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Business Models for Commercial-Scale Carbon Dioxide Sequestration; with Focus on Storage Capacity and Enhanced Oil Recovery in Citronelle Dome

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BUSINESS MODELS FOR COMMERCIAL-SCALE CARBON DIOXIDE SEQUESTRATION; WITH FOCUS ON STORAGE CAPACITY AND ENHANCED OIL RECOVERY IN CITRONELLE DOME

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A DISSERTATION

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INTERDISCIPLINARY ENGINEERING

ABSTRACT

Fossil fuels, such as coal and natural gas, currently play an enormous role in our nation's base-load energy supply and provide reliable domestic energy security. If fossil fuels are to remain a component of future energy production in a carbon constrained world, then carbon-neutral energy options must be available. With fossil fuels, point-source environmental control technologies will be required to help comply with future carbon dioxide (CO_2) emissions standards. One very promising technology, carbon capture and storage (CCS) consists of the separation of CO_2 from fossil fuels or flue gas, pipeline transport, and injection into deep geologic formations. CCS has been identified as a critical enabling technology to mitigate the large quantities of CO_2 emitted from coal-fired power plants and subsequently discharged to the atmosphere.

For successful commercial-scale deployment of CCS understanding the earth's subsurface storage capacity of proposed injection target reservoirs, including the potential reuse of CO_2 as a commodity in enhanced oil recovery, are key research & development issues. Electrical utilities will also need to develop and evaluate potentially new business models for the commercial deployment of CCS technologies. This dissertation supports the larger picture of CCS with a focus on establishing capacity estimates for geologic formations; the design of a pilot injection project for enhanced oil recovery; and the development of prototypical physical and business models for future deployment of CCS.

Keywords: Carbon Capture and Storage, Geologic Sequestration, Enhanced Oil Recovery, Carbon Dioxide, Geologic Storage Capacity Estimates, Commercial CCS Business Models

DEDICATION

This dissertation is dedicated to the following people:

- To my loving wife, Kellie, for endless and unwavering faith, encouragement, and patience and who carried the weight of my busy schedule and late nights in front of the computer
- To my parents who always supported and inspired me to attend school and for the ongoing message of the importance of education in life's success
- To my doctoral advisor, Dr. Peter Walsh, as a role-model for hard work, persistence and personal sacrifices, and who instilled in me the inspiration to set high goals and to be a good scientist

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For successful commercial-scale deployment of carbon capture and Storage (CCS) it will be key for electrical utilities and site operators to understand 1) the subsurface geologic storage capacity of proposed injection target reservoirs, 2) the potential for reuse and storage of captured CO_2 as a commodity in enhanced oil recovery (EOR), and 3) the types of business models best suited for secure and cost-effective long-term storage at commercial scale. This dissertation considers the larger picture of CCS, including all of these components.

Information and experience gained from oil and gas exploration, underground natural gas storage, and underground acid gas injection all support a safe geologic storage solution. These sources of data and experience, as well as subsurface geologic investigations, suggest that more than enough accessible pore volume exists for geologic storage to be a long-term, high-capacity, carbon sequestration option. The Citronelle Dome, chosen as the example for detailed study, is a giant salt-cored anticline in the Mississippi Interior Salt Basin of southern Alabama. The dome forms an elliptical structural closure providing opportunities for both CO_2-EOR and large-capacity storage in saline formations. The range of preliminary static estimates of CO_2 storage capacity in the Citronelle Dome was estimated to be between 500 million and 2 billion short tons. Therefore, the Citronelle Dome can be considered as a major geologic sink where CO_2 can be safely stored while realizing the economic benefits associated with EOR.

CO_2 pilot injection studies, with site-specific geologic assessment and engineering reservoir design, can be instrumental in demonstrating both enhanced oil recovery and geologic storage of greenhouse gases. The purpose of this component of the research is to present the geologic and reservoir analyses in support of a field pilot test that will evaluate the technical and economic feasibility of commercial-scale CO_2-enhanced oil recovery to increase oil recovery and extend the productive life of the Citronelle Oil Field, the largest conventional oil field in Alabama (SE USA). Screening of reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition indicates that the Cretaceous-age Donovan sand, which has produced more than 169 million bbl from the Citronelle Oil Field, is amenable to miscible CO_2 flooding. An 81 ha (200 ac) inverted 5-spot test well pattern with one central gas injector and four producers was chosen for study. Injection is planned in two phases, each consisting of 6,804 t (7,500 short tons) of food-grade CO_2. The Citronelle Unit B-19-10 #2 well (Permit No. 3232) is the CO_2 injector for the first injection test. The 14-1 and 16-2 sands of the upper Donovan are the target zones. These sandstone units consist of fine to medium-grained sandstone that is enveloped by variegated mudstone. Selection of the sands was based on the distribution of perforated zones in the test pattern, their production history, and the ability to correlate individual sandstone units in geophysical well logs. The pilot injections will evaluate the applicability of tertiary oil recovery to Citronelle Field and will provide data on the pressure response of the reservoirs, the mobility of fluids, time to breakthrough, and CO_2 sweep efficiency. The results of the pilot injections will aid in the formulation of commercial-scale reservoir management strategies, including geologic sequestration options that can be applied to Citronelle Field and to other geologically heterogeneous oil fields. It can also serve as a model for the design of similar pilot injection projects.

Even before carbon capture and storage technology has been fully developed, electric utilities will need to consider the logistics of deployment of widespread commercial-scale operations. The framework of CCS will require utilities to adopt business models that ensure both safe and affordable CCS operations while maintaining reliable electric power generation. The possible physical models include: 1) an infrastructure with centralized CO_2 pipelines that focus geologic sequestration in pooled regional storage sites or supply CO_2 for beneficial use in enhanced oil recovery (EOR), or 2) a dispersed plant model with sequestration operations which take place in close proximity to CO_2 capture. Several prototypical business models, including hybrids of these two physical models, will be in play, including: 1) a self-build option, 2) a joint venture, and 3) a pay-at-the-gate model. In the self-build model, operations are vertically integrated and utility owned and operated by an internal staff of engineers and geologists. In contrast to that arrangement, a joint venture model stresses a partnership between the host site utility/owner's engineer and external operators and consultants. The third, pay at the gate model is turn-key external contracting to a third party owner/operator with cash positive fees paid out for sequestration and cash positive income for CO_2-EOR. The selection of a business model for CCS will be based in part on the desire of electric utilities to be vertically integrated, on source-sink economics, and on the demand for CO_2-EOR. Another element in this decision will be how engaged a utility decides to be and the experience the utility has had with pre-commercial research and development. Through its own research, development, and demonstrations, a utility would likely have already addressed, or at least been exposed to, the many technical, regulatory, and risk management issues related to successful CCS. This dissertation provides the framework for identifying the different physical and related prototypical business models that electric utilities may choose to adopt for commercial-scale CCS.

CITRONELLE DOME: A GIANT OPPORTUNITY FOR MULTIZONE CARBON STORAGE AND ENHANCED OIL RECOVERY IN THE MISSISSIPPI INTERIOR SALT BASIN OF ALABAMA

by

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ABSTRACT

The Citronelle Dome is a giant, salt-cored anticline in the eastern Mississippi Interior Salt Basin of southern Alabama that is located near several large-scale, stationary, carbon-emitting sources in the greater Mobile area. The dome forms an elliptical, four-way structural closure containing opportunities for CO_2-enhanced oil recovery (CO_2-EOR) and large-capacity saline reservoir CO_2 sequestration.

The Citronelle oil field, located on the crest of the dome, has produced more than 169 million bbl of 42–46° API gravity oil from sandstone bodies in the Lower Cretaceous Rodessa Formation. The top seal for the oil accumulation is a thick succession of shale and anhydrite, and the reservoir is underfilled such that oil-water contacts are typically elevated 30–60 m (100–200 ft) above the structural spill point. Approximately 31–34% of the original oil in place has been recovered by primary and secondary methods, and CO_2-EOR has the potential to increase reserves by up to 20%.

Structural contour maps of the dome demonstrate that the area of structural closure increases upward in section. Sandstone units providing prospective carbon sinks include the Massive and Pilot sands of the lower Tuscaloosa Group, as well as several sandstone units in the upper Tuscaloosa Group and the Eutaw Formation. Many of these sandstone units are characterized by high porosity and permeability with low heterogeneity. The Tuscaloosa-Eutaw interval is capped by up to 610 m (2000 ft) of chalk and marine shale that are proven reservoir seals in nearby oil fields. Therefore, the Citronelle Dome can be considered a major geologic sink where CO_2 can be safely stored while realizing the economic benefits associated with CO_2-EOR.

INTRODUCTION

From the standpoints of cost and technical readiness, CO_2 capture and geologic storage are among the most promising options for reducing atmospheric CO_2 emissions. Large-scale industrial sources of CO_2, such as fossil-fuel-fired electric power generation facilities, fertilizer plants, oil refineries, and the calcination of carbonates during cement manufacture, are all candidates for carbon capture and geologic storage. Information and experience gained from oil and gas exploration, underground natural gas storage, and underground acid gas injection all support a safe geologic storage solution. These information resources, as well as subsurface geologic investigations, suggest that more than enough accessible rock volume exists for geologic storage to be a long-term, high-capacity carbon sequestration option.

Among the major geologic sinks, which include conventional hydrocarbon reservoirs, coal seams, and saline formations, mature oil reservoirs are attractive because the cost of CO_2 separation and compression for storage can be offset by CO_2-enhanced oil recovery (CO_2-EOR) (Reichle et al., 1999). CO_2-enhanced oil recovery has been performed successfully in the Permian Basin of Texas since the early 1970s and more recently in Mississippi and Canada. If injection is engineered properly, a significant amount of CO_2 can be sequestered in the reservoir during oil recovery by CO_2-EOR (Asghari and Al-Dliwe, 2005). Additional CO_2 can be stored by continuing to inject into the formation after EOR operations are completed.

Saline formations also have a large storage capacity, potentially more than mature oil reservoirs. Oil reservoirs are typically localized in geologic traps, whereas storage in saline reservoirs does not require a conventional hydrocarbon trap. Existing oil-field infrastructure in many areas throughout the United States could be used to inject CO_2 into saline formations for sequestration. This presents very large multizone storage opportunities in geologic structures containing stacked oil reservoirs and saline formations.

Alabama currently ranks 16th among the 31 oil-producing states. Advanced Resources International (2006) estimated that 172 million bbl (27.3 x 10^6 m^3; 966 x 10^6 ft^3) of the oil remaining in five Alabama reservoirs is technically recoverable. Of this, 111 million bbl (17.6 x 10^6 m^3; 623 x 10^6 ft^3) were estimated to be economically recoverable from the largest of the five reservoirs using CO_2-EOR technology, at a crude oil price of U.S. \$40.00/bbl (U.S. \$251.60/m^3) and CO_2 cost of U.S. \$2.00/1000 ft^3 (U.S. \$7.06/100m^3). Holtz et al. (2005) obtained a similar estimate of 98 million bbl (15.6 x 10^6 m^3; 550 x 10^6 ft^3) of oil recoverable from all Alabama oil fields by miscible CO_2-EOR.

Although CO_2-EOR has been implemented successfully in other oil-producing areas, notably in the Permian Basin of west Texas and eastern New Mexico, the Williston Basin of Canada, and the Gulf of Mexico Basin of Mississippi, this technology has yet to be applied commercially in Alabama oil fields. The primary impediment to CO_2-EOR in Alabama is the lack of a CO_2 supply. Large continuous supplies of CO_2 captured from sources such as electric power plants seeking storage sites would change this situation significantly.

This article explores the potential use of the Citronelle Dome as a geologic sink with stacked oil and saline reservoirs, where a large volume of CO_2 can be stored permanently while realizing the economic benefits of CO_2-EOR. The Citronelle oil field, which produces oil from sandstones of the Lower Cretaceous Rodessa Formation, is an excellent candidate for CO_2-EOR. Upper Cretaceous sandstone units in the lower Tuscaloosa Group and in the upper Tuscaloosa-Eutaw interval all have the potential to be large-capacity carbon sinks. All of these sinks are capped by low-permeability anhydrite, shale, and chalk, which are proven reservoir seals in a broad range of structural settings throughout southwest Alabama.

Geologic Setting

The Gulf of Mexico Basin in southwest Alabama consists of a thick wedge ranging from 3660 to 6100 m (12,000 to 20,000 ft) of Mesozoic–Cenozoic sedimentary strata that generally dip and thicken south westward. The subsurface geology of this area has been well studied, and research has been driven by industrial water supplies, oil and gas exploration, and the subsurface disposal of industrial waste in brine aquifers. Water supply studies have been performed by Grubb (1998) and Miller (1990), and brine aquifer waste-disposal studies have been conducted by Alverson (1970) and Tucker and Kidd (1973). Most of the deep subsurface information in this area comes from oil and gas development. Most development has been in the Jurassic Norphlet and Smackover formations and in Cretaceous units ranging from the Rodessa Formation through the Selma Group (e.g., Eaves, 1976; Mancini and Benson, 1980; Mancini et al., 1985; Esposito and King, 1987; Mancini et al., 1987; Bolin et al., 1989; Raymond, 1995; Pashin et al., 2000; Kopaska-Merkel, 2002).

Citronelle Dome is a giant salt-cored anticline in the eastern part of the Mississippi Interior Salt Basin. The dome is a broad, open structure that is located west of the Mobile Graben. At the crest of the dome, more than 600 wells have been drilled, and most reach total depth within the Lower Cretaceous section. East of the crest, numerous wells penetrate the Jurassic section and produce gas and condensate from the Smackover and Norphlet formations in the Chunchula and Hatter's Pond oil fields. The Citronelle Dome forms an elliptical, fourway structural closure in which strata dip away from the crest at only 1–2°. Structural contour maps demonstrate that the area of structural closure increases upward in section from about 36 mi^2 (93 km^2) at the top of the Rodessa Formation to more than 72 mi^2 (186 km^2) at the top of the Tuscaloosa-Eutaw interval (Figures 1, 2).

Citronelle Oil Field

The Citronelle oil field is located approximately 50 km (30 mi) north of Mobile, Alabama. This domestic giant oil field is situated within the Cretaceous Donovan sand, which is historically considered to be part of the Rodessa Formation (Eaves, 1976), on a subtle dome that is developed above a broad, deep-seated Louann Salt pillow (Figure 3). The field was discovered in 1955 in the Zack Brooks Drilling Company Donovan #1 well (State Oil and Gas Board of Alabama Permit 608), which is located in Sec. 25, T2N, R3Win northern Mobile County, Alabama. The discovery well was drilled to a total depth of 3510 m (11,517 ft) and produced oil from two separate intervals in the Donovan sand. The field was drilled on a 40-ac (16-ha) spacing, covering an area of 16,400 ac (6637 ha). To date, 524 wells have been drilled in the field, with 414 wells currently listed as active or temporarily abandoned by the State Oil and Gas Board of Alabama. By December 1973, the field had produced more than 107 million bbl of oil. The field has been in water flood since 1961, and cumulative oil production now exceeds 169 million bbl. The present rate of production is approximately 50,000 bbl/month; thus, the Citronelle is a mature oil field, and application of CO_2-EOR technology has the potential to increase recovery substantially. According to Kuuskraa et al. (2004), CO_2-EOR has potential to increase oil reserves in the Citronelle oil field by 85 million bbl.

Although the oil field is developed within a simple domal structure, Donovan reservoirs are extremely heterogeneous. A 244-m (800-ft)-thick gross pay interval containing at least 42 productive sand zones, composed of 300 separate reservoirs, is produced in the field (Eaves, 1976; Fowler et al., 1998). The initial reservoir pressure in the field was 38 MPa (5500 psi); thus, the original reservoir pressure was effectively normal, and the reservoir temperature was about 98.9°C (210°F). The reservoir pressure was depleted significantly during primary production (Fretwell and Blair, 1999), and current pressure levels are typically below 20.7 MPa (3000 psi).

Rodessa Formation

The Rodessa Formation constitutes more than 244 m (800 ft) of interbedded shale and sandstone (Figure 4). It overlies a thick succession of Lower Cretaceous red beds that include the Hosston and Sligo formations. The Rodessa Formation is overlain by the Ferry Lake anhydrite, which is, in turn, overlain by shale of the Mooringsport Formation.

The principal rock types in the Rodessa Formation include variegated (i.e., red and gray) shale and yellowish brown quartz sandstone commonly stained with oil. The shale units contain a varied assemblage of physical and biogenic sedimentary structures ranging from pedogenic slickensides and root structures to burrows and oyster accumulations. The sandstone units typically form fining-upward successions between

2.4 and 12.2 m (8 and 40 ft) thick. The sandstone units generally have a sharp basal contact overlain by a lag of intraclastic conglomerate. The sandstone is composed predominantly of medium- to very fine-grained, cross-bedded quartzarenite that grades upward into shale. Subsurface mapping indicates that the sandstone is preserved in narrow single- to multistory sandstone bodies with a sinuous to linear geometry (Wilson and Warne, 1964; Eaves, 1976). The depositional environment of the Rodessa has been interpreted as a stacked series of meander belts that formed in a coastal embayment (Wilson and Warne, 1964; Eaves, 1976; Fowler et al., 1995). The high mica content of many of the sandstones indicates that the source of the sediments was probably the Paleozoic and Precambrian complex of the Southern Appalachian structural trend.

Eaves (1976) subdivided the Donovan sand into three intervals based on their reservoir attributes. The lower Donovan contains numerous oil-bearing sandstone units with a minor negative deflection in spontaneous potential (SP) logs and generally low resistivity. The middle Donovan, by contrast, contains water-bearing sandstone units with a strong negative deflection in SP logs and a large separation between the deep and shallow resistivity curves. The upper Donovan sand resembles the lower Donovan, except that the upper Donovan sandstone units tend to have a stronger SP response and higher resistivity. Historically, the bulk of the oil produced in the Citronelle oil field has come from the upper Donovan. The porosity of the Rodessa sandstone units is approximately 13%, and the permeability averages 13 md and is, in places, higher than 75 md. Reservoir energy for the field is provided by solution gas (Bolin et al., 1989; Fretwell and Blair, 1999). Geochemical evidence suggests that the oil trapped in the Donovan sand is sourced from the Jurassic Smackover Formation (Claypool and

Mancini, 1989), although the precise migration pathway and the origin of the oil-water-oil stacking in the Rodessa is unknown. Shale units in the Rodessa Formation apparently form effective reservoir seals locally, and the thick anhydrite-shale section in the Ferry Lake and Mooringsport formations forms the top seal for the hydrocarbon system in Citronelle oil field.

Tuscaloosa Group and Eutaw Formation

Produced water in the Citronelle oil field is primarily disposed in saline sandstone units within the Tuscaloosa Group. Accordingly, the Tuscaloosa-Eutaw section may be an attractive saline formation for the storage of CO_2.

