Several large (tens of km), subtle, elongate structures in close proximity to the power plant; some have four-way closure, and storage potential could be large

Potential Problems or Issues Needing Study

- Structures potentially already contain significant quantities of CO₂, hence storage capacity is uncertain; none of the nearby structures has been targets of exploratory drilling
- CO₂ injection pipeline may have to cross lands belonging to the Navajo Nation requiring special permits and significant right-of-way fees

- CO₂ may be injected into rocks that underlie the Glen Canyon National Recreation Area raising environmental concerns

Four Corners/San Juan Power Plant site

Two coal-fired power plants are 15 km apart near Farmington, San Juan County, Arizona (Fig. 4a). The Four Corners plant has 2000 MW capacity (operated by Arizona Public Service Company), and the San Juan plant has a capacity of 1650 MW (operated by Public Service Company of New Mexico). The combined CO₂ emissions from these plants is 15 million tons/year – similar to the capacity of the McElmo Dome to West Texas CO₂ pipeline 35 km to the east. The following references have been used to assist the geologic setting discussion: Fassett (1978, 1983), Molenaar (1977), Ward (1990), Whitehead (1993a, b, c), Woodward and Callender (1977).

Geological Setting (Figs. 4b)

- The Four Corners area of northwest New Mexico consists of the Laramide-age (middle to late Paleocene to early Oligocene) San Juan structural basin and the Four Corners platform. The boundary between the Four Corners platform and the San Juan Basin is defined by a prominent monoclinical feature called “The Hogback” where the Cretaceous Cliff House Sandstone dips gently southeast into the basin. The San Juan Basin and Four Corners platform includes part of southwestern Colorado.

The San Juan Basin is a major producer of gas in the United States with cumulative production over 17 trillion cubic feet (TCF) of gas from over 21,000 wells. Gas is produced primarily from: (1) a giant basin-centered stratigraphic trap; (2) fluvial, deltaic, and shallow-marine sandstones in stratigraphic traps; and (3) minor structural traps. Major reservoirs are the Fruitland Formation, Pictured Cliff Sandstone, Point Lookout Sandstone, Cliff House Sandstone, Mancos Shale, and Dakota Sandstone; all are Cretaceous in age. Unconventional gas production includes fractured tight sands in the Mancos and coalbed methane in the Fruitland.

Rocks deposited in the Pennsylvanian-age Paradox Basin extend from Utah, Colorado, and Arizona into the Four Corners platform. Both oil and gas are produced from carbonate-buildup-type (phylloid-algal mounds) reservoirs in the Alkali Gultch and Barker Creek zones of the Pennsylvanian Paradox Formation. Unlike the fields in the San Juan Basin, hydrocarbons on the Four Corners platform are trapped in both structural (anticlines) and stratigraphic traps. The axes of these anticlines strike parallel with the northeast trend of the Four Corners platform and The Hogback monocline. These structures formed at the same time as the San Juan Basin.

Rocks exposed on the surface of the region include the Cretaceous Mancos through Kirkland Shales. The Fruitland Formation outcrops just east of The Hogback where its coal beds are extensively mined in open pits to supply coal to the nearby Four Corners and San Juan power plants. The region also includes extensive Tertiary sandstone and Quaternary surficial deposits. Pliocene basaltic dikes and volcanic necks, including the famous landmark “Ship Rock,” are exposed locally in the western part of the region on the Four Corners platform. Minor high-angle normal faults are also mapped on the surface in the Four Corners platform area.

- Over 4,500 m of sedimentary rock ranging in age from Cretaceous to Cambrian including marine, fluvial, deltaic, eolian and continental deposits in the San Juan Basin and Four Corners platform, New Mexico and Colorado.
- Potential **coal** reservoirs: (1) **Cretaceous Fruitland Formation** is 80 to 120 meters thick and contains shale, cross-bedded sandstone, and coal deposited in coastal swamps. It is the largest producer of coalbed methane in the United States (over 1,000 wells from three coal zones) with proved and undeveloped reserves of over 10 TCF of gas. (2) **Cretaceous Menefee Formation** is 250 to 300 m thick and contains fine- to coarse-grained sandstone, shale, and coal deposited in coastal swamps. It may contain between 22 and 34 TCF of coalbed methane.

- Potential **sandstone** reservoirs: (1) **Devonian McCracken Sandstone Member** of the Elbert Formation is less than 75 m thick and is present in the subsurface only in the Four Corners platform area. It consists of fine-grained dolomitic sandstone deposited in environments ranging from intertidal to delta front. (2) **Permian Cutler Sandstone** is 120 to 600 m thick and contains coarse arkosic sandstones that were shed off the Uncompahgre Highlands to the north-northwest. (3) **Jurassic Wingate and Entrada Sandstones** are as much as 270 m thick and contain fine- to medium-grained cross-bedded sandstone. These sands were deposited initially in an eolian setting. (4) **Cretaceous Dakota Sandstone** is 50 to 70 m thick, and contains sandstone, conglomeratic sandstone, shale and lenses of coal. These rocks were deposited in fluvial, deltaic and shallow-marine shoreline environments.
- Potential **shale** seals: (1) **Triassic Chinle Formation** is 200 to 450 m thick, consisting mostly of varicolored, bentonitic, and non-resistant mudstone and claystone with some locally interbedded resistant channel sandstone. The Chinle Formation was deposited under continental conditions by streams and in lakes. (2) **Cretaceous Mancos Shale** is greater than 600 meters in thickness, consisting mostly of marine shales deposited in the Cretaceous Interior Seaway. It is divided into to upper and lower parts separated by the Gallup Sandstone. (3) **Cretaceous Lewis Shale** is about 150 m thick, but locally it is as thick as 440 m and consists of marine shale with some limestone and sandstone beds deposited in the Cretaceous Interior Seaway. (4) **Cretaceous Kirkland Shale** is about 450 m thick and is divided into three members each being exposed on the surface. They consist of carbonaceous shale and fluvial sandstone.
- Potential **evaporite** seals: **Pennsylvanian Paradox Formation** within the Hermosa Group is about 300 m thick and is present in the subsurface only in the Four Corners platform area. It contains cyclic beds of penesaline and hypersaline anhydrite and halite deposited in the restricted shallow sea of the Paradox Basin.
- Carbon dioxide and other low-BTU gases are present in Pennsylvanian and Mississippian rocks of anticlines on the Four Corners platform (Tocito Dome, Ute Dome, and Hogback fields, for example). The thick sections of Paleozoic carbonate rocks in the region (Devonian Ouray Limestone, Mississippian Leadville Limestone, and Honaker Trail Formation) are the probable CO₂ source rocks. Metamorphism of these marine carbonates by the heat of nearby igneous intrusive rocks (including the laccoliths that form Sleeping Ute Mountain in southwestern most Colorado, the Carrizo Mountains in extreme northeastern Arizona, and Ship Rock on the Four Corners platform of New Mexico) generated CO₂. Alternatively, the CO₂ could be more recent and associated with lower crustal metamorphism as discussed earlier.

Opportunities for CO₂ Sequestration

- + Numerous unmineable coal seams provide an excellent location for CO₂ sequestration and enhancing coalbed methane production
- + Thick sandstone deposits with good porosity provide excellent reservoir potential
- + Thick shale, anhydrite and halite deposits provide excellent seals with few faults
- + Injection targets are relatively shallow
- + A CO₂ pipeline lies about 35 km to the east of the Four Corners and San Juan power plants
- + Tertiary CO₂ enhanced oil recovery programs could be conducted in nearby mature oil fields of the Four Corners platform.

Potential Problems or Issues Needing Study

- The Fruita and Menefee Formations (coal seams) are exposed at the surface nearby and may not be deep enough for efficient injection; surface leakage of CO₂ is a possibility; the Dakota and older formations are exposed farther west along the east flank of the Defiance uplift and the Red Rock monocline, and could also leak.

- Some structures in the Four Corners platform area already contain significant quantities of CO₂ and other low-BTU gases
- Benefits of CO₂ enhanced oil recovery unproven for mature oil fields in the Four Corners platform
- A 35-kilometer-long CO₂ pipeline(s) is needed to access McElmo CO₂ pipeline to west Texas. This may have to cross tribal lands

Jim Bridger Power Plant Site

The coal-fired Jim Bridger plant has a capacity of 2034 MW and is situated on the eastern flank of the Rock Springs Uplift, 35 km east of Rock Springs, Sweetwater County, south Wyoming (Fig. 5a). It is operated by PacifiCorp (Scottish Power).

Geological Setting (Fig. 5b; derived from DeBruin, 1997, Lickus and Law, 1988)

- South-to-north trending basement involved anticline.
- 1,800 m (6000 feet) structural closure encompassing about 3,000 km² (1,200 square miles) at the Cretaceous Baxter Shale datum (Lickus and Law, 1988).
- Surface exposures range from Tertiary Green River Formation on the flanks to Baxter Shale on the crest of the anticline.
- Normal faults have been mapped on the surface and drilling has identified many more that are not visible on the surface.
- Potential reservoirs for CO₂ injection are the Jurassic-Triassic Nugget Sandstone with an overlying seal formed by the Gypsum Springs Formation and the Pennsylvanian Weber Sandstone with the Permian Phosphoria Formation possibly forming an overlying seal.
- Baxter Shale is a secondary seal.
- Numerous oil and gas fields produce from secondary structures, fault traps and stratigraphic traps. Most of the hydrocarbon production is from Cretaceous-aged sandstone with minor production from the Nugget Sandstone and Phosphoria Formation. The Mississippian Madison contains CO₂ and water.

Opportunities for CO₂ Sequestration

- + Large trap, 3,000 km² of four-way closure.
- + Laterally extensive sandstone reservoirs (Nugget Sandstone and Weber Sandstone).
- + Primary seals directly overlying the potential reservoirs (Gypsum Springs overlying the Nugget and Phosphoria overlying the Weber) and a thick secondary seal (Baxter Shale).

Potential Problems or Issues Needing Study

- Oil and gas operators who own production and leases in the area may fear contamination of proven and undiscovered hydrocarbon resources from injected CO₂.
- Uncertainties where normal faults in region may allow upward leakage of injected CO₂.
- The quality of the primary seals is questionable, the Phosphoria is a porous reservoir in some locations and the Gypsum Springs is thin (17 m) in the Rock Springs Uplift area.

