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Principal Author(s): Kathryn A. Baskin

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6325 Amherst Court
Norcross, Georgia 30092 USA

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Evaluating Terrestrial Carbon Sequestration Options for Virginia

EXECUTIVE SUMMARY

Terrestrial carbon sequestration options are defined as land-resource management actions that have the potential to increase carbon storage, relative to a baseline of unchanging management. This study assesses the potential for terrestrial carbon sequestration options to offset carbon emissions from energy production within the state of Virginia. Using a Geographic Information System (GIS) approach, three options were evaluated by applying two modeling methods. The terrestrial carbon sequestration options evaluated are conversion of marginal agricultural land to long-term forest cover, conversion of tillage practices for row crops, and afforestation of agricultural lands within riparian zones and farmed wetlands; each was evaluated on a statewide basis and within each of the state's 7 Level III ecoregions. Modeling methods applied were the "Winrock method," which was intended to develop estimates from a basis comparable to that applied by Winrock International over other portions of the SECARB region, and alternative methods developed at Virginia Tech ("VT method") which consider additional factors and local conditions. Publicly available data were gathered to develop a spatial database of relevant variables, and that database was manipulated through a variety of GIS analytical techniques to estimate the carbon sequestration for each option. Because the VT methods are based on a more detailed analysis, conclusions regarding the options' carbon sequestration potentials are drawn from the VT method's application. Of the options evaluated, afforestation of marginal agricultural lands was found to have the highest carbon sequestration potential (1.4 Tg C yr^{-1}, on average, over the first 20 years if applied on all eligible lands). The areas with greatest opportunity for application of this option are the Ridge and Valley ecoregion of western Virginia (steep, shallow soils) and in the Tidewater area in eastern Virginia (wet soils). Sequestration potential estimates for the afforestation options are for biomass carbon only and do not consider soil carbon, but other investigators' findings indicate a likelihood that consideration of soil carbon changes would increase the estimated carbon sequestration potentials of these options. The analysis indicates that widespread implementation of this option within the near-term would be capable of offsetting about 3 percent of annual energy-related CO_2 emissions, on average, over the following 20

years, with sequestration continuing but at declining rates beyond that initial 20-year time frame. Considering societal effects as well as estimated C sequestration rates, we consider the most promising option to be afforestation of marginal agricultural lands in combination with afforestation of selected riparian agricultural lands and management enhancements on residual agricultural lands. The sequestration potential estimates developed through this research are general estimates and do not include carbon losses or gains associated with harvested products, management activities, or any other source/sink of carbon. The estimates presented here are best regarded as potentials that serve as starting points for regional planning projects.

Abbreviations: AGBD, aboveground biomass density; BEF, biomass expansion factor; CT, conventional tillage; CTIC, Conservation Technology Information Center; EI, Erodibility Index; GHG, greenhouse gases; GVS, growing stock volume; HEL, Highly erodible land; IPCC, Intergovernmental Panel on Climate Change; MODIS, Moderate Resolution Imaging Spectroradiometer; NED, National Elevation Dataset; NHD, National Hydrography Dataset; NPP, net primary productivity; STATSGO, State Soil Geographic Database; NLCD, National Land Cover Dataset; NASS, National Agriculture Statistics Service; NRCS, Natural Resource Conservation Service; NT, No Till ; RBD, Root Biomass Density; T, soil loss tolerance; TIGER, Topologically Integrated Geographic Encoding and Referencing system; NRCS, Natural Resources Conservation Service; USEPA, U. S. Environmental Protection Agency; Department of Agriculture; USGS, U. S. Geological Survey; RUSLE, Revised Universal Soil Loss Equation. SECARB, Southeastern Regional Carbon Sequestration Partnership.

Introduction

Large quantities of carbon dioxide (CO_2) and other infrared-absorbing “greenhouse” gases (GHGs) are being emitted to the atmosphere globally by fossil-fuel combustion and other activities. Scientific observations indicate atmospheric GHG concentrations are rising steadily, creating potential influence on global climate and consequent negative impacts on the US environment and economy.

Terrestrial carbon sequestration options are land-resource management actions that have the potential to increase carbon storage, relative to a baseline level assuming no change in the current management. The potential for terrestrial sequestration to influence atmospheric carbon can be gauged by considering several quantities: While annual global C emissions are on the order of 6.3 Gt yr^{-1} and the annual atmospheric

increase is on the order of 3.2 Gt yr^{-1} (Schimel and others, 2001), the total amounts of carbon stored in global soils (approximately 2000 Gt) and terrestrial vegetation (approximately 500 Gt) dwarf these amounts (IPCC, 2000). At present, terrestrial systems are believed to be responsible for removal of approximately 1.4 Gt C yr^{-1} from the atmosphere (Schimel and others, 2001), preventing an even more rapid atmospheric buildup. A number of recent studies indicate that C removal by terrestrial systems could be increased through alternative management of those systems. For example, the IPCC (2000) estimates a potential for increasing terrestrial removal by rates in the range of 0.8 – 1.6 Mt C yr^{-1} through targeted land-use change and by improved carbon management by current land uses. Thus, the use of land management practices to sequester carbon from the atmosphere is widely considered as a promising means for partial mitigation of the effects of global warming caused by the emission of GHGs (e.g., Lal et al., 1998; Kimble et al., 2003). Carbon exchange between the atmosphere and terrestrial systems is a primary focus of the Intergovernmental Panel on Climate Change's (IPCC) Special Report designed to assist Parties to the KYOTO Protocol (IPCC, 2000).

Land management practices that can be applied to sequester atmospheric carbon include practices to increase agricultural land soil organic matter contents such as reduction of tillage intensity on croplands; fertility and other management enhancements; the use of winter cover crops; converting marginal, degraded and/or cultivated lands to forest or grasslands; and changing forest management practices (Bruce et al., 1999; Eve et al., 2002). Such management changes have varying effects on carbon stocks and sequestration rates. An assessment of the potential of such practices to store carbon can aid policymakers in developing strategies to offset US carbon emissions, and in designing incentives for implementation.

Assessing the potential of various land-use changes to sequester carbon has prompted development of a variety of modeling approaches. Dynamic carbon accounting models such as ROTHC and CENTURY have been linked to GIS to simulate management actions on soil organic carbon fluxes, and thus estimate future carbon sequestration potential (Parton et al., 1987; Falloon et al., 1998; Falloon et al., 2002; Ardo and Olsson, 2003). Likewise, a forest carbon model (FORCARB) has been used with forest inventories to estimate forest carbon pools (Birdsey and Heath, 1995;

Smith et al., 2004). Models such as these are valuable when assessing potential changes in carbon pools; however, these studies have only considered changes to soil carbon pools, and their data requirements often preclude application over large geographic areas so as to address issues associated with potential application extents. The use of satellite imagery such as the Moderate Resolution Imaging Spectroradiometer (MODIS) data may give estimates of net primary productivity (NPP) over time and over broad areas but does not address potential management alternatives associated with management actions.

This report describes carbon-sequestration modeling methods that can be applied over broad geographic areas, and application of those methods to estimate the carbon sequestration potential of alternative agricultural and forested land management options in Virginia. Options considered include afforestation of marginal agricultural lands, conversion of row crops from conventional tillage (CT) to no till (NT), and afforestation of riparian areas currently in agricultural production. The options were evaluated using two models: the first (and more general) modeling method (Winrock International 2004) was applied with the intent of generating estimates using methods comparable to those applied in other southeastern states through the Southeast Regional Carbon Sequestration Partnership (SECARB), while the second modeling method, developed here at Virginia Tech, was developed and applied with the intent of reflecting more localized factors than those considered by the general model.

The goals of this research are to evaluate and compare the potentials of three terrestrial systems' management options to sequester atmospheric carbon; to evaluate the potential for those options to offset Virginia's energy-related CO_2 emissions; and to identify the most promising terrestrial carbon sequestration option for Virginia. Three primary carbon sequestration options were considered: afforestation of marginal agricultural lands; row-crop tillage conversion; and afforestation of riparian agricultural areas. Marginal agricultural lands are defined as those lands with properties that are poorly suited to agriculture.

Research methods

Data for this study consisted mainly of spatial data drawn from a variety of public databases and were compiled into a statewide GIS project file. The data layers provided a database of relevant spatial and tabular information. All of the spatial data layers to be used were projected to the Albers Conical Equal-Area projection using the North American Datum of 1983 (NAD83) and processed using ArcGIS® (Environmental Systems Research Institute, Redlands, CA) software tools.

National Elevation Dataset (NED) tiles were downloaded from the U.S. Geological Survey (USGS) Seamless Server which allows access to 1:24,000 scale raster grids in a seamless format (USGS, 2004). Individual 1-degree x 1-degree data tiles for the state of Virginia (extending beyond the border) were mosaicked together with a 30-m resolution to form a single continuous layer. The Seamless Server also contained the National Land Cover Datasets (NLCD) (USGS, 2005a) for both 1992 and 2001 (partial). These datasets also had a 30-m resolution but were created at a scale of 1:100,000. The partial data for NLCD 2001 included the eastern side of Virginia. This dataset was used to estimate forest growth rates for the Coastal Plain and Piedmont areas.

Hydrographic features from the USGS National Hydrography Dataset (NHD) were created at a scale of 1:100,000 (USGS, 2005b). Data for each Virginia hydrographic feature were merged to form a statewide dataset that included both stream features and water bodies such as lakes and wetlands. Other hydrographic data such as flow accumulation were derived from the NED mosaic within Virginia's 14 major river basins (Virginia Department of Conservation and Recreation, 2004). Sinks (depressions with no outlet) were filled on each group and flow direction/flow accumulation rasters were created. The flow accumulation layer was used in subsequent analyses involving erosion potential.

A tillage database containing acreages planted to various crop types for each county across the state was also created. This dataset was developed by linking county boundary files with agricultural data from both the U.S. Department of

Agriculture (USDA) National Agricultural Statistics Service (NASS) and the Conservation Technology Information Center (CTIC) (CTIC, 2000; USDA, 2000). Both NASS and CTIC provided the acreage planted with row crops while CTIC provided additional information on the acreage in no-till (NT) and conventional tillage (CT). Data for the crops of corn, soybean and wheat are identified for each county for the year 2000. The county boundary files were obtained from the U.S. Census Bureau's Topologically Integrated Geographic Encoding and Referencing system (TIGER) for the year 2000 (U.S. Census Bureau, 2000).

Soils data were obtained from the USDA-Natural Resources Conservation Service (NRCS) State Soil Geographic Database (STATSGO) for Virginia (NRCS, 1994b). The data files included a polygon layer created at a scale of 1:250,000 and several attribute tables. STATSGO data is hierarchical in nature with each polygon representing a particular mapunit. Each mapunit was composed of multiple soil components while each soil component was composed of multiple soil layers. The MAPUNIT table in STATSGO included general information for each mapunit such as the name and the mapunit ID (MUID), the unique identification code. The COMPONENT table included aggregated information for each of the soil components of the STATSGO polygon mapunits and was linked to the mapunit table by the MUID. Each record in the LAYER table was then linked to the COMPONENT table by a unique mapunit sequence number (MUIDSEQ).

Level III ecoregion boundaries were obtained as GIS shapefiles were obtained from the U.S. Environmental Protection Agency (USEPA) Western Ecology Division (USEPA, 2003; Figure 1). The ecoregion maps were originally developed at a scale of 1:250,000 and were used to characterize the differences in carbon sequestration potential among regions of the state (US EPA, 2003)

Model 1 (Winrock Method)

Model 1, developed by Winrock International (2004), estimated the potential for carbon sequestration through implementation of two land management options that differ from the baseline or current management. The

first option was the conversion of marginal agricultural lands to long-term forest cover using native tree species. The second option was the reduction in tillage intensity through the conversion of CT row crops to NT row crops. For this option, NT refers to practices that do not till the soil (West and Post, 2002).

Model 1, Option A (1A): Afforestation of Marginal Agricultural Lands

Identifying Marginal Agricultural Lands:

The first step was to identify “marginal” agricultural lands. This was done using three of the data sources: elevation, land cover and soils. Agricultural lands were identified as pasture/hay, row crops, small grains, and grassland, land cover types that correspond with NLCD grid cells with values of 81, 82, 83, and 71, respectively. Marginal agricultural lands were defined as those areas that have one or more of the following limiting factors: frequent and long-term flooding, steep slopes (>10%), and soils that have shallow or rocky surfaces (Winrock International, 2004). An overview of Model 1A is given in Figure 2.

The process began with the creation of a new binary field “marginal” in the STATSGO COMPONENT table for the existence of limiting factors thought to restrict agricultural production. The STATSGO database was used to locate wet, shallow, or rocky soils. The COMPONENT table fields “annflod” and “anflodur” were queried for mapunit components that were prone to flooding, based on the following condition combinations: 1) “annflod” = “frequent” and “anflodur” = “very long” and 2) “annflod” = “occasional” and “anflodur” = “very long”. Shallow soils were defined as components with the “panhard” field = “yes” and the “pandeph” field less than “12”. High rock content soils were identified where the “rockhard” field = “hard” and the “rockdeph” was less than “12”. All of the mapunit components with any one of the above combinations were assigned a code of “0” in the “marginal” field that was added to the COMPONENT table, while all other components received a “1”. The dominant component within each mapunit was then identified as the component with the highest percentage in the “comppct” field. When the representative component had a value of “0” in the “marginal”

field, the entire mapunit area was identified as marginal land. With each mapunit being either marginal or non-marginal, the STATSGO mapunits are converted from a vector file to a binary raster file.

Slope percent was calculated from the NED layer for Virginia using the Spatial Analyst extension within ArcGIS®. Slopes with greater than a 10% (model-defined value) gradient were assigned a value of “0” and all other slopes assigned a value of “1”. This new raster layer was multiplied by the “STATSGO marginal” raster to produce a STATSGO/NED raster layer. Raster cells with a value of “1” were identified as “non-marginal” land and those with a value of “0” were “marginal” land. Values in this new raster were then switched to identify “marginal” land with a value of “1” and “non-marginal” land with a value of “0”. In Virginia, NLCD identified agricultural land as either “pasture/hay” or “row crops.” Raster cells of non-agricultural and agricultural lands are assigned a code of “0” or “1”, respectively. This raster was then multiplied by the values in the STATSGO/NED layer to produce a final raster layer called “MARGAGLAND” showing marginal agricultural land with values of “1” and non-marginal agricultural land with value of “0”.

Estimating Carbon Sequestration Potentials:

Once the spatial location of marginal land was obtained, the STATSGO WOODLAND table was used to estimate the carbon sequestration potentials (carbon potentials) for time periods of 20, 40 and 80 years after planting. This table contains the fields “plantsym” and “suitcode” which identified the various tree species existing (code = “E”) or with the potential to be planted as a tree crop (code = “EP”). Indications of site quality were obtained from the site index “sitind” and productivity “woodprod” fields for each tree species.

Tree species that already exist or had the potential for planting (EP) were identified for each STATSGO mapunit component. The tree species with the highest planting potential was used for those components with multiple EP codes. Empirical yield tables (Beck and Della-Bianca, 1981; McClure and Knight, 1984), biomass expansion factors (BEFs) (Brown and Schroeder, 1999), and

regression equations for predicting root biomass density (RBD) (Cairns et al., 1997) were used to calculate Mg C $cell^{-1}$ for each time period assuming that 50% all biomass was carbon (Table 1). Growing Stock Volume (GSV) was obtained from the yield tables based upon the various tree species and site qualities of a component and used to calculate aboveground biomass density (AGBD) and RBD. The reason for expressing the densities on a grid cell basis was the need for spatially explicit values that correspond to grid cell locations of marginal agricultural lands. Therefore, units of carbon potential were converted from Mg C ha^{-1} to Mg C $cell^{-1}$. These units allow for the summation of the cell values for the total amounts of carbon by ecoregion.

Once a carbon potential was estimated for each soil component, a weighted summation of the carbon potential for each STATSGO mapunit was calculated using the percentage of each mapunit component. Units of carbon potential (Mg C $cell^{-1}$) were added to the STATSGO MAPUNIT table and joined to the STATSGO polygon layer. The resulting carbon potential STATSGO vector layer was converted to 30-m raster layers for each mapunit for each of the three time periods and multiplied by the “MARGAGLAND” raster layer to produce three carbon potential layers for marginal agricultural lands. The total amount of carbon (Tg) sequestered for the three time periods was then calculated within each level III ecoregion in Virginia by overlay of each of the final carbon potential raster layers with the level III ecoregion vector polygon map. Finally, the total carbon potential (Tg) within each ecoregion was divided by the hectares of marginal agricultural land for that ecoregion to develop sequestration rates.

Model 1, Option B (1B): Tillage Conversion

Identifying Lands Eligible for Conversion:

The county level statistics (NASS) data for the year 2000 were used to assess the effects of converting from CT to NT on the number of acres planted in various row crops, based on cropping patterns in the year 2000. To associate the county level data with the more spatially explicit soil and land cover types, the

county statistics were used to obtain a raster layer showing the NASS cropland area (m^2) represented by each NLCD “row crop” grid cell within each county. The total NASS land area in m^2 that each county planted with corn for grain (including silage), soybeans, and wheat was then divided by the number of NLCD “row crop” grid cells within that county to identify the area (m^2) of NASS-defined row-crop land that each NLCD “row crop” grid-cell represented. These new values were then rasterized to a resolution of 30 m For this model, all row-cropped area was assumed to be in CT operation. Ten counties , primarily the state’s mountainous and urbanized areas, and 37 of 40 independent cities did not have any data reported in the NASS database and were not included in the analyses.

Estimating Carbon Sequestration Potentials:

STATSGO mapunits were assigned values from West and Post (2002) for the potential carbon that could be sequestered when converting from CT to NT for the “All crop systems (no wheat-fallow)” crop system. The West and Post values ranged from 43 to 71 with a mean of 57 g C m^{-2} yr^{-1} for approximately 14 years (West and Post, 2002; Table 2, “All treatments, no wheat-fallow”). Following the findings of West and Post (2002), STATSGO mapunits were assigned a carbon potential value based upon the texture of the surface layers (from STATSGO LAYER table) of each component. To define a textural class, a field for a numerical texture value was created in the STATSGO COMPONENT table to represent three broad textural categories: (1) coarse, (2) medium, and (3) fine. The ‘surftex’ field in the COMPONENT table was used to assign one of the three integer values to each component (all loams were considered as medium-textured, sands as course-textured, and clays as fine-textured). These values were then multiplied by the component percent and a weighted sum was calculated for each mapunit. If the total mapunit value within a mapunit was ≤ 1.5 the mapunit was considered coarse-textured and assigned a value of 43 g C m^{-2} yr^{-1}. If the value was between 1.5 and 2.5, the mapunit was considered medium-textured and assigned a value of 57 g C m^{-2} yr^{-1} while a value ≥ 2.5 was considered fine-textured and assigned a value of 71 g C m^{-2} yr^{-1}. After joining

these values to the STATSGO polygon layer, a new raster layer was created based upon those values. Finally, the raster layer of planted land area was multiplied by the potential carbon sequestration raster and an NLCD raster showing the location of “row crops”, then multiplied by 14 yrs. This overlay process is illustrated in Figure 3. The final raster displayed the total carbon potential (g C) for each grid cell after the system comes to equilibrium (14 yrs). The total carbon potential raster was then combined with the level III ecoregion polygon map to calculate the sum (g C) within each ecoregion.

Model 2 (Virginia Tech Method)

Model 2, Option A (2A): Afforestation of Marginal Agricultural Lands

Model 2 included a more advanced approach to defining marginal agricultural lands, incorporating information on local and regional parameters (Figure 4). We define marginal lands as those not suited for intensive farming because of inherent site, soil, and management limitations such as poor drainage, frequency of flooding, high slope, high erodibility, poor physical and chemical conditions, proximity to water or wetlands, or degradation due to improper use and management.

Three criteria were used to identify marginal agricultural lands: Steepness of slope, high erodibility, and other STATSGO soil properties.

<u>STATSGO Soil Properties:</u>

One method for defining marginal agricultural lands considered soil properties. Under the Farmland Protection and Policy Act, US Department of Agriculture is required to identify “Prime Farmlands” and Farmlands of Statewide Importance.” Natural Resources Conservation Service (NRCS) personnel in each state develop criteria for classifying farmlands of these types. We identified all farmlands that were not classified as “prime” and did not fit Virginia criteria for “farmlands of statewide importance,” as one mechanism for identifying “marginal” agricultural lands. The following STATSGO soil properties were used in this procedure: hydrologic conditions such as the hydrologic group, drainage class,

and if the soil was hydric; factors indicating high erosion potential; and other limiting properties (Table 2). Prime farmland status was also checked as part of this procedure, to assure that prime farmlands were not designated as marginal.

Properties in different soil layers were summarized by component and component properties were summarized by mapunit as described by the NRCS to calculate the percent of STATSGO mapunit that was considered marginal (NRCS, 1994a) Each soil property was grouped as in Table 2 and assessed for the average percent of the mapunit considered to be marginal. Mapunits with marginality of over > 50 % for any soil property were considered marginal. A raster dataset was created with the raster calculator tool where marginal mapunits were indicated by value = “0”.

Steepness of Slope:

Because pastures are commonly located on steeper slopes than row crops, separate slope thresholds were determined for cropland and pastureland. To obtain these thresholds, the slope percent at each row crop or pasture grid cell was calculated. Then, a frequency distribution showing the number of grid cells occurring at various slope percents was used to identify the slope percent at which 95% of each land-use occurred to reflect the majority of area associated with these land-uses. Lacking a standard for excessive steepness, the 95% criterion was selected as a means of identifying the steepest lands. Figure 5 shows that 95% of all pasture grid cells in Virginia occur on slopes less than 20% while 95% of all row crop grid cells occur on slopes less than 13%. Pasture cells ≥ 20 % and row crop cells ≥ 13 % are then identified as marginal due to excessive steepness, and assigned a marginal value of “0”.

Highly Erodible Lands (HELs):

The Food Security Act of 1985, as amended, requires that all persons that produce agriculture commodities must protect all cropland classified as being highly erodible from excessive erosion. As a result, the Natural Resource Conservation Service has defined procedures for identifying highly erodible land

(HEL) (NRCS, 2004). Those procedures were applied in this analysis, as described below. The basis for the procedure is the Revised Universal Soil Loss Equation (RUSLE) (Renard et al., 1997):

$$A = R\ K\ LS\ C\ P, \tag{1}$$

where A = potential erosion expressed as soil loss, t ha^{-1} yr^{-1}; R = rainfall erosivity factor; K = soil erodibility factor; LS = slope length x steepness factor; C = crop factor; and P = management factor.

The R factor was digitized and interpolated from the original map in Wischmeier and Smith (1978), the K factor was summarized (using a weighted average by component) to the mapunit level from the surface layer from the STATSGO LAYER table and converted to raster format, The C factor was assigned based upon the vegetation type in NLCD (Table 3), and the P factor was assumed to equal 1. The LS factor was then calculated from the NED using the following equation:

$$LS = (0.4 + 1)\left[\frac{A_s}{22.13}\right]^{0.4}\left[\frac{sin\beta}{0.0896}\right]^{1.3} \tag{2}$$

where LS = slope length factor, A_s = flow accumulation * cell size, (m); and β = slope angle (degrees) (Moore et al., 1993). The R, K, C, P, and LS values at each raster cell were then multiplied to estimate the potential erosion A for each grid cell.

