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ORIGINAL ARTICLE

An assessment of geologic sequestration potential in the panhandle of Florida USA

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Abstract One alternative to reduce global greenhouse gas emissions is to store the emissions in underground geologic sequestration repositories. The efficacy of this approach has been favorably evaluated by numerous authors over the last 15 years. This paper discusses an assessment of the overall feasibility of storing emissions in three different repositories in the Florida panhandle located in the Southeastern United States. The feasibility assessment evaluates both saline aquifers and oil reservoirs located in the panhandle region. The overall feasibility is driven by the available geologic sequestration capacity, the transportation cost to deliver emissions to a respective repository, and other engineering and regulatory issues. The geologic sequestration capacity is generally controlled by the so-called storage efficiency, a variable dependent on the site-specific geology, reservoir conditions, and the injected fluid characteristics. For this paper, storage efficiency for saline repositories was assessed in more detail using numerical modeling. Based on the work completed, the 3 repositories studied have at least 4.55 gigatonnes of capacity to sequester CO_2.

Keywords Geologic sequestration · CO_2 transportation · Florida emissions · Storage efficiency

Abbreviations

Gt	Gigatonne
Mt	Megatonne
Km	Kilometers
M	Meters
GHGs	Greenhouse gases
CCS	Carbon capture and storage/sequestration
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
DOE	Department of Energy

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Introduction

Greenhouse gases (GHGs) in the atmosphere contribute to the trapping of radiant heat from the sun in the Earth's atmosphere, also known as the greenhouse effect (DOE 2010). Carbon dioxide (CO_2) is of greatest interest because it is the most prevalent GHG (DOE 2010). Manmade or anthropogenic CO_2 is primarily generated from the burning of fossil fuels for power generation, transportation, and a wide range of other industrial activities (DOE 2010). Focus lately has been directed at reducing the CO_2 emissions from power generation facilities. One technology currently under research, development, and testing is carbon capture and storage (CCS), or geologic sequestration.

The CCS process involves capturing CO_2 from the source, transporting it in pipelines to a storage location, then injecting the CO_2 as a liquid or gas into saline formations, oil fields, natural gas fields, or unmineable coal seams (IPCC 2005). The emission sources upon which this paper focuses are fossil fueled power plants, which account for 78 % of stationary source CO_2 emissions in the United States and Canada (DOE 2010). Florida, a state in the Southeastern United States, is a typical case. Florida is heavily dependent on the fossil fuels for electricity generation with nearly 97 % of generators in the state producing carbon emissions (EPA 2011). In total, Florida power plants accounted for 143 million tonnes (143 Mt) of CO_2 in 2007 (EPA 2011). Fortunately, Florida has ample geologic resources available to store the CO_2 emissions if it so chooses. This paper evaluates the overall feasibility of storing CO_2 emissions from 13 sources (see Table 1) underground using saline formations and depleted oil reservoirs in the Florida panhandle (e.g., northwestern Florida). The previous work has reviewed the preliminary feasibility of CCS throughout the state of Florida (Poiencot and Brown 2011), as well as preliminary sequestration potential in the panhandle (Poiencot et al. 2012). The work presented herein provides further review of sequestration potential in the Florida panhandle region through analysis of site-specific geology, numerical modeling of a range of storage zone parameters, and consideration of engineering aspects. This paper outlines and describes the evaluation methodology utilized to pick the most feasible CCS repositories and determines their sequestration capacity and engineering feasibility. It also presents the results of the analyses followed by a general discussion of the practical consequences of the results and conclusions gleaned from the overall effort.

Geologic methods

A variety of methodologies and approaches to characterize the geologic sequestration capacity of candidate areas was undertaken. A literature review was conducted to evaluate potential storage formation geology. Then, the spatial extent of the most promising formations was evaluated for CCS. Individual areas were delineated and their respective capacity estimated using accepted methods originally developed by the United States Department of Energy (DOE) and others. The most feasible areas for CCS were selected using results from repository simulations, pipeline transportation models, and other aspects described within the paper.

Geological considerations overview

There are currently four primary geologic alternatives being studied for the storage of CO_2 in geologic formations, including saline formations, active or depleted oil fields, active or depleted natural gas fields, and coal seams (IPCC 2005; Litynski et al. 2006). The capacity of each of these repository categories to sequester CO_2 is an important consideration during feasibility-level investigations of potential projects (Koide et al. 1992; Bachu 2000; Bachu and Adams 2003; Bradshaw et al. 2007). Deep saline formations offer the highest potential storage capacity of the four primary options (Bachu et al. 1994; Van der Meer 1995; Obdam et al. 2003; Herzog 2009). Saline formations also contain a majority of the potential sequestration capacity in the Southeastern United States representing approximately 92 % of the total (DOE 2010). Active and depleted oil and gas reservoirs exist in Florida, but are typically located deeper in the subsurface than available saline formations. In addition, the mature oil and gas fields in the study area have limited sequestration capacity when compared with saline formation alternatives. Consequently, these oil and gas reservoirs are viewed less favorably by those interested in large-scale sequestration such as electric utilities. For this paper, one large depleted oil reservoir (Jay

Table 1 Florida panhandle CO_2 stationary emission sources

Map ID	Plant name	Northing	Easting	Annual CO_2 emission (Mt)
1	Crystal River	3204678.076	334313.2099	14.53
3	St Johns River Power Park	3366685.069	447107.3266	9.38
4	Seminole	3289401.62	438698.3555	8.95
6	Crist	3398084.815	−97895.92908	6.62
10	Northside Generating Station	3365145.497	446936.553	4.46
13	Lansing Smith	3357948.163	47642.89122	3.44
22	Deerhaven Generating Station	3292844.025	365772.0841	1.58
26	Cedar Bay Generating Company LP	3365693.624	441618.5065	1.28
32	S O Purdom	3341056.505	191654.8001	0.64
33	Brandy Branch	3354692.44	408803.1779	0.63
37	Arvah B Hopkins	3373808.201	173480.9335	0.52
38	Scholz	3399359.3847	127519.0930	0.52
39	Putnam	3277742.366	443310.436	0.50