Craig Power Plant Site

The Craig coal-fired power plant is located near the southern boundary of Craig, Moffat County, Colorado. The site is on the north-dipping flank of the Axial Basin Uplift formed by the Cretaceous Lewis Shale and Mesaverde Group (Fig. 6a). The plant is operated by The Tri-State G & T Association Inc. and it has a capacity of 1200 MW.

Geological Setting (Fig. 6b; Tweto, 1987)

- Flank of the Axial Basin Uplift, a regional structure formed by the plunge of the Uinta arch.
- Several smaller structures superimposed on the larger structure.
- Moffat Dome has fault-related structural closure 14 km south of the plant.
- Surface exposures range from Cretaceous Lewis Shale at the plant site to Mancos Shale at the crest of the Moffat Dome.
- Potential reservoirs for CO₂ injection are the Jurassic Entrada/Glen Canyon Group, and the Permian Weber Sandstone with overlying seals formed by the Mancos Shale and Chinle/State Bridge Formations, respectively.
- Moffat Dome is a producing oil field that is very near depletion. Oil has been produced from the Cretaceous Mancos Shale, Mesaverde Group, Dakota Sandstone and the Permian Weber Sandstone.

Opportunities for CO₂ Sequestration

- + Moffat Dome is a moderate size asymmetrical trap with about 700 meters of closure at the Permian horizon over perhaps 3.5 km².
- + Laterally extensive sandstone reservoirs (Entrada/Glen Canyon Group and Weber Sandstone) with potential reservoir in the Mississippian carbonate.
- + Thick Mancos Shale provides an excellent seal between the reservoirs and surface.
- + Possibility of using CO₂ for enhanced oil recovery

Potential Problems or Issues Needing Study

- More geologic detail is needed. Subtle structural features between the plant and Moffat Dome could result in gas migration pathways not currently considered.
- Formations directly overlying the potential reservoirs (Chinle/State Bridge and Dakota/Morrison/Curtis/Summerville) are mixed seal and reservoir so upward migration of gas could occur along the path from the plant to Moffat Dome.
- Moffat Dome and other neighboring structures are oil productive. It is not known whether the oil and gas operators would welcome the opportunities for enhanced oil recovery through CO₂ injection, or fear contamination and degradation.

IPP-Delta Power Plant Site

The Intermountain Power Agency power plant near Delta, Millard County, Utah is coal-fired and has a capacity of 1600 MW (Fig. 7a; after Hintze and Davis, 2002). The plant is owned by the City of Los Angeles.

Geological Setting (Fig 7b; from Hintze and Davis, 2002)

- Situated in the Basin and Range physiographic province (normal faulting) and also overlies a low-angle Cretaceous thrust zone at depth
- 77.2 m of Pliocene - Miocene basin deposits
- Sand, silt, clay, and gravel, with traces of volcanic material.
- 1570.4 m of Miocene - upper Oligocene halite with some anhydrite.
- 9.7 m of Tertiary conglomerate.
- Unknown thickness (1076.6 m drilled thickness) of Cambrian (?) carbonates consisting of white, light-gray and gray, fine- to medium-crystalline dolomite and dark-gray to black, argillaceous dolomite; some minor light-gray green shale is present, pyrite is common throughout the carbonate section. H. J. Bissell interpreted the carbonates as Tertiary, G. C. Mitchell interpreted the carbonates as Ordovician through Devonian in age.
- Structural dip of the Cambrian carbonates is not known.

Opportunities for CO₂ Sequestration

- + Thick salt deposit provides an excellent seal.
- + Potential injection into salt, combination seal and reservoir.
- + Carbonate reservoirs below salt, porosity zones identified by drilling, 3012.0 - 3013.3 m has 12.5% density/neutron, 3079.7 to 3084.6 m appears to be fracture zone, 3099.8 to 3102.3 m has 12.5% density/neutron; several other zones with 4 to 6 % porosity.

Potential Problems or Issues Needing Study

- Salt reservoir (cavern) would be of limited volume.
- Carbonate porosity zones are thin and lateral extent unknown.
- Structure below the salt is unknown, beds could be horizontal, steeply dipping, or overturned.
- Carbonate stratigraphy is still highly questionable.

Discussion and Conclusions

Five of the six power plants sites were sited because of proximity to coal outcrop and seams suitable as a long-term feedstock for the plants. These five plants are situated on the Colorado Plateau and southern Rocky Mountains physiographic provinces and have similar geologic settings. The exception is the Intermountain Power Plant, Delta, Utah, where coal is brought by truck and rail from the east side of the Wasatch Plateau about 100 km away. With this site, other factors such as proximity to major power transmission corridors were important. This site is in the Basin and Range physiographic province which has been affected by tensional faulting since mid-Tertiary time. With the other five projects, the occurrence of near-surface coal is a consequence of a gentle local dip ($< 5^\circ$) of the Cretaceous and early Tertiary sediments in combination with differential erosion. Despite the near-horizontal layer-cake stratigraphy characteristic of much of the Colorado Plateau, the dipping structures near these power plant sites mean that lateral migration of a subsurface CO₂ plume is possible if injection occurs close to the power plant. This need not be considered a negative factor, depending on the continuity of overlying sealing units, and an absence of major faults disrupting seal competency. White et al., (2003) show that slow lateral migration of a plume of injected CO₂ increases the opportunity for rock-fluid interactions, and this increases the potential for sequestration of CO₂ in minerals and as dissolved species.

Both the Jim Bridger (Wyoming) and the Craig (Colorado) power plants are situated on the flanks of large domal features with four-way closure that are also sites of oil and gas fields (Rock Springs Uplift and Moffat Dome respectively). In both cases, injection of CO₂ to 1 - 2 km depth near the power plants would target potential reservoirs that are stratigraphically below the proven petroleum fields. The presence of trapped oil and gas suggests that adequate seals are present over these domes, at least higher in the stratigraphic section. An issue in both areas is whether operating oil and gas lease-holders would welcome or oppose nearby CO₂ injection. Some CO₂ could be used for enhanced oil recovery in the mature oil fields, but without further investigation of likely flow paths of the injected CO₂, some CO₂ may be perceived as diluting or displacing natural gas resources. An additional strategic factor with the Jim Bridger plant is its location within 30 km of a major CO₂ pipeline through southern Wyoming, northeast Utah and northwest Colorado. There is a possibility for power plant CO₂ to displace natural CO₂ production from LaBarge field, resulting in a net CO₂ offset of emissions.

The Hunter-Huntington power plants site in central Utah is also situated on the flanks large monoclinial structure, the San Rafael Swell. Here erosion of the Swell has breached many of the potential Mesozoic reservoir and seal units, although in the case of the Permian White Rim sandstone, the outcrop area is small and displaced about 30 km east of the nearest power plant. The dip on the formations in the vicinity of the power plants is 1° to the west. This site is used by White et al. (2003) to simulate the fate of

injected CO₂ based on the predicted CO₂ plume flow at depth and likely fluid-rock interactions. The study shows that on a 1000-year timescale, most of the CO₂ is sequestered.

The Navajo power plant in northern Arizona is also on a monoclinical structure that dips at about 2° to the northwest. Immediately south of the power plant there is little regional dip and a gently undulating structure. A regionally extensive reservoir-seal combination in the Permian at about 1,500 m depth appears ideal for sequestration. There are few faults and those that are present have minor displacements and are unlikely to provide high permeability channels through the seal rocks.

The Four-Corners/San Juan power plants are adjacent to a northeast-trending monocline known as The Hogback. This feature raises the sedimentary section to the northwest about 1 km in elevation, and this would be the direction that injected CO₂ would migrate. Suitable reservoir and seal units are present at appropriate depth, with 500 m of Mancos Shale immediately beneath the surface being the primary seal. These two power plants are 35 km from the McElmo-West Texas CO₂ pipeline, so like the Jim Bridger plant, opportunities exist for offsetting natural CO₂ production for enhanced oil recovery.

The geology of the Intermountain power plant near Delta, Utah is the least well-determined of all six sites considered in this paper. A nearby well intersected a thrust zone at 2.5 km depth with Cambrian carbonate rocks lying beneath the thrust, and upper Tertiary sediments above the thrust plane. The Basin and Range history of upper Tertiary faulting probably means that this region has more faults, and potential leakage of CO₂ to the surface may be more of a problem than with the other five sites. A buried salt/gypsum deposit near the plant may provide a secure location for gas storage, but whether it is large enough to store CO₂ emissions from 10 – 20 years of power plant operation is unknown.

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Figure 1. Location of major sources of CO₂ emissions from fossil fuel power plants in the Southern Rocky Mountains-Colorado Plateau, with size of the red dots proportional to emissions (in millions tons/year, after Hovorka, 1999). The six largest power plant sites are labeled, and are the subject of this paper.

Figure 2a: Geologic map of the vicinity of the Hunter power plant, central Utah, and the location of the cross-section shown in Fig. 2b. Geology is taken from Hintze et al., (2000). The Huntington power plant is north of the map edge, about 15 km north of Orangeville.

- Potential Reservoir**
- Potential Shale Seal**
- Potential Evaporite Seal**

Figure 2b. Northwest-southeast cross-section through the Hunter power plant and across the San Rafael Swell. See Fig. 2a for map.