The Tuscaloosa-Eutaw section is of Upper Cretaceous age and is nearly 460 m (1500 ft) thick in the Citronelle Dome (Figure 5). The Tuscaloosa Group disconformably overlies Lower Cretaceous deposits of the Dantzler Formation and has a distinctive internal stratigraphy. The lower Tuscaloosa Group is subdivided informally into the Massive and Pilot sands, which can be traced across southwest Alabama and into Mississippi. The lower part of the Massive sand in Citronelle Dome has a blocky well-log pattern and low resistivity, whereas the upper part has a fining-upward log pattern and higher resistivity. At the top of the lower Tuscaloosa section, the Pilot sand includes multiple sandstone layers with a serrated to blocky log pattern. The Pilot sand contains significant oil reservoirs in southwest Alabama, and overall, the lower Tuscaloosa section is interpreted as transgressive shoreline deposits (Mancini et al., 1987). Significant oil reservoirs also exist in both the Tuscaloosa Group and Eutaw Formation throughout the Mississippi Interior Salt Basin of Alabama (e.g., Bolin et al., 1989).

The Pilot sand is overlain by thick shale that is commonly called the Marine Tuscaloosa, and this shale unit is the top seal for the lower Tuscaloosa oil reservoirs. The shale coarsens upward into a thick succession of interbedded shale and sandstone assigned to the upper Tuscaloosa Group and is likely fluvial-deltaic in origin. Above the upper Tuscaloosa, the Eutaw Formation consists of about 84 m (275 ft) of sandstone that fines upward into shale. Although the upper Tuscaloosa is not oil productive, significant reservoirs exist in the Eutaw Formation, which is interpreted to include transgressive shoreline and shelf facies (Pashin et al., 2000). Porosity values are typically 20% or higher in the Tuscaloosa-Eutaw sandstone, and permeability ranges widely from less than 50 to more than 3000 md. The Eutaw Formation is overlain by more than 366 m (1200 ft) of chalk, which composes the Selma Group. The Selma Group acts as the top seal for Eutaw reservoirs and separates the Mesozoic hydrocarbon system in the eastern Gulf of Mexico Basin from underground sources of potable drinking water in the Tertiary section.

Storage Capacity

Formation-specific capacity estimates are integral to the implementation of carbon capture and geologic storage at existing facilities. These estimates will also be an important factor in the siting of new large-scale stationary emitting sources and are required for the selection of geologic sinks that are capable of providing stable, long-term storage.

Static capacity estimates do not consider transient phenomena and depend exclusively on reservoir properties and geometry. The methodology used to estimate capacity in this evaluation does not account for the site-specific partitioning of CO_2 among gas, liquid, and solid phases, as in the analysis by Pruess et al. (2001), but is a volumetric calculation based on receiving formation area, thickness, porosity, CO_2 density, temperature, and pressure. An efficiency factor that has upper and lower limits of 0.4 and 0.1, respectively, was incorporated to account for residual water saturation. In addition, permeable fraction efficiency factors of 0.9 for the Tuscaloosa-Eutaw sands and 0.6 for the Rodessa Formation were assigned to account for shale dispersion, based on visual observations on drill-core samples of the rock matrix.

The geometry of the lower Tuscaloosa (Pilot and Massive sands) and the upper Tuscaloosa-Eutaw interval is based on the areal extent of the four-way structural closure and the apparent structural spill point of the Citronelle Dome (72 mi^2; 186 km^2). The current production area of the Citronelle oil field is 36 mi^2 (93 km^2). Reservoir thickness was determined from geophysical well logs, and porosity was determined from records in the open files of the Geological Survey of Alabama and the State Oil and Gas Board of Alabama. The porosity of the Tuscaloosa-Eutaw sands was estimated at 20%, whereas an average porosity of 13% was used for the Rodessa sands.

The results of the capacity calculations are summarized in Table 1. At the greatest depth, in the Rodessa Formation, oil reservoirs in the lower and upper Donovan sands are estimated to have the capacity to store between 115 and 460 million tons of CO_2. The saline reservoirs of the middle Donovan sand could provide an additional 24–100 million tons of CO_2 storage. In the lower Tuscaloosa, between 200 and 790 million tons of CO_2 can be sequestered in the Massive sand, and between 40 and 160 million tons is the estimated range of storage capacity for the Pilot sand. Significant capacity also exists in the upper Tuscaloosa-Eutaw section, which may hold between 150 and 600 million tons of CO_2. The total static estimate of the storage capacity of the Citronelle Dome is then between approximately 500 million and 2 billion tons of CO_2 (480 million to 1.9 billion t of CO_2).

James M. Barry Electric Generating Plant, a major coal-fired power plant operated by Alabama Power Company, is located about 10 mi (16 km) east of the Citronelle oil field and only 4 mi (6 km) from the eastern flank of the Citronelle Dome. This plant produces about 14 million tons of CO_2 per year, and separation and capture of CO_2 from its flue gas can provide CO_2 for EOR in the Citronelle oil field, followed by sequestration in the Citronelle Dome. Based on current emission rates and the present capacity estimates, the Citronelle Dome can provide at least 37 yr of sequestration capacity for the James M. Barry Generating Plant or plants of similar size. Additional capacity may well exist in saline formations that were not evaluated during the current investigation.

SUMMARY AND CONCLUSIONS

The Citronelle Dome is a giant salt-cored anticline in the Mississippi Interior Salt Basin of southern Alabama. The dome forms an elliptical structural closure containing opportunities for both CO_2-EOR and large-capacity saline reservoir storage. The range of preliminary static estimates of CO_2 storage capacity in the Citronelle Dome is from 500 million to 2 billion tons.

The dome provides the opportunity for CO_2-EOR within the Citronelle oil field located at the crest of the dome. The oil field has produced more than 169 million bbl of

42–46° API gravity oil from the sandstone in the Lower Cretaceous Donovan sand. The oil accumulation is sealed by a thick succession of shale and anhydrite, with the oil-water contact being more than 30 m (100 ft) above the structural spill point. The range of static estimates of CO_2 storage capacity in the oil reservoirs of the Donovan sand, after oil recovery is complete and CO_2 injection is continued until the reservoirs are returned to a pressure of 34.5 MPa (5000 psi), is from 115 to 460 million tons.

Structural contour maps demonstrate that the area of the structural closure increases upward in section. Saline reservoirs of Upper Cretaceous age, which are stratigraphically above the Citronelle oil accumulation, include the Massive and Pilot sands of the lower Tuscaloosa Group and sandstone units in the upper Tuscaloosa Group and Eutaw Formation. These sandstones are characterized by high porosity (capacity) and permeability (injectivity) with low heterogeneity. The Tuscaloosa-Eutaw interval is capped by more than 366 m (1200 ft) of impermeable chalk that is a proven reservoir seal in nearby oil fields. The lower Tuscaloosa is capped by about 107 m (350 ft) of marine shale. Therefore, the Citronelle Dome can be considered as a major geologic sink where CO_2 can be safely stored while realizing the economic benefits associated with EOR.

A recently initiated project entitled Carbon-Dioxide-Enhanced Oil Production from the Citronelle oil field in the Rodessa Formation, south Alabama, supported by the U.S. Department of Energy (DOE), National Energy Technology Laboratory (Cooperative Agreement no. DE-FC26-06NT43029), will include pilot CO_2 injection testing that will evaluate the EOR potential, sweep efficiency, and long-term storage potential of the Citronelle oil field. Site-specific information, collected from the perspective of geologic storage, will help verify and refine the source-sink relationships and the preliminary capacity estimates presented here. Projects currently being initiated as part of the DOE Southeast Regional Carbon Sequestration Partnership in the lower Tuscaloosa Formation will further refine these estimates.

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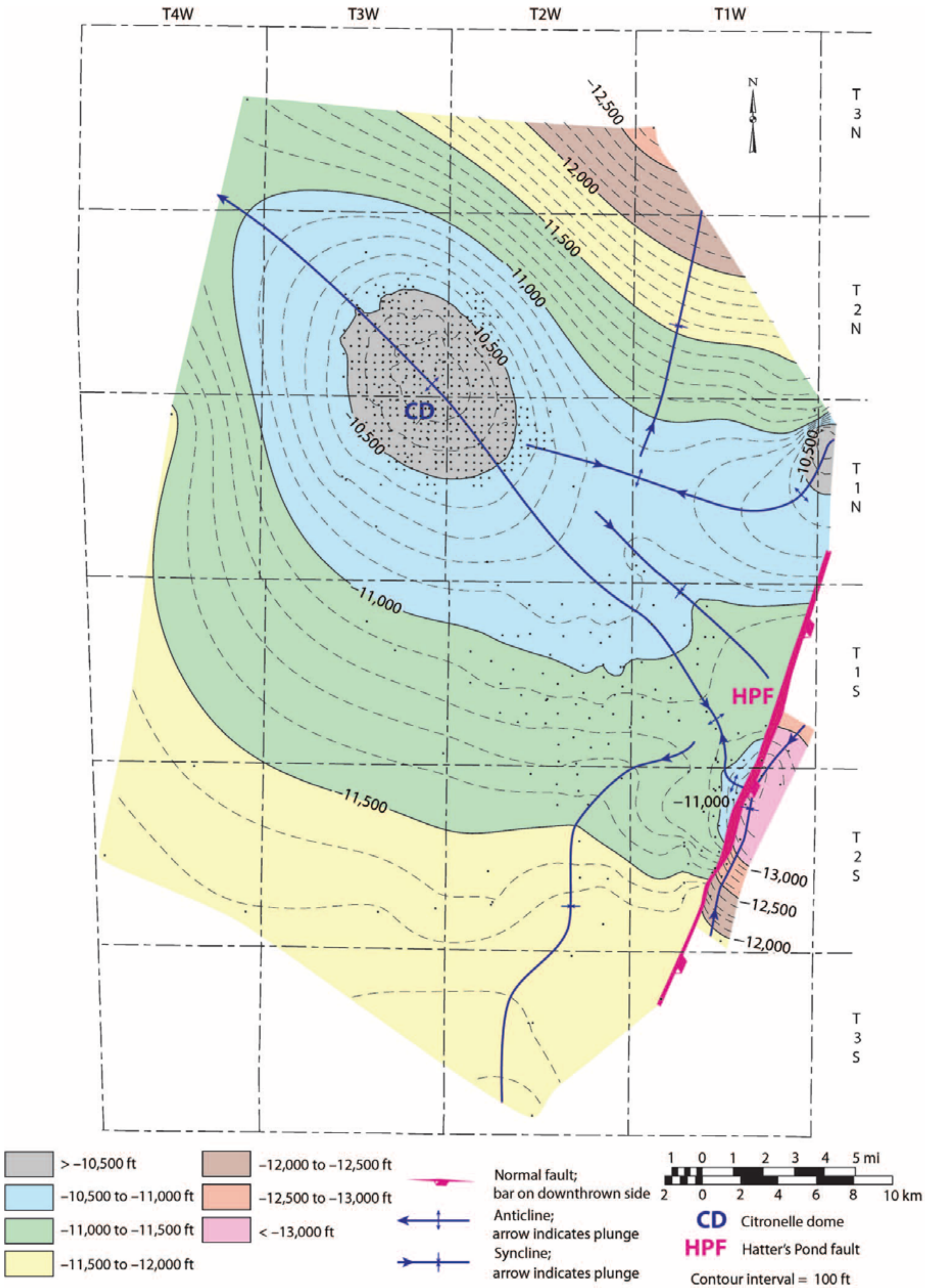

Figure 1. Structural contour map of the top of the Rodessa Formation.

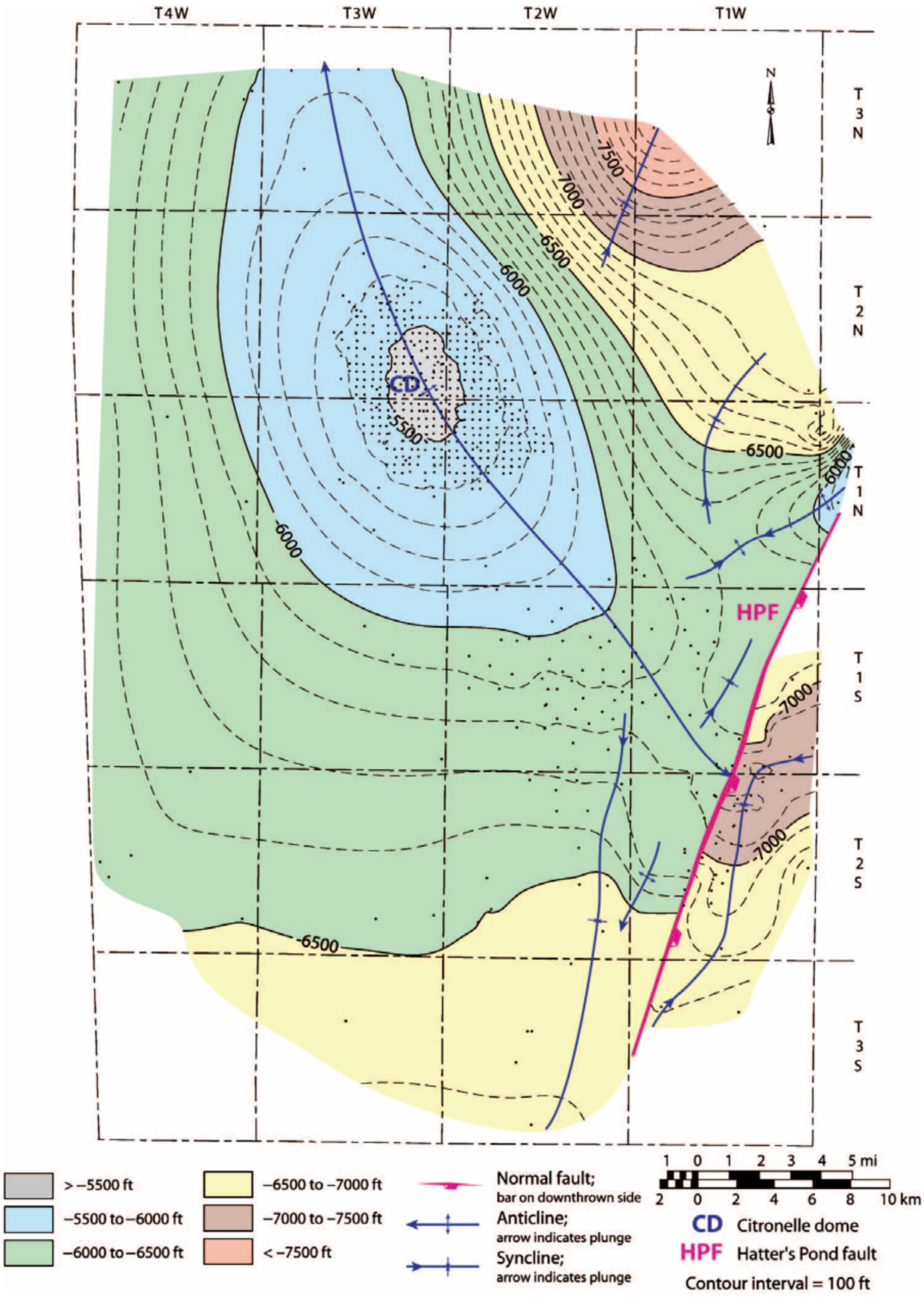

Figure 2. Structural contour map of the top of the Eutaw Formation.

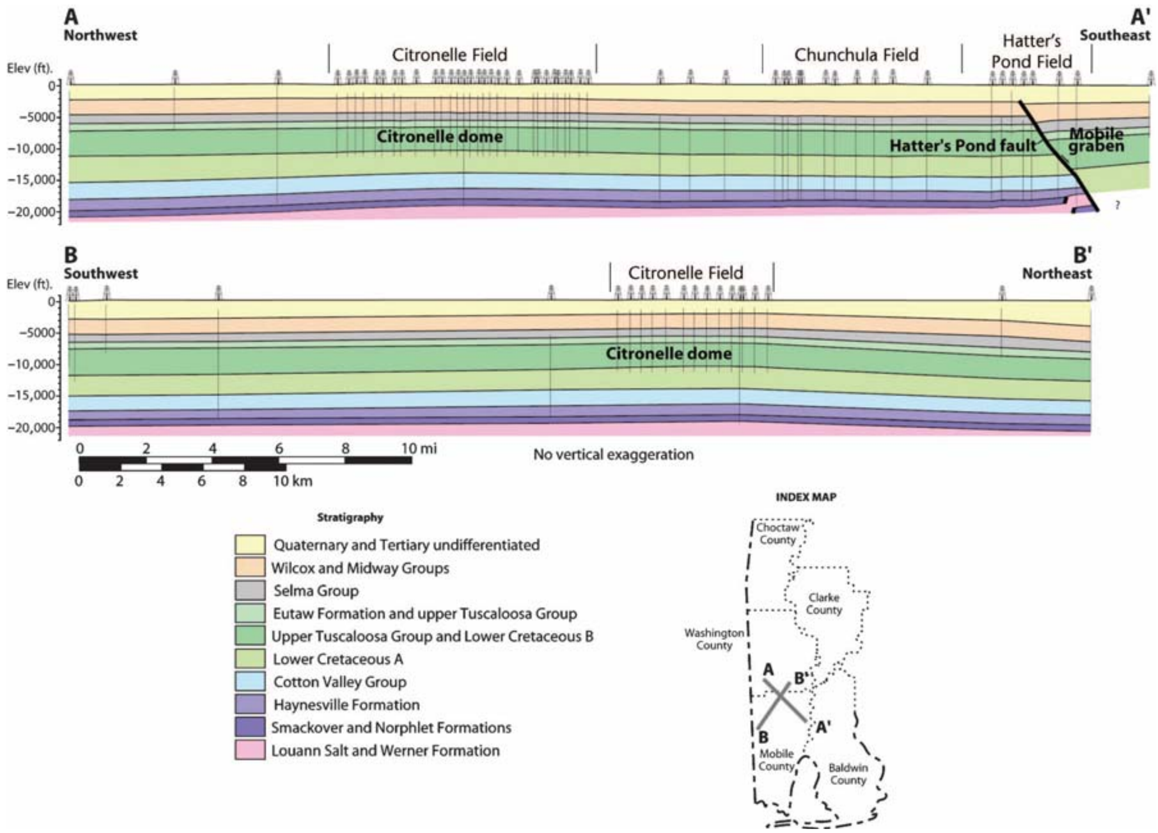

Figure 3. Structural cross sections of the Citronelle Dome and nearby structures in the eastern Mississippi Interior Salt Basin of Alabama.