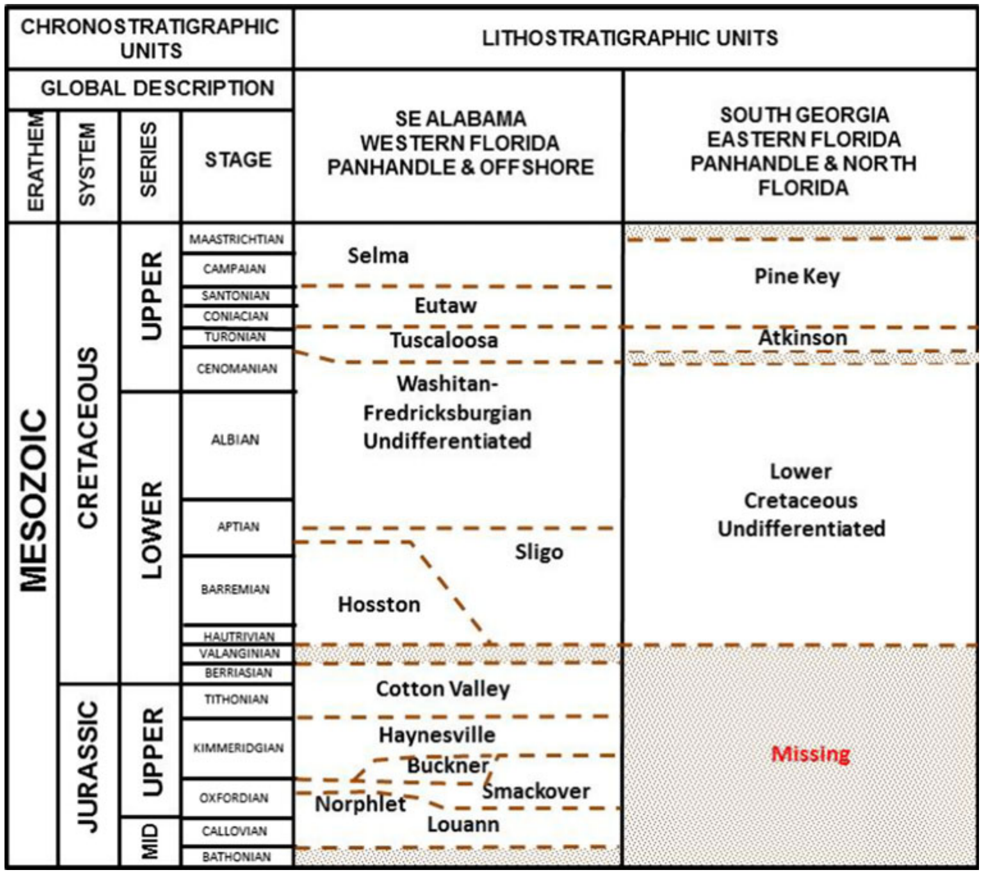

Fig. 1 Geologic correlation chart across Florida panhandle (adapted from Randazzo and Jones 1997)

field) and two small, nearby fields (Blackjack Creek and Mount Carmel) are examined to determine their feasibility to store CO_2. These three fields are collectively termed the "Jay field complex" and are treated as one potential CCS repository. Coal seam sequestration is not considered herein because there are limited opportunities in Florida (Pugh et al. 2008; DOE 2010).

Saline formations

Saline formations are abundant in the Southeastern United States (Petrusak et al. 2010). They include sandstone, weakly consolidated sand and gravel, and carbonate rocks (e.g., limestone and dolomite). Preliminary assessment of available Florida saline formations has been completed by Pugh et al. (2008), DOE (2008, 2010), Roberts-Ashby (2010), and Poiencot and Brown (2011). The Florida panhandle has a number of Cretaceous age formations that should be suitable for geologic sequestration, including the Eutaw Formation (also called the Pine Key Formation in the eastern Florida panhandle), the Tuscaloosa Group (time equivalent to the Atkinson Formation in the eastern Florida panhandle), and a greater than 2,000 m thick zone of undifferentiated Lower Cretaceous sandstones, shales, limestones, and evaporites (Randazzo and Jones 1997). The Jurassic age Norphlet and Smackover Formations are also potential saline formations viable for sequestration, but these also contain petroleum reserves (discussed below). Figure 1, adapted from Randazzo and Jones (1997), provides a general geologic correlation chart linking the western and eastern Florida panhandle showing only Cretaceous and Jurassic age units. Within the panhandle area, a majority of the potential shallow saline formation storage zones are characterized as primarily sandstone grading to a combination of sand/sandstone towards the eastern panhandle. The degree of consolidation is variable and changes with burial depth and cementation style.

Initially, three different saline repositories were evaluated for geologic sequestration in the panhandle. Repository Area 1 (RA 1) consists of formations below the western panhandle. Repository Area 1b (RA 1b) consists of formations below the central panhandle. Repository Area 3 (RA 3) is located offshore and south of the panhandle in the Gulf of Mexico. These three locations and one depleted oil field complex (discussed below) are shown in Fig. 2. Although RA 3 was originally considered in our analysis due to its low risk to humans in the event of a CO_2 release (Celia et al. 2009), not much data exist to geologically characterize this region. Preliminary characterization by Poiencot and Brown (2011, 2012) was accomplished by