E X P L A N A T I O N

<p>Tertiary</p> <p>TKn North Horn Fm.
Mudstone, Claystone, Sandstone, Conglomerate, Limestone</p> <p>Cretaceous</p> <p>Kpr Price River Fm.
Conglomerate, Sandstone</p> <p>Kc Castlegate Sandstone
Sandstone</p> <p>Kbh Blackhawk Fm.
Sandstone, Shaly Siltstone, Shale, Coal</p> <p>Ksp Star Point Sandstone
Sandstone, Shale, Shaly Siltstone</p> <p>Km Mancos Shale
Shale, Shaly Siltstone</p> <p>Kdc Dakota Sandstone & Cedar Mtn. Fm. undivided
Sandstone, Mudstone, Conglomerate</p> | <p>Jurassic</p> <p>Jm Morrison Fm.
Claystone, Mudstone, Sandstone, Conglomerate</p> <p>Js Summerville Fm.
Shaly Siltstone, Sandstone</p> <p>Je Entrada Fm.
Sandstone</p> <p>Jc Carmel Fm.
Shaly Siltstone, Limestone</p> <p>Jn Navajo Fm.
Sandstone</p> <p>Jk Kayenta Fm.
Sandstone</p> <p>Jw Wingate Sandstone
Sandstone</p> <p>Triassic</p> <p>Trc Chinle Fm.
Sandstone, Shaly Siltstone, Conglomeratic Sandstone</p> <p>Trm Moenkopi Fm.
Sandstone, Oolitic Limestone, Shaly Siltstone, Mudstone</p> <p>Permian</p> <p>Pk Black Box Dolomite
Dolomite</p> <p>Pwr White Rim Sandstone
Sandstone</p> <p>Pec Elephant Canyon Fm.
Limestone, Dolomite, Sandstone</p> | <p>Pennsylvanian</p> <p>IPht Honaker Trail Fm.
Sandstone, Limestone, Dolomite</p> <p>IPp Paradox Fm.
Sandstone, Limestone, Shale, Dolomite</p> <p>IPpt Pinkerton Trail Fm.
Shale, Mudstone</p> <p>Mississippian</p> <p>Mr Redwall Limestone
Limestone, Dolomite</p> <p>Devonian</p> <p>Do Ouray Limestone
Limestone</p> <p>De Elbert Fm.
Dolomite, Shale</p> <p>Cambrian</p> <p>-CIm Lynch & Maxfield undivided
Dolomite, Limestone, Shale</p> <p>-Co Ophir Fm.
Shale, Limestone</p> <p>-Ct Tintic Quartzite
Quartzite</p> <p>Pre-Cambrian</p> <p>p-C Schist</p> |
|--|--|---|

Figure 3a. Map showing location of cross-sections (lines A-A' and B-B') through Navajo power plant, northern Arizona in Fig. 3b, and generalized geology of the area.

Figure 3b. Geologic cross-sections through Navajo power plant site. Refer to Fig. 3a for location.

0 Kilometers 20

Figure 4a. Simplified geologic map of the region around the Four Corners and San Juan power plants. The location of the two cross-sections shown in Fig. 4b are shown as lines A-A' and B-B'.

E X P L A N A T I O N

Quaternary/ Tertiary	Q	Quaternary surficial deposits	Jurassic	Jm	Morrison Formation
	Tu/Qu	Tertiary/Quaternary undivided		Jwk	Wanakah Formation
Cretaceous	Kk	Kirtland Shale	Triassic	Je	Entrada Sandstone
	Kf	Fruitland Formation		Jw	Wingate Sandstone
	Kpc	Pictured Cliff Sandstone	Permian	TRC	Chinle Formation
	Kl	Lewis Shale		Pc	Cutler Sandstone
	Kch	Cliff House Sandstone	Pennsylvanian	IPh	Hermosa Group
	Kmf	Menefee Formation		MI	Leadville Limestone
	Kpl	Point Lookout Sandstone	Mississippian	D	Devonian undivided
	Km	Mancos Shale		-Ci	Ignacio Quartzite
	Kd	Dakota Sandstone	Cambrian	p-C	Precambrian basement

Potential Reservoirs

Sandstone (Dakota, Entrada, Wingate, Cutler, McCracken Sandstone Member of the Elbert Formation [Devonian] in northwest area of San Juan Basin)

Coal (Fruitland, Menefee)

Potential Seals

Shale (Kirtland [lower member], Lewis, Mancos, Chinle)

Evaporite (Paradox Formation in Hermosa Group, northwest area of San Juan Basin)

Figure 4b. Geologic cross-sections through the Four Corners and San Juan power plants. Refer to Fig 4a for location.

Figure 5a. Simplified geologic map of the region around the Jim Bridger power plant and Rock Springs Uplift, southern Wyoming. Location of cross-section in Fig. 5b shown as heavy line.

Structure contours drawn on Baxter Shale for west half of map and on the Lewis Shale for the east half of the map.

Figure 5b. Geologic cross-section through the Jim Bridger power plant and Rock Springs uplift. Refer to Fig. 5a for location. 27

Figure 6a. Simplified geologic map of the region around Craig power plant and Moffat Dome, northwest Colorado. Location of cross-section in fig. 6b shown as heavy line.

Figure 6b. Geologic cross-section through the Craig power plant. Refer to Fig. 6a for location.

Intermountain Power Plant

Figure 7a. Simplified geologic map of the region around the Intermountain Power Agency plant near Delta, central Utah. Location of cross-section in Fig. 7b shown as heavy line.

Figure 7b. Geologic cross-section through the Intermountain Power Agency plant. Refer to Fig. 7a for location.

CO₂ Mobility in Natural Reservoirs Beneath the Colorado Plateau and Southern Rocky Mountains: An Example from the Springerville-St. Johns Field, Arizona and New Mexico

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Abstract

The Springerville-St. Johns CO₂ field in eastern Arizona and western New Mexico is one of more than a dozen gas fields developed within the Colorado Plateau and Southern Rocky Mountain region. The reservoir is associated with spectacular travertine deposits that cover an area of about 250 km². Pressure measurements from deep exploration wells indicate that springs in the travertine area could be fed by lateral outflow of water from the region of the CO₂ field. Groundwater in the immediate vicinity of the gas field is enriched in HCO₃ and displays the highest degree of dolomite supersaturation. Interactions between the basin fluids and the clastic sediments that host the CO₂ reservoir resulted in the dissolution of carbonate cements and detrital feldspars and the formation of kaolinite and rare dawsonite. Geochemical simulations indicate that kaolinite will become stable at a CO₂ fugacity of <1 bar but that a fugacity of 20 bar is required to stabilize dawsonite. The limited occurrence of dawsonite may reflect the presence of local anhydrite-rich seals that allowed high CO₂ fugacities to develop. Taken together, the results of these mineralogic and geochemical investigations demonstrate that the Springerville-St. Johns CO₂ field represents a natural analogue for evaluating the potential effects of CO₂ leakage from subsurface reservoirs with imperfect seals and the effects of mineral sequestration.

Keywords: CO₂ field, Springerville-St. Johns, dawsonite, water chemistry

Introduction

Increasing global interest in geologic sequestration of CO₂ has raised important questions about its long-term fate. Geochemical models suggest that substantial amounts of CO₂ injected into deep reservoirs can be removed through fluid-fluid and fluid-mineral reactions, particularly those that lead to the formation of Ca, Fe and Mg carbonates (e.g. Gunter et al., 1993; Bachu et al., 1994; Perkins and Gunter, 1996; Xu et al. 2001). Because CO₂-charged ground waters are chemically reactive, other minerals, including zeolites, kaolinite and quartz can be expected to form through reactions involving HCO₃ and the host rocks. Such reactions, for example, are typical of the marginal parts of modern geothermal systems, which are characterized by argillic alteration and calcite (Hedenquist and Stewart, 1985). However, autoclave experiments designed to test predictions of the geochemical models have been hampered by the slow kinetics of the mineral reactions (Gunter et al., 1996, 1997; Pearce et al., 1996).

Few studies of natural CO₂ reservoirs are currently available to determine the efficiency of mineral sequestration and the effects of fluid-mineral reactions. Pearce et al. (1996) suggested that the influx of CO₂-rich groundwater into the Bravo Dome of New Mexico resulted in the dissolution of anhydrite, dolomite and plagioclase and the formation of kaolinite and zeolites. On the other hand, ongoing investigations of the productive White Rim Sandstone in the Gordon Creek field, Utah, showed no clear evidence of interactions between CO₂-rich fluids and the host rocks (J. Moore, unpub. data).

In this paper, the results of geochemical and hydrologic investigations conducted on the Springerville-St. Johns CO₂ field in eastern Arizona and western New Mexico are described. It is one of more than a dozen generally similar CO₂ reservoirs developed in domed Mesozoic and Paleozoic sedimentary rocks of the Colorado Plateau and Southern Rocky Mountain region of the western U.S. (Fig. 1; Allis et al., 2001). Within these reservoirs siliciclastic rocks, and to a lesser extent carbonates, serve as the primary aquifers, whereas anhydrite beds and mudstones act as local seals. The Ridgeway Arizona Oil Corp. is presently developing the Springerville-St. Johns field for CO₂ and He.

The Springerville-St. Johns field is significant for three reasons. First, spectacular travertine deposits, which we suggest record the effects of long term CO₂ leakage from the reservoir, are present. Leakage of CO₂ and other gases to the atmosphere is an important consideration in any sequestration project. Second, core from the CO₂ reservoir is available for petrologic studies. These samples provide direct mineralogic evidence of interactions between the CO₂-charged fluids and the host rocks. Finally, pressure data from deep wells and chemical analyses of well and spring waters are available. These data provide insight into the fluid flow paths and the hydrologic connections between the deep and shallow fluids.

Geologic Setting of the Springerville-St. Johns Area

The Springerville-St. Johns CO₂ field covers approximately 1813 km² (Rauzi, 1999) on the southeastern edge of the Colorado Plateau, east of the Pio-Pleistocene Springerville volcanic field (Sirriner, 1951; Crumpler et al., 1994). K-Ar ages of the basaltic rocks that make up this field range from ~0.3 to 3 Ma. (Condit et al., 1994). The CO₂ field and the travertine deposits lie adjacent to the Little Colorado River (Fig. 2). The gas reservoir is developed in Permian rocks that define a broad, northwest-trending asymmetrical anticline with steeper dips on the faulted southwest flank of the structure. This fault zone is thought to be controlled by Precambrian structure that affects the underlying granitic rocks.

The producing zones in the St. Johns-Springerville field occur primarily in the Fort Apache Limestone Member, Big A Butte Member, and Amos Wash Member of the Supai Formation (Fig. 3; Rauzi, 1999). The Fort Apache Limestone Member consists of red siltstones capped by anhydrite and underlain by dolomite. The Big A Butte Member is composed of 5 anhydrite beds within a sequence of red siltstones and minor dolomite. The Amos Wash Member is heterogeneous, consisting of red mudstones, siltstones, and very fine-grained sandstones. At the base of the unit, it contains lenses of conglomerate with fragments of the underlying Precambrian granitic rocks. These lenses are interpreted as channel fillings. The granitic rocks are highly altered and in one well contain abundant secondary dolomite. Gas has been reported from the conglomerates and it is likely that CO₂-charged fluids have circulated through the fractured granite. However, a relationship between the alteration of the granite and these fluids has not yet been established.