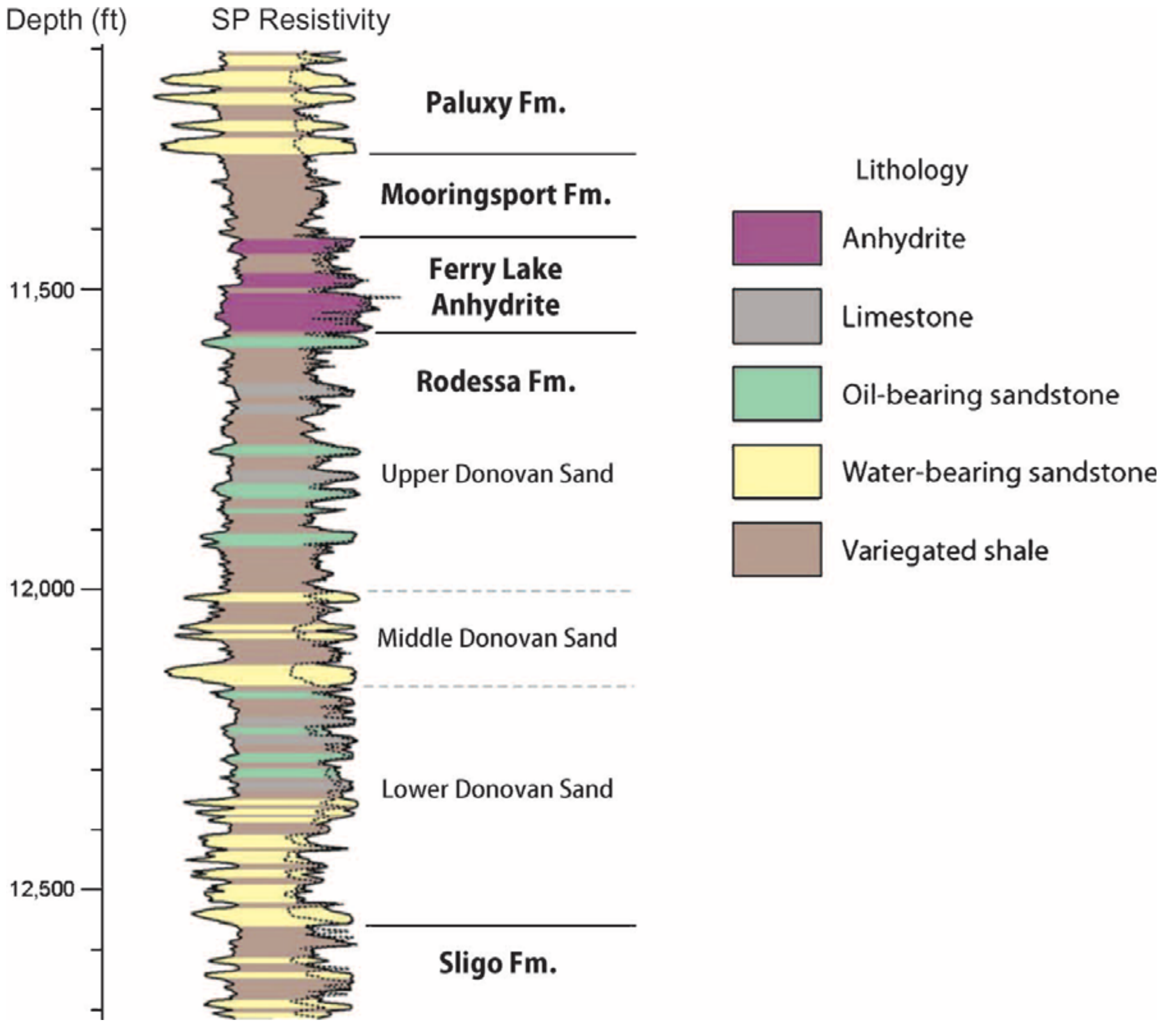

Figure 4. Geophysical well logs and stratigraphy of the Rodessa Formation and adjacent strata in the Citronelle Dome (State Oil and Gas Board of Alabama Permit 1067).

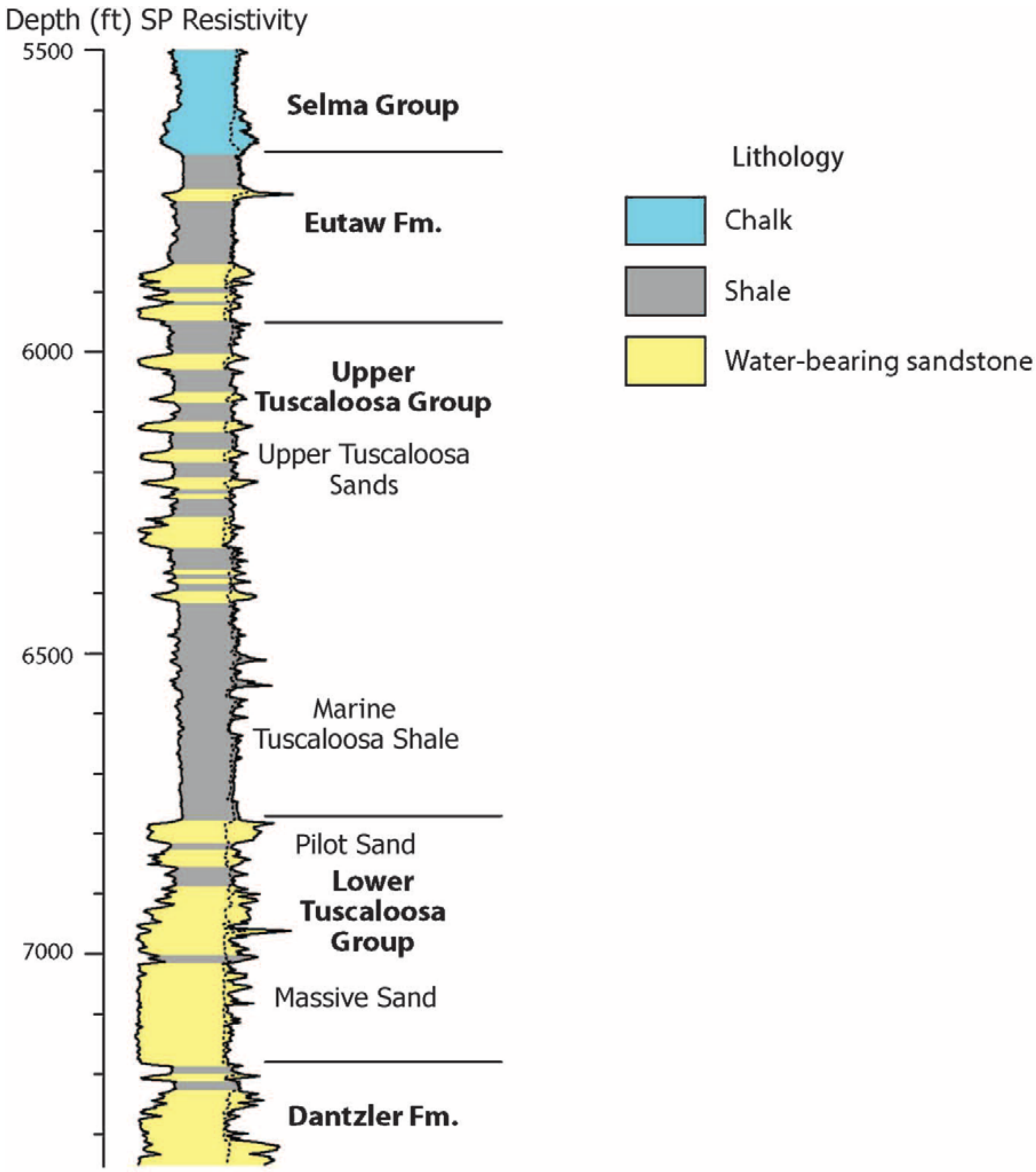

Figure 5. Geophysical well logs and stratigraphy of the Tuscaloosa-Eutaw interval and adjacent strata in the Citronelle Dome (State Oil and Gas Board of Alabama Permit 1067).

Table 1. Citronelle Dome Storage Capacity

Formation	Reservoir or Seal	Lower Limit (10%) Capacity (in Million Tons)	Upper Limit (40%) Capacity (in Million Tons)
Selma Chalk	Seal	~0	~0
Eutaw Formation and upper Tuscaloosa Group			
Eutaw and upper Tuscaloosa sands	Reservoir	150	600
Marine Shale	Seal	~0	~0
Lower Tuscaloosa			
Pilot sand	Reservoir	40	160
Massive sand	Reservoir	200	790
Ferry Lake Anhydrite	Seal	~0	~0
Rodessa Formation			
Upper and lower Donovan sands	Reservoir	115	460
Middle Donovan sand	Reservoir	24	100
Total		529	2110

GEOLOGIC ASSESSMENT AND INJECTION DESIGN FOR A PILOT CO_2-ENHANCED OIL RECOVERY AND SEQUESTRATION DEMONSTRATION IN A HETEROGENEOUS OIL RESERVOIR: CITRONELLE FIELD, ALABAMA, USA

by

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ABSTRACT

CO_2 pilot injection studies, with site-specific geologic assessment and engineering reservoir design, can be instrumental for demonstrating both incremental enhanced oil recovery and permanent geologic storage of greenhouse gases. The purpose of this paper is to present the geologic and reservoir analyses in support of a field pilot test that will evaluate the technical and economic feasibility of commercial-scale CO_2-enhanced oil recovery to increase oil recovery and extend the productive life of the Citronelle Oil Field, the largest conventional oil field in Alabama (SE USA). Screening of reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition indicates that the Cretaceous-age Donovan sand, which has produced more than 169 x 10^6 bbl in Citronelle Oil Field, is amenable to miscible CO_2 flooding. The project team has selected an 81 ha (200 ac) 5-spot test site with one central gas injector, two producers, and two initially temporarily abandoned production wells that are now in production. Injection is planned in two separate phases, each consisting of 6,804 t (7,500 short tons) of food-grade CO_2. The Citronelle Unit B-19-10 #2 well (Permit No. 3232) is the CO_2 injector for the first injection test. The 14-1 and 16-2 sands of the upper Donovan are the target zones. These sandstone units consist of fine to medium-grained sandstone that is enveloped by variegated mudstone. Both of these sandstone units were selected based on the distribution of perforated zones in the test pattern, production history, and the ability to correlate individual sandstone units in geophysical well logs. The pilot injections will evaluate the applicability of tertiary oil recovery to Citronelle Field and will provide a large volume of information on the pressure response of the reservoirs, the mobility of fluids, time to breakthrough, and CO_2 sweep efficiency. The results of the pilot injections

will aid in the formulation of commercial-scale reservoir management strategies that can be applied to Citronelle Field and other geologically heterogeneous oil fields and the design of similar pilot injection projects.

Keywords: Citronelle Oil Field, Enhanced oil recovery, CO_2 pilot injection, Carbon sequestration

INTRODUCTION AND BACKGROUND

Commercial-scale enhanced oil recovery with carbon dioxide (CO_2-EOR) can be optimized by pilot-scale injection studies that improve understanding of pressure response, fluid mobility, and CO_2 sweep efficiency. In this paper, we present the design of a pilot injection study for CO_2-EOR in a large geologically heterogeneous US oil field. This miscible flood demonstration represents the first step of implementing CO_2-EOR and carbon sequestration in Alabama, USA.

The Citronelle Oil Field, the largest oil field in Alabama, was selected on the basis of reservoir characteristics, the desire of the field owner and unit operator to implement CO_2-EOR, and the need for the certification of safe geologic sinks for the sequestration of anthropogenic CO_2. Aside from some early experiments in Citronelle Field during the 1980s (Gilchrist 1981, 1982), no miscible CO_2 floods have been performed in Alabama, primarily because of the availability and distance from existing commercial CO_2 sources.

Eighty commercial CO_2-EOR projects are currently underway in the USA. These projects produce 234,000 bbl/day and account for approximately 5% of total US oil production. This percentage has the potential to increase significantly over the next 10 years depending on CO_2 supply, reservoir characteristics, and economics. Most CO_2-EOR projects involve a miscible flood and require planning to optimize sweep efficiency. Many historical CO_2-EOR initiatives, such as those performed in the Permian Basin of Texas and New Mexico, were initiated as tax concessions, or ‘‘tax floods’’ (Hustad and Austell 2004). These programs were not optimized for sweep efficiency and, in many cases, resulted in large CO_2 utilization rates and poor recovery per unit volume of injected CO_2 (Hustad and Austell 2004). An analysis of net recovery from the Permian Basin of West Texas and Eastern New Mexico reveals gross CO_2 utilization between 6 and 18 thousand cf/stb for miscible fieldscale EOR projects and between 7 and 27 thousand cf/stb for pilot projects (Brock and Bryan 1989).

Despite the currently favorable economics of CO_2-EOR, CO_2 floods frequently exhibit poor sweep efficiency caused by viscous fingering and gravity override, which can be exacerbated by a high degree of reservoir heterogeneity (Grigg et al. 2005). Low productivity can also result from reservoir injectivity that is lower than expected. Poor sweep efficiency results from a high mobility ratio caused by density contrasts and the low viscosity of supercritical CO_2 compared to that of water or oil (Grigg et al. 2005; Department of Energy 2006). The effectiveness of water-alternating-gas (WAG) injection, a common process used for mobility control during CO_2 floods, can be reduced by gravity segregation between water and CO_2 and is amplified by differences in reservoir permeability (Grigg et al. 2005; Department of Energy 2006).

CO_2-EOR has been implemented in relatively few oil producing areas, most notably in the Permian Basin of Texas and New Mexico, the Williston Basin of Saskatchewan, and the Gulf of Mexico Basin of Mississippi. This technology is yet to be applied commercially in Alabama, which is one of the many regions where CO_2-EOR technology appears to be applicable (Esposito et al. 2008; Advanced Resources International 2006; Pashin and Payton 2005). It is estimated that more than 80 separate oil reservoirs in Alabama are candidates for CO_2-EOR based on depth and oil viscosity (Pashin and Payton 2005; Advanced Resources International 2006). The primary impediment to CO_2-EOR in Alabama, as well as in many other regions, is the lack of an immediate supply of CO_2. However, large coal-fired power plants are located near many of the major oil fields and may be used as CO_2 sources, not only for EOR, but also as part of a larger strategy for greenhouse gas control (Esposito et al. 2008; Advanced Resources International 2006; Austell 2005).

Alabama currently ranks 16th among the 31 US oil producing states. Advanced Resources International (2006) has estimated that 172 x 10^6 bbl (27.3 x 10^6 m^3) of the oil remaining in the five largest Alabama oil reservoirs where CO_2-EOR is feasible is technically recoverable, regardless of the oil price. Of this, 111 x 10^6 bbl (17.6 x 10^6 m^3) is estimated to be economically recoverable from the largest of the five reservoirs using CO_2-EOR technology, at a crude oil price of \$40.00/bbl (\$251.60/m^3) and a CO_2 cost of \$2.00/1,000 ft^3 (\$0.07/m^3). Holtz et al. (2005) obtained a similar estimate of 98 x 10^6 bbl (15.6 x 10^6 m^3) of oil recoverable from all Alabama oil fields by miscible CO_2-EOR.

Martin and Taber (1992) have estimated that an incremental 5–30 billion barrels of oil could be recovered from CO_2 flooding in the United States, depending on the oil price and economic incentives. Taber et al. (1997) projected that approximately 80% of the world's reservoirs could recover some incremental oil from CO_2 flooding. A key to realizing this potential is the availability and extension of CO_2 transportation infrastructure into areas distant from sources or utilizing new sources such as coal-fired power plants that are close to candidate fields. Floods that are near CO_2 infrastructure are recovering significant amounts of incremental oil, while those that are distant from the infrastructure are studying the economics of extending pipelines and compression facilities to outlying areas. Many suitable Alabama reservoirs are highly heterogeneous and thus require extensive reservoir characterization to predict the outcomes of CO_2-EOR and permanent geologic sequestration. Maximizing sweep efficiency for oil recovery through intelligent application of mobility and conformance-control measures would greatly improve the economics of extending the infrastructure to these outlying areas by ensuring that the CO_2 contacts more of the reservoir. Understanding the volume of CO_2 required for the long-term flood requirements of a given field supports the localized use of coal-fired electric utility boilers as a CO_2 source. The knowledge gained from the detailed analysis of pilot testing will support operating practices that will serve as a guide to improving oil recovery in active CO_2 floods and as a strategy for implementing new CO_2 floods.

Citronelle Field

The Citronelle Oil Field is approximately 50 km (30 mi) north of Mobile, Alabama. Oil is produced from the Lower Cretaceous Donovan sand within a subtle structural dome that is developed above a broad, deep-seated pillow of the Jurassic-age Louann salt (Fig. 1). The field was discovered in 1955 by Gulf Oil Company in the Zack Brooks Drilling Company No. 1 Donovan well (State Oil and Gas Board of Alabama Permit 608; Sec. 25, T. 2N., R. 3W.). The discovery well was drilled to a total depth of 3,510 m (11,517 ft) and produced oil from two separate intervals in the Donovan sand. The Citronelle Field was selected for an injection pilot because it is a promising candidate for miscible CO_2-EOR and contains one of the largest stranded oil reserves in the southeastern USA (Advanced Resources International 2006; Esposito et al. 2008). The field is also within 15 km (10 mi) of a coal-fired power plant that emits about 10 million t of CO_2 per year. Installation of economical capture technology at the plant could provide a reliable source of CO_2 for EOR. In addition to the Donovan oil accumulation, Citronelle Dome contains numerous stacked saline reservoirs of Cretaceous age suitable for carbon sequestration. Esposito et al. (2008) estimated that the Donovan sand plus Upper Cretaceous sandstone units in Citronelle Dome have the capacity to safely store between 0.48 and 1.9 Gt of CO_2, and additional capacity exists in Lower Cretaceous sandstone units whose capacity has not been assessed in detail. The sale and utilization of anthropogenic CO_2 for EOR would help to offset the cost of CO_2 capture.

According to the criteria proposed by Kovscek (2002), Citronelle Field is an ideal site for both CO_2-EOR and sequestration. From a reservoir engineering perspective, the site is mature, water flooded and has a diverse and well-developed infrastructure, including deep wells and lines for the distribution and gathering of fluids. From a geologic perspective, the field is ideal for EOR and long-term CO_2 storage because it contains fluvial-deltaic sandstone reservoirs that lack faults and are sealed locally by mudstone and regionally by impermeable anhydrite in a simple structural dome (Esposito et al. 2008). Citronelle Dome forms an elliptical, four-way structural closure in which strata dip away from the crest at only 1°–2°. Structural contour maps demonstrate that the area of structural closure is about 93 km^2 (36 mi^2) at the top of the Donovan sand (Fig. 2).

The Donovan sand constitutes a 244-m thick (800 ft) gross pay interval containing at least 42 productive sand zones comprising 300 distinct reservoirs (Eaves 1976; Fowler et al. 1998) (Fig. 3). Initial reservoir pressure in the field was 38 MPa (5,500 psia), slightly above hydrostatic, and the reservoir temperature was approximately 98.9°C (210°F). Initial reservoir energy for the field came from solution gas (Bolin et al. 1989; Fretwell and Blair 1999). Reservoir pressure was depleted substantially during primary production (Fretwell and Blair 1999), and current pressure is typically below 20.7 MPa (3,000 psia).