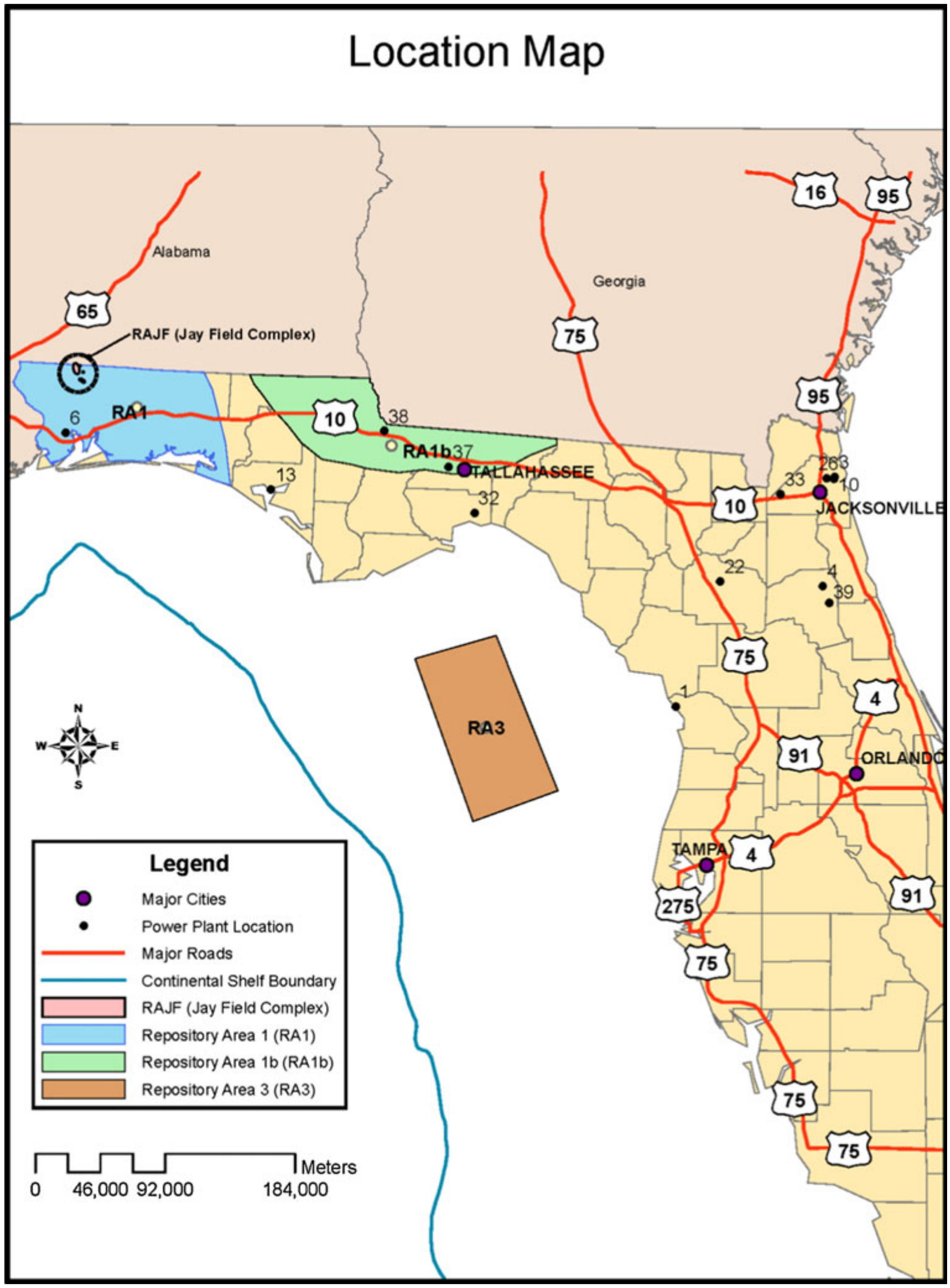

Fig. 2 Location of potential geologic sequestration repository areas in the Florida panhandle

extrapolating known Western Florida geology offshore. However, the initial engineering analysis completed for this effort revealed that RA 3 was not very economical except for one possible emission source in the Tampa area. Therefore, it was eliminated from further consideration such that the focus of this paper will be on RA 1, RA 1b, and the Jay field complex.

ArcGIS coverages obtained from the National Energy Technology Lab (NETL) depicted the general areas of suitable saline formations for CCS across the United States. The ArcGIS polygon area of RA 1 was created from a much larger coverage that spanned most of Alabama, Mississippi and the Florida panhandle. The overall coverage was edited to only include the portions that existed within the boundary of Florida. Area RA 1b was estimated on the basis of previous work completed by Southern Company (Pugh et al. 2008). The Eutaw Formation and Tuscaloosa Group are the primary geologic sequestration zones considered for RA 1 and RA 1b.

The Eutaw Formation is described as a gray to cream, calcareous, fine sandstone that changes character downdip into a sandy chalk with limestone seams with a total thickness ranging from 40 to 90 m in Bay County, Florida (Schmidt et al. 1980). Overlying the Eutaw Formation in

Bay County are chalk beds of Austinian age (Schmidt et al. 1980) included in the Selma Group. Raymond et al. (1988) provided a similar characterization of the Eutaw Formation noting that it also contains beds of greenish-gray micaceous, silty clay and medium-dark-gray carbonaceous clay. The formation is approximately 30–45 m thick in easternmost Alabama. After the deposition of the Eutaw Formation, a broad epicontinental sea formed over the present Gulf Coastal Plain. Accumulations of micro-organisms in the epicontinental sea formed thick deposits of chalk designated as the Selma Group. Limited hydrogeologic characterization has been conducted in the Eutaw Formation, but it is estimated to have a permeability ranging from 5 to 50 mD (Fetter 2001). Porosity is expected to range from 10 to 20 % and is further characterized below.

Schmidt et al. (1980), Mancini et al. (1987), and Petty (1997) divided the Tuscaloosa Group into three separate members, a nonmarine lower Tuscaloosa, marine (middle) Tuscaloosa, and upper Tuscaloosa. This characterization is consistent with Applin and Applin (1947). The nonmarine member is characterized as a poorly sorted, gray to green, fine to coarse sand or sandstone with layers of variegated shales. The marine member is gray, laminated, micaeous, glauconitic, hard shale, with shell fragments and a few carbonaceous seams. The upper member includes gray to cream, fine, calcareous, silty sandstone with shale beds. The thickness varies, but can be greater than 200 m in Bay County, Florida (Schmidt et al. 1980).

Petty (1997) and Puri and Vernon (1964) noted that the lower Tuscaloosa member is 122–145 m thick with increasing shale percentages downdip. They describe the middle marine member as gray, hard, “poker-chip” shale with laminated, micaceous, glauconitic sand, containing *Globotruncana* fauna fossils. They note that the member varies in thickness from 76 to 114 m. Limited hydrogeologic characterization has been conducted in the Tuscaloosa Group, but it is estimated to have a permeability ranging from 5 to 50 mD in its sandier flow zones (Alverson 1970; Fetter 2001). The porosity is expected to range from 10 to 20 % and is further characterized below. Downdip the unit changes to more sand interbedded with shale, and ranges in thickness from 122 to 152 m (Puri and Vernon 1964). Foote et al. (1985) noted that carbonates and shales of lower Cenomanian-Albian age underlie the Tuscaloosa section making an effective vertical seal for the storage of CO_2. Both Applin and Applin (1947) and Puri and Vernon (1964) correlated the Atkinson Formation in northern Florida and the eastern Florida panhandle with the Tuscaloosa Group in the western Florida panhandle (see Fig. 1). Babcock (1969) noted that the Atkinson is underlain by a Lower Cretaceous age unit dominated by interbedded red shale.