The T factor (soil loss tolerance) for each component's surface layer was obtained from the STATSGO LAYER table and a weighted average of T was computed by component percent for each STATSGO mapunit. The calculated erosion potential (A) was then divided by T to obtain the erodibility index (EI) for each STATSGO mapping unit.. An erodibility index, EI, was calculated as

$$EI = [\ R \times K \times LS\ ] / T$$

the potential erosion (A), t ha^{-1} yr^{-1}, divided by the soil loss tolerance (T), ha^{-1} yr^{-1}, and HELs were defined as grid cells with EI ≥ 8 (NRCS, 2004).

As a final reclassification, HELs raster cells were assigned a new value of "0" to indicate marginality. The marginal soils, marginal slopes, agricultural lands, and HEL maps were then combined and assigned carbon potentials (Figure 4).

Estimating Carbon Sequestration Potentials:

This procedure was performed as described for Model 1, Option A.

Model 2, Option B (2B): Tillage Conversion

The only difference in the methodology between Model 2 and Model 1 to assess the effects of tillage conversion was in the assumption of the proportion of land area already in conventional tillage (CT). While Model 1 assumed that all row-cropped land area was in CT, the Model 2 used CTIC (2000) estimates of the proportion of row-crop land in each county that is currently cropped using CT methods to determine row-crop area of each county eligible for tillage conversion. The CTIC includes information for all counties (and the 3 cities from NASS); however, no further information was provided for the remaining independent cities although NLCD and TIGER boundaries indicate that there are row crops within those city limits. Those areas are treated as no data and excluded from the analysis.

The areas of row crops within each county/city from NASS were multiplied by proportion of row-crop defined by CTIC (2000) being in CT to re-calculate the m^2 represented by each "row crop" grid cell that is eligible for tillage conversion. These new values were then divided by the number of "row crop" cells to give a new representation of planted area. The remaining part of the procedure followed that in Model 1, Option B.

Option C: Afforestation of Riparian Areas and Farmed Wetlands

All stream, lake and wetland features from the NHD were buffered by a distance of 16.7 m (55 ft), the minimum distance for Zones 1, 2, and 3 as described in the National Handbook of Conservation Practices (NHCP) for the Riparian Buffer Strip standard (practice code 391) and Filter Strip standard

(practice code 393) (NRCS, 2003). Once buffered, the buffer polygons were assigned a value of “1” and converted to a 30-m raster. This raster of stream, lake, and wetland buffers was then combined with the 30-m NLCD raster to identify agricultural lands within the buffer. Using the same carbon potentials used for the afforestation of marginal agricultural lands, these areas within the buffer were assigned carbon sequestration potentials. The annual, per ha, and total carbon sequestration potentials within each ecoregion were then summarized as in the previous analyses.

RESULTS

Option A: Afforestation of Marginal Agricultural Lands

Results of both modeling techniques indicate that, of the options considered, afforestation marginal agricultural lands demonstrates the highest potential for carbon sequestration statewide (Tables 4 and 5; Figure 6). Model 1 estimated a statewide sequestration potential of 41.4, 62.0, and 84.0 Tg C over a period of 20, 40, and 80 yrs, respectively, while Model 2 estimated potentials of 28.4, 43.9, and 56.4 Tg C for the same time periods. Model 1 estimated higher total sequestration potentials than Model 2, but only minor differences in average sequestration rates. Both models indicate that sequestration rates decreased over time, from 3.5 Mg C ha^{-1} yr^{-1} over the first 20 yrs and declining to 0.93 Mg C ha^{-1} yr^{-1} over years 41-80 (Figure 7); this result is consistent with the well-known fact that forest growth rates tend to decline as the forest matures. Both models indicate that the spatial distribution of carbon sequestration potential varies across the state (Figure 8). Over a 20-yr period, Model 1 and Model 2 both estimated the highest amounts of sequestration in the Ridge and Valley ecoregion, 24.1 and 13.7 Tg C, respectively. However, the two modeling methods derived very different conclusions for the easternmost ecoregion, the Middle Atlantic Coastal Plain, as Model 1 estimated its sequestration potential for Option A at 0.1 Tg C) while Model 2 predicted a much higher amount (5.42 Tg C) because it utilized soil wetness as a marginality criterion.

Of the three determinations used in Model 2 to identify marginal agricultural lands, the STATSGO criterion identified lands with the greatest carbon sequestration potential, 18.1 Tg over 20 years, while the HEL criterion demonstrated the least (5.0 Tg C over 20 years). The steepness criterion identified lands with a 10.2 Tg C (20 years) total sequestration potential. These estimates sum to greater than the combined total because some areas were defined as marginal using more than one criterion.

The larger sequestration quantities estimated by Model 1 were primarily due to the low slope gradient threshold (>10%) which caused larger acreages to be classified as “marginal”. The methods of Model 1 classify almost half of western Virginia’s agricultural land as marginal (Figure 9), while the higher slope thresholds used in Model 2 are less inclusive. Alternatively, Model 2 defines coastal areas with wet soils as marginal, while Model 1 does not (Figure 7). The implementation of HELs in Model 2 increased the area of marginal land; however, the total area of marginal land using Model 2 was still lower than Model 1. The Coastal Plain was found to have a higher potential for sequestration in Model 2 due to the increased number of soil limiting factors.

Option B: Conversion of Tillage Practice

The Model 1 estimate for statewide tillage-conversion sequestration potential, which assumes that all corn, wheat, and soybeans grown in the state would be converted from CT to NT, is 3.7 Tg C over a period of 14 yrs (Table 4). The sequestration potential estimated by Model 2, which considers only conversions of crops currently grown under CT to NT, is 1.3 Tg C over the same period. Under both models, the ecoregions with the greatest potential to sequester carbon through tillage conversion are the Southeastern Plains and the Middle Atlantic Coastal Plain, in eastern Virginia. These areas contain the majority of Virginia’s row crops. Model 1 estimates that Southeastern Plains could potentially sequester approximately 1.4 Tg C while the Middle Atlantic Coastal Plain could potentially sequester 1.0 Tg C over 14 yrs. Although Model 2 also indicates that the greatest potential to sequester C through tillage

conversion occurs in these two ecoregions, estimated sequestration quantities are much less (0.6 Tg C in the Middle Atlantic Coastal Plain, and 0.4 Tg C in the Southeastern Plains) because no-till and reduced tillage cropping methods are already in use on many farms in this region (Figure 12). The Central Appalachians and Blue Ridge demonstrated the smallest tillage-conversion sequestration potentials for both models because row cropping is not common in these regions.

Option C: Afforestation of Riparian and Farmed Wetland Areas

The locations of agricultural lands within riparian areas are spread out and not well represented with a map of the entire state; however, concentrations of these areas can be found in the northern Ridge and Valley ecoregion and in the Middle Atlantic Coastal Plain, where large areas of wetlands are located. The Ridge and Valley ecoregion was found to have the highest potential (1.4, 2.0, and 2.5 Tg C for 20, 40 and 80 yrs) for carbon sequestration through the afforestation of riparian areas (Table 4). In this region, the best agricultural areas are generally located in the valley bottoms, are often adjacent to streams. Statewide, this management option demonstrated sequestration potentials of 3.5, 5.3, and 7.1 Tg C over 20, 40, and 80 yrs, respectively.

The Option C sequestration potential over 20 yrs was estimated as more than double the carbon sequestration potential due to tillage conversion (Model 2). Statewide carbon sequestration rates declined over the 80-yr period and ranged from 3.4 to 1.8 Mg C ha^{-1} yr^{-1}, slightly less than the rates of sequestration for afforestation of marginal lands. The Piedmont and the Middle Atlantic Coastal Plain were found to have the second and third highest carbon sequestration potentials under this option while the Central Appalachians and the Southeastern Plains have the lowest sequestration potentials.

ANALYSIS

We consider the Model 2 results to be a more realistic representation of carbon sequestration potentials than Model 1, and will use Model 2 as the basis for our analysis and conclusions.

Sequestration Rates:

In evaluating terrestrial systems, we have considered average sequestration rates calculated over a 14-year period for tillage conversion, and 20-, 40-, and 80-year periods for the afforestation options. We have used annual average values as estimates of potential sequestration rates in the analyses that follow, recognizing that sequestration rates can be expected to change with time over these periods (Figure 15).

Additionality:

In order to be useful for consideration relative to mitigation of global atmospheric change, the condition of “additionality” must be satisfied. That is, under the current global treaty, only carbon that accumulates in response to management actions in quantities over and above that which would have accumulated in the absence of such management may be considered as “sequestered” and eligible for carbon credits.

Tillage Conversion (Option B)

Option 2 estimates were derived from factors drawn from West and Post (2000) which represent effects of changing management from conventional tillage (CT) to no tillage (NT), and thus satisfy the additionality criterion.

Site-specific soil carbon responses to tillage conversion can be expected to be highly variable. The values used in this study, derived by West and Post (2002), ranged from 43 to 71 g C m^{-2} yr^{-1} based on soil texture. West and Post (2002) based their estimates on analysis of data from 67 long-term agricultural experiments. A review of other estimates (Table 6) reveals the West and Post

(2000) estimates are well within the range of estimates by other researchers. Thus, the decision to utilize the West and Post (2002) estimates, as opposed to other values that are available from the scientific literature, does not appear to have influenced our results and conclusions substantively. Readers should be aware that significant site-to-site variation among sequestration rates can be expected when tillage conversions are implemented.

Option 2 estimates are calculated over a 14-year period, recognizing that potential soil carbon increases in response to tillage conversion are finite and limited. West and Post (2002) state that rates of soil carbon increase can be expected to peak 5 to 10 years after tillage conversion and to decline thereafter, with soil carbon levels reaching a steady state in 10 to 15 years. Lal et al. (1998) take a more liberal view, stating an expectation that the favorable effects of tillage conversion may extend for a period of 25 to 50 years with the most rapid rates of carbon accumulation occurring during a 5-to-10 year period that begins approximately 5 years after implementation. Once the tillage-conversion soil-carbon increment has been attained, it is necessary that conservation-tillage, or other carbon-conserving management practices, be continued in order for the soils to retain the carbon gain. Should conventional tillage practices resume, re-releases of the sequestered soil carbon to the atmosphere can be expected.

Carbon sequestration potentials for tillage conversion were estimated conservatively, assuming that only corn for grain, wheat, and soybean acreages currently in conventional tillage are available for tillage conversion. Approximately 80% of Virginia's row-crop acreage is listed by NASS as being planted to corn-for-grain (including silage), wheat, and soybeans. CTIC lists 36% of the corn, wheat, and soybean acreage as being in conventional tillage, and therefore available for tillage conversion, while 41% is already in no-till and an additional 23% are in various forms of reduced tillage.

Afforestation (Options A and C)

<u>Additionality on Marginal Soils</u>

The Option A and C data of Tables 4 and 5 represent estimates of the above- and below-ground woody biomass that can be expected to accumulate in response to a specific land management change (afforestation), and are not adjusted to reflect what could be expected to occur in the absence of such change. Thus, these estimates are not adjusted to reflect the additionality criterion. Neither changes in soil C nor any loss of biomass C due to conversion of preexisting agricultural vegetation were considered.

Since most of the above-ground biomass in agricultural systems is generally either harvested or recycled into the soil system, any losses of such biomass C to the atmosphere that may occur as a result of afforestation are assumed to be minor and inconsequential to the analysis, especially when these minor losses are considered as relative to likely soil carbon gains.

Because root mass is difficult to measure, quantitative studies of below-ground biomass are not common. However, it is well known that, in agricultural soils, C generally occurs as soil organic matter (soil C) in far greater quantities than as below-ground living biomass (root C). For example, in studies of Virginia pasture systems in Pulaski, Grayson, and Louisa Counties, Conant et al. (2003) found that, while total Soil C ranged from 30 to 60 Mg/ha, maximum root C levels ranged up to only 1.27 Mg/ha, and up to only 3% of soil C. It is also well known that annual row crops generally contain less below-ground biomass than perennial pasture and hay crops. As a site is afforested, the agricultural crops' residual root biomass can be expected to decompose, with the majority of its component C being transformed to soil C. Thus, we would also consider losses of below-ground biomass C to the atmosphere that occur through afforestation to be minor and inconsequential to the analysis, especially relative to likely soil carbon gains.

It is well known that transformation of forested sites to agricultural uses generally results in a loss of soil C (Huggins et al. 1997; Lal et al. 1998, Post and Kwon 2000), which indicates a potential to accumulate soil C by afforesting agricultural sites. Research on soil C changes in response to afforestation of

agricultural lands has found that these changes are highly variable, in the short term, but over longer terms soil C generally accumulates in the afforested sites to levels exceeding those present under agriculture. Post and Kwon (2000) reviewed 29 published studies of research conducted at 48 locations, and found that the rates of soil C accumulation averaged 0.33 Mg/ha/yr. Paul et al. (2002) conducted a similar study of 43 published and unpublished studies of research conducted at 210 sites, and found that soil C (< 30 cm) decreased 0.63% per year relative to the initial soil C content during the first 5 years of afforestation, followed by a decrease in the rate of decline and eventually recovery to C contents found in agricultural soils at about age 30. They found these studies to be highly variable, however, and that short-term soil C recovery occurred more consistently in response to afforestation of annual row-crops than pastured areas, where soil C levels tend to be higher. They also found that soil C tended to accumulate more consistently under conversion to hardwoods than conifers. Several studies of afforestation effects on soil C in temperate climates all found that soil C accumulated in response to afforestation (Table 7).

Our analysis is based on an expectation that afforestation of marginal agricultural lands can be expected to cause soil C increases, and that these increases will begin to occur more rapidly than the 30-year figure cited by Paul et al. (2002). Numerous researchers have found that soil C increases in response to afforestation of agricultural sites (Table 7). Where soil conditions are favorable to afforestation, soil C increases in the short term are most likely to occur where the original soil C has been most depleted. Given that the lands under consideration for Option A are currently in use for agricultural pasture or cropland, an assumption that soil properties that will allow successful afforestation appears as quite reasonable. The fact that these lands are marginal for agriculture, however, indicates a likelihood that soil fertility and organic matter content have not been maintained to the same extent as generally occurs on more favorable soils, since soils' economic response to fertilization generally increases with productive potential. Therefore, it would appear reasonable to expect a higher likelihood of short-to-medium term (as well as long term)

increases in soil C as a response to afforestation on marginal agricultural lands, than on lands that are more favorable to agriculture.

Because soil C changes in response to afforestation on marginal sites were not considered explicitly, we believe that we are underestimating the carbon sequestration potentials of afforestation options. Thus, we believe our results can be considered as conservative estimates of the C sequestration potentials due to afforestation under the additionality criterion.

Riparian and Farmed Wetland Afforestation

We utilized the 1:100,000 scale (medium resolution) NHD coverage, which corresponds (roughly) to the “blue-line” streams on USGS 7.5 minute topographic maps, which are primarily permanent streams. The potential for afforestation of areas adjacent to ephemeral and intermittent streams is not considered in our methods.

Our analysis does contain potential source of sequestration-potential underestimation for riparian afforestation. We believe that the coarse resolution of the STATSGO data set causes underestimation of soil productivity in riparian areas. Generally speaking, higher levels of moisture availability are present in soils adjacent to streams than in those further away from streams. STATSGO soil mapping units are large, relative to the mapping units used in the more-detailed SSURGO data sets, and the STATSGO mapping units over stream corridors typically include both riparian and non-riparian soils, with riparian soils present only as a minor soil component. Because our methods applied soil productivity values to potential afforestation areas based on average values for STATSGO mapping units, the higher moisture availability of riparian soils is not reflected in our results. The fact that average estimated sequestration rates for Option A (marginal agricultural lands) exceed those of Option C (riparian afforestation) confirms our belief that Option C sequestration rates are underestimated. As well as stimulating higher rates living-biomass C accumulation in afforested sites, the higher moisture levels of these soils will have a favorable effect on their ability to retain soil C.

Potential Significance of Terrestrial Sequestration Options:

Considering all options modeled using the VT method, Virginia has an estimated cumulative sequestration potential of 32 Tg C (an average of 1.6 Tg C yr^{-1}) over the first 20 yrs following implementation. The majority of this potential (≈ 1 Tg C yr^{-1}) is located within the Ridge and Valley and the Middle Atlantic Coastal Plain ecoregions, with the remainder distributed among the state's other 5 ecoregions.

In order to evaluate the significance of these potentials, consider a hypothetical scenario where Options A, B, and/or C (as modeled by VT method, Model 2) are implemented on all eligible lands within a relatively short term; the total sequestration potential can be compared to several benchmarks (Table 8). In order to construct our benchmarks, we projected Virginia energy-related CO_2 emissions data from 1999 (USEPA, 2001) to the years 2020 and 2030 using the U.S. Energy Information Administration's projected national increase of 1.5 % per year (U.S. Department of Energy, 2005). Using the years 2020 and 2030 as baseline references and estimated average annual 20-year average sequestration rates, we found that forests planted on marginal agricultural lands today (Option A, Model 2 – Afforestation of marginal agricultural lands) have the potential to sequester about 3% of statewide energy-related CO_2 emissions.

Although we cannot predict the goals or structure of any future US program intended to curb carbon emissions, we can reference the current international treaty (Kyoto Protocol) in seeking to place terrestrial systems' potential as a contributor to US carbon offsets into perspective. That treaty does not seek to offset total emissions of participating nations, but it does seek to reduce emissions to baselines calculated relative to 1990 levels, when Virginia's estimated energy-related CO_2 emissions total was 24.85 Tg (US EPA, 2001).

We have compared terrestrial systems' sequestration potential to (a) estimated increases in annual emissions, relative to 1990 levels, in 2020 and 2030; and (b) estimated annual increases in 2020 and 2030. Option A's (marginal lands afforestation) annual 20-year average sequestration potential is

on the order of 9% of the projected 2020 emissions increase, relative to 1990, and about 6% of the projected 2030 emissions increase. Although selective application of riparian afforestation, in addition to marginal lands' afforestation, has the potential to increase these amounts, that potential is slight. Widespread implementation of Option A does, however, have the potential to offset projected annual emissions increases by about 2X.

Most Promising Option:

To identify the most promising option(s) for terrestrial carbon sequestration in Virginia, we compared the Model 2 (VT method) annual sequestration rates (Mg C ha^{-1} and Mg C ha^{-1} yr^{-1}) and total carbon sequestration potentials (Tg C) for periods of 14 (Option B) and 20 (Options A and C) years. Tables 9 and 10 show a side-by-side comparison of the annual carbon potentials and per-hectare rates for each option using both modeling approaches. In addition, we combined the three options across the state to assess, at each grid cell, the maximum sequestration potential (Tg C yr^{-1}) that could be attained. This step allowed us to derive a statewide sequestration potential that combined the various management options. Where multiple options could be applicable to a single grid cell we chose the option with maximum estimated carbon potential.

The average annual per-hectare rate of soil carbon sequestration from tillage conversion was estimated at .57 Mg C ha^{-1} yr^{-1}, far less than estimated rates due to application of the afforestation options (3.54 and 3.40, respectively, for marginal and riparian agricultural lands afforestation, respectively). Thus, it is apparent that the potential sequestration rates of afforestation far exceed those that can be expected due to tillage conversion, and that the total sequestration potential of afforested marginal agricultural lands far exceeds that of afforested riparian areas due the greater acreages involved.

Both the total and per-ha carbon sequestration potentials due to tillage conversion under that option are small compared to the afforestation options. The estimated total C sequestration potential for Option A (marginal lands) is far greater than for Option C (riparian lands), but the per-ha rates are comparable.

We consider the reforestation of marginal agricultural lands to be the major component of what we consider as most promising option for carbon sequestration using terrestrial systems in Virginia. The above statement is based on the following logic:

- Impact on Atmospheric Levels: The quantity of carbon that could potentially be sequestered by afforesting of marginal agricultural lands is greater than other options evaluated, and substantial relative to what could be Virginia's emission reduction goals were the US economy to become carbon-constrained.
- Potential for Implementation: It is well known that agricultural enterprises conducted on lands with low soil productivity tend to be less responsive to management inputs, and thus contribute less to farm profitability, than such enterprises conducted on more favorable lands. Therefore, the per-ha financial incentives required by farmers to remove marginal lands from agricultural production could be less than what would be required to remove more favorable lands from agricultural production.
- Impact on Rural, Agricultural Economy: Because these lands are, by definition, of marginal utility for agricultural production, their removal from production can be expected to cause less economic impact than would the removal of more productive lands. By virtue of properties that cause them to be defined as marginal, we expect that the per-ha productivity of marginal agricultural lands is less than that of residual (non-marginal) agricultural acreages. Given the structure of Virginia's agricultural economy, it is reasonable to expect that some of the marginal lands are being managed by part-time farmers who hold full-time jobs for their primary income. Thus, removal of such lands from agricultural production would be likely to cause less negative impact on the rural economy than would removal of lands managed by full-time farm enterprises.

- Environmental Benefits: Afforestation marginal agricultural lands – especially those on steep slopes and those that are highly erosive – can be expected to yield environmental benefits such as reduced soil erosion, increased watershed protection, and increased wildlife habitat, in addition to environmental benefits of carbon sequestration.
- Required Management: Unlike most agricultural options, maintenance of sequestered C in afforested systems does not require active management, although application of appropriate management can be expected to increase sequestration rates and timber yields.
- Total potentials: Unlike agricultural-management options, cumulative sequestration by afforestation can be expected to continue into perpetuity. Afforested systems will continue to sequester carbon for as long as woody biomass accumulation persists, while eventual harvesting of the wood products can remove woody biomass for long-term uses such as construction of housing stock. In contrast, agricultural biomass removal rarely results in a long-term sequestration of C.
- Distribution of Impacts and Benefits: Marginal agricultural lands occur throughout the state.

In addition to technical issues, the most promising option should be defined in a societal context, considering non-technical factors such as environmental, economic, and community impacts. In that sense, we would recommend that the most promising option be considered as the afforestation of marginal agricultural lands, implemented in association with afforestation of selected riparian agricultural lands and enhanced agricultural management on non-afforested agricultural lands.

Our recommendation is that riparian agricultural land afforestation be considered as a component of the most promising option only on a selective basis. Riparian corridors are generally considered as priority areas for watershed protection. Afforestation of selected riparian agricultural lands can be expected to

yield environmental benefits, such as watershed protection and aquatic habitat restoration, in addition to carbon sequestration. The US Natural Resource Service has had some success in stimulating riparian reforestation by providing land owners with relatively modest incentive payments under its Conservation Reserve Enhancement Program (CREP). Current studies of impaired streams under the Clean Water Act's TMDL program commonly identify non-point source pollutants as stressors, and often recommend riparian corridor restoration as a means of remedying stream impairment. If farmers were able to accumulate additional economic benefits from riparian reforestation as carbon sequestration credits, this would be an additional incentive for riparian restoration. Factors which may be considered in selection of riparian areas for afforestation incentives may include location within watersheds of streams with exceptional ecological value, adjacency to streams known to be impaired by non-point source pollutants, or downstream flooding potentials. As noted above, we believe that both the total and per-ha potentials for Option C are underestimated.

Another component of the most promising option could be enhanced management on non-afforested agricultural areas. A program of management enhancement incentives, if implemented in association with selective afforestation, can be expected to offset at least some of the economic impacts of the lost agricultural production. Enhanced management on soils that are well-suited to agricultural can improve both agricultural yields and profitability of the farm enterprise.

Based on our experience, we would expect that the greatest opportunities for management enhancement occurs on pastured areas. First of all, more than 80% of Virginia's agricultural area is hay and pasture (Table 4). Secondly, the majority of the state's row crops are in eastern Virginia, including larger farms where crop and pasture management that incorporates the latest scientific knowledge is an established business practice. In contrast, many of the state's hayland and pastures, especially in western Virginia, are managed by part-time farmers who approach land management from a more traditional basis.