Covering a total of 6,637 ha (16,400 ac), the Citronelle Field was drilled on 16 ha (40 ac) spacing. To date, 524 wells have been drilled with 414 wells currently listed as active or temporarily abandoned by the State Oil and Gas Board of Alabama—these 414 wells are in play for both EOR and geologic sequestration activities. Following the major phase of development in the late 1950s and early 1960s, production declined exponentially. Water flooding began early in 1961, and secondary recovery technology was deployed rapidly throughout the field. By the end of 1973, the field had produced more than 107 x 10^6 bbl of oil. Cumulative oil production now exceeds 169 x 10^6 bbl, and annual production is approximately 675,000 bbl/a.

In the early 1980s a DOE-sponsored CO_2 pilot injection study was performed by the Citronelle Unit Manager. Reports available from the study include a miscibility study (Gilchrist 1981), an evaluation of produced fluids from the CO_2 pilot area (Gilchrist 1982), and a post-injection reservoir engineering study (Kennedy et al. 1983). Initially, a laboratory study was performed with Citronelle Field crude that confirmed CO_2 miscibility at 2,800 psia and 210°F (Gilchrist 1981). Although miscibility was confirmed at this pressure; minimum miscibility pressure was not reported and may be significantly lower. Long tube tests were performed to determine the optimum slug size and were followed by conventional core tests. The results indicated excellent potential for a successful CO_2 flood (Gilchrist 1981). Samples of reservoir fluid were then collected from two wells in the pilot area and analyzed in a pressure cell. Analyses indicated that about 50 bbl of oil measured at 3,320 psia and 210°F can be produced per 28 x 10^3 m^3 (1 x 10^6 ft^3) of CO_2 injected (Gilchrist 1982). The post-injection reservoir engineering study determined the oil in place in the ten 5-spot pilot areas prior to injection, the amount of oil recovered from the pilot injection, and the amount of CO_2 required to produce 1 bbl of incremental oil. The study estimated the oil in place in perforated sands within the ten areas slated for pilot injection at 1,868,776 stb. The total tertiary oil recovery by 31 December 1982 was 87,035 bbl and the CO_2/bbl requirement, determined by the ratio of the total volume of CO_2 injected and the amount of tertiary oil produced, was 481 m^3/bbl (17 x 10^3 ft^3/bbl) (Kennedy et al. 1983).

Original oil in place (OOIP) and recoverable oil in place (ROIP) estimates for the Citronelle Field are estimated at 537 x 10^6 and 362 x 10^6 bbl, respectively (Advanced Resources International 2006). Kuuskraa et al. (2004) estimated the remaining proven reserves at only 7 x 10^6 bbl if current practices, specifically water flooding, continue. In the mid-1970s, the Citronelle unit operators evaluated the feasibility of commercial-scale tertiary recovery. They concluded that a miscible CO_2 flood would recover an additional 20 x 10^6 bbl (Gilchrist 1982). More recently, Kuuskraa et al. (2004) estimated the field's CO_2- EOR potential may increase oil reserves by as much as 85 x 10^6 bbl. Denbury Resources Incorporated (Denbury), the current owner and operator of the Citronelle

Field, estimates the tertiary reserve base to be between 20 and 30 x 10^6 bbl net to the interest to be acquired in the field. Denbury anticipates the increase in reserve potential to be 40 x 10^6 bbl.

Donovan Sand

The Donovan sand is of Lower Cretaceous (Aptian–Albian) age and constitutes more than 244 m (800 ft) of interbedded sandstone and shale with some limestone near the top of the interval (Fig. 4). The Donovan has historically been assigned to the Rodessa Formation (Eaves 1976), although recent work indicates that it includes older deposits equivalent to the James Formation (Mancini and Puckett 2002). The Donovan contains a significant proportion of redbeds, which is unusual for a major oil-bearing succession. The Donovan sand overlies a thick succession of Lower Cretaceous redbeds that includes the Hosston and Sligo Formations. The Donovan is overlain by the Ferry Lake Anhydrite, which is in turn overlain by shale of the Mooringsport Formation. The basic aspects of Donovan stratigraphy and sedimentology are discussed in the following paragraphs, and additional details on reservoir architecture are discussed in the section on the pilot test design.

Eaves (1976) recognized the extreme vertical and lateral heterogeneity of the Donovan sand and subdivided it into three intervals (Fig. 4). The lower Donovan sharply overlies the Sligo Formation and contains a series of low-resistivity, water-bearing sandstone units near the base. The upper half of the lower Donovan contains numerous oil-bearing sandstone units with a minor negative deflection in spontaneous potential (SP) logs and resistivity slightly higher than that of the basal sandstone units. The middle

Donovan, in contrast, contains water-bearing sandstone units with a strong negative deflection in SP logs and a large separation between the deep and shallow resistivity curves. The upper Donovan sand resembles the lower Donovan in geophysical well logs, except the upper Donovan sandstone units tend to have a stronger SP response and higher resistivity. In places, limestone units near the top of the Donovan are productive of oil. Historically, the bulk of the oil produced in Citronelle Field has come from the upper Donovan sand, and in many wells, the lower Donovan is inactive and is isolated below cement plugs. Geochemical evidence suggests that the oil trapped in the Donovan sand is sourced from the Jurassic Smackover Formation (Claypool and Mancini 1989), although the precise migration pathway and the origin of the oil–water–oil stacking within the Donovan are unknown. Shale units in the Donovan apparently form effective reservoir seals locally, and the thick anhydrite-shale section in the Ferry Lake and Mooringsport Formations forms the topseal for the hydrocarbon system in Citronelle Field. Nineteen standard 2.54 cm (1 in.) core plugs were cut from the 14-1 and 16-2 sands in the B-19-10 #2 well (Permit No. 3232) at 30.48 cm (1 ft) intervals for determination of porosity, permeability, and grain density. Core analyses from throughout Citronelle Field indicate that porosity of the 14-1 and 16-2 sands range typically from 5 to 20% and averages 12%. Reservoir permeability is typically low and is between 0.02 and 13 mD, with an average of 2 mD. Locally, however, permeability can exceed 100 mD.

The Donovan sand is dominated by fining-upward successions of conglomerate, sandstone, and variegated shale and contains a diverse suite of depositional facies (Fig. 5). Conglomerate and conglomeratic sandstone units have sharp bases, gradational tops, and are typically clast supported. Lithoclasts are predominantly pebbles of dolomicrite and shale, and some conglomerate beds contain an abundance of oyster shells or coalified plant debris. Conglomeratic intervals tend to have poor reservoir quality because of pervasive intergranular calcite cement.

Sandstone units have sharp to gradational contacts and are generally very fine to medium grained; they are commonly interbedded with conglomerate. Donovan sandstone is quartz arenite to subarkose. The sandstone can be calcareous or micaceous and exhibits a broad range of color. Most Donovan sandstones are medium gray to light gray. In pay zones, however, pore-filling pyrobitumen gives much of the sandstone a very dark gray color, and oil staining tends to impart brownish hues. Some non-productive sandstone units can be classified as redbeds and range from pink to grayish-brown. Physical sedimentary structures include cross-beds, horizontal laminae, and ripple cross-laminae. Trace fossils are common in the upper parts of most sandstone successions and include forms such as Teichichnus, Rhizocorallium, and Skolithos.

Many sandstone beds fine upward into heterolithic successions of thin interbedded sandstone, siltstone, and shale. The sandstone is typically medium gray to light gray, and the shale is variegated, ranging from dark gray to red. Flaser, wavy, and lenticular bedding are common, and sedimentary structures include horizontal laminae, current ripple cross-laminae, and locally mud cracks. These heterolithic strata are commonly burrow-mottled and can contain a trace fossil assemblage similar to that in sandstone.

The fining-upward successions are capped by variegated mudstone that contains a diverse suite of sedimentary structures. The mudstone tends to be silty and sandy, poorly fissile, and ranges from dark gray to greenish-gray or red; color mottling is common.

Dark gray mudstone is typically burrow-mottled and can contain oyster shells. Red mudstone, by comparison, contains diverse physical and biogenic sedimentary structures. Some variegated mudstone contains mud cracks. Much of the red mudstone is slickensided and has a blocky texture, and the mudstone commonly contains argillaceous dolomicrite nodules that are commonly cracked and display fitted fabrics.

The Donovan sand was originally interpreted as sinuous fluvial deposits that accumulated in a coastal embayment (Wilson and Warne 1964; Eaves 1976), and bedding styles and sedimentary structures in the Donovan sand indicate a complex interplay between marine and terrestrial processes. The slickensided and nodule-bearing red mudstone units have characteristics of vertic paleosols (Retallack 1990; Mack et al. 1993), which indicate significant episodes of exposure and weathering, and the occurrence of anhydrite in the section confirms a semi-arid to arid paleo climate. Oyster shells and trace fossils, such as Teichichnus, indicate a stronger marine component to sedimentation than was envisioned by early workers. Although some fluvial sediment may be preserved in the lower parts of the oil-productive Donovan sandstone bodies, intense burrowing in the upper parts of the sandstone bodies points toward extensive marine reworking and sedimentation in estuarine environments.

Mancini and Puckett (2002, 2005) recognized the Donovan sand and Ferry Lake Anhydrite as part of a back stepping, transgressive succession. The intercalation of marine-influenced strata with numerous well-developed paleosols within the Donovan interval suggests that high frequency changes of sea level punctuated the Donovan marine transgression. The numerous paleosols and sharpbased, fining-upward conglomerate-sandstone bodies indicate that there is an abundance and complex hierarchy of erosional surfaces within the Donovan interval that can be interpreted as depositional sequence boundaries formed by valley incision and tidal ravinement.

Field Pilot Design

The pilot injection area is in the northeastern part of Citronelle Field and constitutes an 81 ha (200 ac) 5-spot test site with one central gas injector, two producers, and two initially temporarily abandoned production wells that are now in production (Fig. 6). All four production wells are currently producing 4–9 bbl oil/day under water flood. The varied state of the wells in the test pattern is typical of a mature oil field, and considerable attention must be paid to well engineering and integrity as 5-spot injection-production patterns are developed for a commercial CO_2 flood. Citronelle Field has long been unitized for water flooding, and unitization affords flexibility in field design that facilitates a variety of field activities, including CO_2-enhanced oil recovery.

All ten injection wells drilled during the 1980s DOE sponsored EOR program were drilled as infill wells within the established 40-acre well pattern in Citronelle Field. Unitization of the field during the 1960s effectively waived the need to maintain 40-acre well spacing and the requirement to drill wells within the confines of governmental land units. Thus, unitization enabled the drilling of injectors at optimal locations to form 5-spot patterns. The Citronelle Unit B-19-10 #2 well (Permit No. 3232), which was originally drilled and permitted as a CO_2 injector as part of the 1980s EOR program but was never used for CO_2 injection, will serve as the CO_2 injector for the pilot test. The well has been used intermittently as a producer, and recently was re-established as an injector for water flooding and again as a gas injector for the CO_2-EOR test.

Although only two of the wells in the test pattern were active producers when the present project began, all the wells had the potential to be restored to production. The temporarily abandoned wells (B-19-7 and B-19-9) contained bridge plugs that have been removed, and these wells have been successfully restored to production. The abandoned well at the southwest corner of the 5-spot pattern (B-19-10) contains a cement plug above the productive sandstone units, and the plug was to be reamed so that the well could be returned to production. However, substantial difficulty was encountered upon reentry, and because of a fatal casing flaw, the well was abandoned permanently and cannot even be used for passive observation. Because of this, the production well immediately to the west (B-19-11) will be used to observe the far-field effects of the CO_2 injection experiments.

The vast majority of the oil produced in the northeastern part of Citronelle Field is from a cluster of sandstone units within the upper Donovan sand. Correlating geophysical well logs demonstrates significant geologic heterogeneity within this cluster of sandstone units, as is shown in cross section A–A′ (Fig. 7), which traverses the pilot area. This cluster consists of Sands 18 through 12, and the injection well (Permit 3232) is perforated in the 16-2 and 14-1 sands.

Each well log along the line of the cross section specified in Fig. 6 penetrates a different combination of sandstone units. At the base of the cluster, the 18 and 17-B sands are discontinuous and appear to fill a small channel. These channel deposits can be interpreted as incised valley fills based on the close relationship with the variegated mudstone, which is dominated by vertic paleosols in this area.

The 16-2 sand is the main pay zone in northeastern Citronelle Field. The sandstone is readily identified in well logs by a strong negative deflection in SP curves (Fig. 7). A core log of the B-19-10 #2 injector shows a basal conglomerate that fines upward into cross-bedded sandstone with pyrobitumen (Fig. 5). An upper conglomerate bed sharply overlies the sandstone and fines upward into another interval of sandstone with cross-beds and pyrobitumen. The sandstone continues to fine upward and contains abundant vertical and horizontal burrows in the upper 1.5 m (5 ft). The sandstone is overlain sharply by a thick, red mudstone unit. The 16-2 sand is a widespread unit, and the sharp base defines a low-relief erosional discontinuity, such as a tidal ravinement (Fig. 7). The burrowing in the upper part of the sandstone points toward a marginal marine origin. Correlating well logs suggests that channeling in the upper part of the sandstone has a strong effect on facies heterogeneity and sandstone thickness. Some channels, such as the one in the B-20-4 well, are filled with conglomerate and sandstone, whereas others, such as that in the B-19-10 #2 well, are filled with mud. The 15-B sand is discontinuous and is locally in contact with the 16-2 sand (Fig. 7). The log signature of the 15-B sand is highly variable, indicating significant internal heterogeneity. No cores are available for the 15-B sand, so depositional environments are indeterminate.

The 14-1 sand is a significant pay zone that overlies a low-relief ravinement surface similar to that at the base of the 16-2 sand (Fig. 7). Well logs suggest that the 14-1 is a composite of multiple sandstone bodies. The lower part of the sandstone can be traced throughout the map area, whereas the upper part appears to contain a series of channel fills of variable lateral extent. In the core of the B-19-10 #2 well, the 14-2 sand consists of 0.7 m (2 ft) of fine-grained sandstone containing horizontal burrows. The sandstone is overlain by 0.3 m (1 ft) of shale-pebble conglomerate that appears to mark the base of a mud-plugged channel.

The top of the sandstone cluster is marked by the 12 sand (Fig. 7). The basal contact of the sandstone has significant erosional relief, and cores indicate that the lows are filled with conglomerate. The 12 sandstone extends throughout the field area. The SP and resistivity response of the sandstone indicate poor reservoir characteristics in comparison to 16-1 and 14-2 sandstone, and this is confirmed by micrologs, which indicate marginal pay quality within the 12 sand. In contrast to the other sandstone units, relief is limited at the top of the 12 sand. Cores indicate that the vertical succession of rock types, sedimentary structures, and trace fossils is nearly identical to that in the 16-2 sandstone, indicating deposition in a marginal marine setting and perhaps sedimentation in a system of channels and shoals above a widespread tidal ravinement.

The 14-1 and 16-2 sands are the focus of the pilot program. These sands are the only zones perforated in Well B-19-10 #2 and are productive in all wells in the area of the field test. Cross section A–A0 (Fig. 7) indicates that injection will take place in a constriction in the two sands below mud-plugged channel fills. The permeability of the conglomerate intervals tends to be on the order of 0.1 mD because of calcite cementation. Crossbedded sandstone with pyrobitumen, by comparison, is the most permeable rock type with permeability on the order of 10 mD. Bioturbated sandstone, in contrast, has intermediate reservoir properties with permeability being on the order of 1.0 mD.

Maps of net sandstone thickness and net pay thickness have been constructed for both the 14-1 and 16-2 sands, into which CO_2 will be injected during the first pilot test and from which enhanced production is expected. The net pay map illustrates the amount of oil to be recovered as related to sand thickness. 3D visualization of the sands were constructed by superimposing their net pay maps on structural models of the bases of the sands (Fig. 8). The net pay of the 16-2 sand suggests that the first and greatest response to CO_2 injection into the Permit No. 3232 Well might be observed at Permit No. 1235, in the northeast corner of the test pattern, followed by response at Permit No. 1205, at the southeast corner of the 5-spot due to the thickness of the pay zone. The next well to the north of Well 1235, Permit No. 1254, also in the high net pay zone, is a water injector, so no response can be observed there. There is a slight increase in depth of approximately 12.2 m (40 ft) at the base of Sand 16-2 on going from the injector to the producer at the northeast corner of the 5-spot, Permit No. 1235. Figure 8 shows that the characteristics of Sands 14-1 and 16-2 in the test pattern and its vicinity nicely capture the lack of connectedness of Citronelle Field sands, a feature that points to the importance of a thorough study of the geology of the field, combined with reservoir simulation, in the planning and optimization of a commercial CO_2 flood.

Injection is planned in two separate phases, each consisting of 6,804 t (7,500 short tons) of food-grade (99% pure) CO_2. Total CO_2 injection over a 2-year period is planned at 13,608 t (15,000 short tons) of CO_2. The sands are being water flooded for 6 months prior to CO_2 injection, to restore the reservoir to conditions similar to those that will exist in other wells when they are converted from water injection to CO_2, and establish a baseline for production from the test pattern under water flood conditions. Water flooding will resume after the first phase of injection is complete, until the second phase of injection is begun. The injector, Well B-19-10 #2, is currently injecting 150–170 bbl/day of water. A step rate test is planned as soon as a steady water injection rate is achieved.

The injector is already equipped with a well head and tubing that can be used for CO_2 injection. Producers B-19-7 and B-19-9 have been worked over, returned from temporarily abandoned status, and are each producing 4–5 bbl/day of oil. Producers B-19-8 and B-19-11 are each producing 8–9 bbl/day of oil. Gas–liquid cylindrical cyclones for separating oil and water from gas have been installed at the B-19-8 and B-19-11 tank batteries. Flow meters will be used to meter the power oil going to the wells, because oil production is the relatively small difference between the power oil flow rate to a well and the power oil plus produced oil received at the tank battery. Variation in dissolved solids in produced water, causing variation in the density of the water, complicates the measurement of liquid flow rates. A CO_2-compatible triplex positive-displacement reciprocating plunger pump at the B-19-8 tank battery is prepared to deliver CO_2 at high pressure to the injector.

An interference test was performed at the site and showed good connectivity between injector well B-19-10 #2 and the B-19-7 and B-19-9 production wells. The results of the interference test demonstrate interconnectivity in the 14-1 and 16-1 Donovan sand units. The test was performed between 17 April 2008 and 23 May 2008. Pressure gauges were placed in the shut-in Wells B-19-9 and B-19-7, while injection of water occurred in Well B-19-10 #2. Well B-19-9 is 822 ft southeast of the injector, while Well B-19-7 is 1,049 ft to the northwest. Injection commenced on 3 May 2008. The injection rate was variable, but stayed close to approximately 140 bbl/day of water. A fit of the data gave a total mobility of approximately 0.61 mD/cP, and an average production thickness, h, of approximately 6.1 m (20 ft), assuming a porosity of 15.5%, total compressibility of 10 x 10^{-6}/psi, and average reservoir injection rate of 140 bbl/day.