Depleted oil reservoirs

There are a number of active and depleted oil reservoirs in Florida, including a cluster in South Florida (FGS 1991; Roberts-Ashby 2010) and a cluster in the Florida panhandle near the Alabama border. This paper focuses upon a portion of those in the panhandle called the “Jay field complex”, a cluster of larger mature oil fields that includes Jay field, BlackJack Creek field, and the Mount Carmel field. Jay field is the largest of the three fields with a productive area in Florida of approximately 5,272 ha (Lloyd 1997). Blackjack Creek and Mount Carmel fields have productive areas of 2,316 and 195 ha, respectively (Lloyd 1997). As of 2011, only the Jay field and Blackjack Creek field were active (FGS 2012). The Jay field complex is a potential CCS alternative, although it is considerably deeper than the saline aquifers discussed previously (see Fig. 1).

The geology of the Jay field complex is fairly multi-faceted. The oil accumulation is contained within the permeable portions of the Smackover and Norphlet Formations with the Norphlet Formation gaining in importance in the northern and western sections of the complex as it thickens in those directions. Oil in the Jay field and Blackjack Creek field is primarily located within the Smackover Formation, while oil in the Mount Carmel field is predominantly pumped from the Norphlet Formation. The Norphlet Formation in the subsurface of southwest Alabama includes an updip conglomeratic sandstone, discontinuous and localized basal shale, red beds, and an upper quartzose sandstone that constitutes most of the formation (Foote et al. 1985). Paleozoic ridges and paleo-highs, such as Conecuh Ridge and the Wiggins Arch (Foote et al. 1985, Figure 23), were partially emergent and served as sediment source areas and depositional limits for the Norphlet Formation. In Florida waters, Norphlet sediments were deposited in alluvial plain, braided stream, eolian, intertidal, and/or beach shoreface environments (Foote et al. 1985). Kugler and Mink (1999) noted that sediments contained within the Norphlet Formation downdip were deposited in a broad desert plain with erg development in some areas. A marine transgression reworked the upper portion of the formation towards its latter time of development.

The Smackover Formation is quite extensive and has been described from Texas to western Florida (Foote et al. 1985). The Smackover Formation, which overlies the Norphlet Formation or Louann Salt, is a carbonate deposit primarily composed of dolostone (FGS 1991; Lloyd 1985; Foote et al. 1985; Mancini and Benson 1998). The Smackover Formation has also been described as a lime mudstone, wackestone, or dolostone, where the upper part is mostly dolomitized limestone which accumulated in supratidal to subtidal environments (Foote et al. 1985). In

Southwest Alabama, the most common Smackover reservoir rocks are non-skeletal grainstone (Kopaska-Merkel et al. 1993). The porosity of the Smackover Formation resulted from dolomitization of the pelletal grainstones within the upper section of the formation (Lloyd 1997; Claypool and Mancini 1989). The oil accumulation is within an asymmetric anticline bounded on the east by the Foshee fault system. The Jay field and Blackjack Creek field lie on the west side of the fault system while the Mount Carmel field sits adjacent to the east side of the fault system. The northern extent of the complex extends into Alabama, where the porous dolostone changes to dense, micritic limestone (Lloyd 1997). The Smackover Formation is approximately 75–175 m thick within Santa Rosa County, Florida, while the Norphlet Formation ranges from 0 to 122 m (Foote et al. 1985; Scott 1991) thick, generally thickening from east to west and south to north. In the vicinity of the Jay field complex, the Smackover Formation is approximately 100–125 m thick, while the Norphlet Formation is approximately 53–75 m thick (Foote et al. 1985, Figure 17; Mink et al. 1985; Scott 1991, Figure 4). The Smackover Formation has a porosity ranging from 14.6 to 16.5 % as measured in Jay field and Blackjack Creek field, while the porosity in the Mount Carmel field ranges from 9.1 to 11 % (Lloyd 1997). The estimated weighted average porosity in the "pay production zone" for the complex is about 14.2 %. The permeability of the Smackover and Norphlet Formations is generally greater than 25 mD. The depth to the Jay field complex ranges from about 4,500 to 4,825 m in the study area in Florida (Foote et al. 1985, Figure 17; Lloyd 1997, Appendix 1 & Figures 14–16). The Smackover Formation is capped by anhydrite of the Buckner Member of the Haynesville Formation (Lloyd 1997). The Louann Salt underlies the porous sections of both the Smackover and Norphlet Formations and is generally impermeable providing a perfect bottom seal for the potential sequestration storage zone.

Geologic sequestration capacity evaluation methodology for saline formations

A series of pertinent geophysical and lithological logs were compiled for developing a geological model to aid with estimating capacity of the saline storage zones. Wells were chosen with priority if they had a bulk density, borehole compensated sonic, compensated neutron, or a compensated neutron-compensated formation density geophysical log since interpretation of these logs for sequestration purposes has been previously illustrated for use in Florida (Roberts-Ashby 2010). These logs provide a relatively simple method to determine the porosity of the formations in question based on the published standards. To determine the capacity of the formation, the volumetric equation for capacity estimation for saline formations was used. This formula is defined in the National Energy Technology Laboratory (NETL) Carbon Sequestration Atlas for the United States and Canada (DOE 2008) and is included herein for completeness:

$$G_{CO_2} = A h_g \phi_{tot} \rho E \tag{1}$$

where the variables are defined as G_{CO_2} carbon mass capable of being stored (kg), A Geographic area of the Disposal Area (m^2), h_g Gross thickness of the injection formation (m), Φ_{tot} Average porosity of the injection formation, ρ Density that the CO_2 would be at given the pressure and temperature of the formation (kg/m^3); and, E Storage efficiency factor.

Capacity estimates were determined for RA 1 and RA 1b using the ArcGIS spatial polygon, storage zone thickness estimates, estimated porosities, estimated storage efficiencies, and assuming in-place CO_2 densities. A permeability of 25 mD was assumed for both repositories based on the similar sandstone formations (Fetter 2001). Well logs (FGS 2011) used in conjunction with existing cross-section and lithologic data were needed to determine the gross thickness of each repository zone. This was required to determine the total thickness of the various storage zones, but also was required in formations, such as the Tuscaloosa, to determine the percentage of the formation that was available for sequestration given that much of the Tuscaloosa Group contains shale stringers. This was done by matching the limited lithological well logs available to corresponding geophysical well logs. It should be noted that storage zone thickness shown on tables in this paper generally indicates "total" sandstone layer thicknesses or "net sand thickness". Corresponding figures report the total formation thickness, including both shale and sandstone.