Drill stem and initial flow tests indicate that the wells can produce up to approximately 2000 Mcf per day (Rauzi, 1999). Analyses of the gas from the 1 Plateau Cattle well and the 3-1 State well yielded 90% CO₂, 6-10% N₂, and 0.5 to 0.8% He, and 0.1% each of CH₄ and Ar, although some wells are reported to produce gas with higher CO₂ contents. The 1 Plateau Cattle well produced 640 Mcf of gas and 436 barrels of water per day. The CO₂-charged waters are chemically aggressive due to their acidity and the 1 Plateau Cattle well had to be replaced because of corrosion to the steel casing.

The Ridgeway Arizona Oil Corp. cut 210 m of conventional core in 3 wells drilled in Arizona and 233m of core in 5 wells drilled in New Mexico. In addition, sidewall cores were taken. Conventional and sidewall core samples from 5 of the Arizona wells (9-21 State, 10-22 State, 10-26 State, 11-21 State, and 22-1X State; refer to Fig. 2) that include samples of the Precambrian granite were collected for study. All but 10-26 State produced dry gas or CO₂-charged waters in drill-stem or flow tests. The 10-22 State well has been producing CO₂ for a liquid CO₂ plant since July 2002.

Travertine Deposits

The Springerville-St Johns area contains one the greatest concentrations of travertine spring deposits in the U.S. These carbonate deposits cover an area of approximately 250 km² primarily south and east of St. Johns (Sirriner, 1951). They are particularly prevalent adjacent to a 10 km length of the Little Colorado River between Lyman Lake and Salado Springs (Fig. 2), where numerous springs and seeps occur today. None of the springs had temperatures greater than 10°C above ambient.

Many of the individual deposits are unusually large and symmetric (Fig. 4; Crumpler et al., 1994). Travertine sheets up to 6.4 by 3.2 km in extent and circular domes up to 610 m in diameter suggest a long history of spring discharge (Sirriner, 1951). The domes typically contain large central chambers that mark

the locations of the spring vents. The sheets and domes occur adjacent to seepage areas as well as on terraces up to nearly 60 m above the valley floor. The height of the cones is often difficult to determine because the travertine frequently caps raised terraces of sedimentary rocks (typically red Moenkopi Formation). Based on assumptions about the elevation of the underlying sedimentary platform, most of the domes have travertine thicknesses ranging in height from less than 3 to about 60 m.

The size of the travertine deposits presumably points to a long history of continued outflow with a nearly constant head from the same vent positions. The age of the travertine deposits, however, is uncertain. Sirrine (1954) suggested that deposition of the deposits began in the late Pleistocene because they postdate the basaltic volcanism and are locally interbedded with late Pleistocene Richville Formation gravels. No older deposits are known. Compared to the extent of past activity implied by the large fossil deposits, travertine deposition appears to be relatively insignificant today. Furthermore, none of the dome-like features are currently forming.

Springs can change their location and elevation over time as erosion occurs and lowers the base level controlling the local groundwater hydrology. In the Crystal Geysers area of central Utah, extinct travertine deposits are preserved several tens of meters above the active springs located adjacent to the Green River (Doelling, 1994). Erosion rates in tributaries of the Colorado River in central and southern Utah range from ~20–40 cm/1000 years (Biek et al., 2000; Baer and Rigby, 1978; Doelling, 1994). Based on these rates, travertine deposition at Crystal Geysers could have begun 10^4 – 10^5 years ago. Similar erosion rates are probable in the arid Little Colorado River area of Arizona. If it is assumed that the differences in the elevations of the travertine deposits in the Springerville-St. Johns area is due to erosion and a change in the base level of the Little Colorado River, then it is possible that some of the travertine could have been deposited as much as 10^5 years ago. However, the apparent lack of extensive erosion of some of the larger, higher elevation deposits suggests that factors other than a declining base level may have influenced the drop in activity. These factors could include a combination of climatic and hydrologic changes and a decrease in the CO₂ partial pressure at depth. In this case, the travertine deposits could be much younger than indicated by the erosion rates.

Hydrology of the Springerville-St. Johns Travertine Area

All flowing features in the travertine area appear to be less than 3 m above the elevation of the Little Colorado River, suggesting that the river is the primary control on the outflows. Some of the pools had no obvious overflow and presumably were leaking below the ground surface. The greatest outflows appeared to be in a swampy area immediately below the Lyman dam (estimated to be about 10 l/s), and in the swampy area of Salado Springs (about 15 l/s).

Figure 5 shows the pressure-elevation trends for the St. Johns-Springerville area. Two trends are apparent. The travertine-CO₂ field forms one obvious aquifer with a pressure intercept close to 1830 m above sea level (asl). The Tucson Electric Power Co. groundwater wells have been plotted collectively by showing an average head (zero pressure) at 1830 m asl although actual water levels rise to over 1890 m asl on the east side of the Salado Springs fault zone (unpublished Tucson Electric Power Co. data). The scatter in pressures from the Ridgeway Arizona Oil Corp. wells is consistent with localized zones of CO₂ causing slightly higher pressures at the top of the gas zones, but the overall near-hydrostatic trend shows the system is water-dominated. This pressure trend explains how the springs and pools adjacent to the Little Colorado River area could be fed by lateral outflow of water from the region of the CO₂ field.

Within ~8 to 16 km west of Salado Springs, the pressure trend is significantly different, and indicates a laterally extensive aquifer system that has a pressure intercept at about 1525 m asl. This elevation is similar to that of the Little Colorado River about 16 km west of Holbrook. It is possible that the Kaibab-Glorieta aquifer is in pressure equilibrium with surface water in that location. The cross-section in Figure 6 illustrates this lateral change in potentiometric head and compares it to the gross structural changes in some of the main sedimentary units. The transition between the two pressure trends is poorly controlled and perched groundwater aquifers may overlie the deep hydrologic units identified here.

Fluid Chemistry

The compositions of waters from the Springerville - St. Johns region were studied to evaluate their relationships to the CO₂ field and to assess the ability of the reservoir rocks to sequester CO₂ through naturally occurring water-rock interactions. The geochemical data were taken from compilations of groundwaters by Mann and Nemecek (1983), geothermal waters by Witcher (1995), unpublished analyses of well waters provided by Tucson Electric Power Co and Ridgeway Arizona Oil Corp. and analyses of spring and shallow well waters collected by the authors during the spring of 2002. Although the number of analyzed chemical species varied, all of the analyses contained data on the dominant groundwater ions Na, K, Ca, Mg, HCO₃, SO₄ and Cl. The quality of each analysis, which depends on the purpose of the sampling, was found to range from poor to good. The analytical quality was evaluated by calculating the charge balance. Poor quality analyses can have an adverse effect on thermodynamic modeling efforts; however, even poor quality analyses can be used to track water types.

The locations of the water samples utilized in this study are shown in Figure 7. The waters range continuously in chemical character from Ca-Mg HCO₃ to Ca-Mg Cl-SO₄ (Fig. 8). The distribution of water types is illustrated in Figure 9. Although the waters are high in HCO₃, SO₄ and Cl, these constituents are not necessarily coupled. Relationships shown on the piper plot in Figure 8 indicate the samples are a mixture of Ca-Mg HCO₃ and Na SO₄-Cl waters. The SO₄/Cl and Ca/Mg components display reasonably constant ratios, while HCO₃ and Na proportions of the anions and cations respectively range from less than 40% to nearly 100%. This suggests that the concentrations of SO₄, Ca, and Mg are determined by a combination of source rock abundances and fluid-mineral equilibria, while acidification and neutralization caused by the addition of CO₂ are responsible for the variations in HCO₃ and Na (e.g. Mahon et al., 1980). Na-K HCO₃, Na-K HCO₃-SO₄, and Ca Cl water types dominate in the immediate vicinity of the CO₂ field.

The hydrologic data suggest a possible connection between the basin waters and the waters that discharge from Salado Springs. Water from the Ridgeway Arizona Oil Corp. well 11-21 State is Na-K HCO₃-SO₄ in character (Table 1). In contrast, waters from the Tucson Electric Power Co. wells and Salado Springs are Na Cl in character, although the Salado Springs water is also enriched in HCO₃. It can be postulated that the Salado Springs water is a mixture of waters encountered in the CO₂ field wells and the power plant wells. Possible mixing relationships were examined by considering ratios of the conservative components B and Cl. Although B/Cl ratios are relatively constant proportions of reactive components such as Ca, Mg and SO₄ differ among the waters. Thus, the compositions of the spring and deep waters may reflect the effects of multicomponent mixing and water-rock interactions.

Mineralogy of the CO₂ Reservoir Rocks

Mineral assemblages and textures in core samples representative of the Permian Supai Formation encountered between depths of 420 and 825 m and the underlying Precambrian granite were examined in detail. Approximately 100 samples were studied petrographically in thin section. Mineral identifications were supported by X-ray diffraction analyses of bulk rock and clay (<5micrometer) separates of 41 samples. A scanning electron microscope equipped with an EDX analyzer provided additional key textural data and qualitative chemical analyses of mineral phases. The core samples of the Supai Formation consisted dominantly of red, fine-grained siltstones intercalated with minor sandstone, anhydrite, limestone and dolomite beds.

Despite the relatively large number of samples that were examined, only those from depths between 462 and 472 m in well 22-1X yielded clear evidence of reactions that could be related to interactions with CO₂-rich fluids. These samples are characterized by the dissolution of authigenic cements and detrital feldspar grains and by the formation of dawsonite (NaAlCO₃(OH)₂) and kaolinite. Well 22-1X produced 1894 Mcf per day of gas from depths of 463-495 m. Other cored intervals in this well were not tested. This interval is significant because it is the only interval sampled that produced CO₂ gas. Cored intervals in other wells were either non productive or produced water containing various proportions of gas.