As well as increasing agricultural productivity, improving management on agricultural areas can sequester soil C. For example, Lal (2002) describes a potential to restore 18 to 35 mg C ha^{-1}, on average, through agricultural intensification (restoration of degraded soils, and adoption of improved management practices on prime soils) on US crop and pastureland. Conant et al. (2001) reviewed 115 studies of management effects on grassland (hay and pasture) soil carbon, and found that the average soil C increase in response to management improvements was 0.54 Mg C ha^{-1} yr^{-1}. Conant et al. (2002) found that implementation of management-intensive grazing, a program which includes fertility management, on 4 Virginia hay fields was able to increase average soil C by 8 Mg C ha^{-1} (20%).

Potential Mechanisms for Implementation:

Given that existing US farm programs are primarily voluntary and incentive based, we expect that efforts to implement terrestrial sequestration options involving the farm sector would be most successful if approached on a comparable basis.

Opportunities for Further Research

This study was conducted with limited resources. The study concludes that terrestrial carbon sequestration options, if employed on a widespread scale, have the potential to aid in offsetting Virginia's energy-related carbon emissions. Terrestrial sequestration options could be implemented in the short term using existing technologies. In order to identify the most promising strategy for using terrestrial sequestration to offset GHG emissions, we combined a quantitative evaluation of 3 terrestrial carbon sequestration options with a qualitative evaluation of societal effects.

Given the accumulating evidence that human activity is influencing global climate; the consequent possibility that, at some point in the future, the US economy will adopt carbon constraints; and an expectation that terrestrial carbon sequestration strategies can be employed using existing technologies and at lower costs (per unit C) than alternative carbon-emissions offsetting measures, a more thorough evaluation of terrestrial carbon sequestration options explored by this research is recommended. Such a study should include

- a more complete evaluation of the carbon sequestration potentials of terrestrial options, including the option identified as most promising by this research, considering both biomass and soil C;
- an evaluation of the adequacy of anticipated carbon-credit payments as an incentive for landowners to afforest marginal and/or riparian agricultural acreages, and of policy instruments that might be employed to provide additional incentives for implementation;
- an evaluation of the societal impacts of implementation, emphasizing effects of agricultural land transformation to forests on the rural economy, and the potential for management enhancements on residual agricultural lands to offset those effects by increasing agricultural productivity while sequestering additional carbon; and

- an evaluation of environmental effects other than carbon sequestration that would result from implementation of terrestrial sequestration options.

Conclusions

This study used GIS to develop empirical estimates of the additional carbon sequestration that would occur from changes in the management of agricultural and forested lands in Virginia. Our aim was to determine the most promising option(s) for increasing terrestrial carbon sequestration on a regional scale. Therefore, our modeling procedures were designed to give regional estimates and are not intended as site-specific assessments. Our results do, however, provide relative magnitudes of the potential for additional carbon storage and indicate that, of the options evaluated, afforestation of marginal agricultural lands has the greatest carbon sequestration potential. The annual carbon sequestration potential estimated for this option (3.5 Mg C ha^{-1} yr^{-1}) is comparable to the average rate of carbon uptake (1.5 to 4.5 Mg C ha^{-1} yr^{-1}) for afforesting lands estimated in the IPCC Special Report for Annex I countries (IPCC, 2000), equivalent to about 4% of Virginia's total energy-related CO_2 emissions, and is 2 to 3 times greater than Virginia's annual energy-related CO_2-emissions increase.

Considering societal context as well as potential sequestration quantities and rates, we conclude that the most promising terrestrial carbon sequestration option for Virginia is the afforestation of marginal agricultural lands, implemented in association with afforestation of selected riparian agricultural lands and enhanced agricultural management on residual (non-afforested) agricultural lands.

These conclusions assume the widespread adoption of management options as if implemented in the short term. Additionally, our results do not consider changes in current forest carbon fluxes due to harvesting, burning, and/or deforestation. The sequestration values developed for afforestation do not include carbon losses associated with harvested products, site preparation, fertilizer production, or other processes. The values derived for afforestation are for tree carbon only and do not consider soil carbon, and thus may underestimate actual sequestration potentials. Furthermore, the annual rates of sequestration

developed are averages over multiple-year time periods and would not be achieved immediately. Additional factors essential to implementation such as the adequacy of anticipated carbon-sequestration credits as incentives for landowners to adopt terrestrial sequestration options, societal costs associated with removal of afforested lands from agricultural production such as impacts on the rural economy, and potential environmental benefits of afforestation such as erosion control, water quality protection, and habitat creation, have not been considered quantitatively and would be basis for further study.

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TABLES

Table 1. Equations used to determine Aboveground Biomass Density (AGBD), Root Biomass Density (RBD), Biomass Expansion Factors (BEF), and Total Biomass Density (TBD) from Growing Stock Volume (GSV).

Biomass Component	**Equation used**	
	Softwoods	**Hardwoods**
BEF, Mg m^{-3}	If GSV < 10 m^3 ha^{-1} then BEF = 1.68 If GSV = 10 - 100 m^3 ha^{-1} then BEF = .95 If GSV > 100 m^3 ha^{-1} then BEF = .81	= exp(1.912 - 0.344 * ln(GSV)
AGBD, Mg ha^{-1}	= BEF * GSV	
RBD, Mg ha^{-1}	= exp(-1.0587 + 0.8836 * ln(AGBD) + 0.2840)	
TBD, Mg ha^{-1}	= AGBD + RBD	
GSV, m^3 ha^{-1}	From 'WOODPROD' field in STATSGO† component table	

†Source: Virginia STATSGO Database, 1994. USDA NRCS, Fort Worth, Texas.

Table 2. Soil properties from the State Soil Geographic (STATSGO) database considered as defining marginal agricultural lands, as applied to Model 2, Option A (afforestation of marginal agricultural lands, VT method, STATSGO criterion).

Soil properties	**Condition considered marginal**	
	STATSGO table	
	Component	**Layer**
Hydrologic conditions	Hydrologic group = D Hydric = Yes Drainage = Poorly or Very Poorly Annual Flooding = Occasional AND Duration = Long or Very Long Annual Flooding = Frequent	
Erosion potential	Phase = Severely eroded Slope average ≥ 4 %	AND Clay content ≥ 27 % in surface layer
Other limiting properties		Available water content < 4.5 in upper 40 in. pH < 3.5 or pH > 8.4 Sodium adsorption ratio ≥ 15 in upper 24 in. Salinity ≥ 8 mmhos cm^{-1} upper 24 in.
Farmland Class	Prime farmland classification = 0	

Table 3. C Factor values used in the Revised Universal Soil Loss Equation in procedure to define agricultural lands that are marginal due to high erosivity (afforestation of marginal agricultural lands, VT method, HEL criterion).

1992 NLCD Class	NLCD Code	C Factor
Water	11	0.000
Low Intensity Residential	21	0.030
High Intensity Residential	22	0.020
Commercial/Industrial/Transportation	23	0.000
Bare Rock/Sand/Clay	31	0.000
Quarries/Strip Mines/Gravel Pits	32	0.000
Transitional	33	0.000
Deciduous Forest	41	0.009
Evergreen Forest	42	0.004
Mixed Forest	43	0.007
Pasture/Hay	81	0.050
Row Crops	82	0.240
Urban/Recreational Grasses	85	0.050
Woody Wetlands	91	0.003
Emergent Herbaceous Wetlands	92	0.003

Table 4. Average carbon sequestration potentials resulting from the implementation of various land management changes over 14-yr time period (Option B), and 20-, 40, and 80-yr time periods (Options A and C).

	Area	Agricultural Area			Total Carbon				Sequestration Rate			
		Total	- - - Affected - - -		14 yr	20 yr	40 yr	80 yr	14 yr	20 yr	40 yr	80 yr
									- - - - - - Mg C ha^{-1} yr^{-1} - - - - - -			
Ecoregion	- - - - - - - - - - ha - - - - - - - - - -			%	- - - - - - - Tg C - - - - - - -				-			
					Afforestation of Marginal Agland (Option A) - Winrock Method (Model 1)							
Blue Ridge	914592	138941	88049	63.4	4.70	7.43	12.08		2.67	2.11	1.71	
Cent. Appalachians	436277	13746	9580	69.7	0.70	1.10	1.36		3.66	2.88	1.77	
M.A. Coastal Plain	782958	229843	696	0.3	0.05	0.08	0.10		3.74	3.01	1.87	
Northern Piedmont	746578	312727	57369	18.3	3.69	5.63	8.19		3.22	2.45	1.78	
Piedmont	3358366	719334	119290	16.6	7.21	11.29	17.14		3.02	2.37	1.80	
Ridge and Valley	2627739	745222	304333	40.8	24.14	34.99	43.28		3.97	2.87	1.78	
Southeastern Plains	1456731	320449	12353	3.9	0.89	1.46	1.85		3.61	2.96	1.87	
Statewide	**10323241**	**2480262**	**591670**	**23.9**	**41.39**	**62.00**	**84.01**		**3.50**	**2.62**	**1.77**	
					Afforestation of Marginal Agland (Option A) – VT Method (Model 2)							
Blue Ridge	914592	138941	33750	24.3	1.78	2.81	4.44		2.64	2.08	1.64	
Cent. Appalachians	436277	13746	7374	53.6	0.53	0.85	1.04		3.62	2.88	1.77	
M.A. Coastal Plain	782958	229843	73107	31.8	5.42	8.86	10.53		3.70	3.03	1.80	
Northern	746578	312727	47316	15.1	3.43	5.53	6.94		3.63	2.92	1.83	

Piedmont										
Piedmont	3358366	719334	30900	4.3	2.24	3.35	4.60	3.62	2.71	1.86
Ridge and Valley	2627739	745222	188363	25.3	13.67	20.29	26.21	3.63	2.69	1.74
Southeastern Plains	1456731	320449	20823	6.5	1.36	2.21	2.63	3.27	2.65	1.58
Statewide	**10323241**	**2480262**	**401633**	**16.2**	**28.43**	**43.90**	**56.38**	**3.54**	**2.73**	**1.75**

Table 4 (con'd)	**Area**	**Agricultural Area**			**Total Carbon**			**Sequestration Rate**			
		Total	**- - - Affected - - -**		**14 yr**	**20 yr**	**40 yr**	**80 yr**	**14 yr**	**20 yr**	**40 yr**	**80 yr**
									- - - - - - Mg C ha^{-1} yr^{-1} - - - - - -			
Ecoregion	- - - - - - - - - - ha - - - - - - - - - -			%	- - - - - - - Tg C - - - - - - -				-			
			Afforestation of Steep Ag Land (Option A) – VT Method(Model 2)									
Blue Ridge	914592	138941	29631	21.3	1.57	2.49	4.01	2.64	2.10	1.69		
Cent. Appalachians	436277	13746	6503	47.3	0.47	0.74	0.91	3.61	2.86	1.76		
M.A. Coastal Plain	782958	229843	152	0.1	0.01	0.02	0.02	3.42	2.79	1.74		
Northern Piedmont	746578	312727	4294	1.4	0.27	0.42	0.62	3.20	2.45	1.79		
Piedmont	3358366	719334	11317	1.6	0.65	1.02	1.60	2.86	2.26	1.77		
Ridge and Valley	2627739	745222	89767	12.0	6.99	10.23	12.69	3.89	2.85	1.77		
Southeastern Plains	1456731	320449	2799	0.9	0.20	0.32	0.41	3.50	2.90	1.85		

Statewide	**10323241**	**2480262**	**144463**	**5.8**	**10.15**	**15.24**	**20.27**	**3.51**	**2.64**	**1.75**
		Afforestation of STATSGO Marginal Land (Option A) – VT Method (Model 2)								
Blue Ridge	914592	138941	5593	4.0	0.28	0.41	0.52	2.50	1.81	1.17
Cent. Appalachians	436277	13746	1643	12.0	0.12	0.19	0.24	3.58	2.93	1.81
M.A. Coastal Plain	782958	229843	72698	31.6	5.38	8.81	10.47	3.70	3.03	1.80
Northern Piedmont	746578	312727	42446	13.6	3.13	5.07	6.25	3.68	2.98	1.84
Piedmont	3358366	719334	12704	1.8	1.23	1.72	2.03	4.83	3.38	2.00
Ridge and Valley	2627739	745222	103287	13.9	6.93	10.47	14.11	3.35	2.53	1.71
Southeastern Plains	1456731	320449	16064	5.0	1.02	1.65	1.91	3.18	2.56	1.49
Statewide	**10323241**	**2480262**	**254435**	**10.3**	**18.08**	**28.31**	**35.53**	**3.55**	**2.78**	**1.75**
		Afforestation of Highly Erodible Land (Option A) – VT Method (Model 2)								
Blue Ridge	914592	138941	9169	6.6	0.49	0.77	1.19	2.66	2.10	1.62
Cent. Appalachians	436277	13746	4238	30.8	0.30	0.49	0.60	3.60	2.87	1.76
M.A. Coastal Plain	782958	229843	458	0.2	0.03	0.06	0.07	3.74	3.05	1.89
Northern Piedmont	746578	312727	1853	0.6	0.13	0.19	0.26	3.42	2.58	1.73
Piedmont	3358366	719334	11615	1.6	0.66	1.08	1.64	2.85	2.31	1.77
Ridge and Valley	2627739	745222	41355	5.5	3.05	4.58	5.77	3.69	2.77	1.75
Southeastern Plains	1456731	320449	4060	1.3	0.29	0.48	0.60	3.54	2.94	1.86
Statewide	**10323241**	**2480262**	**72748**	**2.9**	**4.95**	**7.63**	**10.13**	**3.40**	**2.62**	**1.74**
Table 4 (con'd)	**Area**	**Agricultural Area**			**Total Carbon**			**Sequestration Rate**		
		Total	**- - - Affected - -**	**14**	**20**	**40 yr**	**80 yr**	**14 yr**	**20 yr**	**40 yr**	**80 yr**

Ecoregion	ha			%	Tg C			Mg C ha^{-1} yr^{-1}
				-	yr	yr		
Conversion of Tillage Intensity (Option B) (CT → NT) – Winrock Method (Model 1)								
Blue Ridge	914592	3797	3797	100.0	0.03			0.53
Cent. Appalachians	436277	125	125	100.0	0.00			0.52
M.A. Coastal Plain	782958	129127	129127	100.0	1.03			0.57
Northern Piedmont	746578	33091	33091	100.0	0.26			0.56
Piedmont	3358366	73502	73502	100.0	0.59			0.57
Ridge and Valley	2627739	52253	52253	100.0	0.42			0.57
Southeastern Plains	1456731	177800	177800	100.0	1.41			0.57
Statewide*	**10323241**	**469695**	**469695**	**100.0**	**3.73**			**0.57**
Conversion of Tillage Intensity (Option B) (CT → NT) – VT Method (Model 2)								
Blue Ridge	914592	3928	297	7.6	0.00			0.50
Cent. Appalachians	436277	391	205	52.4	0.00			0.49
M.A. Coastal Plain	782958	129251	77095	59.6	0.62			0.57
Northern Piedmont	746578	33289	4438	13.3	0.03			0.56
Piedmont	3358366	74393	22575	30.3	0.18			0.57
Ridge and Valley	2627739	53096	9382	17.7	0.07			0.57
Southeastern Plains	1456731	177942	51748	29.1	0.41			0.57
Statewide**	**10323241**	**472290**	**165740**	**35.1**	**1.32**			**0.57**
Afforestation of Agland within Riparian Areas (Option C) – VT Method (Model 2)								
Blue Ridge	914592	138941	4238	3.1	0.23	0.36	0.59	2.68 2.12 1.73
Cent.	436277	13746	694	5.0	0.05	0.08	0.10	3.67 2.88 1.76

Appalachians										
M.A. Coastal Plain	782958	229843	8694	3.8	0.56	0.93	1.18	3.21	2.67	1.70
Northern Piedmont	746578	312727	6201	2.0	0.40	0.63	0.87	3.26	2.53	1.75
Piedmont	3358366	719334	10708	1.5	0.62	0.99	1.51	2.90	2.31	1.76
Ridge and Valley	2627739	745222	17160	2.3	1.38	1.99	2.45	4.01	2.90	1.79
Southeastern Plains	1456731	320449	3067	1.0	0.21	0.35	0.43	3.46	2.85	1.77
Statewide	**10323241**	**2480262**	**50762**	**2.0**	**3.45**	**5.32**	**7.13**	**3.40**	**2.62**	**1.76**

*Agricultural areas are based upon the number of planted acres from the NASS database
**Agricultural areas are based upon the number of planted acres from NASS, or from CTIC where NASS is No Data

Table 5. Alternate version of Table 4 representing carbon sequestration potentials of afforestation options over 1-20, 21-40, and 41-80 year periods after implementation.

Ecoregion	1-20 yrs	21-40 yrs	41-80 yrs	1-20 yrs	21-40 yrs	41-80 yrs
	- - - - - - - - - - - Tg C - - - - - - - - - - -			- - - - - - - - - Mg C ha^{-1} yr^{-1} - - - - - - - - -		
Afforestation of Marginal Agland (Option A) - Winrock Method (Model 1)						
Blue Ridge	4.70	2.73	4.65	2.67	1.55	1.32
Central Appalachians	0.70	0.4	0.26	3.65	2.09	0.68
M.A. Coastal Plain	0.05	0.03	0.02	3.59	2.16	0.72
Northern Piedmont	3.69	1.94	2.56	3.22	1.69	1.12
Piedmont	7.21	4.08	5.85	3.02	1.71	1.23
Ridge and Valley	24.14	10.85	8.29	3.97	1.78	0.68
Southeastern Plains	0.89	0.57	0.39	3.60	2.31	0.79
Statewide	**41.39**	**20.61**	**22.01**	**3.50**	**1.74**	**0.93**
Afforestation of Marginal Agland (Option A) – VT Method (Model 2)						
Blue Ridge	1.78	1.03	1.63	2.64	1.53	1.21
Central Appalachians	0.53	0.32	0.19	3.59	2.17	0.64
M.A. Coastal Plain	5.42	3.44	1.67	3.71	2.35	0.57
Northern Piedmont	3.43	2.1	1.41	3.62	2.22	0.74
Piedmont	2.24	1.11	1.25	3.62	1.80	1.01
Ridge and Valley	13.67	6.62	5.92	3.63	1.76	0.79
Southeastern Plains	1.36	0.85	0.42	3.27	2.04	0.50
Statewide	**28.43**	**15.47**	**12.48**	**3.54**	**1.93**	**0.78**
Afforestation of Marginal Ag Land – Steep Only (Option A) – VT Method (Model 2)						
Blue Ridge	1.57	0.92	1.52	2.65	1.55	1.28
Central Appalachians	0.47	0.27	0.17	3.61	2.08	0.65
M.A. Coastal Plain	0.01	0.01	0	3.29	3.29	0.00
Northern Piedmont	0.27	0.15	0.2	3.14	1.75	1.16
Piedmont	0.65	0.37	0.58	2.87	1.63	1.28
Ridge and Valley	6.99	3.24	2.46	3.89	1.80	0.69
Southeastern Plains	0.20	0.12	0.09	3.57	2.14	0.80
Statewide	**10.15**	**5.09**	**5.03**	**3.51**	**1.76**	**0.87**

Table 5 (con'd)

Ecoregion	1-20 yrs	21-40 yrs	41-80 yrs	1-20 yrs	21-40 yrs	41-80 yrs
	- - - - - - - - - - - Tg C - - - - - - - - - - -			- - - - - - - - - Mg C ha^{-1} yr^{-1} - - - - - - - - -		
Afforestation of Marginal Ag Land – STATSGO Only (Option A) – VT Method (Model 2)						
Blue Ridge	0.28	0.13	0.11	2.50	1.16	0.49
Central Appalachians	0.12	0.07	0.05	3.65	2.13	0.76
M.A. Coastal Plain	5.38	3.43	1.66	3.70	2.36	0.57
Northern Piedmont	3.13	1.94	1.18	3.69	2.29	0.70
Piedmont	1.23	0.49	0.31	4.84	1.93	0.61
Ridge and Valley	6.93	3.54	3.64	3.35	1.71	0.88
Southeastern Plains	1.02	0.63	0.26	3.17	1.96	0.40
Statewide	**18.08**	**10.23**	**7.22**	**3.55**	**2.01**	**0.71**
Afforestation of Marginal Ag Land - Highly Erodible Only (Option A) – VT Method (Model 2)						
Blue Ridge	0.49	0.28	0.42	2.67	1.53	1.15
Central Appalachians	0.30	0.19	0.11	3.54	2.24	0.65
M.A. Coastal Plain	0.03	0.03	0.01	3.28	3.28	0.55
Northern Piedmont	0.13	0.06	0.07	3.51	1.62	0.94
Piedmont	0.66	0.42	0.56	2.84	1.81	1.21
Ridge and Valley	3.05	1.53	1.19	3.69	1.85	0.72
Southeastern Plains	0.29	0.19	0.12	3.57	2.34	0.74
Statewide	**4.95**	**2.68**	**2.50**	**3.40**	**1.84**	**0.86**
Afforestation of Agland within Riparian Areas (Option C) – VT Method (Model 2)						
Blue Ridge	0.23	0.13	0.23	2.71	1.53	1.36
Central Appalachians	0.05	0.03	0.02	3.60	2.16	0.72
M.A. Coastal Plain	0.56	0.37	0.25	3.22	2.13	0.72
Northern Piedmont	0.40	0.23	0.24	3.23	1.85	0.97
Piedmont	0.62	0.37	0.52	2.90	1.73	1.21
Ridge and Valley	1.38	0.61	0.46	4.02	1.78	0.67
Southeastern Plains	0.21	0.14	0.08	3.42	2.28	0.65
Statewide	**3.45**	**1.87**	**1.81**	**3.40**	**1.84**	**0.89**

Table 6. Per-ha sequestration potentials due to tillage conversions cited by various authors.

Situation	Annual (Mg C/ha/yr)	Source
Sequestration potentials due to tillage conversion (calculated as averages from national data, assuming totals are achieved over 15 years).	0.7 – 0.8	Kerns and Johnson, 1994
Estimated range for CT to NT conversion, based on review of scientific literature.	0.1 – 0.5	Lal et al. 1998
Measured sequestration due to conversion of conventional tillage to no-till wheat-corn-soybean rotation, Midwest USA	0.3	Robertson et al. 2000
See Soil Tillage Research 61:77-92.	0.1 – 0.6	Follet et al., 2001.
Estimated range of sequestration potentials due to tillage conversion in Europe	> 0 – 0.8	Freibauer et al. 2004

Table 7. Rates of soil C accumulation rates in afforested ex-agricultural systems in temperate climates cited by various authors.

Situation	Annual (Mg C/ha/yr)	Total* (Mg C/ ha)	Source
Deciduous species over 29 years at Kemptville, Ont	0.47	13	Six et al. 2002
Mixed Deciduous (poplar and birch) and Conifers over 50 years at Wildlife area OH site	0.13	6	Six et al. 2002
On 40 to 50 year old soils, estimated from review of earlier studies.	0.30	13	Schlesinger, 1990
Natural regeneration to mixed deciduous woodland at Broadbalk, Rothamstad U.K., over 80 years	0.60	48	Jenkinson 1991
Natural regeneration to mixed deciduous woodland at Geescroft, Rothamstad UK, over 80 years	0.30	24	Jenkinson 1991
Loblolly Pines over 40 years at Calhoun State Forest, SC.	0.04	1.6	Richter, 1999

* Calculated where not available from original publication.

Table 8. Comparison of modeled carbon sequestration potentials to reference emission quantities for 1999, 2020 (projected), and 2030 (projected), using 14- and 20-year average estimates.