Geologic sequestration capacity evaluation methodology for depleted oil reservoirs

The production at Jay field began in 1970 and was focused in the Upper Jurassic Smackover Formation (FGS 1991). Production from the Mount Carmel and Blackjack Creek fields began soon after in 1971 and 1972, respectively. The Jay field complex had total original oil in place of approximately 881,000,000 barrels. Total cumulative oil production from the Jay field complex is 486,766,745 barrels, or approximately 55 % of the total original oil in place (FGS 2012). As evidenced by the high oil recovery percentage and based on the literature (Lloyd 1997), enhanced oil recovery using water flooding has already been used in the Jay field complex to increase the overall production. It is possible that additional capacity could be gained through enhanced oil recovery (EOR) operations using CO_2 at the Jay field complex although detailed investigations and modeling are necessary to develop an exact value of additional recoverable oil. A number of regulated utilities in the USA are already considering EOR operations (Esposito et al. 2010a, b). The FGS indicated that the density of the recovered oil at Jay field ranges from 47 to 51° A.P.I. which should permit further EOR with CO_2 to be feasible (Scott 1991; Lloyd 1997).

To estimate the sequestration capacity of the Jay field complex, two approaches were taken. First, the equivalent amount of compressed supercritical CO_2 that can replace produced oil from the Jay field complex "pay zone" was estimated using analytical techniques developed by Brennan and Burruss (2006). Second, the total thickness and porosity of the Smackover Formation and Norphlet Formation is assessed to estimate sequestration capacity of these zones as if they were saline formations.

Engineering methods

Numerical modeling evaluation of storage efficiency factor *E*

The estimated storage capacity for each of the saline formations is strongly dependent on the storage efficiency factor that is affected by many variables. In situ temperatures and salinities of storage zone brines will result in density stratification effects; these tend to reduce the overall *E* values (Doughty and Pruess 2004). The formation heterogeneity can lead to improved storage efficiency and less CO_2 plume mobility (Doughty and Benson 2006; Flett et al. 2005). Injection pressures will also need to be assessed as they may limit storage (Johnson and Morris 2009; Geibel and Brown 2012). Various researchers have investigated the storage efficiency factor for the entire bulk volume of potential storage zones. Van der Meer (1995) conducted numerical simulations and determined that *E* values ranged from 1 to 6 %. The DOE (2008) estimated *E* to range from 1 to 4 % based on the results of Monte-Carlo simulations. Okwen et al. (2010) compared analytical solutions and numerical reservoir simulations for estimating the storage efficiency factor. Using the analytical approach and realistic saline aquifer repository data in one example, Okwen et al. (2010) estimated a storage efficiency factor ranging from 4.4 to 22 % which is considerably higher than other researchers. Xie and Economides (2009) postulated that in structurally closed basins, the *E* value would be severely constrained due to high injection pressures such that *E* values would be less than 1 %. However, Zhou et al. (2007) questioned this conclusion showing that even stratigraphically "closed basins" would exhibit vertical leakage of CO_2 through top seals which would tend to alleviate much of the potential pressure buildup leading to *E* values greater than 1 %. Although the authors tend to support the case made by Zhou et al. (2007), Brown et al. (2011) clearly showed that for a large regional sequestration network linking multiple fossil fuel power plants, the potential CO_2 plume size could approach that of a typical municipal county in the US. This size plume could be easily supported within the shallower saline formations, but not necessarily in the Jay field complex. As part of this paper, further numerical modeling was completed to examine the value of *E* for the saline formation conditions expected at RA 1, RA 1b, and the Jay field complex. The modeling effort was critical in helping the authors select the appropriate *E* value when estimating the final geological sequestration capacity.

For the evaluation of *E* values, an existing numerical model developed by and discussed by Brown (2011) was slightly modified to include additional vertical resolution. For this effort, the model code UTCHEM (version 9.0) was used to simulate injection of CO_2 into a saline formation (University of Texas 2000). UTCHEM is a reservoir engineering program designed for use by the petroleum industry. Jikich et al. (2003) used a pre-cursor code in their study of sequestration potential in the Ohio Valley.

The three-dimensional model has 20 rows, 20 columns, and 20 vertical layers. The X and Y cell dimensions varied from the injection well location (in the lower lefthand corner of the grid) to the outer boundary using a bias of 1.104. Similarly, the vertical cells varied from the top of the injection well down using a bias of 1.29. The top most cell coincident with the injection well was 0.2 m thick and 8.34 m × 8.34 m in area. The 20th cell in the *X* and *Y* directions had dimensions of 55 m × 55 m. Taking advantage of idealized circular plume geometry, only a quarter domain was constructed. The model used and discussed herein was designed as a "box simulator" that can be used to simulate a wide array of geologies, in situ densities or viscosities, injection rates, well configurations, anisotropy, and fluids. The reader is referred to Brown (2011) for additional model details. Essentially, the value of the box model is that a range of geologic conceptualizations or realizations can be simulated rapidly to develop an array of potential *E* values. That was the approach taken for this study. The resulting *E* values were plotted versus bulk storage zone porosity to examine more realistic *E* assignments for RA 1 and RA 1b. The modeling effort provided the authors a method to validate selected *E* values that were used to determine the final sequestration capacity of each repository. The analysis and discussion of *E* values are presented in the results section.

Primary emission sources

A key component in determining the feasibility of CCS is the characterization of the emission sources and development of a proposed pipeline transportation network. Poiencot and Brown (2012) looked at the 40 largest sources of CO_2 that comprise about 90 % of the 2007 total CO_2 stationary emissions for Florida. Because this paper focuses on the Florida panhandle, the list of sources was narrowed to those in and adjacent to the panhandle. The 13 sources along with a map identification number, location in UTM 1983 (meters) horizontal grid coordinates, and the respective annual CO_2 emissions are listed in Table 1 and shown on Fig. 2. It should be noted that to be consistent with past research (Poiencot and Brown 2012) the map identification numbers (e.g., map ID number) are not consecutive. The total CO_2 emissions from the 13 power plants are 53.05 Mt annually or about 37 % of the total CO_2 utility emissions in Florida in 2007.