The presence of dawsonite is significant because thermochemical calculations suggest that it may be an important mineral sink for CO₂ in deep continental aquifers (Knauss et al., 2001; Johnson et al., 2002; White et al., 2002; Xu et al., 2002; Zerai et al., 2002; Boram et al., 2003). These models indicate that dawsonite can form relatively rapidly, particularly when compared to other carbonate minerals. Although dawsonite is a relatively uncommon authigenic mineral, it does occur in a variety of geologic environments. Dawsonite has been observed in clastic and volcanoclastic sedimentary rocks and coals, as a weathering product of soils and as a hydrothermal mineral associated with intrusive and volcanic rocks. Baker et al. (1995) have provided particularly detailed descriptions of dawsonite occurrences in the Bowen-Gunnedah-Sydney basin system, Australia where it is widely distributed in Permo-Triassic marine and nonmarine rocks as a cement, replacement of framework grains and pore-filling mineral. Although they did not consider growth of dawsonite to have occurred under present-day conditions, the lack of deformation of individual dawsonite fibers led Baker et al. (1995) to conclude that dawsonite was deposited after deposition of other authigenic minerals and compaction of the sediments. At Olduvai Gorge in Africa, dawsonite is associated with zeolites and sodium carbonate minerals in arid alkaline soils (Hay, 1963). In the United States, dawsonite has previously only been identified in saline, alkaline lacustrine basins, such as in the Green River Formation of Eocene Lake Uinta (Hay, 1964; Smith and Milton, 1966; Mason, 1983; Daub et al., 1985). In the following sections, we describe the geologic occurrence of dawsonite at Springerville-St. Johns and then present the results of thermochemical models that help explain its origin.

Dawsonite-Bearing Rocks in Well 22-1X

Rocks containing dawsonite in well 22-1X range from dolomudstones to dolomitic siltstones. They contain 26 to 46 wt % quartz, subequal amounts of plagioclase and potassium feldspar (6 to 13 wt % each), 1 to 2 wt % calcite, anhydrite, and gypsum, 10 to 15 wt % dolomite, 4 to 8 wt % hematite, 2 to 6 wt % kaolin, and 5 to 18 wt % illite, muscovite and biotite. These mineral abundances do not appear to differ in any significant way from rocks sampled in other wells that lack dawsonite.

The siltstones are dolomite cemented grain supported rocks that contain well-sorted silt to very fine sand-sized grains in planar to rippled laminations. In contrast, the mica and silt grains in the dolomudstones are matrix-supported with fine-grained dolomite, iron oxide, and clay minerals. The dolomudstones appear to be intensely bioturbated, but they contain few sand or silt-filled burrows and laminations. Detrital micas, peloids and other clay-rich intraclasts are abundant and commonly accompanied by nodules of anhydrite and gypsum. All the rocks exhibit a strong red color caused by the hematite cement.

Textural relationships demonstrate that the dolomite and hematite represent early cementing phases (Fig. 10). The dolomite occurs as hematite stained microcrystalline rhombohedrons that line and fill pores. The dolomite was followed by the deposition of anhydrite and calcite cement, which are not stained by hematite. Gypsum, a common phase in rocks above and below the dawsonite zone encapsulates anhydrite, indicating it represents hydration of the earlier formed sulfate.

Dawsonite and kaolinite represent the youngest pore filling minerals (Fig. 11). Their occurrence has been confirmed by both X-ray diffraction and EDX analyses. The dawsonite occurs as radiating sprays of elongate to bladed prisms that comprise 5 to 17 weight percent of the samples. Although the dawsonite crystals are commonly spatially associated with corroded plagioclase and potassium feldspars, which are likely to have provided Al for crystal growth, it is also occasionally found growing on the surfaces of quartz grains. An unusual and distinctive feature of the dawsonite crystals are their hollow interiors. The external surfaces of the crystals, however, show no evidence of corrosion. We infer from these textures that the crystals grew outward by cannibalizing their own interiors.

Kaolinite is a common mineral in core samples from all five wells where it generally comprises up 2-7 weight percent of the rock. Scanning electron microscope images of core from 468 m clearly demonstrate that kaolinite is, at least in part, a late authigenic mineral. Here it occurs with dawsonite in intergranular pores as relatively coarse-grained books with individual plates exceeding 10 to 20 micrometers in size. The kaolinite also locally replaces dissolved potassium feldspar grains in the rock. The textural

relationships clearly demonstrate that both the kaolinite and dawsonite are younger than the dolomite and calcite cements on which they have grown. Although the kaolinite and dawsonite are not in contact with each other, the textural relationships displayed in Figure 11D suggest the kaolinite is younger than the dawsonite.

Rocks containing dawsonite are dolomite and calcite-cemented siltstones. Much of the porosity in these rocks, which is visually estimated to be approximately 20 %, appears to be the result of calcite dissolution. Dawsonite is commonly associated with patches of calcite and in places, fills pores that are similar in size to calcite fillings along coarse laminations in the siltstone. These siltstones may have initially been more porous than the overlying and underlying anhydrite-cemented mudstones that now contain 9 to 13 weight percent gypsum. These gypsiferous rocks appear to form a thick (~43 m) upper seal, and a thin (<3 m thick) lower seal.

Water Rock Interactions

The scarcity of dawsonite occurrences in sedimentary basins and its apparently limited distribution at Springerville-St. Johns is not consistent with thermochemical calculations suggesting dawsonite will deposit rapidly during the injection of CO₂ (e.g. Knaus et al., 2001). Instead, the field relationships suggest that the deposition of dawsonite occurs only under a relatively narrow range of geochemical conditions.

Based on their field studies of the Australian basins, Baker et al. (1995) concluded that the dawsonite was deposited by formation waters that had become acidified and enriched in HCO₃ as a result of the influx of CO₂. They argued that these fluids would have been sufficiently aggressive to cause dissolution of feldspars and illitic clays, providing a ready source of Na and Al. Local sources for both the Al and Na are supported by the observation that the Na and K feldspars are commonly replaced by dawsonite (Baker et al., 1995, Heritsch, 1975; Wopfner and Hocker, 1987). A temperature of 25 to 35°C was suggested based on isotopic data (Baker et al., 1995).

Thermochemical modeling by Knaus et al. (2001) and Boram et al. (2003) indicate that high fugacities of CO₂ can lead to saturation of dawsonite. Knaus et al. (2001) simulated reactions between a brine, which was allowed to equilibrate with a gas consisting of 80 bar CO₂ and 10 bar H₂S, and a carbonate-bearing feldspathic sandstone. Deposition of dawsonite occurred after the fluid had equilibrated with the existing siderite and calcite and the pH had stabilized at 4.8. Dissolution of potassium feldspar at these slightly acidic conditions provided a source of Al. In the simulations, Si released during destruction of the feldspar precipitated as quartz and chalcedony.

In the following section we simulate interactions between the Springerville-St Johns waters and the siliciclastic sedimentary rocks that host the CO₂ reservoir. These results are constrained by the compositions of the waters, the presence of carbonate (dolomite, calcite) cements, evidence of feldspar dissolution, and the presence of late pore-filling dawsonite and kaolinite. The calculations were performed using the Geochemists Work Bench (Bethke, 1996) and version 8, release 6 of the Lawrence Livermore National Laboratory thermodynamic database.

Figure 12 shows there is a close relationship between mineral saturations in the groundwaters and the location of the CO₂ field. Saturation indices, given as log Q/K, indicate that all of the waters in the Springerville-St. Johns area are supersaturated with respect to calcite and dolomite but undersaturated with respect to anhydrite and gypsum. The degree of supersaturation of dolomite is highest in the immediate vicinity of the CO₂ field. Similarly, saturation indices for gypsum are highest in the vicinity of the CO₂ field.

Water-rock interactions were simulated by adding CO₂ to water from Ridgeway Arizona Oil Corp. well 11-21 State and then reacting the water with the observed mineral assemblages. This water was taken as being representative of the deep water within the CO₂ field. Table 2 indicates that well 11-21 State water is substantially oversaturated with respect to dolomite but that the other carbonates are only slightly

oversaturated. This degree of oversaturation is unlikely within the reservoir. Consequently CO₂ was added to the water to reduce the pH to the point where dolomite was just saturated (e.g. log Q/K ~0). Quartz saturation was also stipulated in the simulations. The titration of 0.03 moles of CO₂ (g) per kg of water was required to just saturate the solution with respect to dolomite (Table 3). The fluid pH was reduced from 7.1 to 6.0 and the CO₂ fugacity increased from 0.07 to 0.92 bar.

This fluid was allowed to react with 10⁻⁸ moles each of albite, orthoclase, and anorthite feldspar in the presence of dolomite and quartz to examine the possible saturation of aluminous minerals. Figure 13 shows that kaolinite and muscovite rapidly achieved saturation, but that dawsonite remained undersaturated throughout the simulation.

The effect of a further increase in the fugacity of CO₂ on the stability of dawsonite is shown in Figure 14. In this simulation, one mole of CO₂ was added per kg of water in the presence of dolomite and quartz. The addition of the CO₂ lowered the pH of the solution from 7.1 to 5.0. The fluid was again allowed to react with albite, anorthoclase and orthoclase. Saturation of dawsonite was achieved after 0.7 moles of CO₂ had been added and the fugacity of CO₂ reached 20 bar. Kaolinite, however, remained undersaturated throughout the simulation.

The effects of incrementally reducing the fugacity of CO₂ from 20 to 0.92 bar in the presence of dolomite, quartz, albite, orthoclase, and anorthite feldspar are illustrated in Figure 15. As the fugacity of CO₂ in solution decreases, dawsonite becomes progressively undersaturated while the saturation index of kaolinite increases until stability is reached at a CO₂ fugacity of 16 bar. Further lowering of the CO₂ fugacity produces greater undersaturation with respect to dawsonite but has little effect on the solubility of kaolinite. These solubility relationships are consistent with the inferred mineral textures in well 22-1X State suggesting that the deposition of dawsonite preceded kaolinite.

The simulations provide a possible explanation for the common occurrence of kaolinite and overall scarcity of dawsonite in the Springerville-St. Johns rocks. These data suggest that the CO₂ fugacities were generally high enough to stabilize or deposit kaolinite but were too low to allow widespread deposition of dawsonite. High CO₂ fugacities in the dawsonite zone in well 22-1X could have been favored by effective upper and lower anhydrite- and gypsum-rich seals.

The source of the CO₂ in the Springerville-St. Johns field is enigmatic. Baker et al. (1995) noted that many sediment hosted-dawsonite occurrences are associated with volcanic or hydrothermal activity including those in the Australian Basins, the Permian Groeden Sandstone of northern Italy (Wopfner and Hocker, 1987) and the Shengli Oil Field of China (Du, 1982). Dawsonite from these occurrences contains C with similar isotopic compositions that are typically within a few per mil of 0.0, suggesting it has a magmatic origin. Although no isotopic data is available for Springerville-St. Johns, the association of the CO₂ field with young volcanic rocks and the presence of high He allow the possibility that the gases are derived from crustal or mantle sources tapped by through-going deep seated structures.