	Reference Emissions	Carbon Sequestration Potentials					
Model †		1	2	1	2	2	2
Option ‡		A	A	B	B	C	A, B, C
Averaged over Time Period		yr 1-20	yr 1-20	yr 1-14	yr 1-14	yr 1-20	
		- - - - - - - - - - - - - - - - Tg C yr^{-1} - - - - - - - - - - - - - - - -					
Estimated C Sequestration Potentials		2.07	1.42	0.27	0.09	0.17	1.62
	Tg C yr^{-1}	- - - - - - - - - Percent of reference quantity - - - - - - - -					
1999 Reference							
1999 emissions	**29.62**	7.0	4.8	0.9	0.3	0.6	5.5
Emissions increase, vs. 1990	**4.77**	43	30	6	2	4	34
Annual Increase, 1999-2000	**0.44**	470	323	61	20	39	368
Average annual increase, 1990 - 1999	**0.53**	391	268	51	17	32	306
2020 Reference							
2020 emissions	**40.49**	5.1	3.5	0.7	0.2	0.4	4.0
Emissions increase, vs. 1990	**15.64**	5.1	3.5	0.7	0.2	0.4	4.0
Annual Increase, 2019-2020	**0.60**	13	9	1.7	0.6	1.1	10
Average annual increase, 1990 - 2020	**0.52**	345	237	45	15	28	270
2030 Reference							
2030 emissions	**46.99**	4.4	3.0	0.6	0.2	0.4	3.4
Emissions increase, vs. 1990	**22.1**	9	6	1.2	0.4	0.8	7
Annual Increase, 2029-2030	**0.69**	298	204	39	13	24	233
Average annual increase, 1990 - 2030	**0.55**	374	257	49	16	31	293

†Model 1 = Winrock method; Model 2 = VT method.

‡ A = Afforestation of marginal agricultural land; B = Row-crop tillage conversion; C = Afforestation of riparian agricultural areas.

Table 9. Total annual carbon sequestration potential of three land management options by Virginia ecoregion (short-term).

	Total Carbon Sequestered								
	Option A†		Option B‡		Option C§	Option A† Model 2# (Individual Determinations)			
Level III Ecoregion	Model 1¶	Model 2#	Model 1¶	Model 2#	Model 2#	STATSGO	HEL	Steep	All Model 2# Options
	Tg C yr^{-1}								
Blue Ridge	0.23	0.09	0.00	0.00	0.01	0.01	0.02	0.08	0.099
Central Appalachians	0.04	0.03	0.00	0.00	0.00	0.01	0.02	0.02	0.028
M.A. Coastal Plain	0.00	0.27	0.07	0.04	0.03	0.27	0.00	0.00	0.308
Northern Piedmont	0.18	0.17	0.02	0.00	0.02	0.16	0.01	0.01	0.190
Piedmont	0.36	0.11	0.04	0.01	0.03	0.06	0.03	0.03	0.151
Ridge and Valley	1.21	0.68	0.03	0.01	0.07	0.35	0.15	0.35	0.743
Southeastern Plains	0.04	0.07	0.10	0.03	0.01	0.05	0.01	0.01	0.104
Statewide Potential	**2.07**	**1.42**	**0.27**	**0.09**	**0.17**	**0.90**	**0.25**	**0.51**	**1.62**

†Option A: Afforestation of marginal agricultural land (20 yrs)
‡Option B: Conversion from CT to NT row crops (14 yrs)
§Option C: Afforestation of riparian areas currently in agricultural use (20 yrs)
¶Model 1 = Winrock Method
#Model 2 = VT Method

Table 10. Annual rates of carbon sequestration potential of three land management options by Virginia ecoregion (short-term).

	Sequestration rate								
	Option A†		Option B‡		Option C§	Option A† Model 2# (Individual Determinations)			
Level III Ecoregion	Model 1¶	Model 2#	Model 1¶	Model 2#	Model 2#	Determination 1 (Soils)†	Determination 2 (Erodible)†	Determination 3 (Steep)†	All Model 2# Options
	Mg C ha^{-1} yr^{-1}								
Blue Ridge	2.67	2.64	0.53	0.50	2.68	2.50	2.66	2.64	2.51
Central Appalachians	3.66	3.62	0.52	0.49	3.67	3.58	3.60	3.61	3.49
M.A. Coastal Plain	3.74	3.70	0.57	0.57	3.21	3.70	3.74	3.42	1.80
Northern Piedmont	3.22	3.63	0.56	0.56	3.26	3.68	3.42	3.20	2.96
Piedmont	3.02	3.62	0.57	0.57	2.90	4.83	2.85	2.86	1.24
Ridge and Valley	3.97	3.63	0.57	0.57	4.01	3.35	3.69	3.89	3.22
Southeastern Plains	3.61	3.27	0.57	0.57	3.46	3.18	3.54	3.50	0.55
Statewide Potential	**3.50**	**3.54**	**0.57**	**0.57**	**3.40**	**3.55**	**3.40**	**3.51**	**1.97**

†Option A: Afforestation of marginal agricultural land (20 yrs)
‡Option B: Conversion from CT to NT row crops (14 yrs)
§Option C: Afforestation of riparian areas currently in agricultural use (20 yrs)
¶Winrock International
#Modified Winrock International

FIGURES

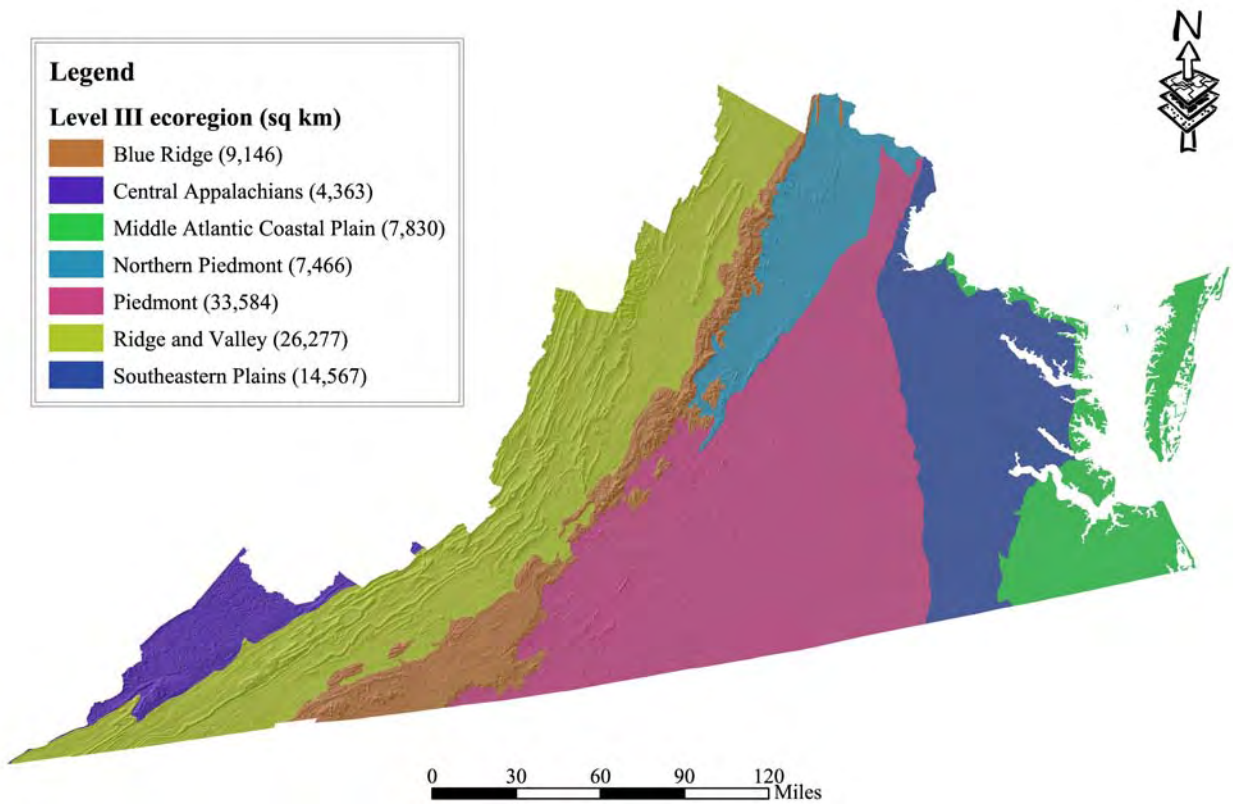

Figure 1. Level III ecoregions of Virginia.

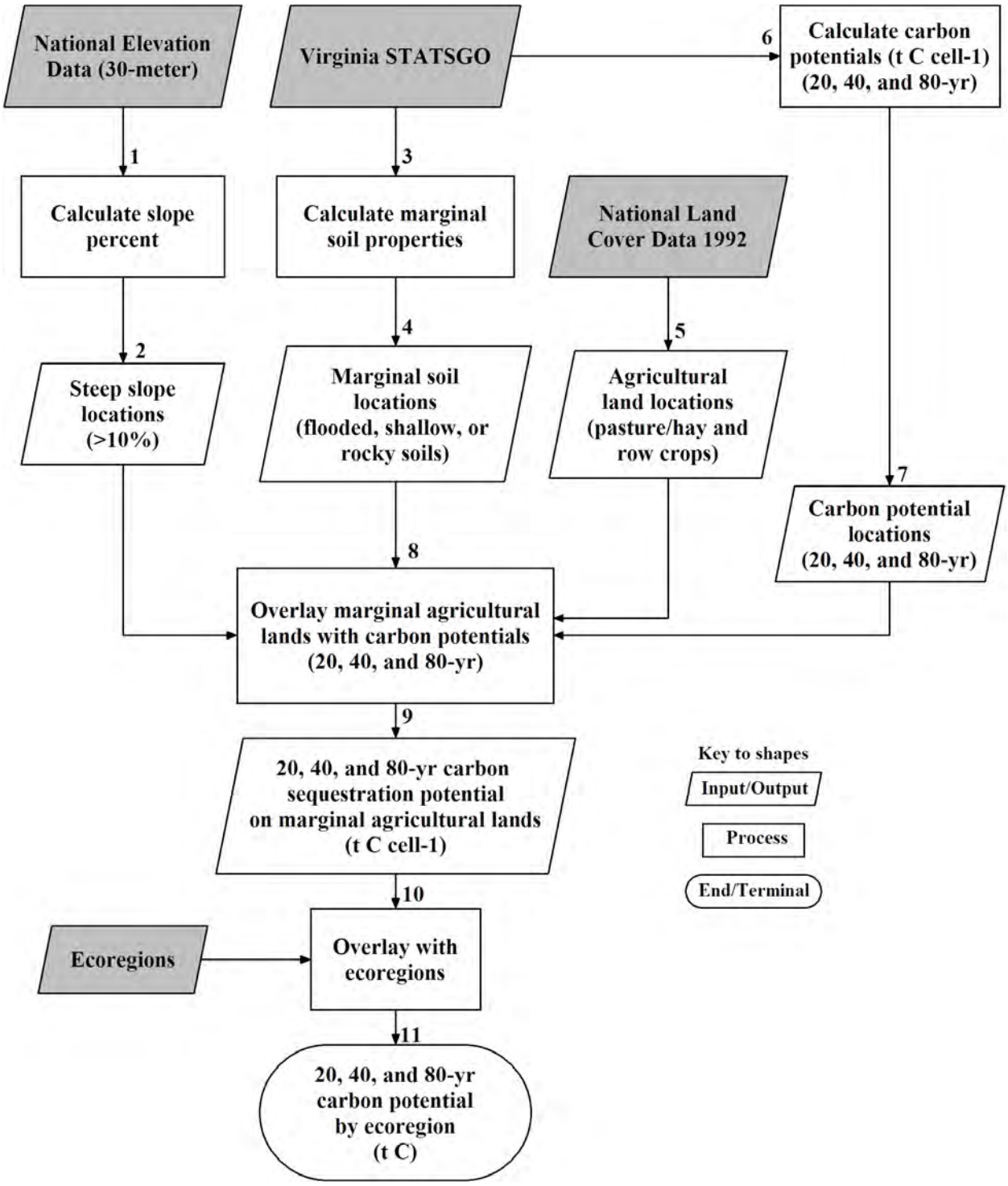

Figure 2. General flowchart for calculating carbon sequestration potential (t C grid-cell^{-1} = Mg C grid-cell^{-1}) from afforestation of marginal agricultural land using Model 1 (Winrock method). Sequence of operations indicated.

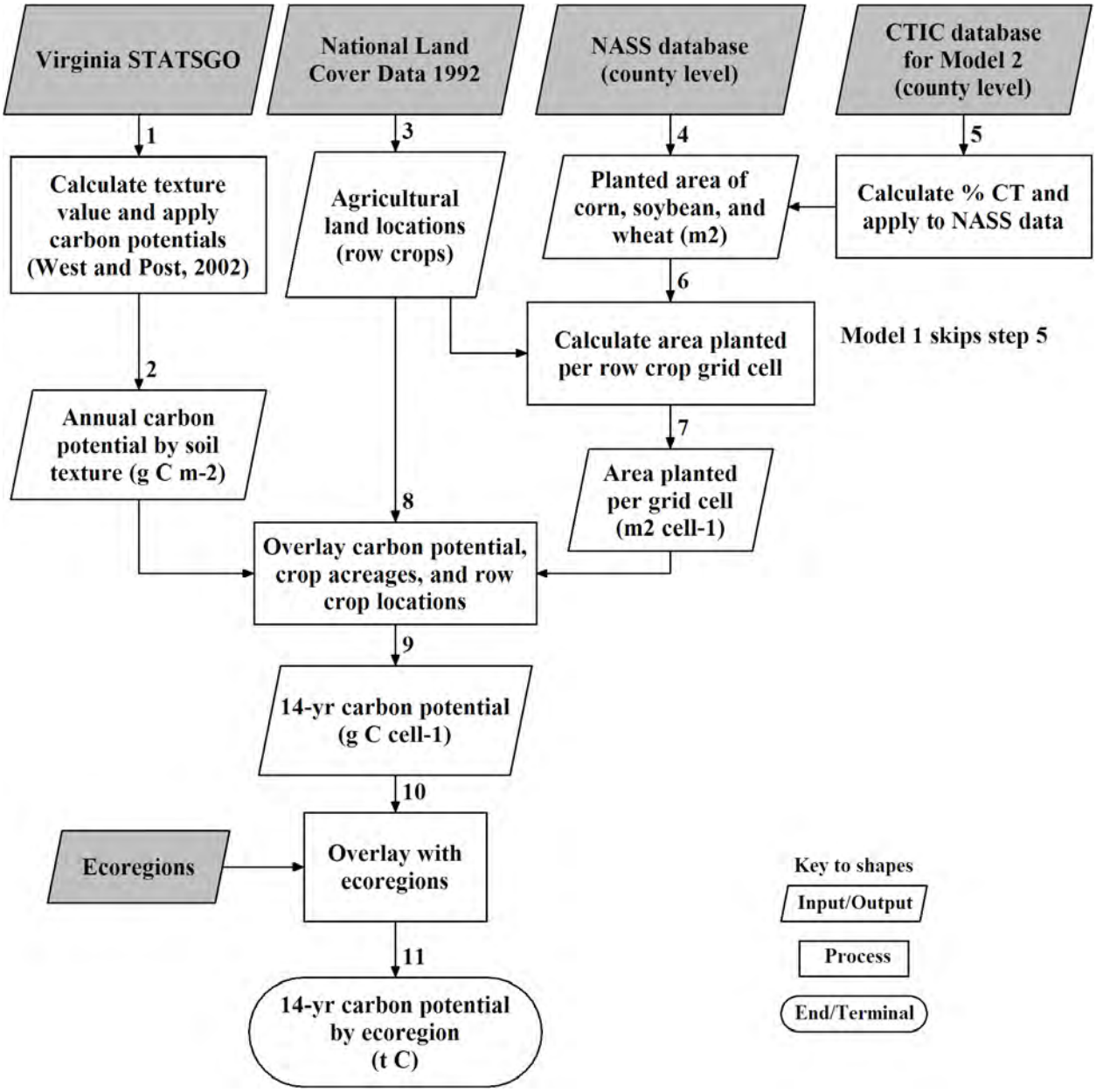

Figure 3. General flowchart for calculating carbon potential (t C cell^{-1} (t C grid-cell^{-1} = Mg C grid-cell^{-1}) over a 14-yr period by tillage conversion using Models 1 (Winrock) and 2 (VT). Sequence of operations indicated.

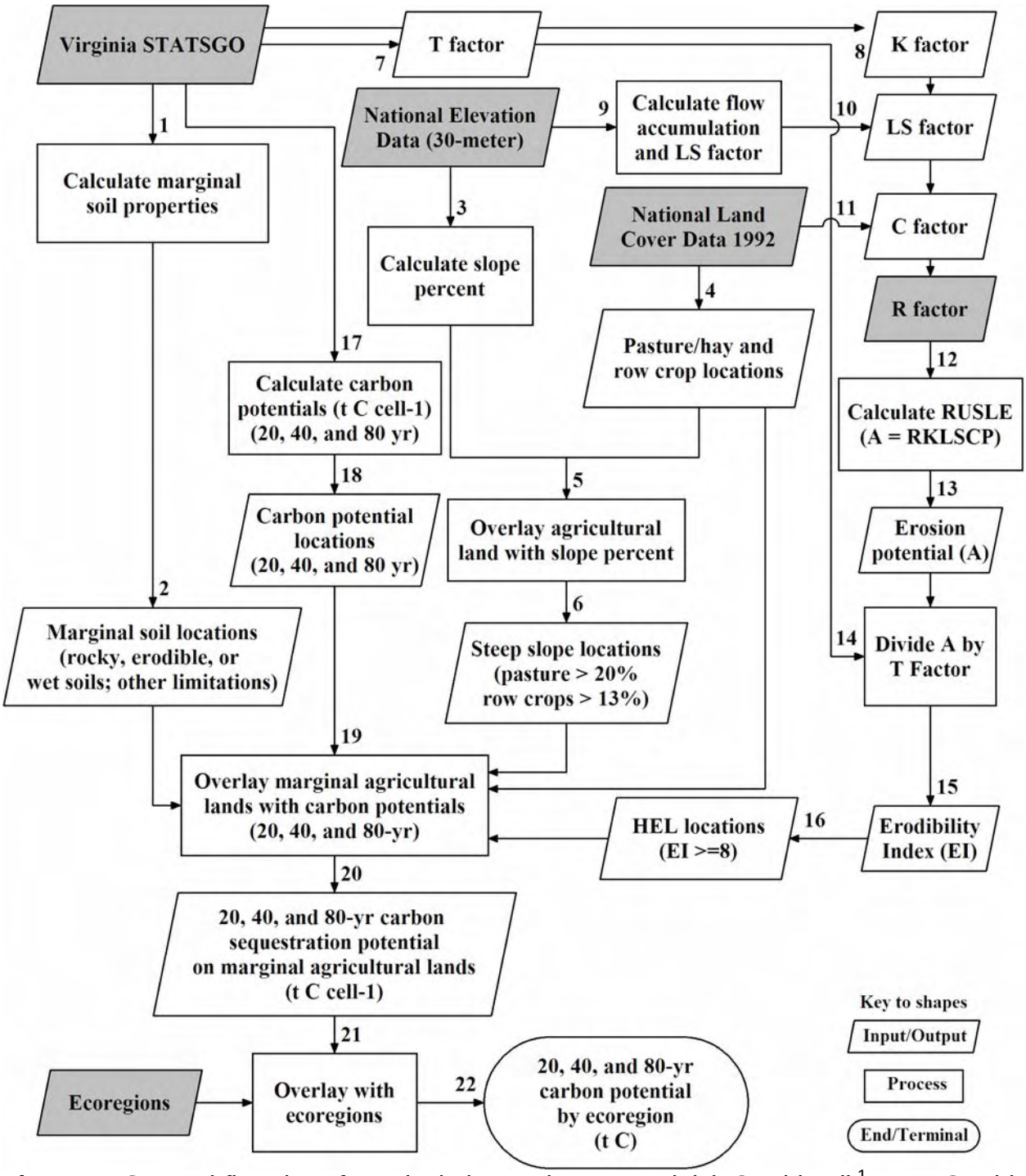

Figure 4. General flowchart for calculating carbon potential (t C grid-cell^{-1} = Mg C grid-cell^{-1}) from afforestation of marginal agricultural land using Model 2 (VT). Sequence of operations indicated.

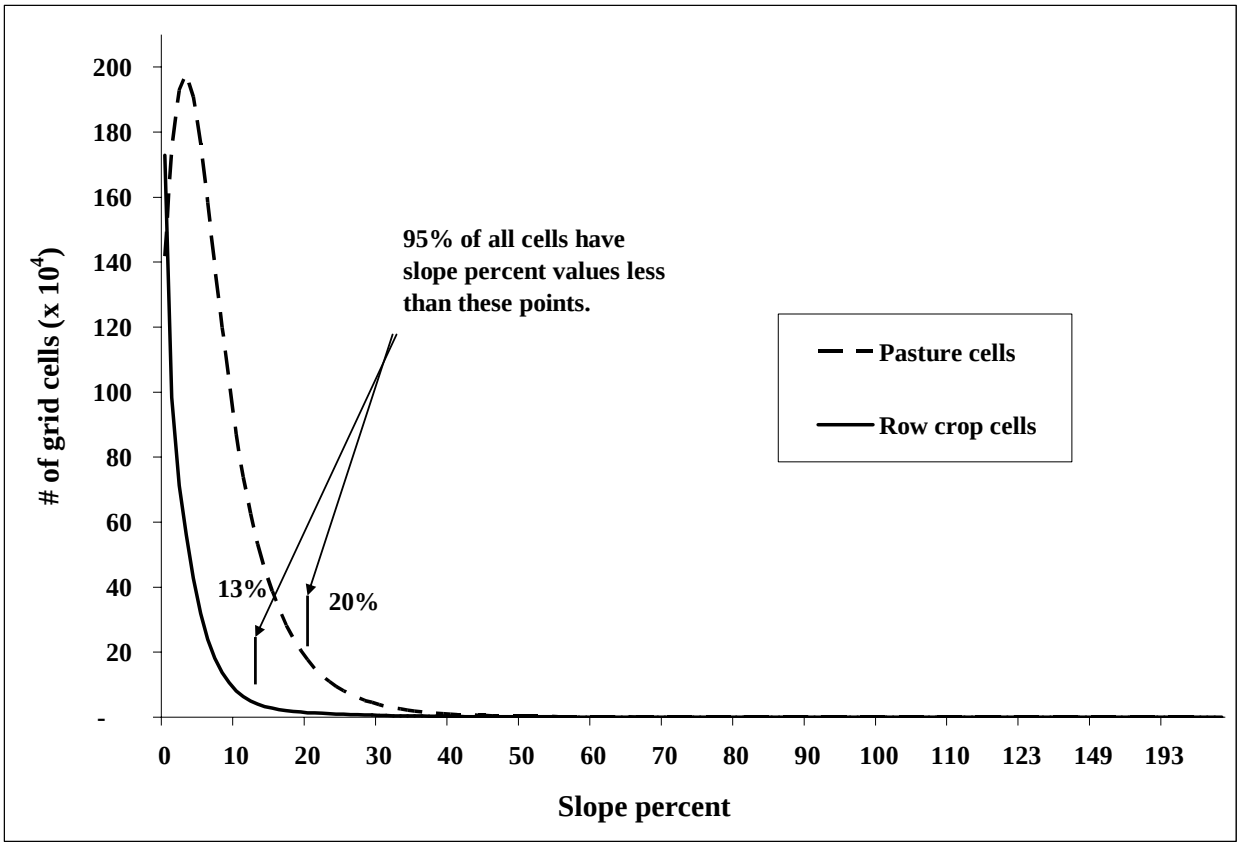

Figure 5. Frequency distribution of slope percent on agricultural lands.