CO_2 Liquefaction, Transportation, and Injection

CO_2 for injection will be sourced from the Jackson Dome, which is located within the central Mississippi Interior Salt Basin. The Jackson Dome is one of the deepest natural deposits of commercially marketed CO_2, and was formed by igneous intrusion in the Late Cretaceous. The CO_2 is produced primarily from the Jurassic-age sandstone of the Norphlet Formation, carbonate rocks of the Smackover Formation, and the Buckner-Limestone of the Haynesville Formation at depths below 4570 m (15,000 ft) (Stevens et al. 2001a, b). Seals are mudstones and shale within the overlying Jurassic strata. Several commercial liquid CO_2 plants are located in the Jackson Dome area that distribute food-grade CO_2 throughout the southeastern United States.

Jackson Dome CO_2 reserves are primarily owned and operated by Denbury Resources, Incorporated of Plano, Texas and are currently used by Denbury for multiple CO_2-EOR operations in Mississippi reservoirs. According to Stevens et al. (2001a, b), the estimated reserve base in Jackson Dome is 530 million t (10 Tcf) of CO_2 present in several Jackson Dome Fields. Current production of about 1,600 t/day supplies EOR projects in Mississippi and other industrial applications.

A description of CO_2 transportation options is presented by Odenberger and Svensson (2003). Transportation of large volumes of CO_2 for commercial-scale CO_2-EOR requires pipelines. Options for pilot-scale projects, although expensive, include tanker truck, rail car, and barge transportation. Tanker trucks have been selected to transport CO_2 from Jackson, Mississippi to Citronelle Field for the project, due to their flexibility, direct routing, and reliability. CO_2 will be transported as a refrigerated liquid at its equilibrium vapor pressure of 257–306 psia at temperatures of -10 to 0°F. A typical tanker truck can carry up to 18 t of liquid CO_2.

After CO_2 is transported by truck to the site, secondary storage tanks will be used for on-site storage. Secondary storage will ensure that delivery trucks are not required to remain at the injection well location for unreasonable (uneconomical) durations and for enough reserve to maintain uninterrupted injection operations. A portable tank having a capacity of 45 t of liquid CO_2 has been installed for storage of CO_2 during the project. It is anticipated that two to three tanker trucks will deliver between 36 and 54 t of CO_2 daily to the site for a period of 4–7 months. The CO_2 will be injected as a liquid using the triplex plunger pump.

SUMMARY AND CONCLUSIONS

The Citronelle Oil Field, the largest conventional oil field in Alabama (SE USA), has been selected for a CO_2-EOR pilot injection test designed with emphasis placed on geologic and reservoir engineering analyses, supported by pre-injection field testing, to evaluate the technical and economic feasibility of commercial-scale CO_2-EOR and geologic carbon sequestration. Screening including reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition indicates that the Citronelle Field is amenable to miscible CO_2-EOR. The eventual application of commercial-scale CO_2-EOR in the Citronelle Field will be optimized by analysis of the results from the pilot-scale injection study, based on the understanding of pressure response, fluid mobility, and sweep efficiency. The pilot injection area is in the northeastern part of Citronelle Field and constitutes an 81 ha (200 ac) 5-spot test site with one central gas injector, two producers, and two initially temporarily abandoned production wells that have been returned to production. All four production wells are currently producing 4–9 bbl oil/day under water flood. The 14-1 and 16-2 sands are the targets of the pilot program because these sands are perforated in well B-19-10 #2, are easily identified and isolated, and are productive in all wells of the 5-spot test pattern. CO_2 for the pilot injection will be sourced from the Jackson Dome, liquefied, and transported by tanker truck to the site, approximately 170 miles away. Injection is planned to take place in two separate phases, each consisting of 6,804 t (7,500 short tons) of 99% pure CO_2, over a 2-year period.

The 14-1 and 16-2 Donovan sands selected will allow access to heterogeneity that is typical throughout the field and will provide valuable information on the effect of lithologic heterogeneity on CO_2-EOR. The sands will be water flooded for 6 months prior to CO_2 injection, to restore the reservoir to conditions similar to those that will exist at other wells when they are converted from water injection to CO_2, and to establish a baseline for production from the test pattern under water flood conditions. An interference test was performed and showed good connectivity between injector well B-19-10 #2 and the northwest B-19-7 and southeast B-19-9 wells. The results of the interference test demonstrate interconnectivity in the 14-1 and 16-2 Donovan sand units.

The pilot test will help evaluate the applicability of tertiary oil recovery to Citronelle Field, and will provide information on the pressure response of the reservoirs, the mobility of fluids, time to breakthrough, and sweep efficiency. The results of the pilot injection will aid in the understanding of the geologic framework and the formulation of reservoir management strategies that can be applied to Citronelle Field and other geologically heterogeneous oil fields and will assist in the design of similar pilot injection projects.

ACKNOWLEDGMENTS

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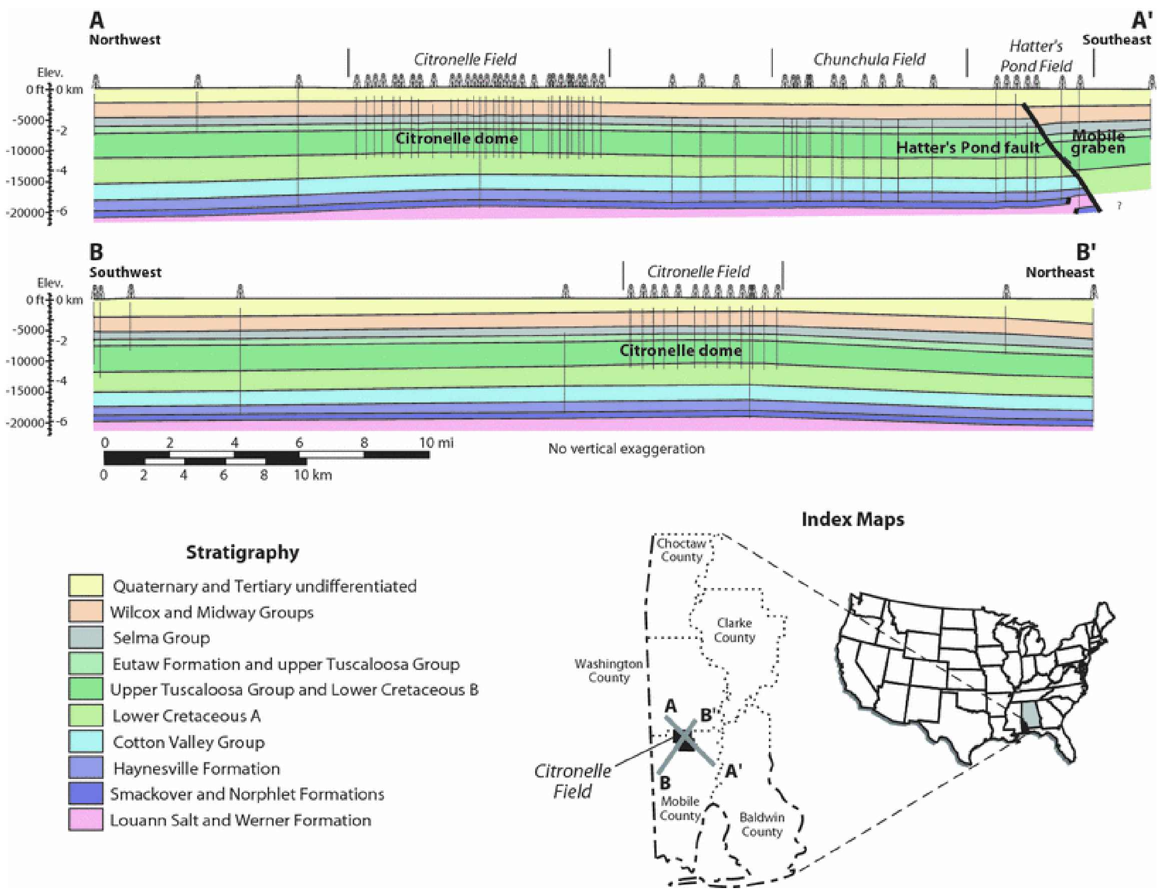

Figure 1. Structural cross sections showing Citronelle Dome and location of Citronelle Field (modified from Esposito et al. 2008)

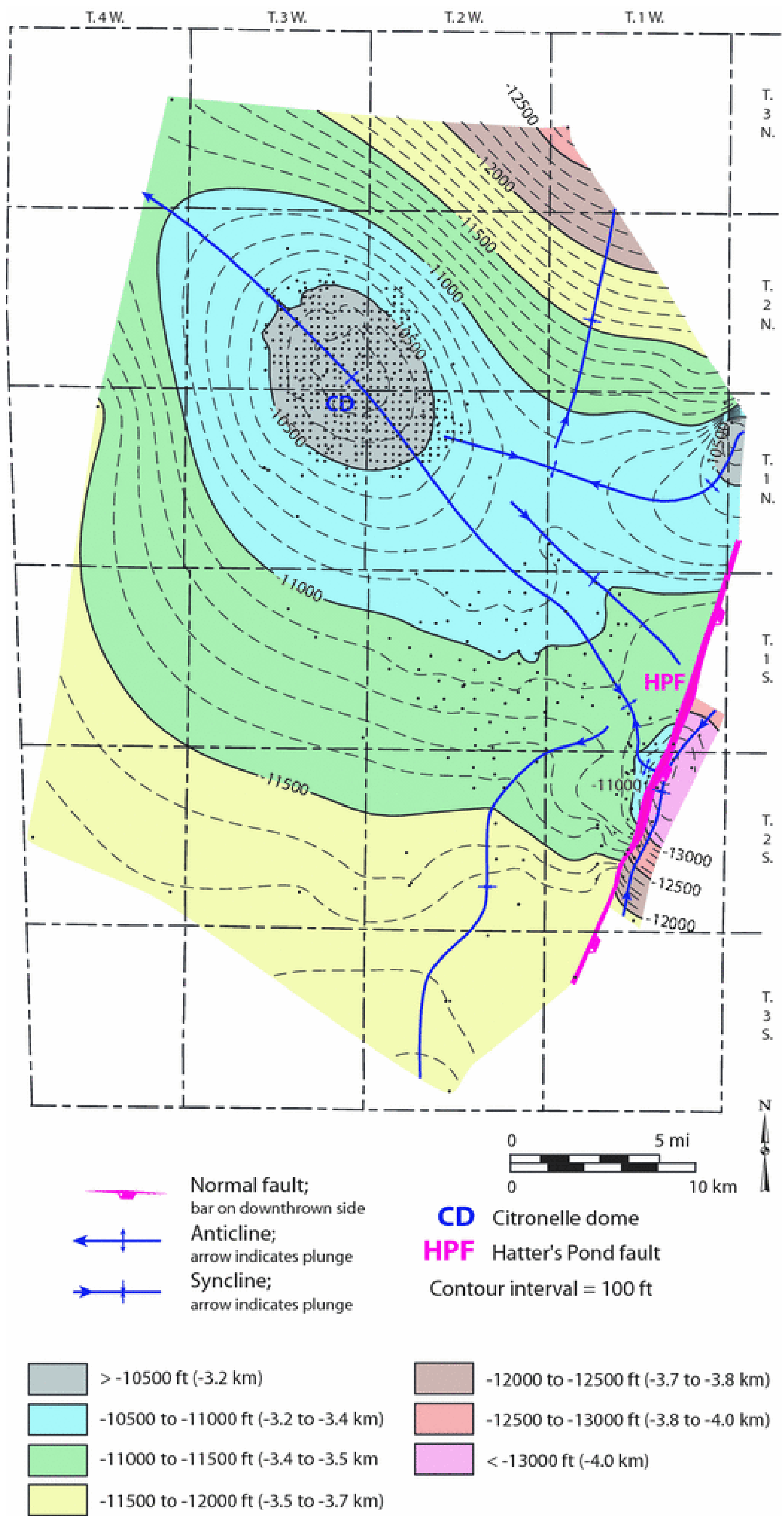

Figure 2. Structural contour map of the top of the Donovan sand in Citronelle Dome and adjacent areas (modified from Esposito et al. 2008)

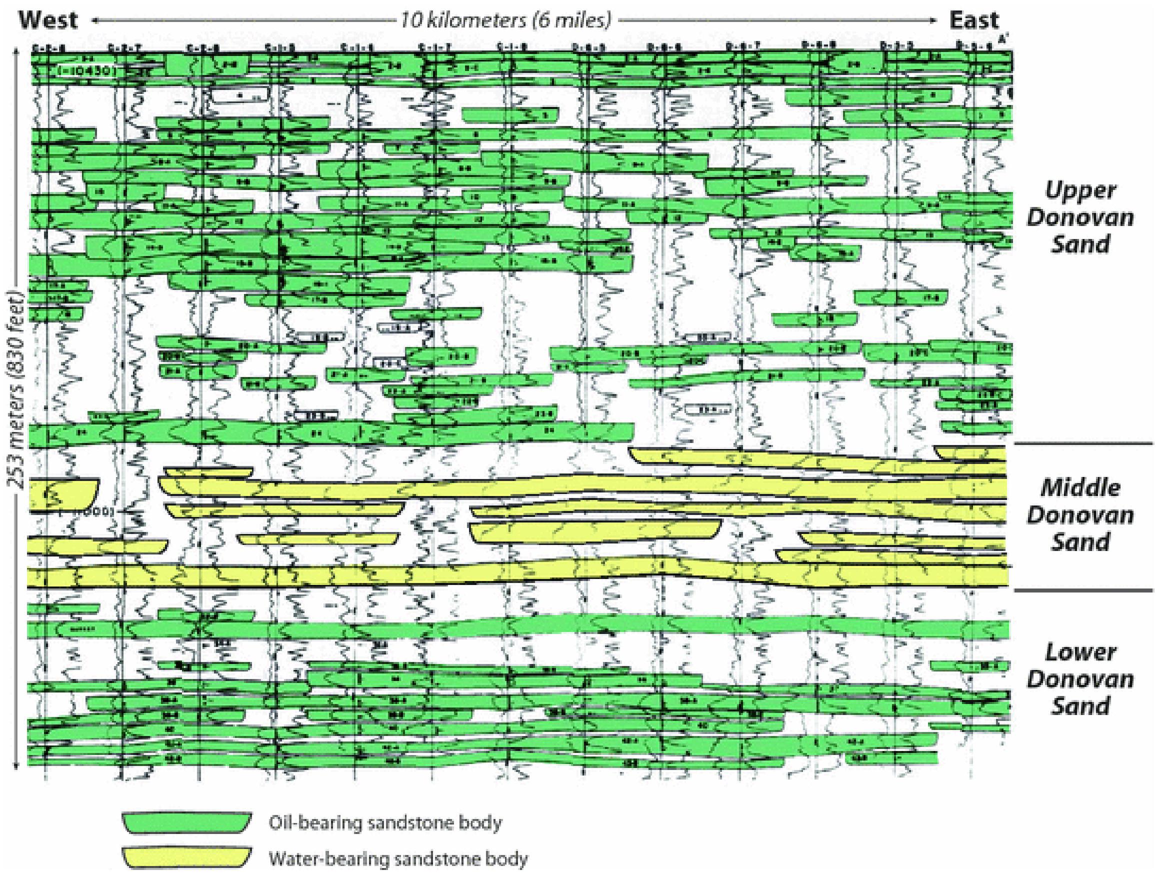

Figure 3. Generalized stratigraphic cross section showing facies heterogeneity in the Donovan Sand (modified from Wilson and Warne 1964)

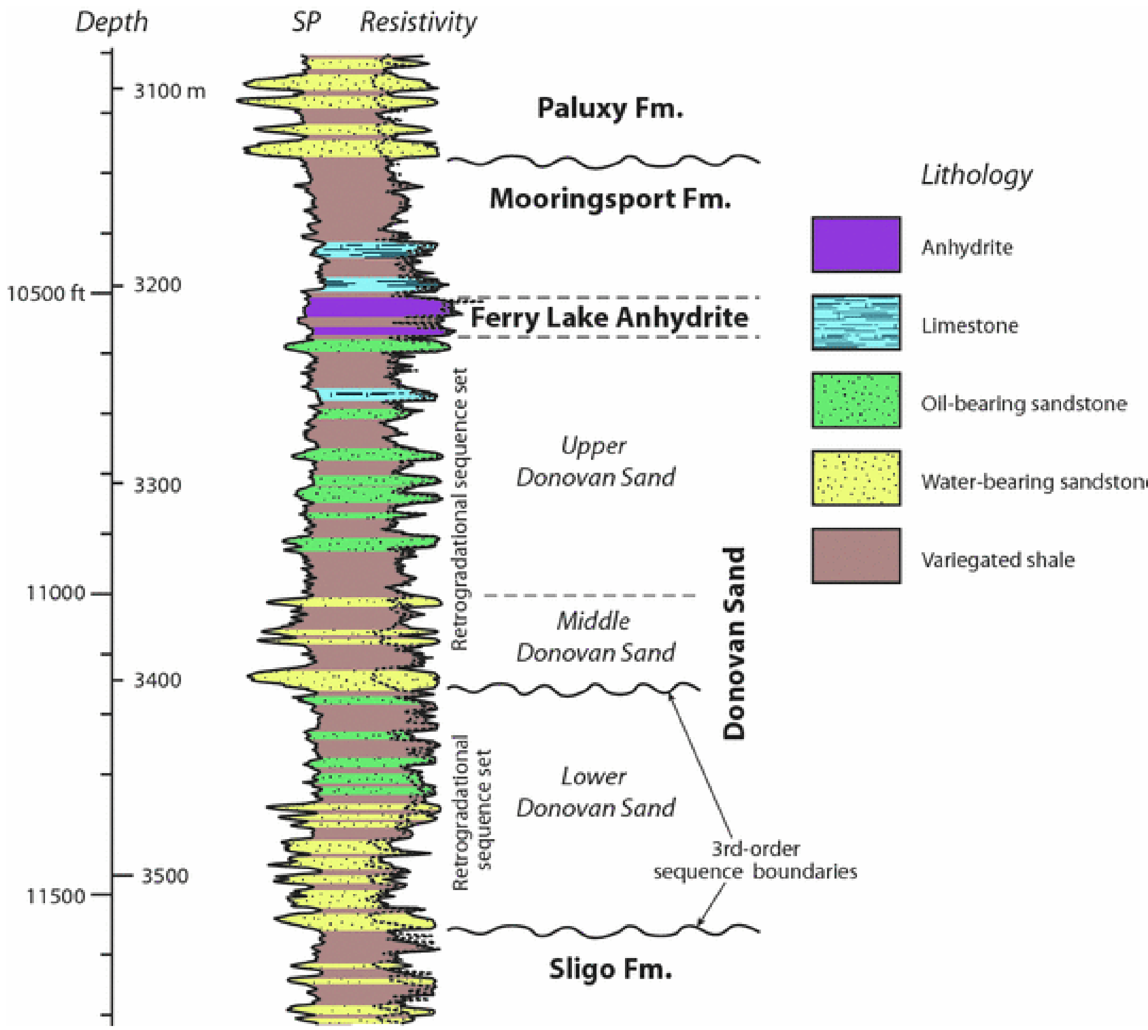

Figure 4. Stratigraphic section and geophysical log characteristics of the Donovan sand in Citronelle Field