Summary and Conclusions

The Springerville-St. Johns CO₂ field represents an example of a relatively shallow gas reservoir that provides insight into the effects of CO₂ leakage to the atmosphere and low temperature interactions between CO₂ charged fluids and typical Colorado Plateau clastic sedimentary rocks. The production of CO₂ comes primarily from Permian silstones at depths of less than 900 m. CO₂-bearing channel fillings lying uncomfortably on Precambrian granite at the base of the Permian section suggest that the reservoir is fed by gas migrating along through-going faults zones extending into deep crustal or mantle rocks. Individual production zones, however, are discontinuous, reflecting the combined effects of permeable horizons, access to crosscutting fractures and the efficiency of local seals.

Dissolution of CO₂ into the local groundwaters has had a profound effect on their chemical character and on their interactions with the rocks that host the CO₂ field. The resulting acidity has produced chemically aggressive waters capable of rapid corrosion of metal drill pipe. There is a clear geochemical signature

over the CO₂ field. Waters in the immediate vicinity of the field are enriched in HCO₃ and SO₄ and show the greatest degree of saturation with dolomite and gypsum, common cements in the reservoir rocks. These waters are commonly Na-K HCO₃, Na-K HCO₃-SO₄ and Ca Cl in character.

Investigations of the reservoir rocks within the CO₂ field have documented several generations of authigenic minerals. Early pore-filling cements consist of dolomite, hematite, calcite, anhydrite and gypsum. These minerals are overprinted by dawsonite and kaolinite. Kaolinite is common throughout the reservoir, but dawsonite has so far been observed only in a single relatively narrow interval of siltstones. Textural relationships indicate that the Al was provided by the dissolution of detrital feldspars. Na may also have been derived from the feldspars. Interactions between the reservoir rocks and basin fluids from the CO₂ field were simulated. The models indicate that kaolinite will become saturated at a CO₂ fugacity of <1 b but that dawsonite will not precipitate until the CO₂ fugacity reached 20 b. The high CO₂ contents of the fluids that precipitated dawsonite may reflect the presence of effective low permeability seals.

Spectacular symmetrical domes ranging up to 610 m in diameter and extensive sheets of travertine up to 6.4 by 3.2 km in area record a long history of CO₂ leakage to the surface. Bicarbonate-rich springs and pools are found within travertine deposits on the valley floors close to the elevation of the modern Little Colorado River, but large terraces of travertine are also perched up to 60 m above the valley floor. The present depositional rates appear to be low and relatively insignificant compared to the amount of past deposition and there is no evidence of CO₂ exsolving from the pools and springs.

Several factors may have contributed to the decline in travertine activity. These include lowering of the water table, significantly diminished outflow of CO₂-charged waters due to a drier climate and a reduced flux of CO₂ at depth resulting in lower dissolved CO₂ in the outflowing water. The occurrence of dawsonite suggests that CO₂ partial pressures were higher in the past.

At the time of dawsonite deposition, and perhaps soon after CO₂ began flooding into the region, the subsurface fluid system could have been over-pressured by the influx of gas which caused major outflows of CO₂-saturated waters producing the travertine domes and plateaus. As the partial pressure of CO₂ declined, the degree of over-pressuring diminished and the newly formed domes became perched above the receding groundwater table. Kaolinite replaced dawsonite as the dominant alteration mineral. Today the pressure is close to hydrostatic from the elevation of the Little Colorado River, and the outflow of water from the CO₂ system at depth is greatly reduced. The absence of obvious CO₂ exsolution in the present day springs is attributed to lateral outflow from the main CO₂ upflow zone further east, and loss of CO₂ along the flow path. The Permian Kaibab-Glorieta sandstone units and the underlying Supai Formation act as one aquifer that extends at depth at least 30 km to the east and south of the travertine area

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Table 1. Chemical analyses of the Tucson Electric Power Co. wells (P-12, P-14), Salado Springs, and Ridgeway Arizona Oil Corp. well 11-21 State.

	P-12	P-14	Salado Springs	11-21 State
Na	140	330	340	804
K	15	32	26	174
Ca	130	290	330	110
Mg	39	55	63	232
Fe		0.84	0.27	18.3
Sr	2.1	5.4	3	
B	0.24	0.59	0.75	
SiO ₂	19	15	13	
HCO ₃	186	288	336	1190
SO ₄	210	640	610	1540
Cl	140	410	660	483
F	2	2.6	2.6	
As	0.008	0.032		
TDS	840	2100	2150	4210
pH	7	6.5		7.1
	Tucson	Tucson		Ridgeway
	Electric	Electric		Arizona
Data Source	Power	Power	This Study	Oil Corp.

Table 2. Mineral saturations for water from well 11-21 State (see Table 1).

Mineral	Log Q/K
Dolomite	2.2667
Calcite	0.3752
Magnesite	0.2627
Gypsum	-1.008

Table 3. Mineral saturations after the addition of 0.03 moles of CO₂ per kg water from well 11-21 State. Compare saturation indices with data in Table 2.

Mineral	Log Q/K
Dolomite	0.0062
Calcite	-0.7548
Magnesite	-0.8678
Gypsum	-1.0071

Fig. 1. Location of natural CO₂ reservoirs within the Colorado Plateau and Southern Rocky Mountain Region of the U.S. (after Allis et al., 2001). The inset shows the location of the Springerville-St Johns region illustrated in Figure 2.

Fig. 2. Location of the Springerville-St. Johns CO₂ field. Only the names of wells discussed in the text are shown.

Fig. 3. Generalized geologic section of the Springerville-St. Johns area (after Rauzi, 1999).

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Fig. 4. Travertine deposits in the Springerville-St. Johns area. A) Travertine sheets and pool adjacent to Salado Springs. B) A small well preserved travertine dome on the valley floor. C) Interior of a large travertine dome located south of Salado Springs (see Fig. 4D). D) Areal view of the Salado Springs area showing extensive travertine sheets north of the springs and a large dome to the south. The dome's central vent is clearly visible. E. Travertine sheets on the bluff above the Little Colorado River (lower left and center of photo).

Fig. 5. Relationships between pressures and elevations in the Springerville-St. Johns area. Wells from the CO₂ field define a trend with a pressure intercept close to 1830 masl, consistent with the elevation of springs and pools adjacent to the Little Colorado River. Symbols as in Fig. 2. West of this area, the pressure intercept is close to 1525 masl. Abbreviations: TEPC = Tucson Electric Power Co.

Fig. 6. Northwest-southeast cross section of the Springerville-St. Johns area. See Figure 2 for the location of the cross section. The sections includes the area of the travertine deposits and the CO₂ field (in the structural high left of Salado Springs).

Fig. 7. Locations of water samples used in this study.

Fig. 8. Piper plot of water analyses.

Fig. 9. Distribution of water types in the Springerville-St. Johns area.

Fig. 10: Photomicrograph of early diagenetic cements. Dolomite and hematite were deposited first, followed by calcite and anhydrite. The anhydrite has been replaced by gypsum. From a depth of 462 m in well 22-1X State. Taken under crossed nicols.

Fig. 11. Scanning electron microscope backscattered electron images showing authigenic dawsonite and kaolinite from a depth of 468 m in well 22-1X State. A) Dawsonite growing on weathered potassium feldspar. The feldspar displays dissolution microporosity. B) Dawsonite prisms showing characteristic hollow interiors. The dawsonite crystals have grown on a grain of detrital quartz. C) Close-up of a hollow dawsonite crystal growing on the surface of a silt grain. There is no corrosion of the crystal's exterior. D) Pore filling kaolinite and dawsonite. A partially dissolved grain of detrital feldspar projects into the pore space that is lined with early authigenic dolomite. Abbreviations: Daw = dawsonite; do = dolomite; Fld = feldspar; Kaol = kaolinite.

Fig. 12. Anion concentrations (in ppm) and mineral saturations (as log Q/K) in the Springerville-St. Johns area. A) Concentrations of HCO₃. B) Concentrations of SO₄.

Elevation (masl)

Dolomite (Log Q/K)

Elevation (masl)

Gypsum (Log Q/K)

Fig. 12 cont. C) Degree of dolomite saturation. Dolomite is strongly supersaturated in the vicinity of the CO₂ field. D) Degree of gypsum saturation. Although gypsum is undersaturated throughout the area, the highest saturation indices are associated with the CO₂ field.

Fig. 13. Saturation state of aluminous minerals after adding 0.03 moles of CO_2 per kg of water from well 11-21 State. Reactions with and $1\text{e-}8$ moles of albite, anorthite, and orthoclase in the presence of quartz and dolomite were modeled. Reaction (Rxn) progress is plotted on the X-axis.

Fig. 14. Effect of adding 1 mole of CO_2 per kg of water on the saturation state of aluminous minerals. Other constraints are the same as were used in the simulation shown in Figure 14. Saturation of dawsonite occurred when the CO_2 fugacity reached 20 bar.

Fig. 15. Effect of reducing the fugacity of CO_2 from 20 to 0.92 bar on the saturation states of the aluminous minerals. Other conditions as in the preceding simulations. Kaolinite saturation was reached at a CO_2 fugacity reached 16 bar.

Injection of CO₂ into an Unconfined Aquifer Located Beneath the Colorado Plateau, Central Utah.

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Abstract

This paper investigates injection of CO₂ into non-dome-shaped geological structures that do not provide the traps traditionally deemed necessary for the development of artificial CO₂ reservoirs.

We have developed a regional scale, two-dimensional numerical model of one such structure on the Colorado Plateau. This model includes the major physical and chemical processes induced by injection of CO₂ for 30 years at a rate of 5 million tonnes/year (equivalent to a 600 MW coal-fired power plant).

Ignoring water-rock reactions, CO₂ returns to the surface after about 250 years and about 40% remains sequestered after 1000 years. However, coupling water-rock reactions to transport calculations shows significantly more CO₂ is sequestered, with dawsonite and calcite the predominant sequestration minerals. There is still some leakage of CO₂ to the surface in all scenarios investigated but we estimate at least 70% remains permanently sequestered.

Introduction

This paper summarizes work investigating the injection of CO₂ into geological structures that are not dome shaped and thus do not provide the conventional reservoir-trap geology usually considered necessary for the development of a gas reservoir. Although such structures are open, they may however, provide very long flow paths between the injection point and the surface, allowing the permanent sequestration of the injected CO₂ as a mineral or dissolved in the groundwater. This type of structure is common in the Colorado Plateau and Southern Rocky Mountains region (Allis et al., these proceedings). A fuller description of the work is provided in White *et al.* (2003).