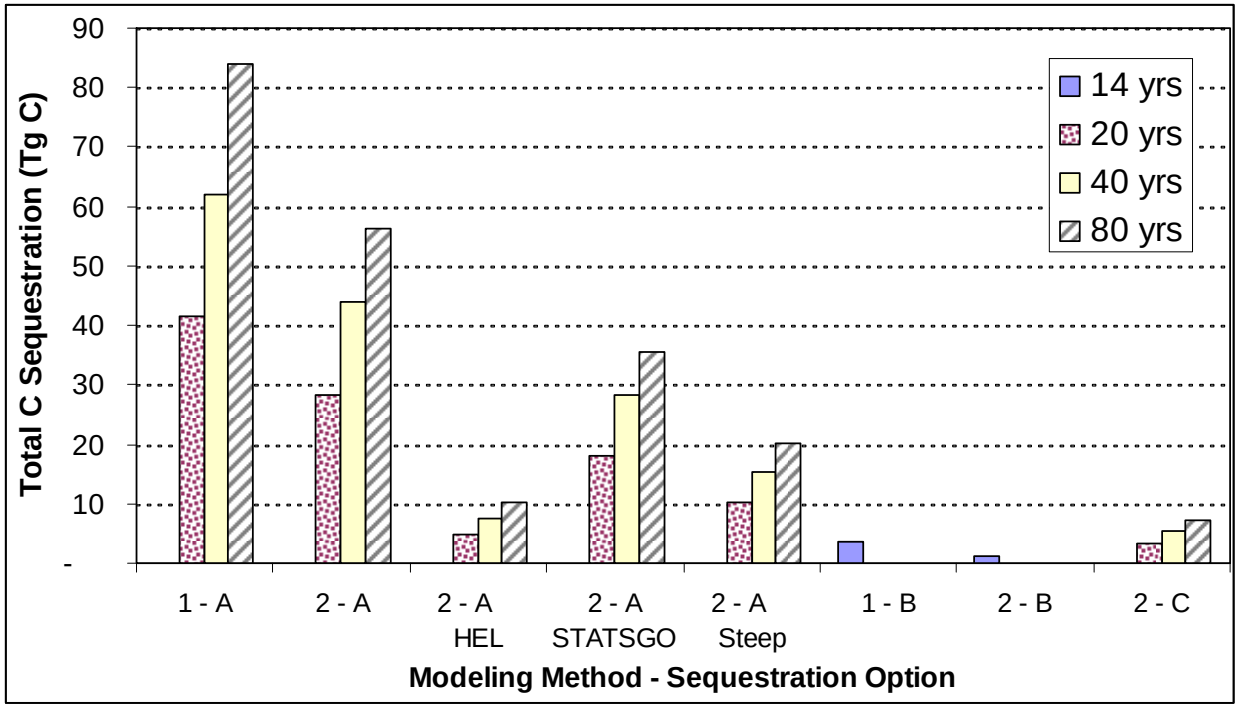

Figure 6. Total carbon sequestration potential by sequestration option (A = afforestation of marginal agricultural lands; B = conversion of row crops to conservation tillage; C = afforestation or riparian agricultural lands) and modeling method (1 = Winrock; 2 = VT).

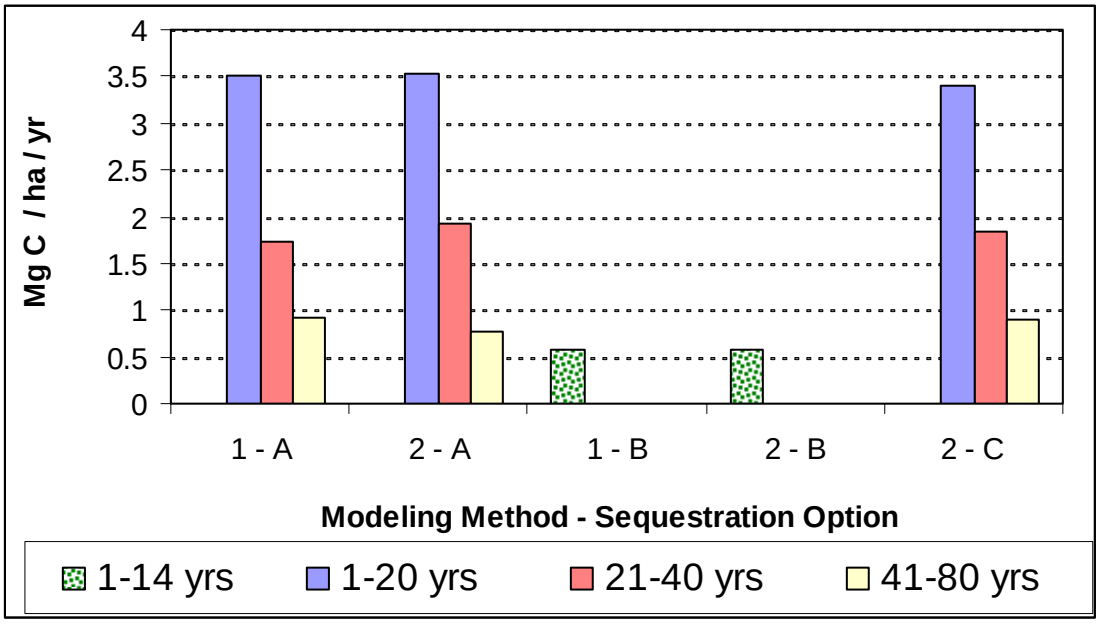

Figure 7. Average sequestration rates for various time periods after implementation for sequestration options (A = afforestation of marginal agricultural lands; B = conversion of

row crops to conservation tillage; C = afforestation or riparian agricultural lands), by modeling method (1 = Winrock; 2 = VT).

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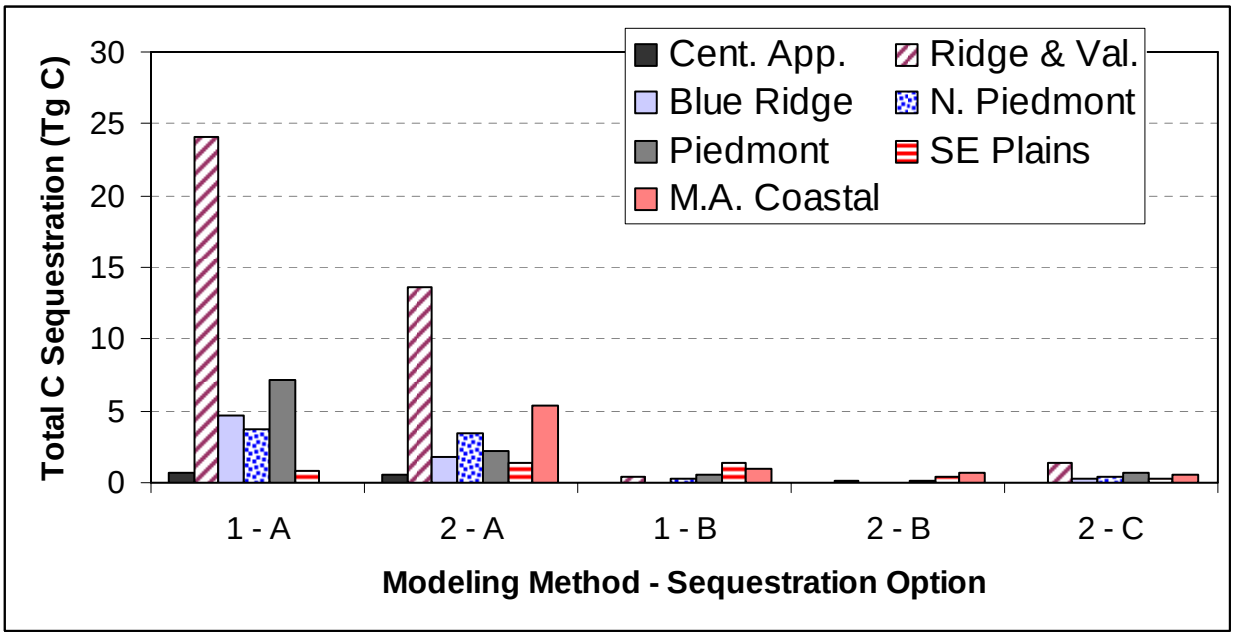


Figure 8. Total carbon sequestration potentials (Tg C) for 14 years (Option B = conversion of row crops to conservation tillage) and 20 years (Option A = afforestation of marginal agricultural lands; Option C = afforestation or riparian agricultural lands) after implementation, by ecoregion and modeling method (1 = Winrock; 2 = VT).

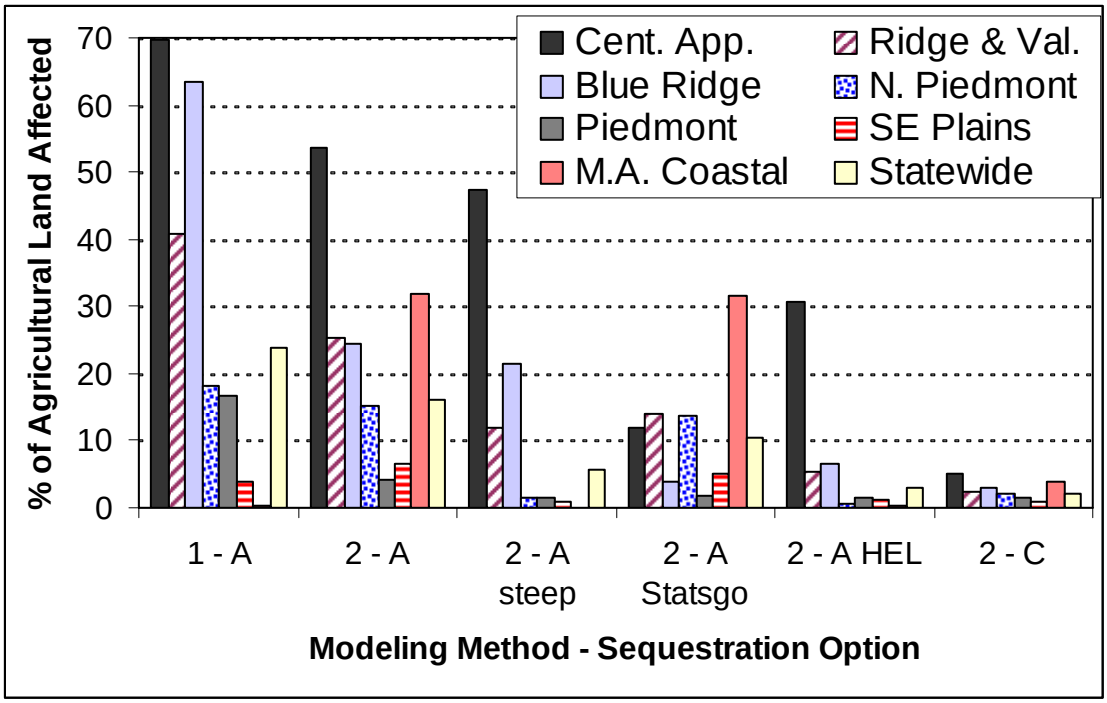


Figure 9. Percent of agricultural land (row crops, plus hay and pasture) affected by afforestation options (A = afforestation of marginal agricultural land, total and as defined by steepness of slope, STATSGO, and high erosivity; C = afforestation of riparian agricultural lands), by ecoregion and modeling method (1 = Winrock; 2 = VT).

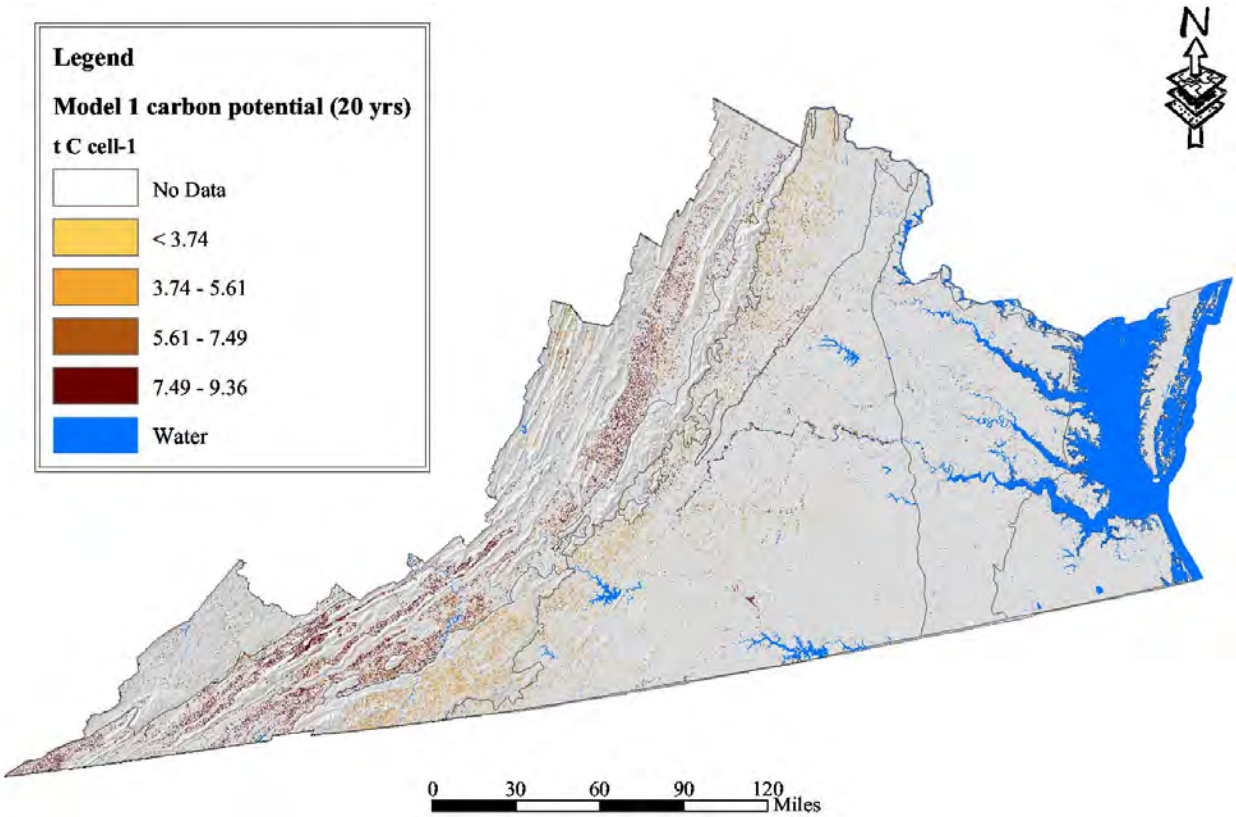


Figure 10. Map depicting areas of carbon sequestration potential (Mg C per 30-m grid cell) for afforestation of marginal agricultural lands (first 20 years) using Model 1 (Winrock method).

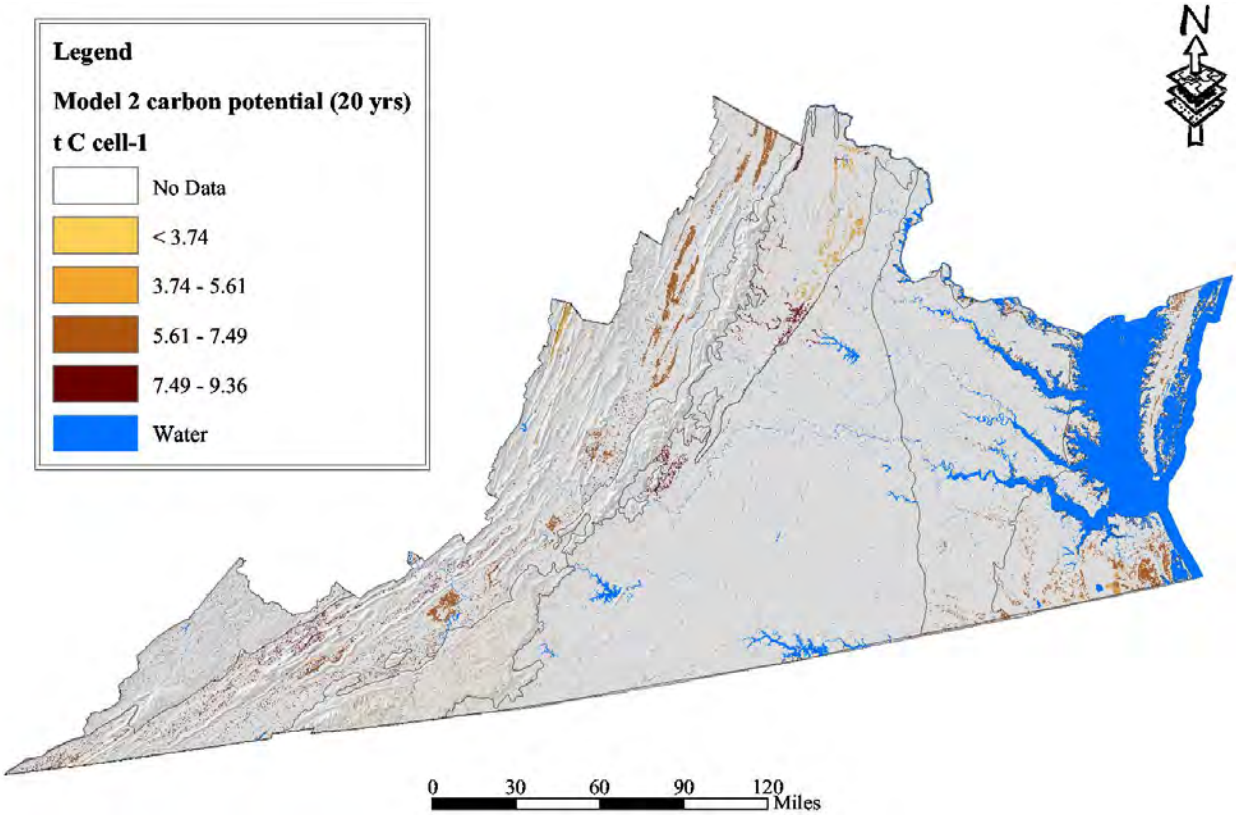


Figure 11. Map depicting areas of carbon sequestration potential (Mg C per 30-m grid cell) for afforestation of marginal agricultural lands (first 20 years) using Model 2 (VT method).

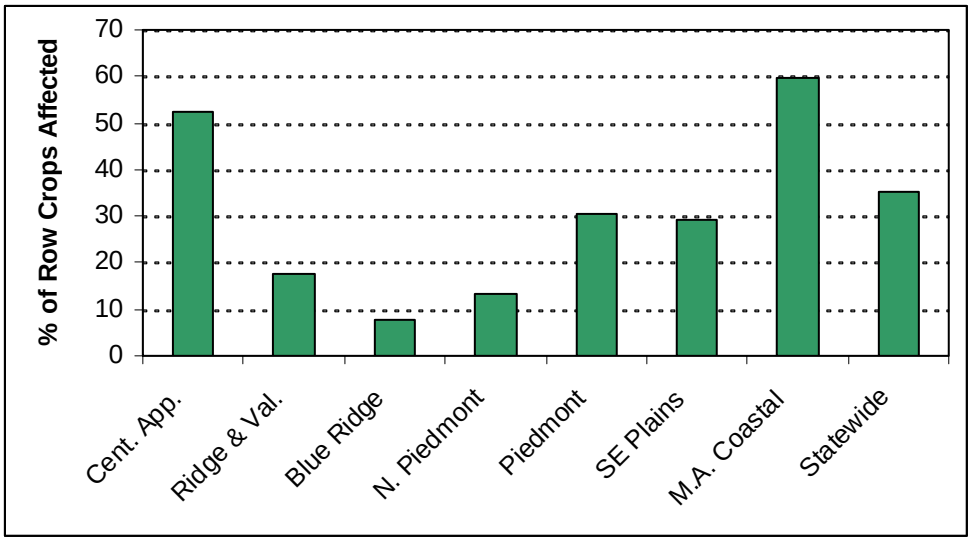
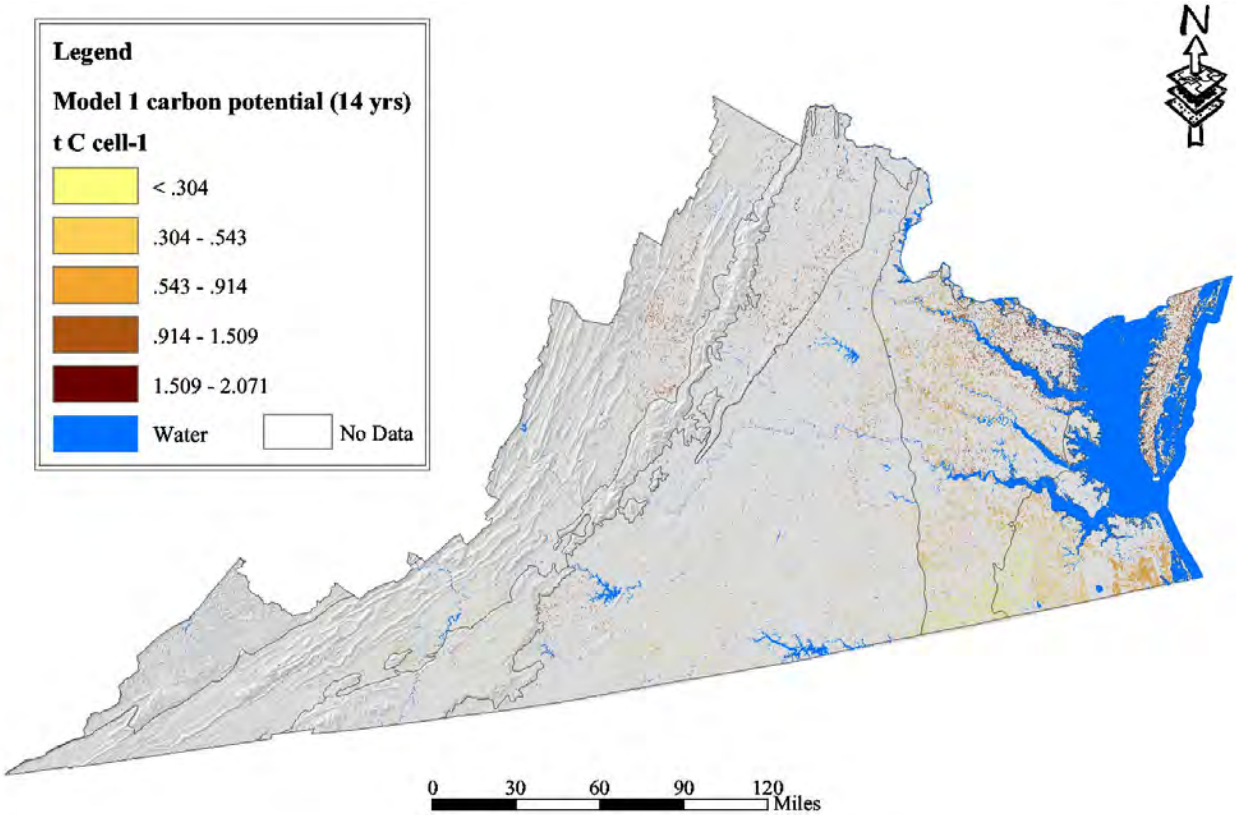
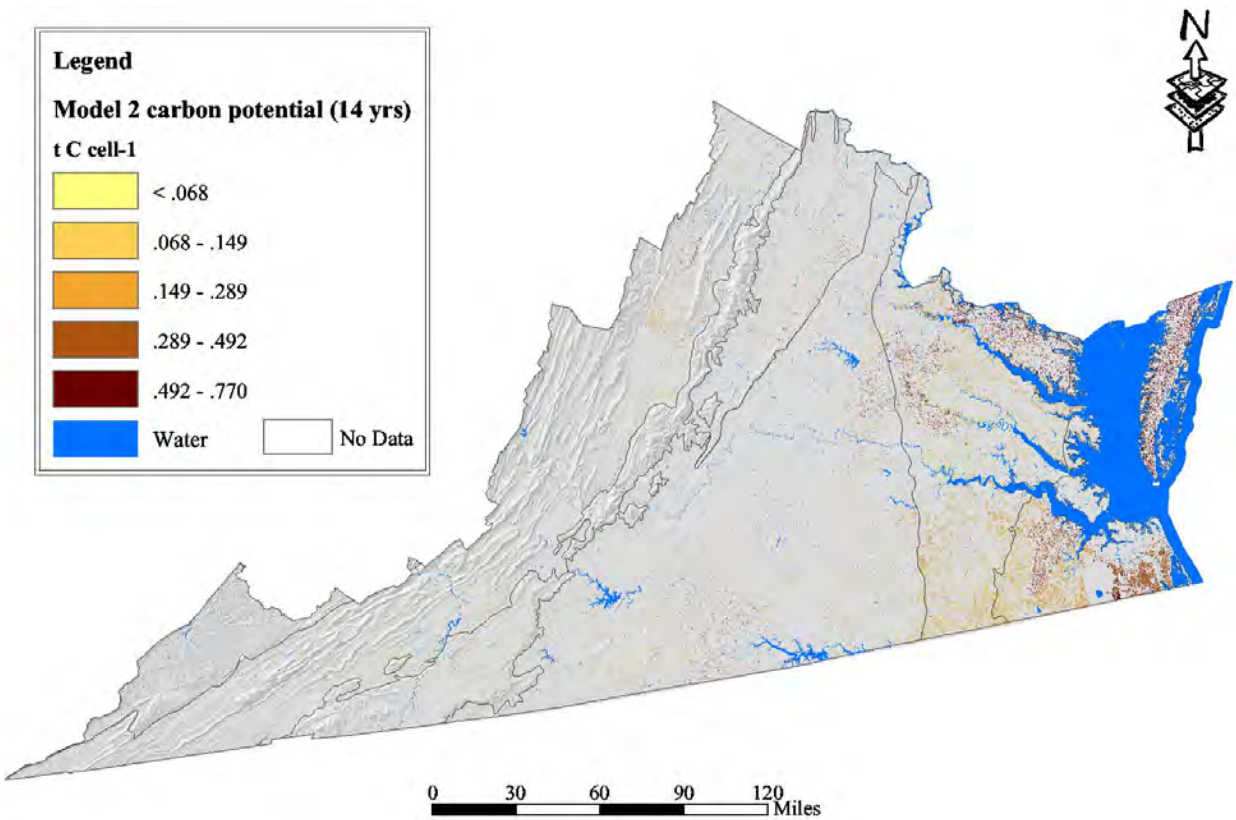


Figure 12. Percentage of total row crops modeled as converted from conventional tillage to no tillage cropping methods, by ecoregion and statewide, modeling method 2 (VT method). Modeling method 1 assumes 100% conversion.