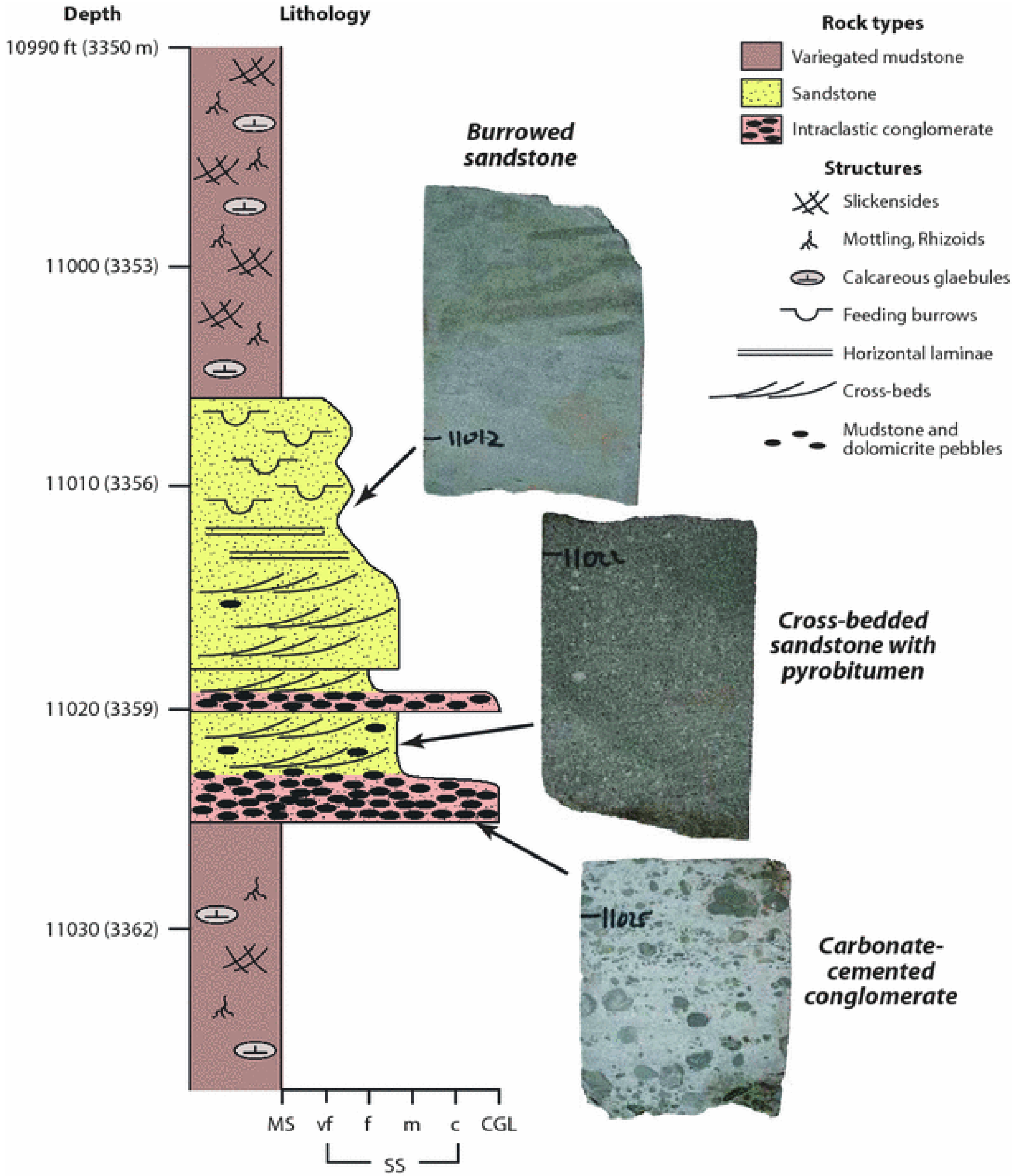

Figure 5. Graphic core log with representative photographs of the 16-2 sandstone in the B-19-10 #2 injection well, Citronelle Field

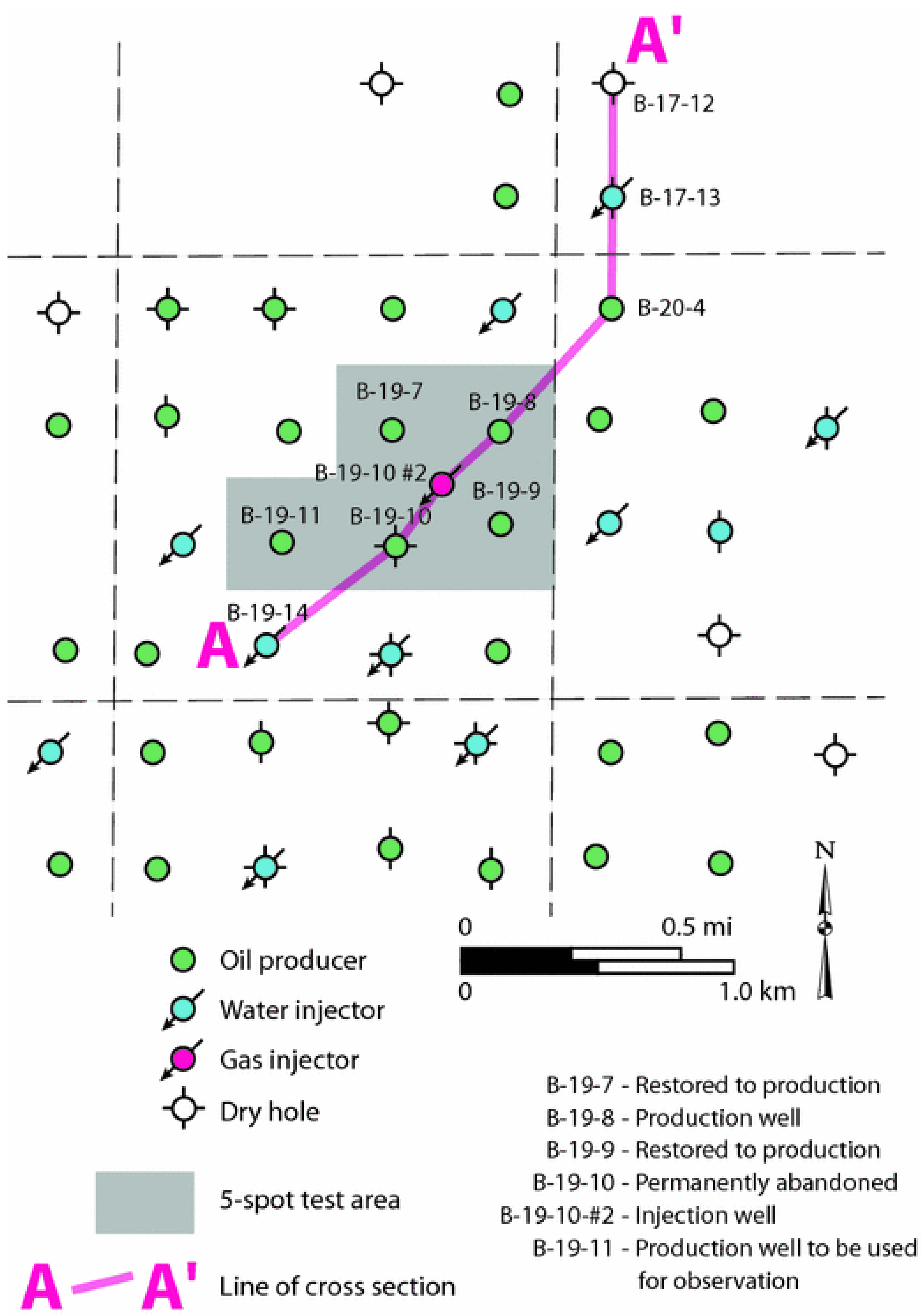

Figure 6. Map of pilot area in northeastern corner of Citronelle Field showing irregular 5-spot pattern being used for field test

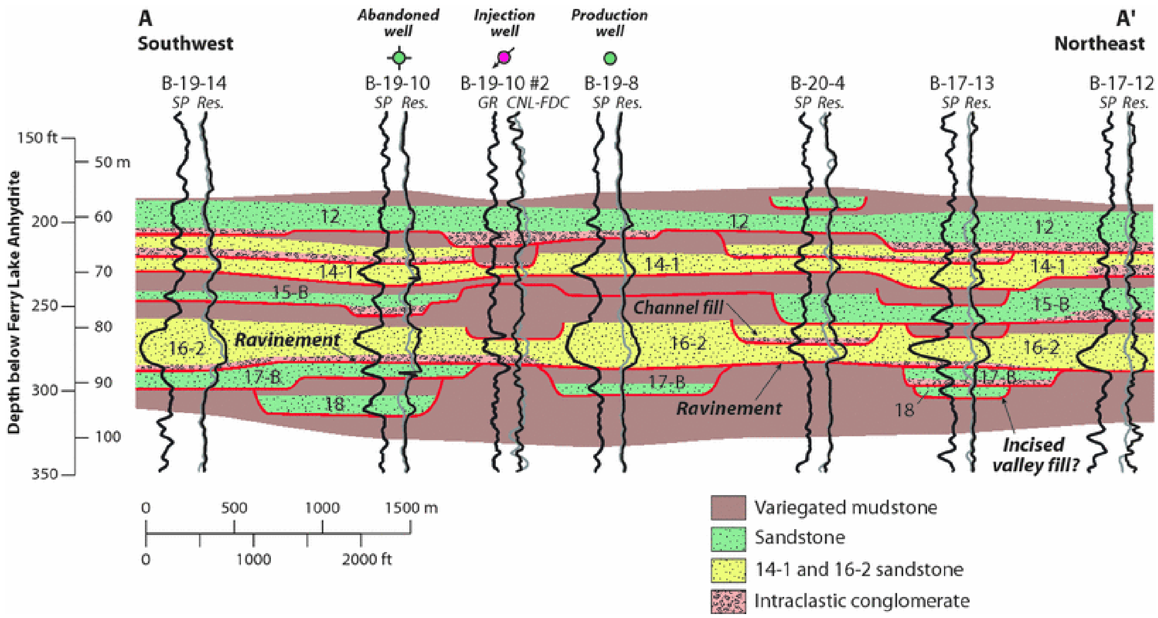

Figure 7. Stratigraphic cross section showing the 14-1 and 16-2 sandstone units and associated facies heterogeneity in the upper Donovan sand in the pilot area

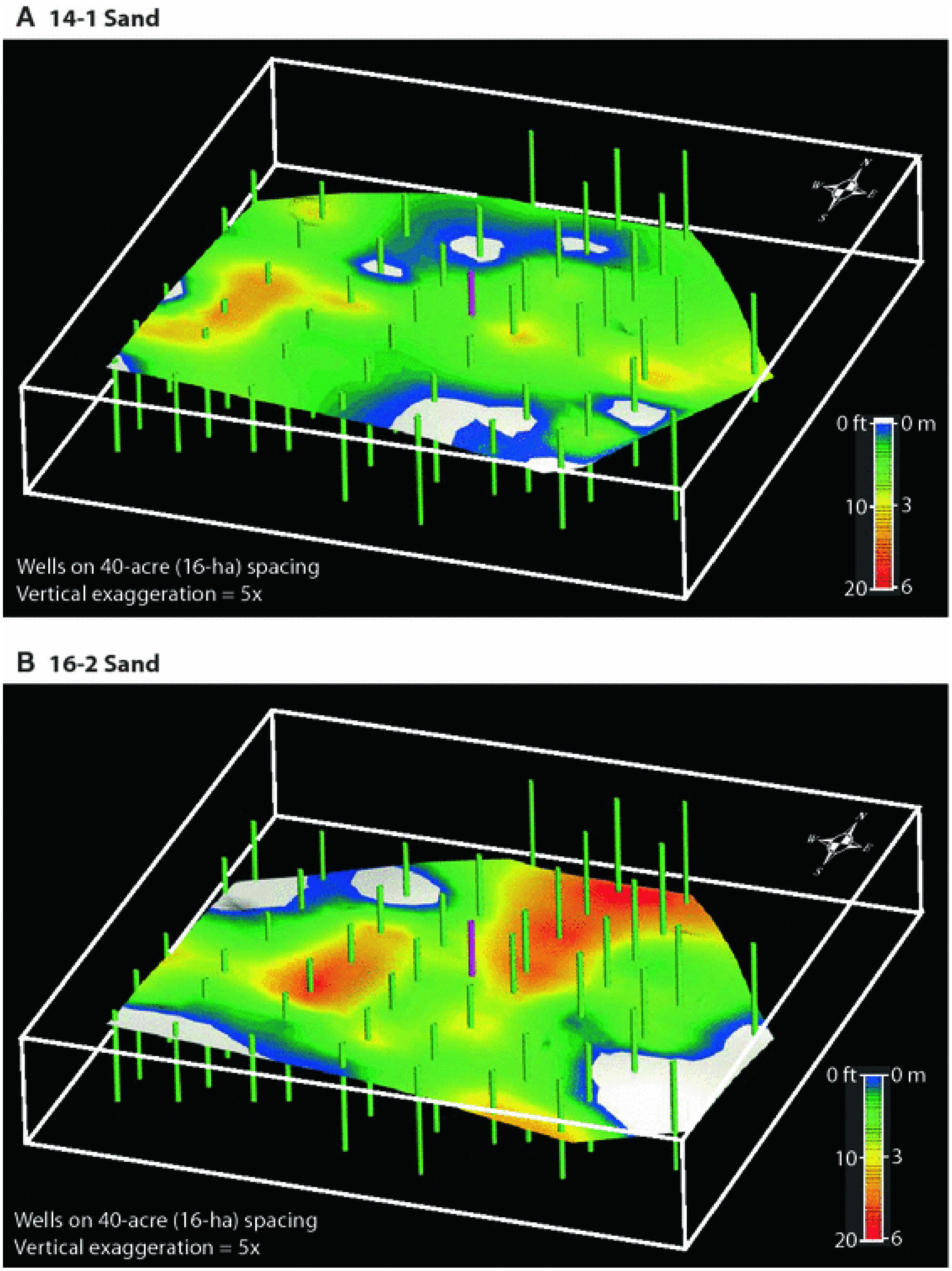

Figure 8. Computer models of net pay in the 14-1 and 16-2 sands draped on geologic structure in northeastern Citronelle Field. Injection well (B-19-10 #2) highlighted in *magenta*

DEPLOYMENT MODELS FOR COMMERCIALIZED CARBON CAPTURE AND STORAGE

by

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Even before technology matures and the regulatory framework for carbon capture and storage (CCS) has been developed electrical utilities will need to consider the logistics of how widespread commercial-scale operations will be deployed. The framework of CCS will require utilities to adopt business models that ensure both safe and affordable CCS operations while maintaining reliable power generation. Physical models include an infrastructure with centralized CO_2 pipelines that focus geologic sequestration in pooled regional storage sites or supply CO_2 for beneficial use in enhanced oil recovery (EOR) and a dispersed plant model with sequestration operations which take place in close proximity to CO_2 capture. Several prototypical business models, including hybrids of these two poles, will be in play including a self-build option, a joint venture, and a pay at the gate model. In the self-build model operations are vertically integrated and utility owned and operated by an internal staff of engineers and geologists. A joint venture model stresses a partnership between the host site utility/owner's engineer and external operators and consultants. The pay to take model is turn-key external contracting to a third party owner/operator with cash positive fees paid out for sequestration and cash positive income for CO_2-EOR.Theselection of a business model for CCS will be based in part on the desire of utilities to be vertically integrated, source-sink economics, and demand for CO_2-EOR. Another element in this decision will be how engaged a utility decides to be and the experience the utility has had with commercial R&D activities. Through R&D, utilities would likely have already addressed or at least been exposed to the many technical, regulatory, and risk management issues related to successful CCS. This paper provides the framework for identifying the different physical and related prototypical business models that may play a role for electric utilities in commercial-scale CCS.

INTRODUCTION

The United States has nearly 1500 electric generating units which burn approximately 1 billion tons of coal each year of the estimated 489 billion ton reserve base (*1*). Based on these figures, the United States has over 300 years of low cost domestic coal resources available for electricity generation into the future. These generating units collectively produce more than 300 gigawatts of power, accounting for 50% of electric power generation, but produce roughly 36% of the total carbon dioxide (CO_2) emissions of the entire U.S. economy (*1*). Based on the fate and timing of CO_2 legislation or regulation, utilities that depend on coal (and natural gas, as proposed in the Waxman-Markey American Clean Energy and Security Act H.R. 2454) as fuel will be faced with not only technical issues but business decisions on how to most efficiently manage the deployment of such technologies at commercial scale. Independent of the timing of carbon legislation or regulation, technical readiness and an understanding of the business of CCS will be necessary for widespread commercial-scale deployment.

Carbon capture and storage (CCS) is a critical enabling technology option to mitigate the large quantities of CO_2 produced by coal-fired units and other CO_2 emitting industrial sources (*2, 3*). If performed cost effectively and safely, the widespread deployment of CCS could allow the nation to preserve economic and energy security benefits while reducing carbon emissions. This would allow the United States to continue to use its vast domestic coal resources and existing power generation and transmission infrastructure. The decision whether or not to deploy CCS will also be driven, in part, by regional limitations on renewable fuel sources such as geothermal, wind, and solar, along with the commercial costs and viability of new nuclear power. CCS, if successful, could provide comparatively low-cost base load coal-fired power to ensure economic prosperity in these regions.

In the 110th Congress, legislative proposals seek reductions of CO_2 emissions to 1990 levels or lower by 2030 (*4*). This would require electrical utilities to commit to commercial CCS deployment, primarily to retrofit existing generating units, by about 2020. Due to this schedule, an unprecedented R&D effort is moving forward to address a wide range of issues such as costs, access to pore space, liability, operations, and the regulatory framework. In parallel with these issues, the business side of CCS for commercial scale deployment is also beginning to be developed. This paper identifies and discusses several physical as well as prototypical business models that would likely be considered in the deployment of utility-scale commercial CCS.

Commercial Industrial-Scale Sequestration Operations

While R&D on CCS is moving forward at an unprecedented rate, carbon capture has been incorporated in petrochemical and chemical processes for many years, and the underground injection of large volumes of CO_2 has been successfully performed for over 40 years. Apart from the lack of economic drivers (i.e., a carbon price), the primary barriers to widespread utility use of CCS are legal issues and the lack of a regulatory framework (*5*). In contrast, the science, applied technology, and engineering of CO_2 injection, coupled with secure geologic sequestration, has already been demonstrated through CO_2-enhanced oil recovery (CO_2-EOR) and by industrial-scale CO_2 injection and sequestration operations associated with natural gas upgrading (*6*).