We investigate one such geological structure using a two-dimensional numerical model of an unconfined reservoir to study the long-term behavior of CO₂ injected in the reservoir. Using the reactive chemical transport code ChemTOUGH2 (White 1995) the model is able to represent the major physical and chemical processes induced by injection of CO₂ into the reservoirs including transport in the liquid and gas phases, the effect of dissolved CO₂ on brine density, and the reaction between the CO₂ plume and the reservoir rocks.

Geological Setting

The geology beneath Hunter Power Plant, located on the San Rafael Swell, is an example of a structure that, although not dome shaped, may provide a suitable CO₂ sequestration site. The San Rafael Swell is a major physiographic feature in east-central Utah. It represents a broad, basement-involved, asymmetrical anticline that trends north-northeast to south-southwest. The San Rafael Swell is one of numerous Laramide-age (middle to late Paleocene to early Oligocene) structures on the Colorado Plateau.

The site is considered an important test case as there are two power plants within 15 km with a combined capacity of 2000 MW producing 15 million tonnes of CO₂ emissions per annum. The sedimentary sequence shown in Figure 1 contains potential reservoir and seal formations at over 1 km depth beneath the power plant, but the regional dip exposes some of these formations at the surface some 40 to 50 km away.

Allis *et al.* (these proceedings) have reviewed the properties of likely reservoirs and capping structures in this region. Table 1 summarizes the properties of the units in the sequence and identifies several potential targets for the injection of CO₂ gas on this cross-section; 1) Navajo Sandstone, 2) Wingate Sandstone, 3) White Rim Sandstone, and 4) Redwall Limestone. Of these, only the Redwall Limestone is not exposed on the crest or flanks of the uplift.

Hydrological model

The regional topography and precipitation pattern give a pressure gradient roughly along the cross-section of Figure 1, with pressures highest in the West. Regional flow is from the high ground of the Wasach Plateau in the West towards the Green River in the East.

In the Wasach Plateau region (topography above about 2000 masl) annual precipitation ranges from 100 cm at the West of the section to 20 cm where the surface drops below 2000 masl. East of this the annual precipitation is 20 cm. Infiltration is taken to be 15% on the High Plateau, above 2500 masl and 2% elsewhere. These values are similar to those assumed by USGS hydrologic modeling of the Colorado Plateau, and one particular study of recharge amounts not too far from the cross-section of Figure 1 (Danielson and Hood, 1984).

Previous modeling studies simulated the formation of the natural CO₂ reservoirs at Farnham Dome on the Colorado Plateau (Allis *et al.* 2001, White *et al.* 2001, White *et al.* 2002). This work found that permeabilities of 100 mD for aquifers, 1 mD for mixed units, and 0.01 mD for confining units lead to the formation of the observed natural CO₂ reservoirs. Increasing these figures by an order of magnitude did not give rise to the formation of reservoirs.

On the eastern boundary of the model we set boundary pressures to those of a hydrostatic column with the water table depth determined from pressure measurements in the area while on the western boundary pressures are either hydrostatic or no flow across the boundary is enforced.

Formation	Typical Thickness (meters)	Age	Porosity	Permeability	Potential as a CO ₂ Reservoir	Potential as a Seal
North Horn Tkn	<250	Tertiary	High	Med	Too shallow	
Price River Kpr	80	Cretaceous	High	Med	Too shallow	
Castlegate Kc	70	Cretaceous	High	High	Too shallow	
Blackhawk Kbh	120	Cretaceous	Med	High	Too shallow	
Star Point Ksp	60	Cretaceous	Med	Med	Too shallow	
Mancos Kmm	380	Cretaceous	Low	Low	Low	Med
Mancos Kmem	120	Cretaceous	Med	Med	Low	Med
Mancos Kmbg	200	Cretaceous	Low	Low	Low	High
Mancos Kmf	10	Cretaceous	High	High	Low	High
Mancos Kmt	20	Cretaceous	Low	Low	Low	High
Dakota and Cedar Mtn. Undivided Kdc	87	Cretaceous-Jurassic	Med	Med	Med	Low
Morrison Jms	201	Jurassic	Med	Med	Med	Low
Summerville/Curtis Js	82	Jurassic	Low	Low	Low	High
Entrada Je	136	Jurassic	Med	Low	Low	Low
Carmel Jc	82	Jurassic	Low	Low	Low	Med
Navajo Jn	160	Jurassic	High	High	High	Low
Kayenta Jk	53	Jurassic	Med	Med	Low	Low
Wingate Jw	107	Jurassic	High	High	High	Low
Chinle Trc	113	Triassic	Low	Low	Low	High
Moenkopi Trm	235	Triassic	Low	Low	Low	High
Black Box Pk	31	Permian	Med	Low	Low	Med
White Rim Pwr	153	Permian	High	High	High	Low
Elephant Canyon Pec	198	Permian	Low	Low	Low	Med
Honaker Trail Pht	190	Pennsylvanian	Med	Low	Low	Low
Paradox Pp	198	Pennsylvanian	Med	Low	Low	High
Pinkerton Trail Ppt	91	Pennsylvanian	Low	Low	Low	Med
Redwall Mr	244	Mississippian	Med	Med	Med	Low
Ouray Do	53	Devonian	Low	Low	Low	Med
Elbert De	76	Devonian	Low	Low	Low	Med
Lynch-Maxfield undivided Clm	312	Cambrian	Low	Low	Low	Med
Ophir Co	61	Cambrian	Low	Low	Low	High
Tintic Ct	62	Cambrian	Low	Low	Low	Low
Schist/Granite Pc	--	Precambrian	Low	Low	Low	Low

Table 1: Properties of geologic units forming the cross-section in Figure 1.

Figure 1: Geology on the cross-section beneath the Hunter Power-plant, Central Utah

Figure 2: Cross-section on which the model is based. Symbols indicate the location of pressure data points used in calibrating the model. Data points on the East San Rafael Swell are to the east of the cross-section and provide a boundary condition on the Eastern boundary of the slice. Filled triangles on the Wasatch Plateau are the locations of downhole pressure data that provide a constraint on the west side of the cross-section. The lateral pressure gradient is about 10 MPa (100 bar).

Numerical Model

Two TOUGH2/ChemTOUGH2 integrated finite difference models of the cross-section shown in Figure 1 have been developed. In both models the cross-section is divided into a number of elements with element geometry determined by the need to match geological layer interfaces (Figure 3). In the first model (Model A) we have used a fine grid in the vicinity of the injection wells to resolve better the early part of the injection period when pressure gradients are large. Resolution in the second model (Model B) is reduced in order to keep the computer time requirements for modeling the CO₂-brine-rock interactions manageable. These models and the parameters used in the modeling are discussed in detail in White *et al.* (2003).

Figure 3: Mesh structure used for detailed flow calculations (a) and reactive chemical transport calculations (b)

Boundary Conditions

Boundary conditions for the numerical model are determined largely from the hydrological model discussed above and they can be summarized as

- Atmospheric pressure at the surface
- 20 cm precipitation on low (below 2000 masl) area with 2% infiltration
- 100 cm precipitation in the West decreasing to 20 cm at the base of the Wasatch Plateau with 15% infiltration
- Constant pressure on the Eastern boundary
- Constant pressure on Western boundary during sequestration simulations. No flow through this boundary during steady state calculations.
- No fluid flow through the base of the model
- Heat flow at the base of the model is set to match the typical terrestrial heat flow for the region.

Sequestration scenarios

Sequestration scenarios investigated fall into two groups. The first group used Model A and the TOUGH2 (Pruess 1991) simulator to model the injection of CO₂ into several reservoirs and tracked the location of the CO₂ over a period of 1000 years. Chemical reactions between the reservoir brine and the host rock were ignored. Reservoirs investigated were the Navajo Sandstone, White Rim Sandstone, Wingate Sandstone and Redwall Limestone aquifers.

The second group used the ChemTOUGH2 (White 1995) simulator and investigated the effects of water-rock interactions on CO₂ sequestration, firstly modeling reactions between a brine with a constant CO₂ partial pressure and reservoir rock and then a reactive transport simulation using Model B.

In all flow simulations reported CO₂ is injected for 30 years at 0.15 kg/s per meter of cross-section thickness. This rate corresponds to about 5 million tonnes / year (approximately equal to the emissions from a 600 MW coal fired power station) into a section 100 meters wide.

Model A Simulations

The Redwall Limestone proved unsuitable for long-term sequestration of CO₂ as very high injection pressures were required to inject into the medium permeability (2 mD) inferred for this reservoir. Figure 4 shows the fraction of injected CO₂ that has not returned to the atmosphere as a function of time. Clearly neither the Wingate nor Navajo formations appear suitable for long-term sequestration of CO₂. In both formations CO₂ begins to reach the surface before injection is completed. Even in the case of the White Rim Sandstone there is significant leakage from the target reservoir and a much larger volume of rock is exposed to CO₂ than just the White Rim sandstone formation (Figure 5).

Of the investigated reservoirs, only the White Rim formation may provide containment of injected CO₂ for the hundreds to thousands of years required for mineral sequestration reactions to complete. However, the geochemical situation is much more complex than has been assumed in Model A. Transport of reaction products in the reservoir, changing reservoir temperature, mineralogy and partial pressure of CO₂ all mean a full reactive transport model must be used.

Figure 4: Fraction of total injected CO₂ remaining sub-surface as a function of time for three potential sequestration sites. Note that these calculations ignored water-rock reactions (i.e. Model A).

Figure 5: Gas saturation resulting from injection is into the White Rim formation at 10 (a), 30(b) and 100(c) years (Model A).

Model B Simulations

Reactive transport modeling is a computer intensive activity and a balance must be struck between model complexity, resolution and computer time. We have included sufficient geo-chemical complexity to represent the interaction of a simplified reservoir mineralogy (Table 2) with a CO₂ rich brine. To achieve this we used the lower spatial resolution of Model B (Figure 3). However it retains a reasonable resolution with over 1300 elements. The fate of injected CO₂ was traced for 1000 years as the geo-chemical calculations described earlier in this section suggest most sequestration reactions will be well advanced in this time. Details of parameters used for water-rock reaction rates and the kinetic model used for these reactions is provided in White *et al.* (2003).