Potential carbon sequestration 14 years after the conversion of conventional tillage (CT) crops to no-till (NT) crops using NASS (Model 1B).

Figure 13. Map depicting areas of potential carbon sequestration (Mg C per 30-m grid cell) over 14 years following conversion of conventional tillage (CT) cropping to no-till (NT) cropping, Model 1 (Winrock method).



Potential carbon sequestration 14 years after the conversion of conventional tillage (CT) crops to no-till (NT) crops using NASS and CTIC (Model 2B).

Figure 14. Map depicting areas of potential carbon sequestration (Mg C per 30-m grid cell) over 14 years following conversion of conventional tillage (CT) cropping to no-till (NT) cropping, Model 2 (VT method).

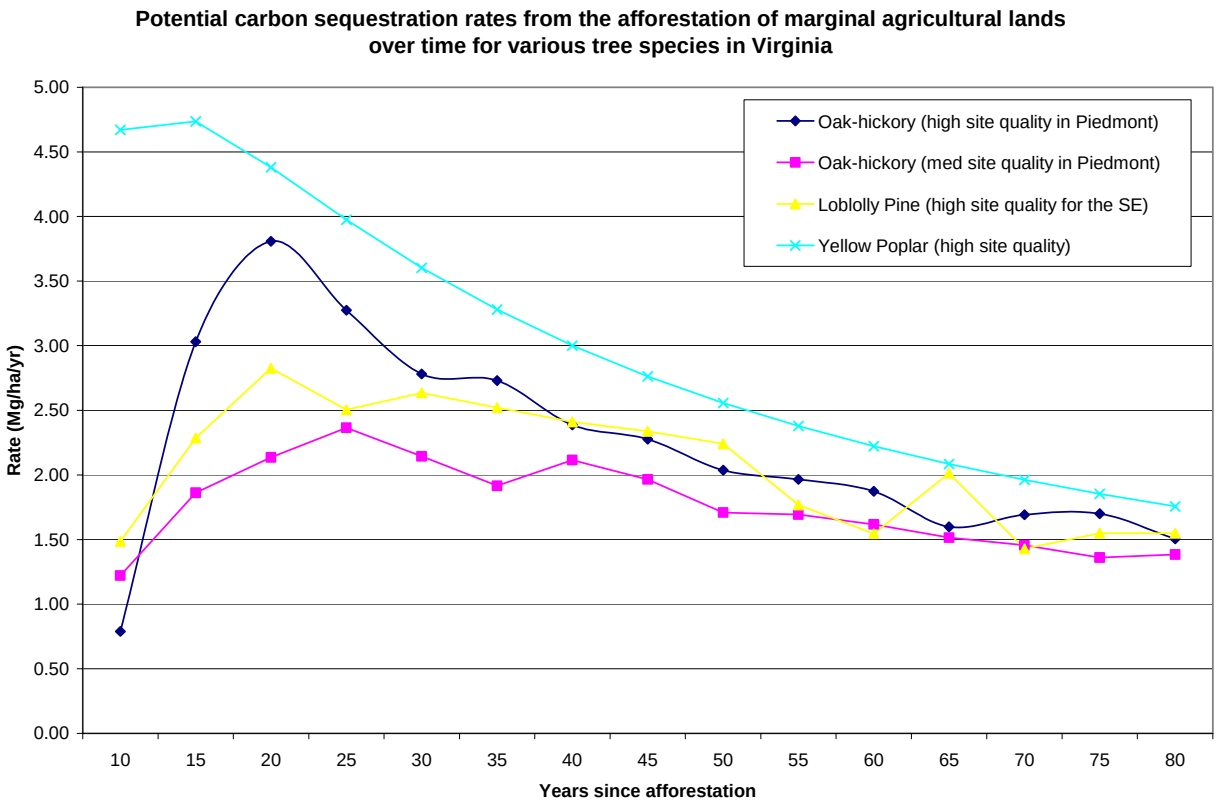


Figure 15. Variability of average sequestration rates through time for 4 common afforestation systems.

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Southeast Regional Carbon Sequestration Partnership

Report Type:	Summary of the Most Promising Terrestrial Storage Options in Texas
Report Issue Date:	August 1, 2005
DOE Award Number:	DE-FC26-03NT41980
Submitting Organization:	Bureau of Economic Geology
Authors	Susan D. Hovorka, Mark H. Holtz, Rebecca C. Smyth, Vanessa Núñez López, Eugene Kim, Caroline L. Breton, Bridget R. Scanlon, Robert C. Reedy

Status of Terrestrial Storage Assessment, Texas

Management of terrestrial ecosystems can be used to mitigate greenhouse gases (GHG). To assess the potential for carbon sequestration in Texas, a baseline analysis of past land-use practices needs to be assembled. Changes in land use will need to be documented, and the baseline is set as land use prior to year 1990 for the Kyoto Protocol. Once past land-use practices have been established, future changes in land use can be documented and presented in the context of past practices, and the impact on carbon storage can be assessed.

The 1992 National Land Cover Data (NLCD)[1] can serve as the baseline land use for Texas. Approximately 50% of the state is rangeland, most of which occurs in Railroad Commission of Texas Districts 7c and 8A. Although forests comprise only 15% of the state's land use, most occur in the east half of the state, with percentages of up to 54 percent in District 6. Agricultural areas are widespread throughout the state, with the exception of west Texas (Districts 7c and 8).

Data sources used to provide baseline information include NLCD, and National Agricultural Statistics Service (NASS) county-level tabular databases. National Resources Inventory data are collected by the National Resources Conservation Service (NRCS). Information on land classifications is available on NRI online at http://www.statlab.iastate.edu/survey/nri/est971nr.pdf . Information from the Farmland Mapping and Monitoring Program (FMMP) will also be collated. Full metadata, data collection details, and class descriptions are available online at ftp://ftp.consrv.ca.gov/pub/dlrp/FMMP/fmmp_meta.txt. A consistent land-use classification scheme will be used to document baseline land use and to assess changes in land use.

Estimates of above-ground biomass will be obtained from satellite imagery (Leaf Area Index, Normalized Difference Vegetation Index). Changes in above-ground biomass are evaluated and will be related to natural or anthropogenic processes where possible. Ground

[1] NLCD, 1992, National Land Cover Database, landcover.usgs.gov/natllandcover.asp.

referencing will be used to validate satellite and air photo information. Below-ground biomass values will be estimated from species-specific rooting information and information on soil texture. Such estimates of below-ground biomass may be uncertain. Litter may also be a mechanism of carbon storage that will be examined.

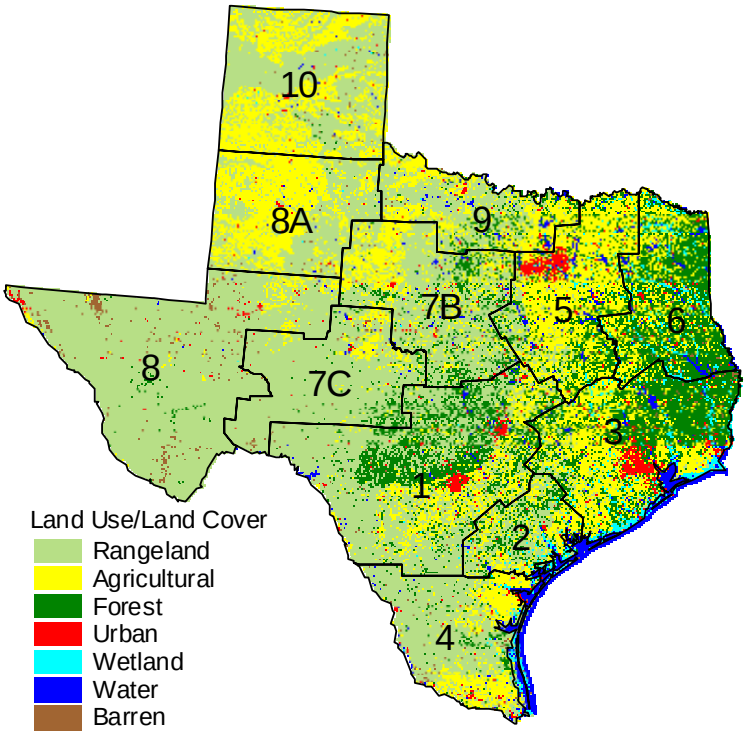

Figure 17. Railroad Commission of Texas district boundaries and National Land Cover Database (NLCD, 1992) land use/land cover.

Table 2. Calculated land use for regions of Texas divided by RRC districts. Districts 1–6 lie in the SECARB region and have much higher forest usage than the rest of the state.

	Land-Use Category Areas (%)						
District	*Rangeland*	*Agricultural*	*Forest*	*Urban*	*Wetland*	*Water*	*Barren*
1	55.9	15.6	24.6	2.2	0.1	1.0	0.6
2	42.4	28.0	20.6	1.1	4.7	2.8	0.4
3	5.4	35.6	40.1	5.7	8.3	3.1	1.7
4	63.0	24.2	5.4	1.7	2.0	2.1	1.7
5	10.0	56.1	21.3	5.8	2.5	3.8	0.4
6	0.1	30.7	54.1	1.8	8.0	3.5	1.8
7B	61.1	24.1	11.7	1.1	0.1	1.3	0.6
7C	85.9	8.0	4.3	0.5	0.0	0.4	0.9
8	92.7	3.0	0.7	0.7	0.0	0.1	2.8
8A	46.9	51.4	0.1	0.6	0.0	0.3	0.7
9	47.4	38.2	9.2	1.5	0.3	3.0	0.4

10	56.6	41.7	0.2	0.5	0.1	0.3	0.6
Texas	51.3	27.0	15.2	2.0	1.8	1.5	1.2

Rangeland: shrublands and grasslands
Agricultural: row crops, small grains, fallow, pasture/hay, orchards
Forest: perennial, evergreen, mixed
Urban: low- and high-density residential, transportation/industrial, urban grasses
Wetland: herbaceous and woody emergent wetlands
Water: open water
Barren: bare rock, quarries/open pit mines, transitional

"Terrestrial Carbon Sequestration in the Southeast and South-central United States"

Prepared by
Diagnostic Instrumentation Analysis Laboratory
Mississippi State University

Prepared for
Southern States Energy Board
Southeast Regional Carbon Sequestration Partnership

October 1, 2004

On characterizing the region

Terrestrial carbon pools in southeast and south-central United States: State level inventories, potentials, and economic impacts[1]

Inventories of regional carbon sources and sinks are essential for assessing the economic feasibility of various carbon sequestration options in mitigating the accumulation of CO_2 in the atmosphere and in preventing global warming. Such inventories are a prerequisite for the regional trading of CO_2 emissions. As a US Department of Energy Southeast Regional Carbon Sequestration Partner, we estimated terrestrial carbon pools in the southeast and south-central US at the state level, and projected the potential for terrestrial carbon sequestration and its economic impacts on the region. This region includes 11 states: Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Texas, and Virginia.

Results show that total terrestrial carbon pools in southeast and south-central US (11 states) were estimated to be 21.1 Pg C (Figure 1). Texas has the highest total terrestrial carbon storage (5.6 Pg C), accounting for 26.6% of total terrestrial carbon pools in the region. Florida has the second highest terrestrial carbon storage (3.8 Pg C, 17.8% of total carbon storage in the region). Tennessee and Mississippi have the lowest terrestrial carbon storage (807-915 Tg C for each state), each accounting for about 4 % of the total terrestrial carbon storage in the region. We divided the terrestrial carbon into the four major carbon pools, which are soil organic carbon, forest biomass, agricultural crop biomass, and grass biomass. Among these pools, soil organic matter is the biggest terrestrial carbon pool, totaling 16.54 Pg C and representing 78 % of the overall terrestrial carbon pools in the region, followed by forest biomass carbon pool (4.45 Pg C, or 21%). Carbon pools in agricultural crops and grass biomass is relatively small, totaling 113 Tg C and accounting for 0.53 % of total terrestrial carbon pools.

Total annual terrestrial C sink in the region was estimated to be 189.1 Tg C/year (Figure 2). Texas is the leading state (38 Tg C/year), accounting for 20.1% of the total annual terrestrial C sink in the region, followed by Arkansas (31.4 Tg C/year, 16.6% of the total annual C sink in the region). South Carolina and Florida have the smallest total annual terrestrial C sink (6.4 Tg C/year, 3.4% of current annual terrestrial carbon storage in the region for each state). Most states have a total annual terrestrial C sink of between 16 and 20 Tg C/year.

Current annual forest carbon storage could compensate for 13% of the annual greenhouse gas emissions in the region (Figure 3). Annual forest carbon sink in Mississippi could compensate for 31.2% of its total greenhouse gas emission, followed by North Carolina (24.8%), Georgia (24.6%), Tennessee (14.3%), and Virginia (18%) (Figure 6). However, Texas has only 4.5% of its total greenhouse gas emission offset by annual terrestrial carbon sink, followed by Louisiana (8.7%) and Florida (9.7%).

Through implementation of policies and best management practices, the total potential of terrestrial carbon sequestration in the region was estimated to be 53.9 Tg C/year, indicating that an additional 9.3% of the total greenhouse gas emissions could be further offset by terrestrial sequestration (Figure 4). The potential for forestland, cropland and grassland was projected as 29.4, 15.1 and 9.4 Tg C/year, respectively (Figure 4). Texas has the largest annual carbon deficit (149 Tg C/year). Current and potential terrestrial carbon sequestration in the region would value $11.2 and $7.98 billion/year, respectively. In other words, terrestrial carbon sequestration is shown to be one of the most cost-effective options for sequestering carbon in the region.

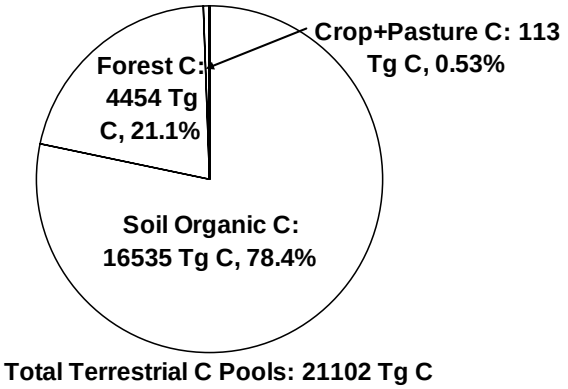

Figure. 1. Total terrestrial carbon pools in the region.

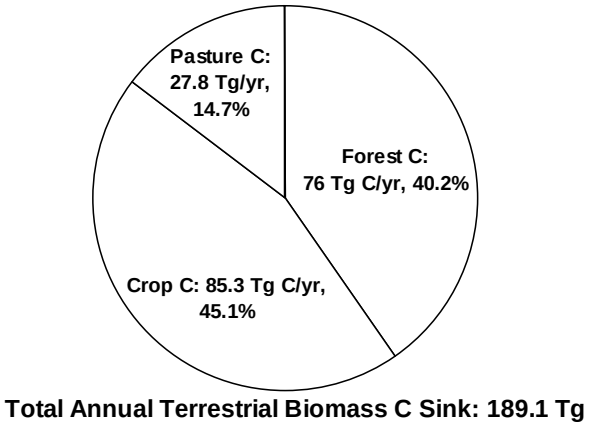

Figure 2. Current annual biomass carbon sink in the region.

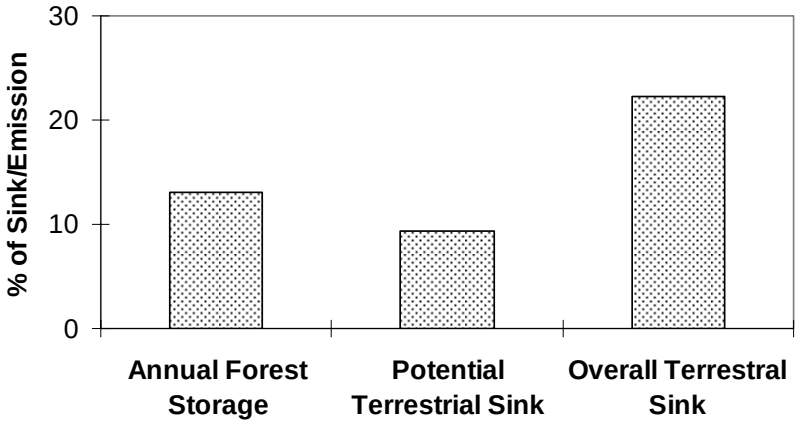

Figure 3. Percentages of annual biomass carbon storage in forest, the potential terrestrial carbon storage, and overall carbon sink over the total greenhouse gas emission in the region. (Since total greenhouse

gas emission in Arkansas and South Carolina is not available, the calculation excluded these two states).

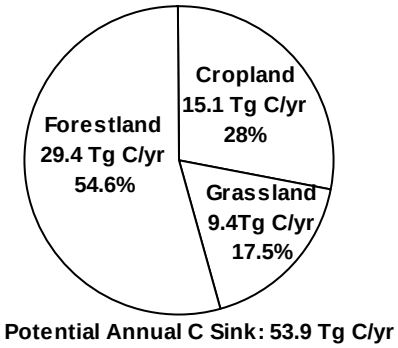

Figure 4. The potential terrestrial carbon sequestration in the region.

References

(1). Fengxiang X. Han[,*], M. John Plodinec, Yi Su, and David L. Monts, Extension of Abstract Submitted to the 4th Annual Conference on Carbon Sequestration, May, Alexandria VA (2005).

SECARB CO_2 Sequestration GIS Analysis

Deliverable 21

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EPRI Project Manager:
Richard Rhudy

Report Prepared by
Carbon Capture and Sequestration Technologies Program
Massachusetts Institute of Technology

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EXECUTIVE SUMMARY

This report presents the GIS analysis part for the Phase I study of the Southeast Regional Carbon Sequestration Partnership (SECARB) in characterizing the CO_2 sequestration potential for the region. The following three components of CO_2 sequestration are evaluated in the study:

- CO_2 source analysis
- CO_2 storage capacity estimation
- CO_2 source-sink matching and sequestration cost

As a first step, the study collected the information regarding the stationary CO_2 sources in the SECARB region. The data was compiled and stored as a database in the SECARB GIS server. The database includes information for 862 facilities from eight categories with total annual emissions estimated at just over 1 Gt[1] of CO_2. Table ES-1 and Table ES-2 summarize the CO_2 emissions from major stationary sources in the SECARB region by facility type and by state, respectively. Power plants are the single largest source of CO_2 emissions, accounting for about 85 percent of the emissions from the stationary sources in the database. The SECARB region, especially Louisiana and eastern Texas, hosts a variety of non-power stationary CO_2 emission facilities and has a higher than national average proportion of non-power stationary CO_2 emissions. Eastern Texas, Florida, Alabama, and Louisiana—all are Gulf Coast states—rank highest in terms of the CO_2 emissions in the region.

Table ES-1: CO_2 Emissions from Stationary Sources by Facility Type

Type of Plant	Facilities #	CO_2 Emissions[1] (Mt/yr)
Ammonia	15	9
Cement	28	20
Ethylene	24	50
Ethylene Oxide	11	2
Gas Processing	164	16
Iron & Steel	32	3
Power Plants	547	859
Refineries	41	62
Total	**862**	**1,020**

Note:
[1]Power plants data are 2000 actual data but others are estimated emissions based on plant production capacity in various years (see Section 2 for details).

[1] 1 Gt is one billion metric tons. 1 Mt is one million metric tons.