Pipeline transportation network and costs

Once the CO_2 sources and sinks were identified, various pipeline transportation alternatives were compared using a pipeline transportation cost model originally discussed in Poiencot and Brown (2011) and subsequently updated in Poiencot and Brown (2012). The pipeline transportation model permits the development of optimum transportation costs of CO_2 in dollars per tonne. Initially, Poiencot and Brown (2011) focused on a simple Florida-wide transport model using straight-line distance from each source to each sink. This method was not constrained by geography, real estate limitations, institutional concerns, or practical engineering considerations regarding pipeline right-of-way (ROW) selection. Later, this method (a.k.a., the Solo-funded model) was updated to a more "real-world" scenario using interstate and highway ROW paths (Poiencot and Brown 2012). The measured distances and pipeline sizes for these networks were used to calculate the capital and operation and maintenance (O&M) costs for the network and a least-cost transport optimization model was run using Microsoft Excel Solver™. The Solo-funded model assumes that each utility operator builds their own individual pipeline to the most cost-effective repository area; therefore, this is the highest cost option (e.g., every utility acts for themselves). The operation and maintenance or O&M portion of the pipeline transportation model was also updated by Poiencot and Brown (2012) to use a constant percentage of the pipeline capital cost. For the updated model and this paper, the O&M cost is 6 % of the capital cost.

Besides the Solo-funded model, two other deployment alternatives were explored. The second deployment alternative envisions development of a regional pipeline network built over time or in "piecewise" fashion by a consortium of power utilities. Owing to the piece-meal construction schedule, the costs of this model were higher than the third option, which was called the "Authority" model, but still considerably cheaper than the Solo-funded model due to economies of scale and fewer total pipe runs. Esposito et al. (2010a, b) discuss CCS deployment alternatives for commercial-scale projects. In the authority deployment alternative, an entity similar to a Toll Road Authority or Turnpike Authority would design, finance, and construct a Florida-wide or panhandle-wide pipeline network and charge all emission generators to use the pipeline. The costs per user would be directly pro-rated based on their total emissions as a percentage of the total emissions in the system.

Results

Numerical modeling of *E*

Figure 3 presents the *E* values versus storage zone bulk porosity. The *E* values were determined from over 50 model simulations varying the degree of plume buoyancy as measured by "gamma" (a dimensionless number postulated by Nordbotton et al. 2006); varying anisotropy ratio; varying residual brine saturation percentage; along with other changes. The figure depicts two general envelopes. Envelope 1 is defined by the dashed "maximum expected" *E* value curve and the continuous "most likely" *E* curve. This region represents best case conditions for CO_2 storage including higher anisotropy ratios and higher residual brine saturation percentage along with lower values of gamma such that buoyancy drive is less important in plume development. Envelope 2 is bounded by *E* values of zero along the *x*-axis and the continuous "most likely" curve. This region represents the likely storage condition case where some variables are not optimum; therefore, this region is far more realistic. The most likely curve starts at about 0.5 % *E* and rises to a value of 6 % *E*, consistent with the previous work presented by Van der Meer (1995).

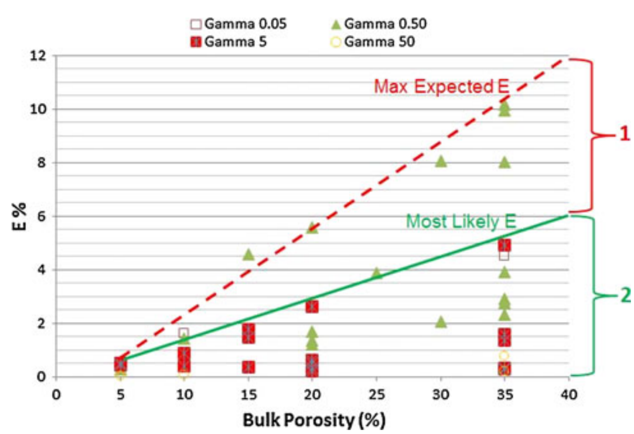

Fig. 3 Model simulation results—*E* versus aquifer porosity

Table 2 Geologic sequestration capacities for the Florida Panhandle

Repository area	Area (m^2)	Thickness (m)	Porosity (%)	CO_2 density (kg/m^3)	Capacity at 1 % *E* (Gt)	Capacity at 4 % *E* (Gt)
RA 1	8.39×10^9	104.0	18	842.75	1.40	5.60
RA 1b	7.35×10^9	369.0	15	757.8	3.10	*12.30*

The thickness represents combined thickness of sandstone stringer zones. The high estimated capacity for RA 1b was not used in the engineering evaluations for this study and therefore this value is shown in italics

There are several items to consider regarding *E* values in Florida. In the case of the Eutaw Formation and Tuscaloosa Group sandstones, it appears (based on geophysical log review completed for this study and the published literature) these formations are interfingered with shales, clay layers, or calcareous sandstones which have very low intrinsic permeability such that vertical plume mobility will be checked, possibly improving *E* values. Unfortunately, this also means that the individual storage zones may be thinner, resulting in increased injection pressures in the aquifer. In addition, the various panhandle formations may also be interrupted by faults or changes in depositional environment such that the storage zones are likely more similar to closed basins which may also reduce *E* values due to lower injectivity (Zhou et al. 2007). In light of these various factors and after a review of Fig. 3, it is believed that the *E* values of the Florida panhandle saline aquifer repositories (RA 1 and RA 1b for this paper) will be on the lower side ranging from 1 to 3 % although a maximum value of four percent (4 %) could be justified for RA 1 based on the model simulations. For the Jay field complex saline storage alternative, it is believed that the *E* values would be approximately 1–2 % based on the structural limits to the storage zone that are located in close proximity to the existing petroleum production area. Table 2 presents the final best estimate for CCS repositories in the Florida panhandle along with relevant storage zone parameters used to develop the estimates.

Saline formations

To determine the total thickness of the potential storage zones, well logs and existing reports were reviewed and synthesized. RA 1 had an abundance of high quality well logs to choose from. In the end, thirteen wells were chosen for this study, seven for a west to east cross-section and six for a north to south cross-section. Figure 4 shows a location map of the test wells and explorations used in this study, as well as the location of a previously published geologic section A–A' (Mancini 2004) and one new geologic section, B–B'. Figure 5 shows the east–west geologic cross-section B–B' for RA 1. Table 2 summarizes the parameters used to estimate the storage capacity for RA 1 and resulting capacity range. Although formation dip may appear steep in the figure, the maximum calculated dip for the Tuscaloosa formation was less than 1° over a majority of the area. The estimated geologic sequestration capacity of RA 1 was calculated to range from 1.4 to almost 5.6 Gt assuming an *E* value range of 1–4 %.

RA 1b was analyzed based upon previous work completed by Southern Company. Table 2 summarizes the parameters used to estimate the storage capacity for RA 1b and resulting capacity range. Based on the estimated thickness, porosity, and storage reservoir conditions, the capacity was calculated to range from 3.1 to 12.3 Gt assuming an *E* value range of 1–4 %. It should be noted that these values are more speculative than those for RA 1 due to the lack of good geophysical logs available in this area. Therefore, for this study, the capacity was assumed to be the low value of 3.1 Gt.