CO_2 has been injected into geologic formations and monitored for permanent storage in several countries, including Norway, Canada, and Algeria. Since 1996 Statoil, Norway's state oil company, has been reinjecting 1 million metric tons of CO_2 per year into an offshore saline sandstone formation (the Utsira formation) located above the Sleipner gas field (1000 m below the seafloor) in the North Sea (*7*). These injection operations have been a successful and environmentally prudent option, as demonstrated by activities designed to monitor and verify the location of the CO_2 plume, assess the integrity of the cap rock, and ensure that associated wells are not leaking (*8*).

Another industrial project, the In Salah natural gas plant, a joint venture of BP, Sonatrach, and Statoil, in Algeria, North Africa involves similar operations. Since 2002 approximately 1 million metric tons per year of CO_2, separated from produced natural gas, has been injected through three injection wells into the water leg of a shallow gas producing zone in the Krechba gas field. The project has had successful injection operations and has succeeded in monitoring the migration of the injected CO_2 (*9, 10*).

Another commercial activity with a proven track record in safe CO_2 injection operations is the CO_2-EOR industry. This industry originated in 1972 in Scurry County, Texas, and has since been implementing commercially viable operations, most notably in the Permian Basin of Texas and New Mexico, the Williston Basin of Saskatchewan, and the Gulf of Mexico Basin in Mississippi. Approximately 80 commercial CO_2-EOR projects are currently in operation in the United States. Many individual CO_2-EOR projects in the United States and Canada are approaching the scale of CO_2 production associated with a 500 MW pulverized coal-fired power plant producing roughly 3 to 4 million metric tons of CO_2 per year. Many of these operations are now implementing monitoring tools to demonstrate the safe and permanent sequestration of the CO_2 injected for EOR. Most notable is the Weyburn EOR project in Saskatchewan, Canada (*11*). In October 2000, EnCana began injecting significant amounts of CO_2 into a Williston Basin oilfield (Weyburn) to boost oil production. Overall, it is anticipated that some 20 million metric tons of CO_2 will be permanently sequestered over the life of the project. The gas is being supplied via a 205 mile long pipeline from the lignite-fired Dakota Gasification Company synfuels plant site in North Dakota. The Weyburn enhanced oil recovery project in Canada currently stores 1-2 million metric tons of CO_2 per year in underground formations utilizing a diverse suite of monitoring methods to confirm the fate of the injected CO_2 (*6*).

CO_2-EOR is not only a “game-changer” in oil production but will serve as a key element in the early project economics and permitting related to the development of commercial scale capture technologies. Several proposed integrated gasification-combined cycle and post combustion coal CO_2 capture projects are teaming with oil companies for use of the captured CO_2 in EOR. The cash positive sale of CO_2 as a commodity will help to offset the high costs of capture in early commercial-scale demonstration projects. An established permitting process for CO_2 injection into oil fields for EOR and an established liability structure of CO_2 injected into oil field pore space is attractive over purely geologic sequestration for early projects.

A consensus is growing that the technical challenges facing CCS are operational, i.e. related to the integration of capture with transportation and injection for storage.

Despite successes and accomplishments, large-scale industrial injections have not fully vetted the integration of capture with power generation and have not involved a great deal of pipeline transportation and injection into saline reservoirs.

Prototypical Utility Business Models for Geologic Sequestration

Commercial CCS will require utilities to develop business models enabling them to cost efficiently deploy safe and reliable operations. This will include many components potentially beyond that of primary cost. The core values of electrical utilities have historically placed emphasis on low cost, strict occupational and environmental safety, and high operational reliability. With new mandates on environmental controls associated with CO_2 these priorities may drive the adoption of new business models. This will be especially relevant considering the projected high costs of commercial deployment of CCS and risk management required on the scale of operations currently envisioned.

Like most industries and individual companies, electrical utilities will be faced with decisions regarding the extent to which they become, or remain, vertically integrated and the need to set up strategic business units (SBUs) related to carbon management. Vertical integration describes a style of management control that characterizes the degree to which a company owns its upstream suppliers and its downstream buyers, i.e., being engaged in different parts of the production process. There are a number of studies that review corporate strategies related to vertical integration (*12*) and the predictive and exogenous variables in the empirical determinates of corporate vertical integration (*13*). Expansion of activities downstream is referred to as forward integration, while expansion upstream is backward integration. For a coal fired electrical utility an example of upstream integration would be to own coal mines and transport coal to generation stations. In contrast, the same utility who self-owns downstream infrastructure such as transmission and distribution assets would be forward integrated. In environmental management, most coal utilities have historically been very forward integrated. For example, coal-fired utilities usually manage coal combustion byproducts produced on site, such as coal ash and flue gas desulfurization system gypsum. This forward integration is founded in a long history of successful operations and risk management associated with these activities. Questions remain regarding the degree of vertical integration that will be assumed with CCS.

One of the best examples of vertically integrated companies, with comparisons to CCS, is in the oil industry. Oil companies often adopt a vertically integrated structure all the way along the supply chain, from crude oil and gas exploration and production, transportation, refining, to sale of the refined products to consumers. This requires one company to have a wide range of technical and commercial skills, in order to successfully operate each link in the chain.

In some instances, the unbundling of vertically integrated business models has led to significant improvements in efficiency, as in the natural gas industry where ownership of natural gas is often separate from the business of pipeline ownership and operation (*14*). A review of various industries by Acemoglu (*15*) reveals that vertical integration does not automatically improve efficiency. It is also concluded that vertical integration in a pair of industries is less likely when the supplying industry is more technology intensive and the producing industry is less so (*15*). An example of the breakup of vertical integration potentially not working well is actually within the power industry. Data from the United States Department of Energy (*16*) show that average electricity rates in deregulated states (13 cents/kWh) are more than 50% higher than the rates in regulated states (8.4 cents/kWh). This suggests that the breakup of vertical integration played a role in the increased rates.

A key element of vertical integration is its provision of a means to circumvent potential hold-up problems, thus vertical integration is expected to be more common where holdup is more costly (*15*). Theories based on supply assurance (*17*, *18*) account for part of the results if more technology-intensive firms require more assurance.

Gale (*19*) separates the traditional vertically integrated utilities with the new players with new integrated models that combine various activities (some more vertical then others) across geographies in a well-connected value chain. A candid look at today's vertically integrated utilities suggests that success is in execution and that integrated utilities that are well managed can perform very well, and those that are not well-managed do not perform well (*19*).

The issue of vertical integration is not that of being completely integrated or not integrated at all but a matter of selecting the optimal degree of vertical integration. Disadvantages of vertical integration include increased capital costs, requirements for radically different skills and capabilities (core competence), and the assumption of more business risk. While vertical integration can solve one problem it can generate other problems by the need to balance old and new activities. Increased vertical integration can result in a higher degree of control over the entire value chain, including economies of scale and scope, resulting in lower costs and greater competitiveness. It is assumed that the savings in transactions and services that integration accomplishes supersede the development of new business units and the risk.

Utilities considering CCS will be driven by economic and reliability considerations to be vertically integrated but at the same time risk averse. For example, many utilities generate, transmit, and distribute electricity. Some own fuel sources and rail cars, and others sell and manage byproducts in direct support of the utility business. The level of vertical integration that utilities are willing to accept with CCS will begin to focus the development of a business model associated with commercial-scale deployment. (It should be noted that the CCS business may be different in technology development projects and ultimate scale.) The pending question is “Will fossil-fuel-based utilities decide to manage CCS projects internally, employ consultants and contractors in joint ventures, or fully outsource these operations to turnkey carbon management companies?”. Some utilities will potentially consider all three options, based on regional and site-specific operating conditions and constraints.

One key question in this equation is “Will turnkey operators be willing or even be able to assume long-term ownership of captured CO2, accept operational liability for injection operations, and indemnify the source utility generator?”. Risk management and liability will be factors in the vertical integration decision associated with CCS and, especially, sequestration. The business models that are associated with the most controlled exposure will be preferred. Some oil companies and oil field service providers such as Schlumberger Carbon Services are currently evaluating this as a business strategy, but to date no one has adopted a clear-cut business model that wins the day with electric utilities. It could be said that, with successful operations, the early movers in this business, including those able to evolve and adapt to changing conditions, could be big winners in a carbon constrained world.

Physical Deployment Models

We identify two physical models for utility-scale CCS: 1) an infrastructure-based model and 2) a dispersed-plant model. The selection of a physical model will be primarily based on hard and fast issues such as site-specific source-sink matching, regional demand of CO_2 for enhanced oil recovery, and the total number of CCS projects in play. Other issues will include availability of in house engineering expertise, ability to finance, federal and state policy, and the utility's position on the risks associated with storage site liability. For the purpose of defining CCS models it is assumed that utilities will always be an owner's engineer in the operations of capture, either in new generation or with retrofits. It would be unprecedented for an electric utility to not retain firm control of the operation of environmental controls directly linked to compliance and reliability of power generation. (Control of other emissions such as nitrogen oxides, NOx, and sulfur dioxide, SO_2, has been exclusively done in the utility industry as a build and operate, with only a handful of third-party owner/operators of such control equipment.) It is with the nontraditional business of CO_2 transportation and sequestration operations that outsourcing will likely be considered.

The infrastructure model involves a centralized and regional "backbone" CO_2 pipeline with a secondary network of pipelines that focus geologic sequestration in pooled regional storage sites or deliver CO_2 for beneficial use in EOR (Figure 1). A current example is the Canadian Province of Alberta where the Alberta Research Council has proposed a provincial pipeline as a cost efficient approach to transport of CO_2 from multiple sources. The proposed 150-mile pipeline would connect the CO_2 emitting industrial heartland northeast of Edmonton to hundreds of depleted oilfields in central and south Alberta (*20, 21*). The movement of large quantities of CO_2 is expected to revitalize light oil production in central and southern Alberta and provide access to sedimentary basins that contain promising geologic formations for carbon sequestration (*22*). The adoption of this infrastructure model by Alberta is being promoted as an economic incentive for industry to locate in Alberta. Other countries such as Australia and some U.S. States such as Wyoming, Illinois, and the Gulf Coast states are evaluating the option of constructing a centralized CO_2 pipeline as the most cost-effective means of moving CO_2 from producers to consumers and sinks in the region. In 2009 Denbury Resources, who is bullish on CO_2-EOR operations, announced plans to extend their existing regional pipeline from its existing terminus in Louisiana into southeast Texas. This pipeline is currently under construction and is designed to move over 800 million cubic feet per day of CO_2 into Texas for EOR and supply more than ten oil fields that would otherwise not have access to CO_2.

It is also possible that this model would be developed by utilizing existing CO_2-EOR infrastructure such as pipelines, access to wells, and drilling rigs, although smart long-term business planning should retain options to sequester in both saline reservoirs as well as in association with EOR. The infrastructure model is more likely to develop in regional settings where localized source-sink matching is not favorable and where transport will be a significant component of project costs and logistics. An interesting issue is that the regions of the United States having the greatest demand for CO_2 for EOR are likely to be the same regions that possess favorable source-sink matching for non-EOR sequestration. These geological settings tend to go hand in hand. This is especially true in the Southeast, where extensive CO_2-EOR operations are underway and large CO_2 emitting sources are also in close proximity to large capacity saline reservoirs (*23, 24*). Other regions of the United States, such as the Ohio Valley, have fewer EOR opportunities, and the Atlantic coast has only limited saline reservoirs onshore for large volume storage capacity. There are potential EOR market opportunities for Ohio Valley CO_2 supply that would link existing pipelines in the Ohio Valley (Illinois, Indiana, Western Kentucky) south to a proposed EOR-based pipeline to the Gulf Coast. Offtake agreements were signed a year or more ago with 4 or more of the major projects under development in those states.

Other issues that will affect this model are interstate pipeline regulations and societal pressure for one region not to accept another region's captured CO_2 if CO_2 is viewed as a waste. In a situation analogous to some solid waste landfill restriction issues, such as public perception of risk and environmental justice, some restrictions on interstate transport and disposal may come into play.

Depending on tax incentives and emission allowances, a strong regional and cash positive demand for CO_2 for EOR could be an economic incentive in early project development, compared to the fees and liability of saline reservoir sequestration. A key consideration is that at some point the EOR market for CO_2, even in expanding CO_2-EOR regions, will eventually mature and reach a limit of demand. Currently 40 million tons of CO_2 are used for EOR each year in the U.S. (*25*). If in an optimistic scenario (given the increase in EOR demand CO_2) this number doubled in 10 years, the EOR industry might absorb nearly all of the CO_2 output of the first 8 and 12 new commercial-scale utility CCS projects to be built over the next 10 to 15 years. In an effort to comply with limits currently proposed by carbon legislation, more CO_2 would potentially be captured and provided as a low-cost option for use in EOR operations. CO_2-EOR options are important to early utility movers as they provide an established regulatory platform and liability framework that helps support investment decisions beyond the value of the CO_2 offsetting existing high carbon capture costs.

The dispersed-plant model (Figure 2) is defined by sequestration operations where source-sink matching is good and can take place in close proximity (20 miles) to generation units equipped for CO_2 capture. In other words, this model represents a single source of CO_2 coupled to a dedicated, local saline reservoir or EOR field. Based on current knowledge of sequestration geology, and reported emission statistics by region published by the Environmental Protection Agency (*26*), an estimated 50% of power plants throughout the United States are in close proximity to suitable geologic sinks. These sinks are primarily saline reservoirs, oil and gas fields, and unminable coal seams. These plants would all be suitable candidates for consideration of the dispersed model. The dispersed-plant model is favored in regions having high-capacity sinks and nearby EOR opportunities. This model will likely be supported by well-defined and site specific sequestration geology demonstrated through R&D programs such as the DOE Regional Carbon Sequestration Partnerships (RCSP) and Clean Coal Power Initiative (CCPI). Utility confidence in safe and affordable sequestration geology and operations developed in robust R&D programs supports this model. It is also more likely that the dispersed plant model would be adopted in the early stages of a utility's commercial development of CCS, before an extensive pipeline infrastructure has been developed.

Business Models

There are many possible business models for CCS on a commercial-scale. Three prototypical models are discussed: including an owner's engineer self build model, a joint venture model, and a "pay at the gate" model.

Self Build and Operate. The self-build model is one in which CCS operations are owned and operated by the utility with an internal staff of engineers, geologists, and onsite field technicians and operators. This model would involve a new organizational structure or SBU that likely does not already exist at most utilities. While some utilities have internal field and engineering service organizations, they would likely not be qualified at the outset to support deep subsurface geologic sequestration activities such as site characterization, permitting, and underground injection operations.

The key advantage in the self-build model is that utilities then control and manage their own risk and the associated costs of operations. Utilities that adopt the self-build approach will need to be confident in their internal operations with core competence in turnkey project management. Many utilities have traditionally been very successful in not only building and operating coal-fired power plants but also building and operating retrofit environmental controls such as selective catalytic reduction systems and flue gas scrubbers as well as managing the associated combustion byproducts.

From a pragmatic standpoint, larger utilities having robust engineering service organizations and especially with a foundation in CCS R&D will be strategically positioned to implement a self-build model. Additionally, utilities having service organizations with CCS experiences are expected to be more comfortable with managing the vertically integrated risk profile required to deploy CCS operations. Utilities with good financial backing should benefit from access to the upfront capital required to develop and operate turnkey CCS projects. The electric utility industry is highly capital intensive, so further capital spending on CCS to reduce operating costs is a natural extension of that business model. The question is which option is the lower-cost model over the long-term life of the project.

The self-build model would theoretically be more easily accepted by utilities in conjunction with a dispersed physical model with localized source-sink matching and storage reservoirs demonstrated through pilot and demonstration CO_2 injection programs. For smaller utilities or industrial sources, even having readily available opportunities for sequestration in one's backyard may not provide great incentive for implementation of the self-build model. A poorly defined liability structure, the cost of capital, and a lack of expertise to operate a sequestration project may be greater driving forces. Utilities that have natural gas subsidiaries with internal experts to scope sequestration activities would be more likely to self-build.

Cost effective technology development in regional geologic formations will play into utility acceptance of this model. For example, the Southeast Gulf Coast Mississippi salt basin is positioned with a thick sedimentary wedge of Mesozoic to Cenozoic age formations and looks to be a region with very promising geologic sinks. Many of these formations are world class sequestration targets overlain by regionally extensive and thick impermeable shale seals that isolate target reservoirs (*27*, *24*). This region has been the focus of several very successful R&D efforts to demonstrate safe and permanent geologic sequestration. Most prominently the Cretaceous Tuscaloosa Formation lies beneath an area of approximately 46,000 square miles in southern Alabama, Mississippi, and the Florida Panhandle. The Tuscaloosa formation has been a target of multiple carbon sequestration pilot and demonstration-scale R&D projects. It appears to be well confined and to possess good injectivity and storage capacity. The presence of good regional sequestration targets with the added benefit of CO_2-EOR opportunities provides the early incentive for these regional utilities to engage in the development and deployment of capture technology.

The primary issue and potential drawback of the self build model is the assumption that all capital and operational risk as well as environmental risk and liability would be the full responsibility of the owner's engineer. The development of mature risk mitigation options such as private insurance, industry mutual's, trust funds, and risk retention groups will play a major role in defining the utilities' comfort level in the deployment of this model. The other downside is that the owner's engineer will require a large and wide range of internal experience for project development, construction, operations, and compliance. New SBUs in areas of nontraditional utility expertise, including engineers, geologists, and land men to secure pore space for storage, would be needed.

The upside of the self-build model is that utilities would have full supply chain management integration, from capture through transportation and storage operations. Efficiencies of scale in development could be realized, operational issues would be simplified, and risk management would be self controlled. The three main components of

CCS (capture-transportation-storage) are all interrelated to the extent that an issue at any stage results in upstream or downstream effects. The prospect of disruption of this supply chain drives vertical integration and a self-build model.

Access to trained professionals and operators in an aging workforce like that in the U.S. oil and gas industry could be an obstacle. In some respects CCS R&D activities have been hampered by lack of access to field services, operators, and equipment traditionally deployed in oil and gas exploration and production. Programs such as the DOE Office of Fossil Energy's carbon sequestration programs have awarded geologic sequestration training and research grants to help develop a future workforce to support the commercial deployment of carbon sequestration technologies. Also, several universities (e.g., Stanford, MIT) have begun to develop curricula for the training of scientists and engineers in CCS for new commercial projects.

Joint-Venture Model. The joint-venture model is a partnership where CCS is executed jointly by the host site utility/owner's engineer and external operators and consultants. In this model, parties would build on each other's strengths, spreading costs and risks and improving access to financial resources and technologies. This model requires some level of internal staffing and expertise but significantly less than that required in the self-build model. A strong project management command with savvy procurement and contracting capabilities would be needed. Even with strong project management, some level of geologic and engineering expertise would be needed, to ensure that the utility's interests are protected. The organizational and staffing requirements for the joint-venture model would be significantly less than in the self-build and operate model but would still require a chain-of-management and technical staff of project managers.