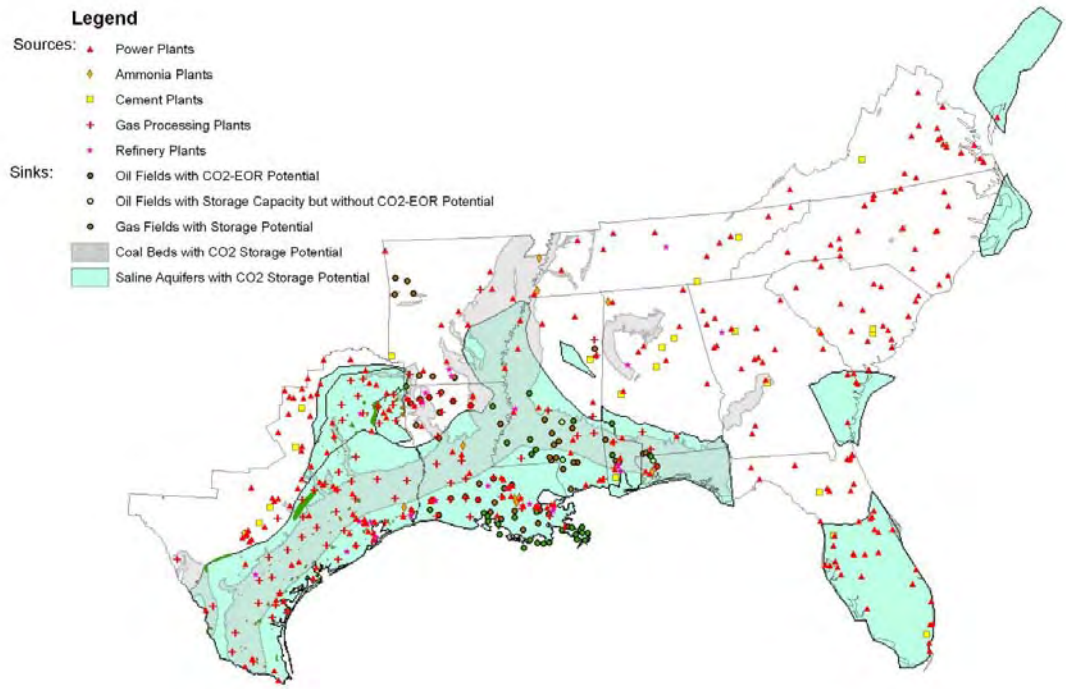
Table ES-2: CO_2 Emissions from Stationary Sources by State

State	Facilities #	CO_2 Emissions (Mt/yr)
AL	48	96
AR	26	35
FL	85	120
GA	65	89
LA	139	95
MS	42	29
NC	51	79
SC	32	44
TN	25	68
TX[1]	298	320
VA	51	43
Total	**862**	**1,020**

Note:
[1]eastern Texas only, consisting of Railroad Commission District 1-6.

The study identified three types of potential geological storage sinks for CO_2 sequestration in the SECAB region: hydrocarbon (oil & gas) reservoirs, saline aquifers, and coalbeds. A similar survey was conducted for candidate CO_2 sinks and the information was also stored in the SECARB database. The database was based on the best information available during Phase I and will be continually updated in Phase II as more detailed data sets are developed. The storage capacity estimation methods in the JOULE II report (Holloway, *et.al.*, 1996) were adapted as the baseline models in estimating the CO_2 storage capacity for hydrocarbon reservoirs and saline aquifers, while the methodology developed by Reeves (2003) was used as the baseline model in estimating the CO_2 storage capacity for coalbeds. When necessary, these baseline models were modified to accommodate incomplete data sets contained in the current database. The modified models were then applied to estimate the CO_2 storage capacity for each candidate CO_2 sink.

Figure ES-1: CO_2 Sources and Sinks in the SECARB Region



After identifying the CO_2 sources and candidate sinks, the study then evaluated the CO_2 sequestration potential in the SECARB region by analyzing the matching between sources and sinks. Figure ES-1 shows the distribution of CO_2 sources and sinks that were considered in the source-sink matching analysis. Table ES-3 summarizes the CO_2 capture capacity from these sources (over 25 years) and the CO_2 storage capacity for these sinks by category. After excluding sources with CO_2 emissions below certain scales[2], the source data set considered in the matching analysis was restricted to 316 power plants and 103 non-power facilities. Over an assumed 25 year project lifetime, a total amount of 34 Gt of CO_2 from these facilities would need to be sequestrated. After excluding sinks with less than 5 Mt of storage capacity[3], the regional CO_2 storage capacity was estimated to be at least 504 Gt[4].

[2] Power plants with design capacity less than 100 MW_e and gas processing plants with design capacity below 300mmcfd are excluded.

[3] 5 Mt is the minimum capacity requirement for a sink to store the 25-year cumulative amount of CO_2 that can be captured from any facility in the interested source set.

[4] Due to incomplete datasets, the study didn't evaluate the CO_2 storage capacity in coalbeds except for Black Warrior Basin (see Section 3.3 for details).

Table ES-3: CO_2 Capture Capacity for Sources and Storage Capacity for Sinks Considered in the Matching Analysis

Field Group		Number of Fields	CO_2 Capture Capacity (Gt)[1]	CO_2 Storage Capacity (Gt)
Sources	Power Plants[2]	316	31.6	-
	Non-power Stationary Sources[3]	103	2.4	-
	Total	419	**33.9**	**-**
Sinks[4]	Oil Fields w/ EOR potential	74	-	1.9
	Oil Fields w/o EOR potential and Gas Fields	246	-	3.6
	Coal Beds[5]	n.a	-	0.3
	Aquifers	n.a	-	497.8
	Total			**503.6**

Note:
1. Project lifetime 25 years.
2. Only design capacity over $100MW_e$ included.
3. Only includes ammonia, cement, gas processing, and refineries. Also, for gas processing facilities, those with design capacity less than 300 mmdcfd were excluded.
4. Only CO_2 storage capacity over 5 Mt included.
5. Only coalbed methane data in Black Warrior Basin, Alabama from AGS included in the estimate.

Table ES-4: Annual CO_2 Storage Capacity (Mt/y) of Various Sinks by Straight-line Distance from Source to Sink

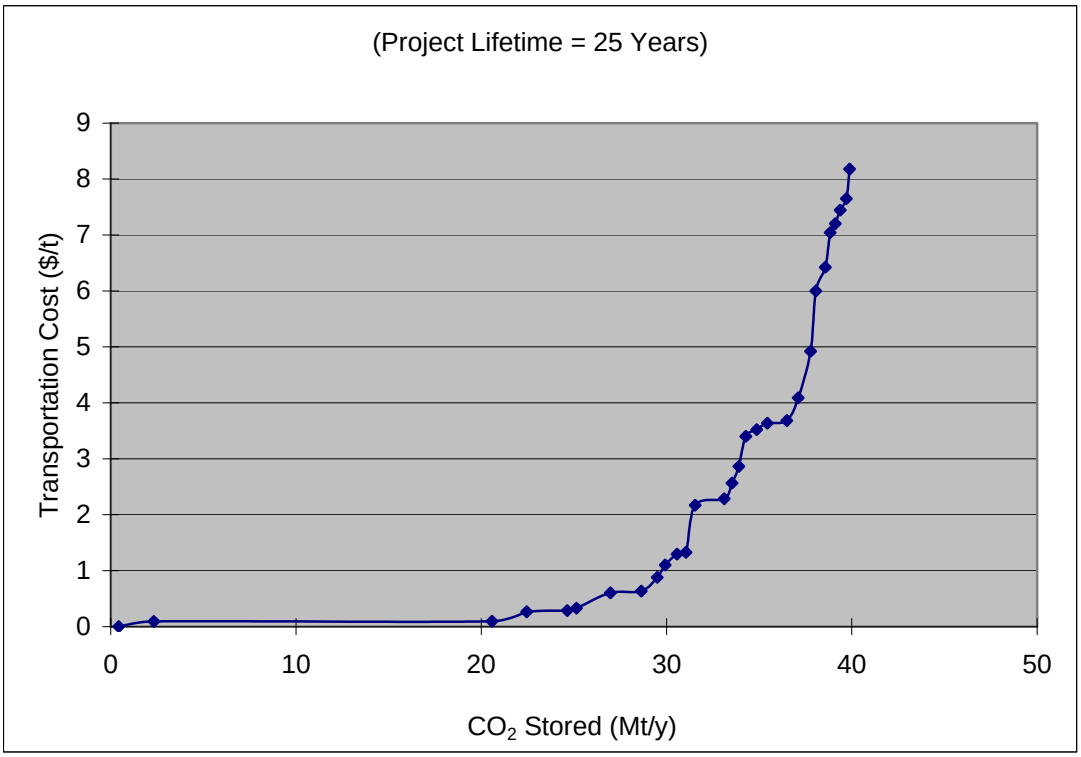
Sink Type	Straight Line Distance from Source to Sink		
	50 km or less	**100 km or less**	**250 km or less**
Oil & Gas Fields with EOR Potential	349	484	675
Oil & Gas Fields	507	598	726
Coalbeds	606	856	1,190
Aquifers	794	867	1,125
All Sinks	972	1,143	1,357

Note:
1. The total annual CO_2 storage rate was 1, 357 Mt.
2. Sinks with less than 5 Mt storage capacity were excluded from the analysis.

As a preliminary analysis, the study performed a straight-line distance based matching for the entire SECARB region, connecting each source to its closest sink in terms of straight-line distance. In this preliminary exercise, neither the optimal pipeline path nor the sink's storage capacity constraints were considered. The straight-line distance matching analysis was performed for each of the four different groups of eligible sinks and a combination of them altogether. Table ES-4 summarizes the matching results based on the straight-line distance in terms of annual CO_2 storage capacity by marginal straight-line distance. If EOR sites were the only sinks used for sequestration, only half of the CO_2 sources (by volume) could be matched with a sink that is less than 250 km from the source. If all sink types were considered for sequestration, however, then all of the CO_2 sources could be matched with appropriate sinks within 250 km from the source. More than 70% of the sources (by volume) would find their nearest sinks within 50 km. Note that the 1,357 Mt/y in Table ES-4 is larger than the 1,020 Mt/y in Table ES-2. This is because in the matching exercise we assumed 80% capacity factors, while Table ES-2 used actual capacity factors for the year reported.

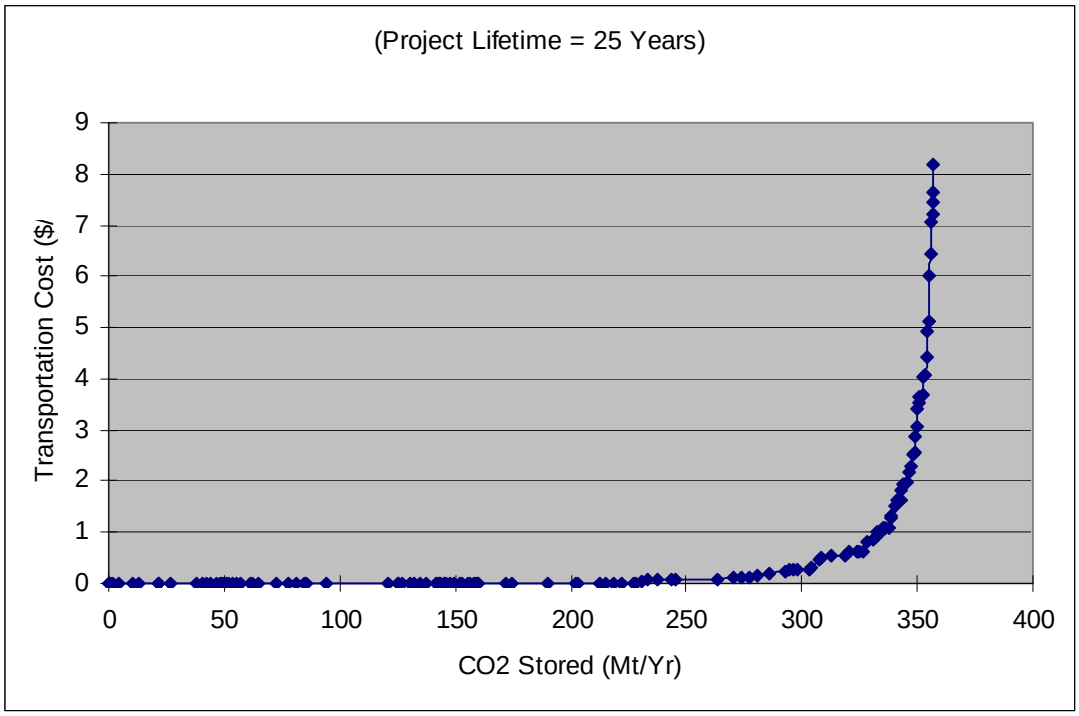
The study also conducted a GIS-based method of matching sources and sinks considering the optimal pipeline route selection and sink's capacity constraint. The pipeline construction costs vary considerably according to local terrains, number of crossings (waterway, railway, highway), and the traversing of populated places, wetlands, and national or state parks. In order to account for such obstacles, the locations and characteristics of these obstacles were loaded into the spatial database and were used to construct a single aggregate transportation obstacle layer. In contrast to the distance-based matching analysis, this least-cost matching analysis links each CO_2 source to a least cost geological sink based on sum of the transportation cost associated with the least-cost path and the injection cost subject to the sink's capacity constraint. An iterative algorithm was used to approximate an optimal system solution. Due to the limited availability of detailed sink data for the SECARB region, this least-cost matching analysis was only performed for eastern Texas where the data sets are relatively rich.

Figure ES-2: Marginal Transportation Cost in eastern Texas Oil Fields with EOR Potential



The least-cost source-sink matching analysis for eastern Texas was conducted in two stages. In the first stage, only EOR sites were included as candidate sinks. The cost calculation assumed a credit of \$16/t CO_2 for EOR injection in place of the injection cost. With the assumption of a constant CO_2 credit, the optimization algorithm only considers minimizing the overall transportation of the network system. Figure ES-2 shows the marginal transportation cost in oil fields with EOR potential. The annual CO_2 storage rate in EOR sites is estimated to be 40 Mt. While the maximum transportation cost is around \$8.2/t CO_2, about 30 Mt CO_2 can be transported to EOR sites annually at transportation cost less than \$1/t CO_2.

Figure ES-3: Marginal Transportation Cost for all Sources in eastern Texas



After allocating the EOR storage capacity to appropriate sources, the remaining unmatched sources were assigned to hydrocarbon fields without EOR potential and saline aquifers in the second stage. Figure ES-3 shows the marginal CO_2 transportation cost in all sinks. Extending the sinks to include non-EOR hydrocarbon fields and saline aquifers, the annual CO_2 storage rate in eastern Texas becomes 357 Mt, among which about 330 Mt can be transported to a sink with transportation cost less than \$1/t CO_2. Figure ES-4 shows the pipeline routes connecting each source to its assigned sink by the least-cost matching. Some sources right on top of aquifers were still assigned to EOR sites as the EOR credit and the saved injection cost outweigh the added transportation cost.

Figure ES-4: Source-sink Matching Final Result

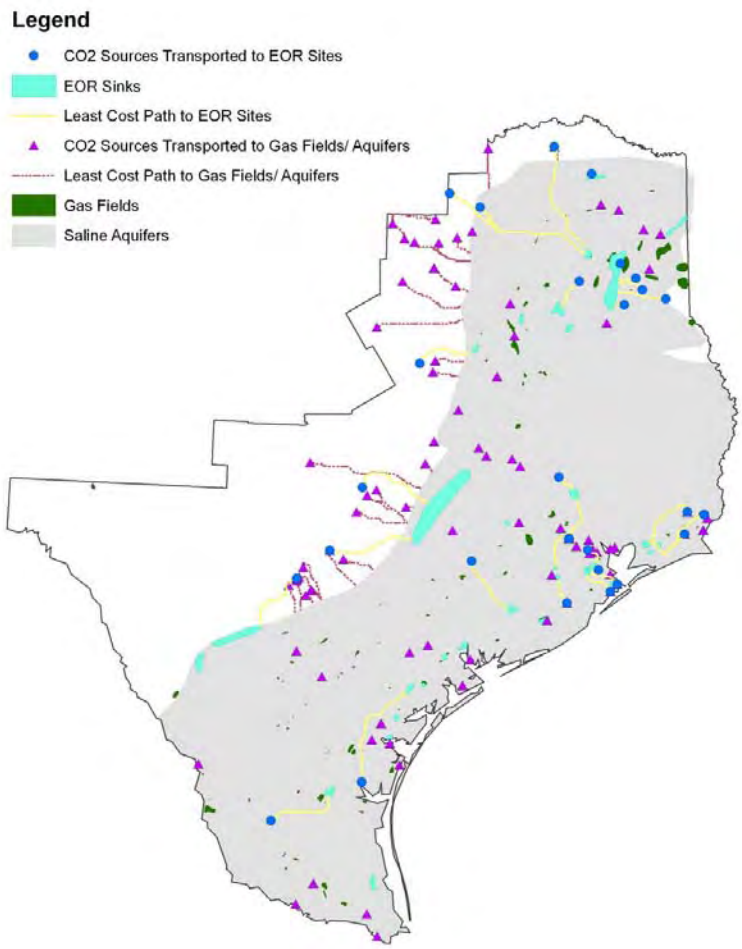


Figure ES-5: Marginal Total Cost of Capture and Sequestration in eastern Texas

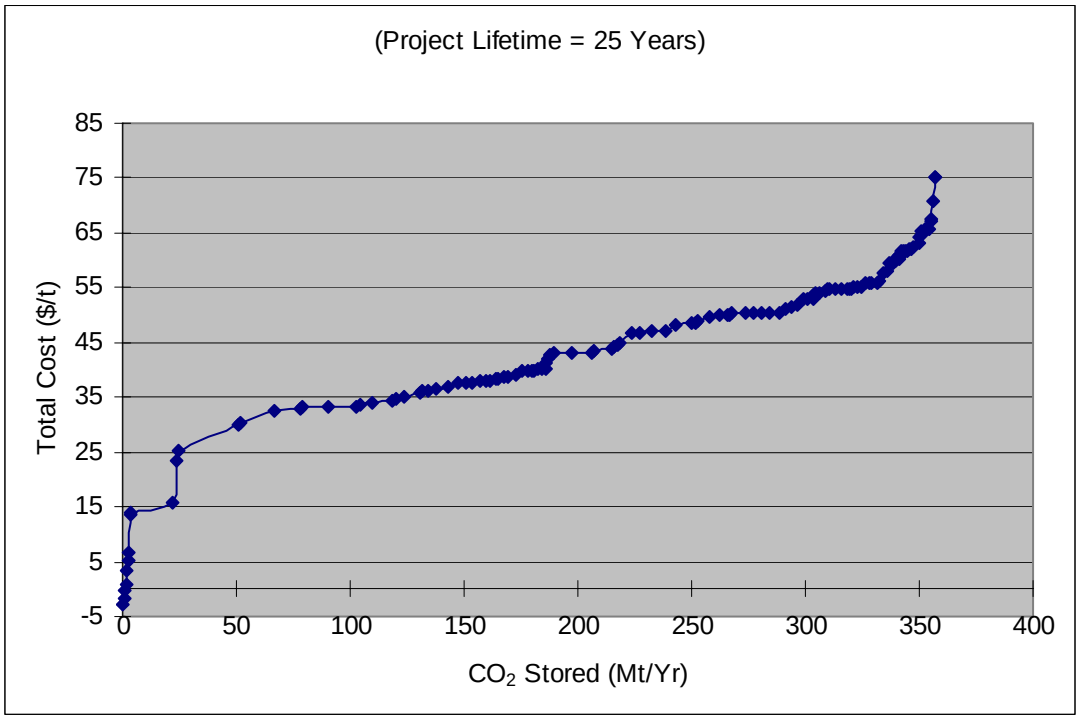


Figure ES-5 shows the full marginal capture and sequestration cost. For sources matched with EOR sites, the full cost estimate includes costs for capture and transportation, net of an EOR credit. For sources matched with non-EOR hydrocarbon fields or aquifers, the full cost estimate included costs for capture, transportation, and injection. The results of the full cost analysis in eastern Texas indicate that 20, 100, or 200 M tonnes of CO_2 per year could be sequestered for marginal costs of $16/t, $33t, or $43/t, respectively. The sequestration cost could be negative for certain ammonia and gas processing plants with low transportation costs since their capture cost was less than the assumed EOR credit.

1 OVERVIEW

This report presents the GIS analysis part of the Phase I study of the SECARB regional partnership. In this report GIS software and other tools were used to characterize the SECARB region and assess its carbon sequestration potential. The SECARB member states include Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and eastern Texas[5].

In this report:

- Section 2 presents a summary of stationary CO_2 sources and the levels of emissions within the SECARB region.
- Section 3 presents a first-order scoping analysis to determine the maximum CO_2 storage capacity of the carbon sinks within the SECARB region.
- Section 4 documents methods for determining the CO_2 capture costs from the types of CO_2 sources included in the study.
- Section 5 presents a methodology for estimating the requirements and costs of transporting CO_2 from the sources to the storage reservoirs.
- Section 6 presents an initial matching between CO_2 sources and sinks in the SECARB region based on minimum straight-line distance.
- Section 7 presents a detailed source-sink matching analysis which is used to develop CO_2 sequestration marginal abatement cost curves. This analysis is restricted to eastern Texas due to the limited availability of more expansive datasets. This type of analysis will be expanded to the entire SECARB region in Phase II.

It must be emphasized that this is only an initial analysis. It was based on the best information available during Phase I of the regional partnerships. This effort will be continued and improved in Phase II using more sophisticated tools and more detailed data sets.

[5] In this report 'eastern Texas' was defined as Railroad Commission (RRC) District 1 to 6.

2 STATIONARY CO_2 SOURCES IN THE SECARB REGION

This report summarizes the CO_2 source database that has been created for the SECARB GIS analyses. The database contains the location and capacities of the major stationary sources of CO_2 in the SECARB study area. It also includes annual CO_2 emissions. CO_2 emissions from power plants were given in the US Environmental Protection Agency (USEPA) eGRID database. For other CO_2 sources, the emissions were estimated using emissions factors based on annual production.

The database contains the following eight major stationary source categories:

- Power plants
- Ammonia Plants
- Cement plants
- Ethylene plants
- Ethylene oxide plants
- Gas processing facilities
- Iron & steel plants
- Refineries

2.1 FACILITY DATA SOURCES

The USEPA eGRID database was used exclusively for the power plant data cited within this report. For other major CO_2 sources, the ECOFYS database developed for the IEA GHG program was used as an initial starting point. Records within the ECOFYS database were then upgraded using the sources listed in Table 2-1. Specifically, new data sources were used for ammonia plants, cement plants and refineries. Updated data was also used for gas processing facilities. No changes were made to the data sources for ethylene, ethylene oxide, and iron and steel plants because the ECOFYS database already contained the most recent and accurate datasets available for these sources. See Table 2-1 for details on the data sources used for each emissions source category.

Table 2-1: Data Sources

Category	Data Source	Details
Power plants	US Environmental Protection Agency (USEPA) eGRID Database (2002) http://www.epa.gov/cleanenergy/egrid/index.htm	- Best data source identified - Plants located - CO2 emissions estimated - Database to be updated when 2004 data released
Ammonia plants	International Fertilizer Development Center Report "North America Fertilizer Capacity" (October, 2004) http://www.ifdc.org/New_Design/Publications/Market_Reports/index.html	- Best data source identified - Plants located - Plant capacities estimated
Cement plants	"U.S. and Canadian Portland Cement Industry: Plant Information Summary," Portland Cement Association, 2002. http://www.cement.org/bookstore/	- Best data source identified - Plants located - Plant capacities estimated
Gas processing facilities	Oil and Gas Journal Worldwide Gas Processing Survey (2003) http://orc.pennnet.com/surveys/aboutsurveys.cfm USGS Organic Geochemistry Database http://energy.cr.usgs.gov/prov/og/ (well CO2 levels)	- Best data sources identified for gas processing capacity and well CO_2 levels - Processing capacities of plants estimated
Refineries	US Department of Energy – Energy Information Administration (2004) http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html	- Best data source identified - Plants located - Plant capacities estimated
Ethylene plants	From Ecofys: *Ethylene Report*, Oil & Gas Journal, April 23, 2001	- Best data source identified - Plants located - Plant capacities estimated
Ethylene oxide plants	From Ecofys: ChemWeek Website; http://www.chemweek.com, 2001	- Best data source identified - Plants located - Plant capacities estimated
Iron and steel plants	From Ecofys: *World Steelworks Survey*, SteelEye, 2001	- Best data source identified - Plants located - Plant capacities estimated

The eGRID and ECOFYS databases contain geographic coordinate information for the vast majority of the stationary CO_2 emissions sources in the SECARB region. In cases where this data was unavailable, the USGS Geographical Names Information System database (GNIS) was used to lookup the missing data.