Depleted oil reservoirs

For this paper, the sequestration capacity of the depleted oil reservoirs located at the Jay field complex were estimated using two separate methods. The first method simply evaluates the total petroleum produced from the Jay field complex and converts that to an equivalent mass of CO_2. Collectively, the three largest distinct fields in Jay field complex have produced 486,766,745 barrels of oil up to the end of 2011 and the produced oil came primarily from the Smackover Formation. Foote et al. (1985) noted that the temperature in the Smackover Formation ranged from about 127 to 165 °C with pay zones usually at the bottom of the range. Wilson and Tew (1985) depict Norphlet Formation temperatures in Escambia County, Alabama ranging from 82 to 132 °C. Assuming typical hydrostatic pressures at the depths of the Jay field complex, a realistic range of carbon dioxide density is 800–850 kg/m^3 (MIT 2007, 2012) with an average of 825 kg/m^3 used for this study. Using the technique published by Brennan and Burruss (2006), the collective Jay field complex oil production is equivalent to 47,807,448 tonnes of compressed supercritical CO_2. The DOE (2010) estimated that there was 38 Mt "additional storage resource capacity" in Florida which compares favorably to the former estimate if DOE assumed a lower in-place CO_2 density and that Jay field produces over 70 % of all of the production in Florida.

The DOE also estimated additional technically recoverable oil from EOR operations to be approximately 32 % of total produced oil in Florida. This value appears somewhat

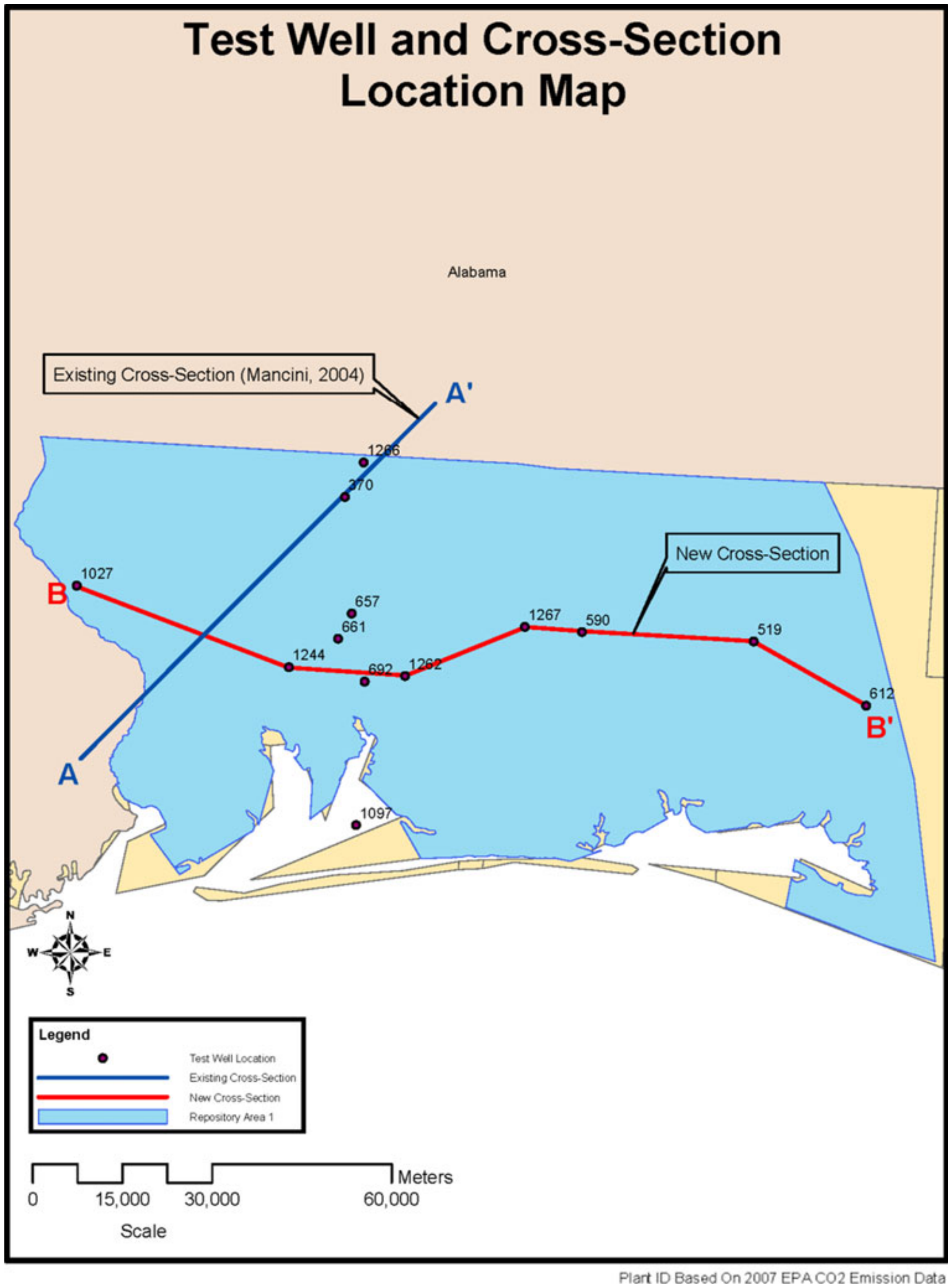

Fig. 4 Location of test wells/geophysical logs and cross-section location map

high given that the Jay field complex has already recovered 55 % of the original oil in place. However, it would not be unreasonable to assume that an additional 10 % of the unrecovered oil, approximately 88,000,000 barrels, could be developed through enhanced EOR with CO_2.