Initial chemical conditions were calculated by firstly assigning the mineralogy specified in Table 2 to model elements, setting the reservoir fluid to a 0.3 M NaCl brine (based on water analyses from exploration wells in the San Rafael Swell region.) and then allowing the brine to react with the reservoir for 1000 years. This modified the original mineralogy slightly and provided initial conditions for the fluid reservoir throughout the reservoir. The initial brine composition in the White Rim sandstone is given in Table 3.

PH	Cl	SO4	HCO3	SiO ₂	Al	Ca	Mg	K	Na	Fe	HS
11.7	10394	0.0	0.1	1442	0.0	3280	0.03	109	6709	0.0	0.1

Table 3: Initial water chemistry (in mg/kg) in White Rim sandstone reservoir

CO₂ was then injected into the White Rim formation for 30 years at the same rate as used in the non-reactive modeling (Model A). The chemistry and flows in the system were then simulated for a total of 1000 years.

The location of the gas at the conclusion of the simulation period is shown in Figure 6. Low permeability formations, primarily the Moenkopi and Chinle formations, have channeled the gas over thirty kilometers horizontally. There is some leakage into shallower permeable formations and the formation of secondary CO₂ reservoirs above the major concentration of gas in the White Rim and Black Box formations. Although it is not obvious from Figure 6, about 10% of the gas has escaped out the top boundary of the model.

Injected CO₂ dissolves in the reservoir brine to form a low pH fluid, this reacts with the feldspars in the reservoir and precipitates kaolinite together with the carbonate minerals calcite and dawsonite. These three secondary minerals have been observed as pore-filling minerals likely related to an influx of CO₂-rich fluids in the Springerville natural CO₂ field, eastern Arizona (Moore et al., 2003; these proceedings). Figures 7-9 show the change in the amount of feldspars throughout the model domain 950 years after injection begins. There is some dissolution of anorthite throughout the domain but it is largest in the area affected by the injected CO₂. K-feldspar is dissolved only in the low pH region formed by the interaction of injected CO₂ with the reservoir brine. Albite is initially supersaturated in some regions and there is some precipitation of albite where these regions are not affected by the injected CO₂. Albite is dissolved in the region affected by the injected CO₂. Figures 10-12 show the location of the precipitated minerals. These are largely confined to the two-phase, low pH region shown in Figure 6 although they are not found throughout this region. Calcite is not found shallower than 1500 masl while dawsonite and kaolinite are found deeper than 1600 masl. Dawsonite is not found in the Moenkopi or Chinle capping rocks.

Figure 13 shows the fate of the injected CO₂ 950 years after injection began and these results are summarized in Table 4. It is not possible to directly compare the results of Model A (Figure 4) and Model B (Figure 13) as the coarse grid of Model B does introduce some errors into the calculation reducing the calculated leakage to the surface. In the long term, the effect of this discretization error is to overestimate the amount of CO₂ sequestered by about 10%. To make clear the effect of including water-rock reactions, also plotted in Figure 13 are the results of running the Model B grid using TOUGH2 rather than

ChemTOUGH2. The effect of including water-rock reactions is not simply to reduce the surface leakage by the amount of CO₂ sequestered in a mineral phase as precipitation of carbonate minerals also reduces the partial pressure of CO₂ reducing flows driven by pressure gradients. Although only 13% of the injected CO₂ is sequestered as a mineral surface leakage is reduced by 60 %.

	With mineral sequestration	Without mineral sequestration
Gas phase	36 %	31 %
Dissolved in brine	34 %	31 %
Calcite	7 %	
Dawsonite mineral	6 %	
Leakage to surface	17 %	38 %

Table 4: Location of CO₂ 950 years after the beginning of injection.

Summary and Conclusions

We have developed a conceptual and two numerical models of the geology and groundwater along a cross-section lying approximately NW-SE and in the vicinity of the Hunter power station on the Colorado Plateau, Central Utah. A number of potential sequestration sites were identified on this cross-section. However after initial modeling (ignoring water-rock interactions) of the fate of CO₂ injected into these sites only the White Rim Sandstone appeared to offer the properties that would make a successful sequestration site.

The capacity of White Rim sandstone for sequestration (assuming a 100 meter wide cross-section) is approximately $50,000 \times 100 \times 200 \times 22 = 2.2 \times 10^{10}$ kg or sufficient to sequester about 150 years of injected CO₂ (White *et al.* 2003). CO₂ is sequestered as a mineral or dissolved in reservoir fluid. In fact, a much larger volume of rock is ‘seen’ by the injected CO₂ than is contained in the White Rim formation (see Figure 7) and there should be ample volume of rock to sequester all the injected CO₂ providing flow to the surface is sufficiently slow.

More detailed modeling of injection into the White Rim Sandstone that included water-rock interactions was carried out. This found that 1000 years after the 30 year injection period began approximately 21 % of the injected CO₂ was permanently sequestered as a mineral, 52% was beneath the ground surface as a gas or dissolved in the groundwater and 17% had leaked to the surface. Leakage to the surface was continuing. Running model B ignoring water-rock interactions for a longer simulation period found gas ceased leaking to the surface at 1500 years. At this stage, by extrapolating Figure 14, we estimate at least 70% of the injected gas is permanently sequestered

A note of caution must be added to these estimates as some of the key parameters governing the results are not well known. In particular the composition and properties of the reservoir and seal units are not well known and nor are the mineral reaction rates or surface areas *in a field setting*. Better grid resolution is also required in the reactive transport model.

Figure 6: Gas saturation 950 years after beginning of CO₂ injection (Model B).

Figure 7: Change in anorthite density 950 years after the beginning of CO₂ injection (M dm⁻³); (Model B).

Figure 8: Change in albite density 950 years after the beginning of CO₂ injection (Mdm⁻³Model B).

Figure 9: Change in K-feldspar density 950 years after the beginning of CO₂ injection (M dm⁻³), (Model B).

Figure 10: Change in calcite density 950 years after the beginning of CO₂ injection (M dm⁻³); (Model B).

Figure 11: Change in dawsonite density 950 years after the beginning of CO₂ injection (M dm⁻³; Model B).

Figure 12: Change in kaolinite density 950 years after the beginning of CO₂ injection (M dm⁻³; Model B).

Figure 13: Location of CO₂ within the reservoir as a function of time. The difference between Total CO₂ and 1.0 is the fraction of CO₂ leakage to the atmosphere.

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Table 2:

Initial Reservoir Mineralogy (Volume %). The code for formation names is given in Table 1.

Formation	Anorthite	Na-Smectite	Calcite	Dolomite	K-Feldspar	Kaolinite	Quartz	Gypsum	Illite	Hematite	Magnetite	Albite	Dawsonite	Siderite	Porosity
Tkn		34.	1.	1.		34.	18.		1.						10.
Tkn	1.	11.	2.		1.	11.	63.		1.			1.			10.
Kpr	1.	11.	2.		1.	11.	63.		1.	0.	0.	1.		0.	10.
Kc	1.	11.	2.		1.	11.	67.		1.	0.	0.	1.	0.	0.	5.
Kbh	1.	11.	2.		1.	11.	63.		1.	0.	0.	1.	0.	0.	10.
Ksp	1.	11.	2.		1.	11.	67.		1.	0.	0.	1.	0.	0.	5.
Kmm		37.	1.	1.		37.	20.		1.	0.	0.	0.	0.	0.	2.
Kmeu	1.	12.	2.		1.	12.	69.		1.	0.	0.	1.	0.	0.	2.
Kmem	0.	6.	1.			6.	35.		0.	0.	0.	0.	0.	0.	5.
Kmel	0.	4.	1.			4.	23.		0.	0.	0.	0.	0.	0.	2.
Kmbg	1.	12.	2.		1.	12.	69.		1.	0.	0.	1.	0.	0.	2.
Kmf		15.	2.	1.		15.	61.		1.	1.	1.	0.	0.	0.	2.
Kdc		29.	1.	1.		29.	29.		1.	0.	0.	0.	0.	0.	10.
Jmbb	1.	11.	2.	1.	1.	11.	68.		0.	1.	1.	1.	0.	0.	2.
Jms		13.	2.	1.		13.	65.		1.	1.	1.	0.	0.	0.	2.
Js	1.	11.	2.	1.	1.	11.	68.	1.	0.	0.	0.	1.	0.	0.	2.
Je	1.	5.	1.	1.	1.	5.	75.		0.	1.	1.	1.	0.	0.	10.
Jc	1.	10.	1.	52.	1.	10.	21.		1.	0.	0.	1.	0.	0.	2.
Jn	1.	2.	1.	1.	1.	2.	73.		0.	1.	1.	1.	0.	0.	20.
Jk	1.	8.	1.		1.	8.	65.		0.	0.	0.	1.	0.	0.	20.
Jw	1.	8.	1.		1.	8.	65.		0.	0.	0.	1.	0.	0.	20.
Trc	1.	22.	2.	2.	1.	22.	44.		1.	1.	1.	1.	0.	0.	2.
Trm	1.	22.	2.	5.	1.	22.	43.		0.	2.	0.	1.	0.	0.	2.
Pk		2.	2.	65.		2.	19.		0.	0.	0.	0.	0.	0.	10.
Pwr	1.	2.	2.		1.	2.	75.		0.	0.	0.	1.	0.	0.	20.
Pec				59.			39.		0.	0.	0.	0.	0.	0.	2.
Pht				28.		16.	47.		0.	2.	0.	0.	0.	0.	10.
Pp		9.		27.		9.	45.		0.	0.	0.	0.	0.	0.	10.
Ppt		37.	1.	1.		37.	20.		1.	0.	0.	0.	0.	0.	2.
Mr				90.					0.	0.	0.	0.	0.	0.	10.
Do				98.					0.	0.	0.	0.	0.	0.	2.
De		20.		59.		20.			0.	0.	0.	0.	0.	0.	2.
Clm		20.		59.		20.			0.	0.	0.	0.	0.	0.	2.
Co		20.		59.		20.			0.	0.	0.	0.	0.	0.	2.
Ct							98.		0.	0.	0.	0.	0.	0.	2.

CONCLUSIONS

Three papers were presented at the DOE's Second Annual Conference On Carbon Sequestration, held in Alexandria VA on May 5-9. Conclusions are contained with each paper and are distinctive to that paper. Since they are given in the above section of this report, they are not repeated here.

REFERENCES

Each of the three papers given in the Results and Discussion section contain a reference list, so the references are not repeated here.