With a joint venture model there would be shared costs, benefits, and liabilities. While capture would still likely remain the responsibility of the host utility's engineer, components such as transportation and sequestration would be managed by joint venture partners. Issues such as permitting and responsibility for compliance would need to be established. A joint-venture model could be set up to transfer operational liability, but long-term ownership and liability would potentially remain with the host utility. This would place host utilities as the primary movers behind long-term risk mitigation, depending on their joint venture partners. One example of a joint venture model is the project with Hydrogen Energy California. This is a joint venture between BP, Rio Tinto, Southern California Edison, and Occidental Petroleum (GE is a partner to the project but not the joint venture).

Pay at the Gate. The "pay at the gate" model includes turn-key (capture and storage) with external contracting to a third party owner/operator with a positive fee for sequestration and cash positive pricing for CO_2-EOR. This model requires limited internal expertise and staffing but will require a clear definition, contractually, of operational and environmental liabilities. This model would require very limited organizational management but a small but competent staff of technical experts such as project geologists and engineers to work with the large technical staff of the third party company. Several companies, such as Schlumberger Carbon Services and Advanced Resources International, are developing the technical capabilities to offer these types of third party services.

The key benefit of this option is in reducing overall risk to the point of indemnification, contractually, with a qualified firm that can perform the transportation and storage activities more cost efficiently and safely. The model would ideally include contracts for performance risk with a risk premium built into the payment through a CO_2 off-take agreement at the gate. In this scenario the third party would be responsible for site selection, developing and paying for the pipeline and storage site through closure, and would be compensated through a “tipping” or user fee on a dollar per ton basis (or some other metric). Clear definitions would be needed on who takes on the long-term stewardship responsibility after closure and plume stabilization.

The downside of this model (for a utility) is the consideration of having this level of trust and confidence in third parties to manage key elements of power generation and compliance. It is likely that many of these relationships could be developed during CCS R&D programs. This would also be the case in the joint-venture model where contractors and consultants, working directly or indirectly with utilities, would have gained trust and also developed and demonstrated expertise in successful CCS operations. A key element to be considered is that downstream operational issues can affect upstream power generation and upstream CO_2 properties can affect downstream operational issues. For example, electrical utilities do not traditionally subcontract management of downstream coal combustion byproducts such as coal ash and gypsum disposal, but, on the other hand, some do rely on third-parties for the beneficial use of these byproduct. The beneficial use of CO_2 in EOR could be viewed in the same comfort zone as the historical beneficial uses of other coal combustion byproducts.

The presence of a regional infrastructure physical model could support the decision to adopt the “pay at the gate” business model where sequestration would not be in proximity to the host facility. Another issue would be the financial and corporate stability of the contracted service provider. Issues such as bankruptcy and hostile takeovers could lead to instability in contracted services, as these relationships would need to be established as long-term contracts with performance standards. The costs of doing business would also need to be considered, i.e. those associated with paying a fee in the “pay at the gate” model. If these fees are excessive, this could result in utilities moving away from this model and in some cases from CCS in general.

Another key issue with the “pay at the gate” model will be the operational need to synchronize the upstream and the downstream operations. The power plant is going to require an ”output” contract where the pipeline is required and able to take 100% of the plants peak output whenever it occurs. The EOR operator is going to want a “requirements” type service where the CO_2 provider provides guaranteed purity and varies the CO_2 supply based on the operational requirements of the oil production. For example, if the EOR operator is doing a ”huff and puff” variation or an alternating injection of CO_2 and water, the intermediate storage requirements to buffer the system will be potentially beyond injection of CO_2, the variability will be less. If the EOR operator is flooding a single isolated field this will present a greater operational challenge than if a backbone pipeline is the initial destination for the CO_2 and field distribution is secondary. Regardless, the operational requirements of the supplier (the power plant) and the user (the EOR operator) will pull in opposite directions. With increased vertical integration this means that the oil producer will be contractually required for ultimately being responsible for accommodating the various operational requirements (with whatever buffering elements integrated into the system to do so).

RESULTS AND DISCUSSION

Individual companies and utilities will find that one of the three prototypical business models outlined above will resonate with their current business practice, company profile, and capitalization. However, near term choices regarding which business model to pursue for a given project will be affected by the evolving landscape of the commercial CCS environment. As government policies coalesce and are codified, businesses may find that one business model has inherent benefits that emerge from new laws, regulations, and financial instruments.

One of the most important of these is the emerging United States regulatory framework. The EPA has found that it can regulate emission of CO_2 under the Clean Air Act and the injection of CO_2 underground under the Safe Drinking Water Act (through underground injection control (UIC). It has begun UIC rulemaking and offered a preliminary regulatory framework for the permitting of a new well Class VI, explicitly forCO2 disposal. At present there is a very distinct difference between Class II (CO_2-EOR) and the proposed Class VI (CO_2 disposal) UIC regulations. It is not clear what components of the proposed regulation will remain or change, and it is not yet clear how a new Class VI framework will relate to CO_2-EOR under Class II, if it is possible to reclassify wells, or how UIC regulation will relate to air permitting and climate regulation. Depending on the regulatory burden (e.g., the necessary extent of monitoring), utilities may opt to either undertake or not undertake full operation of a geological storage project. Similarly, Federal and State decisions about who will accept long-term liability and under what mechanism will likely affect decisions around third party engagement.

Carbon price is another major influence on business model adoption, both in terms of its value and the market mechanism. For very high carbon prices (e.g., \$60/ton CO_2), the value may be high enough to accrue clear economic benefit for a CCS operator. Conversely, a low carbon price (\$20/ton CO_2) may drive utilities to share risk and expenditure. Equally important is the price surety. A carbon tax (fixed or scheduled) would help companies calculate the near and far-term economics through the different business models, while a widely fluctuating cap-and-trade market may drive companies to select fixed fee contracts with third parties to avoid risk (the third party companies would hope for an upside in the same commodity market).

Perhaps the largest impact on the selection of business models is from the nature of the power market itself: regulated vs unregulated and coupled vs uncoupled. In a regulated market, it may be possible for the utility to put the cost and the risk of a self-operated project into the rate base. For unregulated utility companies, a joint venture model may help reduce risk and maximize the benefits for project operators. Also, companies operating in an unregulated market may opt to pursue polygeneration (i.e., making chemicals or liquid fuels along with power). Some of these systems appear to have superior economics and are easily managed in a joint venture or pay-for-service business model but cannot be pursued by a regulated company. The new Texas Clean Energy Project by Summit Power is an example of a polygeneration project pursuing a third party off-take model in an unregulated market.

Another potentially contrasting issue is that of CO_2 purity. There is an industry presumption that a specification of pipeline purity, such as the Kinder Morgan quality specifications, could play a significant role in upstream capture costs, both from a capital and operations standpoint. More burdensome CO_2 capture specifications directly equate to capture capital costs and the loss of megawatts from operations and compression requirements at the host facility. Pipeline purity specifications also seem to be less burdensome, given sole source pipelines, along with the intermixing of captured CO_2 with potentially more pure naturally occurring CO_2 currently being used for EOR. It is noteworthy that in their current draft regulatory framework, the EPA has explicitly avoided the discussion of CO_2 purity.

Finally, other environmental concerns may drive business model choices. For example, water availability may limit choices for either new or retrofit CCS projects because of additional water requirements for their operation (*28*). This could be either resolved or greatly improved through coproduction and treatment of water from deep saline formation injection (*29*) but would almost certainly require self-operation to protect all parts of the plant material and value chains. In contrast, plants having less need for process or cooling water may be more flexible in choosing a business model.

The commercial deployment of CCS will require coal fired utilities as well as other industrial CO_2 emitters to develop a business model for how CCS operations will be managed. Many different factors will play into this decision, including proximity to promising sequestration geology, the regulatory framework, the availability of risk mitigation options, and the desire to be vertically integrated. Physical models that will play into the selection of the most efficient business model include an infrastructure model with centralized CO_2 pipelines that focus geologic sequestration in pooled regional storage sites or provide CO_2 for beneficial use in CO_2-EOR and a dispersed plant model with sequestration operations in which sequestration can take place in close proximity to the source and CO_2 capture. The selection of a physical deployment model will be primarily based on hard and fast issues such as site-specific source-sink matching, regional demand for CO_2 for enhanced oil recovery, the total number of CCS projects in play, and business decisions based on owner operations and engineering expertise, financing, and outlook on storage site liability.

Several different prototypical business models are proposed for deployment of commercial-scale CCS by electric utilities: an owner's engineer self-build model, a joint venture model, and a "pay at the gate" model. The self-build model is where CCS operations are utility owned and operated by an internal staff of engineers, geologists, and technicians. These utilities are likely to be most accepting of vertical integration business styles. The joint-venture model is a partnership in which CCS is executed together by the host site utility/owner's engineer and external operators and consultants. In this model, parties would build on each other's strengths, spreading costs and risks and improving access to financial resources and technologies. The degree to which a utility is vertically integrated in this model will depend on how the joint venture is framed. The "pay at the gate" model includes turn-key capture and storage with external contracting to a third party owner/operator, with cash positive fees for sequestration and cash positive income for CO_2-EOR. These utilities will by nature of the business model be less vertically integrated.

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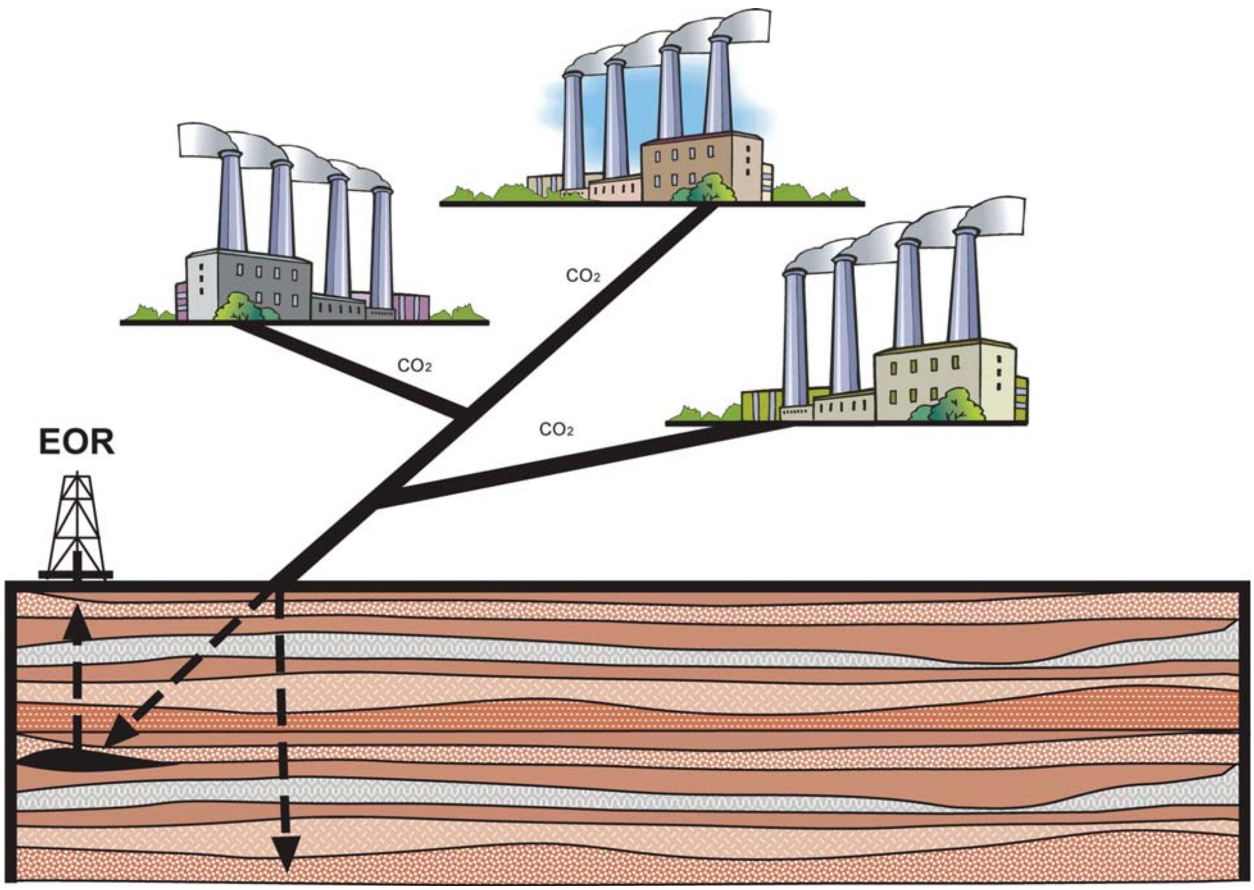

Figure 1. Infrastructure Model

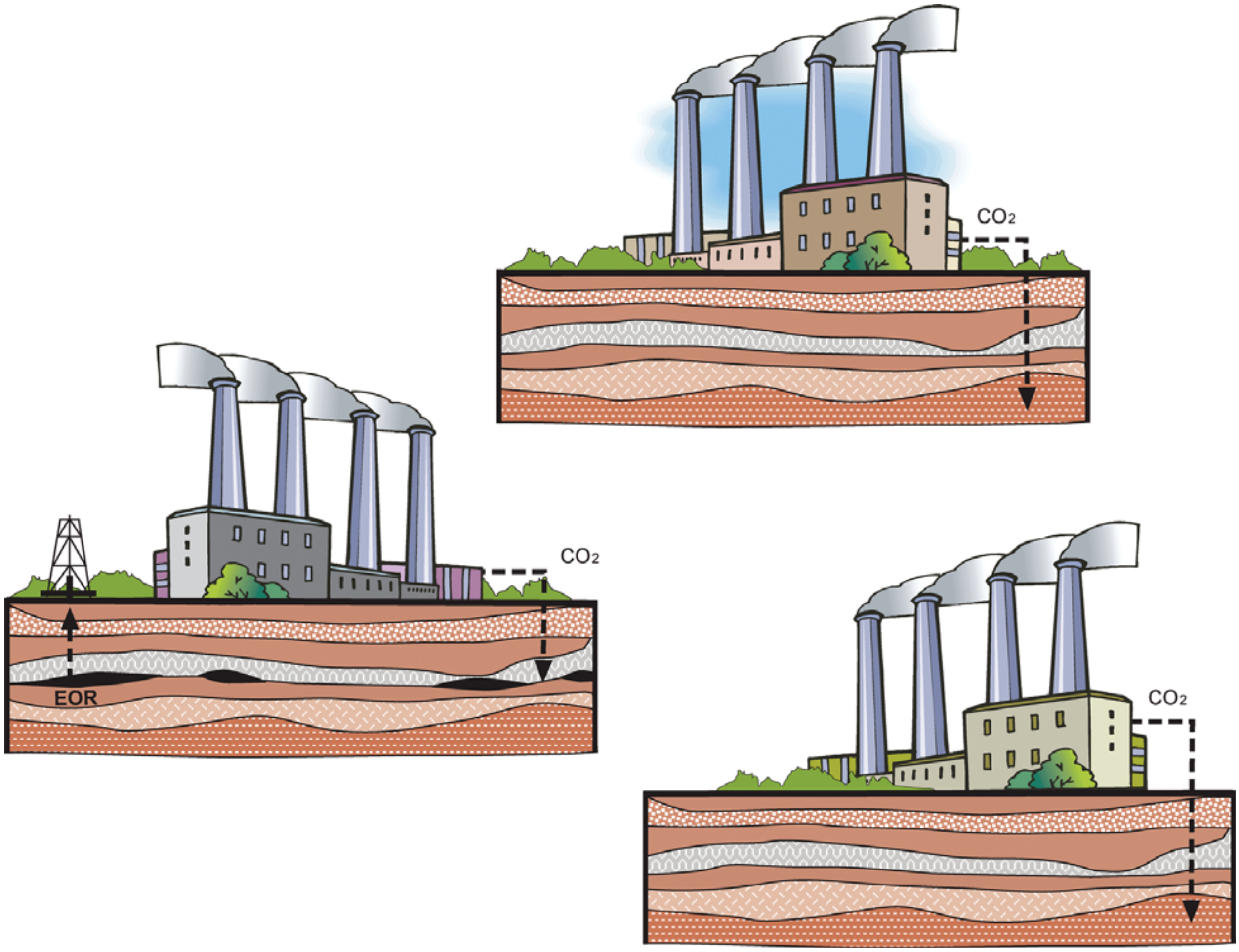

Figure 2. Dispersed Plant Model

SUMMARIZING DISCUSSION

If fossil fuels are to remain a component of future energy production in a carbon constrained world, then carbon-neutral energy options for fossil fuels must be made available. One promising technology, carbon capture and storage (CCS), consists of the separation of CO_2 from the products of combustion of fossil fuels or from fuel gases derived from fossil fuels, followed by pipeline transport and injection into deep underground geologic formations. CCS has been identified as a critical enabling technology with which to mitigate accumulation in the atmosphere of CO_2 produced by coal-fired electric power plants.

For successful commercial-scale deployment of CCS it will be critical for electric utilities and site operators to understand: 1) the storage capacity of proposed subsurface geologic reservoirs, 2) the potential for use and storage of captured CO_2 as a commodity in enhanced oil recovery (EOR), and 3) the types of business models best suited for safe, secure, and cost-effective injection and storage at commercial scale.

The range of preliminary static estimates of CO_2 storage capacity in the Citronelle Dome in South Alabama was estimated to be from 500 million to 2 billion short tons. Therefore, the Citronelle Dome can be considered as a major geologic sink, where CO_2 can be safely stored while realizing the economic benefits associated with EOR.

Screening of reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition indicates that the Cretaceous-age Donovan sand, which has produced more than 169 million bbl from the Citronelle Oil Field, located within the Citronelle

Dome, is amenable to miscible CO_2 flooding. A pilot injection is underway, that will aid in the formulation of commercial-scale reservoir management strategies, including geologic sequestration options, that can be applied to Citronelle Field and other geologically heterogeneous oil reservoirs. The pilot test can also serve as a model for the design of pilot projects in other fields.

Even before carbon capture and storage technology has been fully developed, electric utilities will need to consider the logistics of deployment of widespread commercial-scale operations. Several prototypical business models are possible, including a self-build option, a joint venture, and a pay-at-the-gate model. In the self-build model operations are vertically integrated and utility owned and operated. The joint venture model is a partnership between the host site utility/owner's engineer and external operators and consultants. The pay-at-the-gate model is turn-key external contracting to a third party owner/operator with cash positive fees paid out for sequestration and cash positive income for CO_2-EOR. The selection of a business model for CCS will be based on the desire of electric utilities to be vertically integrated, on source-sink economics, and on the demand for CO_2 for EOR.

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