The Jay field complex also contains porosity filled with salt-water brine that could be used for CCS. These potential storage zone areas are outside of the oil "pay zone". Therefore, the second estimate of sequestration capacity assumes that the remaining pore space in the Jay field complex not filled with unrecoverable petroleum has usable CCS capacity. Using the production area values, porosities, thicknesses, an E value of 2 %, and a CO_2 density of 825 kg/m^3, there could be as much as 20 Mt of additional CCS capacity in the saline portions of the Smackover and Norphlet Formations at the Jay field complex. In summary, the Jay field Complex can conservatively contain at least 48 Mt of CO_2 with total capacity as high as 68 Mt. Pugh et al. (2008) reviewed Jay field in terms of six site suitability screening criteria including:

- Depth (Must be deeper than about 800 m);
- Thickness (Must be greater than about 7 m);
- Porosity (Must be >10 %);

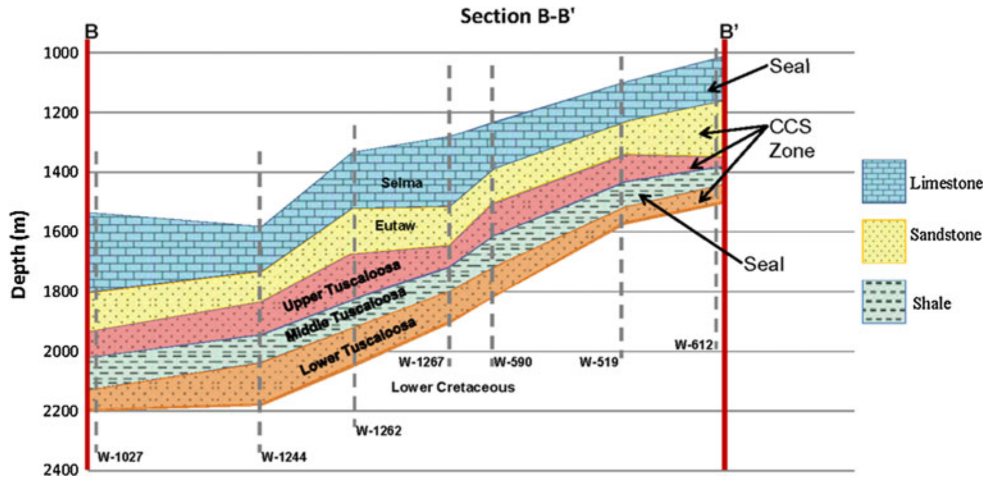

Fig. 5 New West-East cross-section B–B'. *Vertical scale* is exaggerated as compared to *horizontal scale*. Depths are in meters below mean sea level

- Intrinsic permeability (Must be greater than 25 millidarcy (mD);
- Orientation as related mostly to formation dip (must be <6°); and,
- Permanence as related to overlying storage zone seals.

All criteria at Jay field were rated as "adequate" although the eastern portions of Jay field contain some areas where the Smackover Formation dips at more than six° which would be problematic since compressed CO_2 would tend to migrate updip away from existing well infrastructure. Overall, the Jay field complex appears to be a good candidate CCS site.

Transportation modeling

A 25-year planning horizon was used for all CCS transportation modeling. Overall, the capacity of the two shallow saline repositories was sufficient to contain all 25 years of emissions from the panhandle network. The Jay field complex can only provide one to one and one-half years of sequestration capacity. The Jay field complex is slightly more expensive than RA 1 but could be preferable due to in-place infrastructure and the possibility of EOR operations and positive cash flow during year 1. However, it only has one to one and one-half years of CCS capacity if all 13 emission sources are connected. The Jay field complex might prove more useful linked to a single emission source instead. Table 3 depicts the results of the transport optimization modeling in unit cost per tonne of CO_2 for each of the transportation models assuming that all emissions go to only one of the three repositories. The most cost efficient alternative for the entire network is to use both RA 1 and RA 1b with all emissions with the exception of plant Crist (map ID # 6 on Fig. 2) going to RA 1b while plant Crist emissions go to RA 1. In this case the total levelized cost is \$3.86 per tonne CO_2 (this cost not shown on Table 3). Although this may be the most economical, it may not be feasible to permit two separate large repositories in the same area.

Table 3 Levelized unit transportation costs for panhandle network

All costs in \$/tonne	RA 1	RA 1b	Jay field complex
Solo model	\$5.66	\$4.14	\$5.72
Piece wise	\$1.15	\$1.46	\$1.21
Authority	\$0.64	\$0.67	\$0.70

Discussion and conclusions

Overall, the Florida panhandle has the potential to store large amounts of CO_2 using a relatively modest pipeline transportation system. Geologic storage options include both depleted oil fields and Cretaceous age saline aquifers. The Cretaceous age saline formations offer more than 25 years of CCS capacity for the 13 primary emission sources evaluated in this study, while the mature Jay field complex could sequester about 1–2 years of total emissions from the network. The Jay field complex may be a better capacity match to a single emission source in the study area such as Plant Crist, map id 6 (see Fig. 2). If only Plant Crist emissions were directed to the Jay field complex, the capacity would last about 10 years. Also, there is likely additional CCS capacity beyond the confines of each defined field.

Although this study evaluated Upper Cretaceous age saline formations, similar resources most likely exist in the Undifferentiated Lower Cretaceous in the eastern Florida panhandle or Washitan-Fredricksburgian Undifferentiated in the western Florida panhandle. Also, there are significant offshore storage resources that could be investigated for CCS (Poiencot and Brown 2011, 2012). First, the Cedar Keys Formation of Tertiary age that underlies a majority of the Florida peninsula should also be available in the subaqueous portions of the Florida Platform. Storage capacity should also be available in the Destin Dome/Destin anticline area (Foote et al. 1985), although the top of the storage zone in the Smackover Formation may be greater than 5,300 m deep.

The assessment of the Jay field complex was limited to the three largest producing fields in Florida. The potential volume for CCS within the Jay field complex could also be extended into Alabama to include the Pollard field (Foote et al. 1985), as well as the nearby Coldwater Creek field in Florida. This would significantly increase CCS capacity for the complex.

Numerical modeling, using UTCHEM (version 9.0) was conducted to help select appropriate values of storage zone efficiency, *E*. The modeling helped constrain the *E* value of the shallow saline formations to 1–4 %, while the Jay field complex *E* value was estimated to be 1–2 %. The results of the simulations were validated against previous studies; however, newer codes are now available that offer additional capability for sequestration estimates. TOUGH2, one of the new codes available, offers additional algorithms regarding EOR that would probably improve the sequestration estimates made for the Jay field complex.

Overall, CCS is certainly technically feasible in the panhandle of Florida; however, the overall operational cost of a large-scale system of geologic sequestration is still likely to be very expensive. Before the start of such an undertaking, users should consider the total cost of commercial-scale CCS.

Based on the recent research, the total costs excluding capture would probably range from about \$15 to \$30 per tonne of CO_2 (Brown et al. 2011). If capture costs are assumed to be \$40 per tonne CO_2, the total cost could approach \$70 per tonne which would likely be cost prohibitive unless other energy generation options are limited. With the greater availability of natural gas at reasonable cost, the utilities in the study area may opt to look at other lower carbon alternatives in addition to CCS to determine the least-cost option.

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