2.2 CO_2 EMISSION FACTORS

Except for the eGRID database, the data sources in Table 2-1 provide production capacity numbers but do not have information on CO_2 emission rates. In order to convert these capacity numbers to CO_2 emission rates, emission factors for each of the source categories were identified. These are outlined in Table 2-2.

It is important to note that the CO_2 emissions estimated from applying these emission factors are very approximate. They are useful for comparing the total emissions from each source type, but may not be an accurate estimate of emissions from any individual source.

Table 2-2: CO_2 Emission Factors

Category	Emission Factor	Units	Source
Power	n/a	n/a	CO_2 emissions explicitly given in eGRID database
Ammonia	1.13	kg CO_2/kg Ammonia	International Fertilizer Development Center (IFDC)
Cement	0.75	kg CO_2/kg Clinker	Hanle, "CO_2 Emissions Profile of the US Cement Industry," US EPA, 2004
Gas Processing	608	tCO_2/mmcfd/yr	ECOFYS, based on 4% average inlet gas CO_2 concentration
Refineries	9.9	tCO2/BPD/yr	ExxonMobil "Report on Energy Trends, Greenhouse Gas Emissions and Alternative Energy," 2004 - Calculated as the company-wide average refinery emission rate
Ethylene	2.43	kg CO_2/kg Ethylene	ECOFYS
Ethylene Oxide	0.51	kg CO_2/kg Ethylene Oxide	ECOFYS
Iron and Steel	0.1468	Kg CO_2/kg Steel	US EPA, "Direct Emissions from Iron and Steel Production," 2002

2.3 SUMMARY OF SOURCE CATEGORIES

2.3.1 Power Plants

The database used 2002 USEPA eGRID data for power plant capacities, locations, operating factors, and CO_2 emission rates. The database only contains fossil power plants that are fired by coal, oil, or gas. The CO_2 emissions for these power plants were directly reported in the eGRID data and no emission factors were used to calculate total emissions.

The USEPA eGRID database is the best available database of power plant emissions information. The database is updated and re-released on a periodic basis. The analyses within this report are based on the most recent version of the database available during Phase I study, which was released in May 2003 and contains updated data from the year 2000. Table 2-3 summarizes the fossil power plants in the study area by state. Figure 2-1 shows the geographical distribution and the CO_2 emissions for fossil power plants in the SECARB region.

Table 2-3: Power Generation Capacity and CO_2 Emissions by Fuel and State (2000)

State	Gas			Oil			Coal		
	Number	Capacity (MW)	CO_2 Emissions (Mt)	Number	Capacity (MW)	CO_2 Emissions (Mt)	Number	Capacity (MW)	CO_2 Emissions (Mt)
AL	15	1,030	1.9	0	0	0	10	14,904	88
AR	12	2,637	3.4	1	8	0	3	3,911	29
FL	42	10,045	12.4	23	15,218	31.4	13	12,732	74
GA	19	4,501	2	25	1,205	1.1	16	15,804	84
LA	54	14,795	31.1	0	0	0	4	3,360	18
MS	22	4,621	6.6	3	807	2.5	4	2,498	16
NC	7	3,747	1.2	12	118	0	29	14,548	78
SC	8	2,029	0.5	3	246	0	14	7,637	41
TN	5	1,132	0.3	0	0	0	13	12,990	65
TX*	126	47,793	89.6	1	11	0	17	19,197	143
VA	12	3,781	1.6	13	435	0.1	21	6,855	37
Total	**322**	**96,110**	**151**	**81**	**18,048**	**35**	**144**	**114,435**	**671**

* eastern Texas

Figure 2-1: Fossil-Fired Power Plants

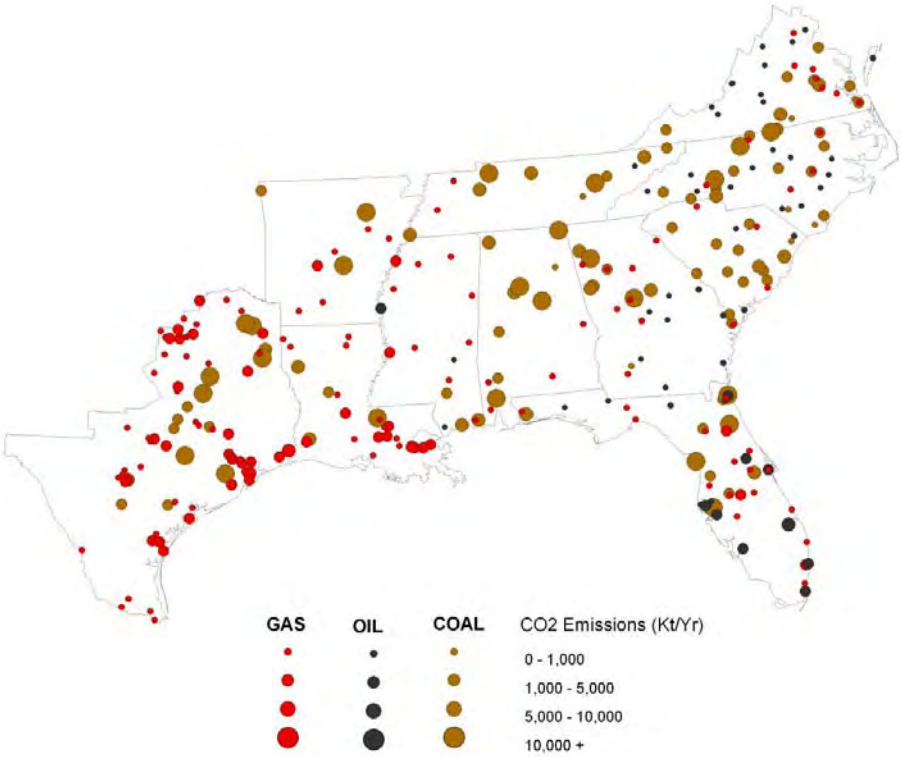
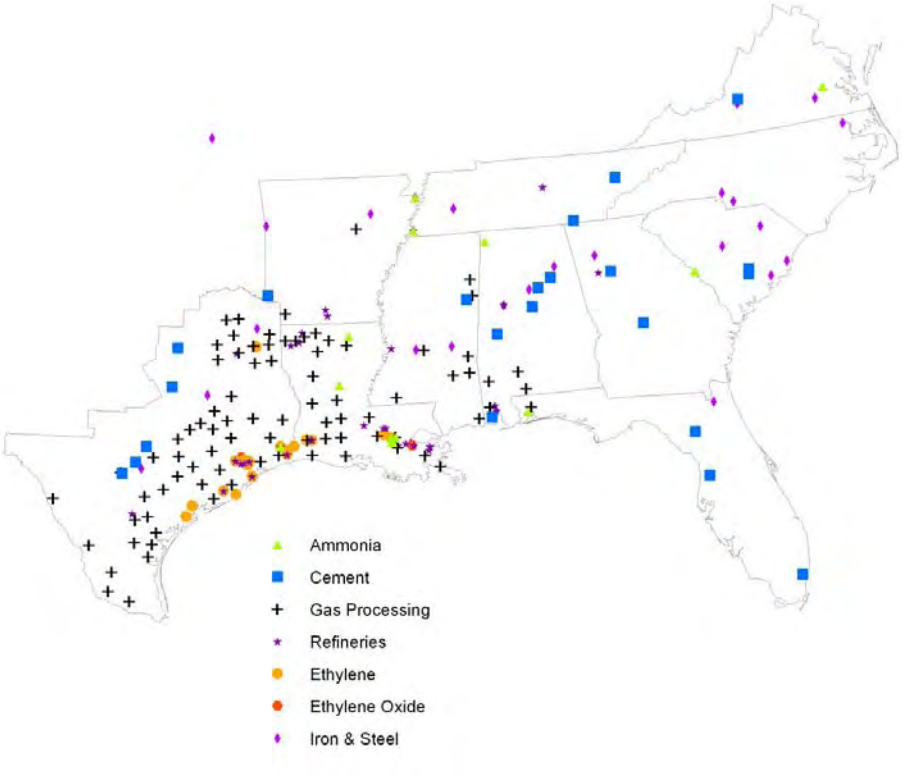


Figure 2-2: Non-Power Stationary CO_2 Sources



2.3.2 Non-Power Stationary CO_2 Sources

The SECARB region also hosts a variety of non-power stationary CO_2 sources. Figure 2-2 shows the geographical distribution of the non-power stationary CO_2 sources included in the database. The following of this section briefly summarizes each type of these non-power stationary CO_2 sources in the database.

Ammonia Plants

The ammonia plant database was updated with the latest available numbers from the International Fertilizer Development Commission (IFDC). The most recent numbers were released in October 2004. This database was cross-referenced with the ECOFYS database to determine the locations of facilities. In addition, the USGS GNIS database was used to locate facilities not included in the ECOFYS database. Table 2-4 summarizes the ammonia facilities in the study area by state.

Table 2-4: Ammonia Plant Capacity and Estimated CO_2 Emissions by State

State	Number	Capacity (kt/yr)	Estimated CO_2 Emissions (kt/yr)
AL	1	193	218
AR	1	467	527
FL	1	86	97
GA	1	758	856
LA	8	5,605	6,334
MS	0	0	0
NC	0	0	0
SC	0	0	0
TN	1	409	462
TX*	1	255	288
VA	1	584	660
Total	**15**	**8,357**	**9,443**

* eastern Texas

Cement Plants

The cement plant database was revised with new data from the Portland Cement Industry Association. The most recent database (December 2001) was used. This database was cross-referenced with the ECOFYS database to determine the locations of facilities. In addition, the USGS GNIS database was used to locate facilities not included in the ECOFYS database. Table 2-5 summarizes the cement production facilities in the study area by state.

Table 2-5: Cement Plant Capacity and Estimated CO_2 Emissions by State

State	Number	Capacity (kt/yr)	Estimated CO_2 Emissions(kt/yr)
AL	5	5,308	3,981
AR	1	803	602
FL	4	3,158	2,369
GA	2	1,355	1,016
LA	0	0	0
MS	1	419	314
NC	0	0	0
SC	3	2,725	2,044
TN	2	1,436	1,077
TX*	9	9,917	7,438
VA	1	1,120	840
Total	**28**	**26,241**	**19,681**

* eastern Texas

Refineries

The online database of the Energy Information Agency (EIA) of the US Department of Energy (DOE) was used to revise capacity estimates of refineries in the study area. The ECOFYS database was used for plant locations, with the USGS GNIS used to verify and update the location of new facilities. Table 2-6 summarizes the refineries in the study area by state.

Table 2-6: Refinery Capacity and Estimated CO_2 Emissions by State

State	Number	Capacity (1000 barrels / stream day)	Estimated CO_2 Emissions(kt/yr)
AL	3	130	1,289
AR	2	97	955
FL	0	0	0
GA	1	34	332
LA	16	2,452	24,275
MS	1	227	2,242
NC	0	0	0
SC	0	0	0
TN	1	120	1,188
TX*	16	3,002	29,719
VA	1	250	2,475
Total	**41**	**6,311**	**62,475**

* eastern Texas

Gas Processing Facilities

The database for gas processing facilities used data from the 2003 Oil and Gas Journal Gas Processing survey. This database was cross-referenced with the ECOFYS database to determine the locations of facilities. In addition, the USGS GNIS database was used to locate facilities not included in the ECOFYS database. Table 2-7 summarizes the gas processing facilities in the study area by state. The estimated CO_2 emissions in Table 2-7 are calculated using the CO_2 emission factor given in Table 2-2.

Table 2-7: Gas Processing Capacity and Estimated CO_2 Emissions by State

State	Number	Capacity (MMCFD)	Estimated CO_2 Emissions(kt/yr)
AL	9	766	466
AR	2	872	531
FL	1	90	55
GA	0	0	0
LA	47	10,015	6,092
MS	9	1,876	1,141
NC	0	0	0
SC	0	0	0
TN	0	0	0
TX*	96	12,455	7,577
VA	0	0	0
Total	**164**	**26,074**	**15,862**

* eastern Texas

However, the CO_2 emission rate from gas processing facilities is highly dependent on the percentage of CO_2 in the gas being processed by each facility. Initial analysis indicate that gas processing facilities in the SECARB region are likely to emit less CO_2 than is estimated in this study using the ECOFYS emissions factor. In order to better estimate these emissions, the USGS organic geochemistry database has been obtained. This database contains the CO_2 concentrations of the gas wells in the study area. Phase II analyses will provide better CO_2

emissions estimates for the gas processing facilities by revising the CO_2 emissions factors using the USGS organic geochemistry database.

Ethylene, Ethylene Oxide, and Iron and Steel Plants

The ECOFYS database contained the most detailed and up to date datasets for ethylene, ethylene oxide, and iron and steel plants. ECOFYS got the ethylene information the Oil & Gas Journal's *Ethylene Report* (April 2001), the ethylene oxide information from the ChemWeek (www.chemweek.com), and the iron and steel information from the 2001 *World Steelworks Survey*. The information from these databases was not supplemented with any additional sources. Table 2-8 summarizes the plant capacity and the estimated CO_2 emissions for these three types of non-power CO_2 sources by states.

Table 2-8: Ethylene, Ethylene Oxide, and Iron and Steel Plants Capacity and Emissions Estimate by State

State	Iron and Steel			Ethylene			Ethylene Oxide		
	Number	Capacity (kt/yr)	CO_2 Emissions (kt/yr)	Number	Capacity (kt/yr)	CO_2 Emissions (kt/yr)	Number	Capacity (kt/yr)	CO_2 Emissions (kt/yr)
AL	5	3,739	549	0	0	0	0	0	0
AR	4	2,115	310	0	0	0	0	0	0
FL	1	356	52	0	0	0	0	0	0
GA	1	712	105	0	0	0	0	0	0
LA	1	712	105	5	3,547	8,619	4	1,730	882
MS	2	401	59	0	0	0	0	0	0
NC	3	890	131	0	0	0	0	0	0
SC	4	2,992	439	0	0	0	0	0	0
TN	3	1,602	235	0	0	0	0	0	0
TX*	6	2,271	333	19	16,870	40,994	7	2,255	1,150
VA	2	1,647	242	0	0	0	0	0	0
Total	**32**	**17,437**	**2,560**	**24**	**20,417**	**49,613**	**11**	**3,985**	**2,032**

* eastern Texas

3 SECARB CO_2 STORAGE CAPACITY ANALYSIS

This section presents the theoretical principles supporting the baseline estimation of CO_2 storage capacity in the SECARB region. Methods were developed to estimate the CO_2 storage capacity of three different types of geological sinks:

- Hydrocarbon (oil & gas) reservoirs
- Saline aquifers
- Coalbeds

These methods were integrated into software tools for use with ArcGIS modeling software. These standardized capacity tools were then used with the collected SECARB data to estimate the total CO_2 storage capacity of the geological sinks in the study region.

Table 3-1: Data Source for Geologic Sinks

Category	Data Source	Details
Oil & Gas Fields (Texas, Louisiana)	University of Texas at Austin, Bureau of Economic Geology (UTBEG)	- Fields outlines - Fields located - Cumulative production - Reservoir depth - API gravity - Reservoir pressure
Oil & Gas Fields (Alabama, Mississippi)	Alabama Geological Survey (AGS)	- Fields located - Cumulative production - Example reservoir depth - API gravity - Example reservoir pressure
Oil & Gas Fields (Other States)	Gas Information System (GASIS)	- Fields located - Cumulative production - Reservoir depth - API Gravity - Reservoir Pressure
Coalbeds	United States Geological Survey (USGS)	- Coalbeds located - Coalbeds outlines
	Alabama Geological Survey (AGS)	- Coalbeds located - Coalbeds outlines - Reservoir depth - Cumulative gas production - Coal rank
	Virginia Center for Coal and Energy Research, Virginia Tech	- Coalbeds outlines - Coalbeds located - Coalbed wells located
Saline Aquifers	the University of Texas at Austin, Bureau of Economic Geology (UTBEG)	- Aquifers outlines - Aquifers located - Depth - Thickness - Reservoir porosity

Table 3-1 provides a summary of the data used to construct the SECARB database for each geologic sink category. The GASIS database provides general information on the oil and gas

fields in much of the SECARB region, but more detailed databases were used when available. Texas and Louisiana oil and gas data was prepared by the University of Texas at Austin, Bureau of Economic Geology (UTBEG). The oil and gas information for Alabama and Mississippi was prepared by the Alabama Geological Survey (AGS). The UTBEG saline aquifer CO_2 storage analysis dataset was also used in this report. The general USGS coalbed data was supplemented with detailed coalbed methane reservoir information provided by the AGS.

The storage capacity estimation methods in the JOULE II report (Holloway, *et.al.*, 1996) were adapted as the baseline models in estimating the CO_2 storage capacity for hydrocarbon reservoirs and saline aquifers, while the methodology developed by Reeves (2003) was used as the baseline model in estimating the CO_2 storage capacity for coalbeds. These baseline models were modified to accommodate the availability of information in the existing data set.

3.1 CO_2 STORAGE IN HYDROCARBON RESERVOIRS

3.1.1 CO_2 Storage Capacity of Hydrocarbon Reservoirs

A significant amount of pore space is vacated in underground hydrocarbon reservoirs when hydrocarbons are produced from the reservoir. CO_2 can be stored in the pore space left vacant by the hydrocarbon production. The CO_2 storage capacity of each reservoir depends on the amount of hydrocarbon fuel produced from the reservoir, with the total expected future storage capacity dependant on the total expected hydrocarbon production. In order to estimate storage capacity an assumption was made in this study that the entire underground volume of the hydrocarbons produced from a reservoir can be replaced by CO_2. Therefore, the future CO_2 storage capacity of a hydrocarbon reservoir can be calculated from *the underground volume of the ultimately recoverable oil and gas*.

Not every hydrocarbon reservoir is suitable for CO_2 storage, and reservoirs were only analyzed for CO_2 storage if the initial pressure and temperature were above the critical point of CO_2. If the pressure and temperature of the reservoir were unknown, the reservoirs were only analyzed if they were at a depth of 3,000 feet or greater. The generalized theoretical formula adopted in estimating the CO_2 storage capacity of a hydrocarbon field with depth over 3,000 feet can be expressed as:

$$Q_{CO2} = (V_{Uoil} + V_{Ugas}) * \rho_{CO_2} \tag{3.1}$$

where Q_{CO2} = CO_2 storage capacity (Mt CO_2)
V_{Uoil} = underground volume of the ultimately recoverable oil (km^3)
V_{Ugas} = underground volume of the ultimately recoverable gas (km^3)
ρ_{CO_2} = CO_2 density at the reservoir conditions (kg/m^3)

The CO_2 density at the reservoir conditions was calculated using correlations from V. V. Altunin (1975) that assumes the CO_2 density is a function of the pressure and temperature of the reservoir[6].

The underground volumes of oil and gas in equation (3.1) are calculated from the standard volumes of oil and gas based on the following conversion formula:

$$V_{Uoil} = V_{oil(st)} * B_o \tag{3.2}$$

$$V_{Ugas} = V_{gas(st)} * B_g \tag{3.3}$$

where $V_{oil(st)}$ = volume of oil at standard conditions (km^3)
$V_{gas(st)}$= volume of gas at standard conditions (km^3)
B_o = oil formation volume factor
B_g = gas formation volume factor

In this study, a default B_o of 1.2 is applied for oil. B_g is estimated using the following equation:

$$B_g = (4.8\,P + 93.1)^{-1} \tag{3.4}$$

where P = the reservoir pressure (MPa).

Data on the underground volume of the ultimately recoverable oil and gas in a field is generally not available, so equation (3.1) usually cannot be directly applied to estimate the CO_2 storage capacity of hydrocarbon fields. But in cases information on the amount of original oil in place (OOIP) or original gas in place (OGIP) is known, the ultimately recoverable oil or gas can be estimated as a proportion of OOIP or OGIP.

$$V_{Uoil} = V_{OOIP} * p_{oil} \tag{3.5}$$

$$V_{Ugas} = V_{OGIP} * p_{gas} \tag{3.6}$$

where V_{OOIP} = underground volume of original oil in place (km^3)
V_{OGIP} = underground volume of original gas in place (km^3)
$p_{oil/gas}$ = volume percentage of OOIP/OGIP that are recoverable (%)

According to the JOULE II report, the average underground volumes of the ultimately recoverable oil and gas are approximately 35% of OOIP and 80-90% of OGIP, respectively. Therefore, when OOIP and OGIP information is available, equation (3.1), together with equations (3.5) and (3.6) give the formula to estimate the CO_2 storage capacity in hydrocarbon fields.

[6] The CO_2 density was calculated using a computer code developed by Victor Malkovsky of the Institute of Geology of Ore Deposits, Petrography, Mineralogy and Geochemistry (IGEM) of the Russian Academy of Sciences, Moscow. We converted his FORTRAN code into Visual Basic.

3.1.2 The Adopted "Conservative" Approach

In most cases, information on the OOIP and OGIP for a reservoir is also not available. The best data that is available is the cumulative oil and gas production up to the date when the data was collected. To make use of this data, the cumulative production of oil and gas was used to replace the ultimately recoverable oil and gas in equation (3.1). This methodology will result in an underestimation of the CO_2 storage capacity, particularly for fields that are in early stages of production. However, this approach provides the ability to calculate consistent estimates of the CO_2 storage capacity for most of the oil and gas fields using available data. Using this methodology, equation (3.1) can be rewritten as:

$$\tilde{Q}_{CO2} = (\tilde{V}_{Uoil} + \tilde{V}_{Ugas}) * \rho_{CO_2} \tag{3.7}$$

where $\tilde{Q}_{CO2}$ = CO_2 storage capacity (Mt CO_2)

$\tilde{V}_{Uoil}$ = underground volume of the cumulative oil production (km^3)

$\tilde{V}_{Ugas}$ = underground volume of the cumulative gas production (km^3)

Equation (3.7) was then used as the baseline formula in estimating the CO_2 storage capacity for hydrocarbon reservoirs.

3.1.3 Categorizing the CO_2 Storage Potential for Hydrocarbon Reservoirs

Oil and gas reservoirs were classified into different types in terms of their depths and API gravities. Reservoirs that are at least 3000 feet[7] deep are under enough pressure for supercritical CO_2 injection, so this depth is used as an initial criterion for determining whether hydrocarbon fields have CO_2 storage potential. The API gravity, a measurement of oil density which indicates CO_2 miscibility, is used to determine the EOR potential for oil fields. Oil fields with API gravity more than 25° are classified as fields with miscible CO_2-EOR potential. Oil fields with API gravity between 17.5^o and 25° are classified as fields with immiscible CO_2-EOR potential. Based on these criteria, the oil fields can be divided into five categories:

(1) Fields with miscible CO_2-EOR potential (depth > 3000 feet, API>25)
(2) Fields with immiscible CO_2-EOR potential (depth > 3000 feet, 17.5<API<25)
(3) Fields with CO_2 storage potential but no EOR potential (depth > 3000 feet, API<17.5)
(4) Fields without CO_2 storage potential (depth < 3000 feet)
(5) Undetermined Fields (depth or API missing)

[7] 3,000 feet (approx. 914 m) is chosen as a conservative depth threshold. Some studies suggest using 800 m as depth threshold. The result does not differ much from using 800 m as the depth threshold as few fields have depth between 800 m and 914 m.

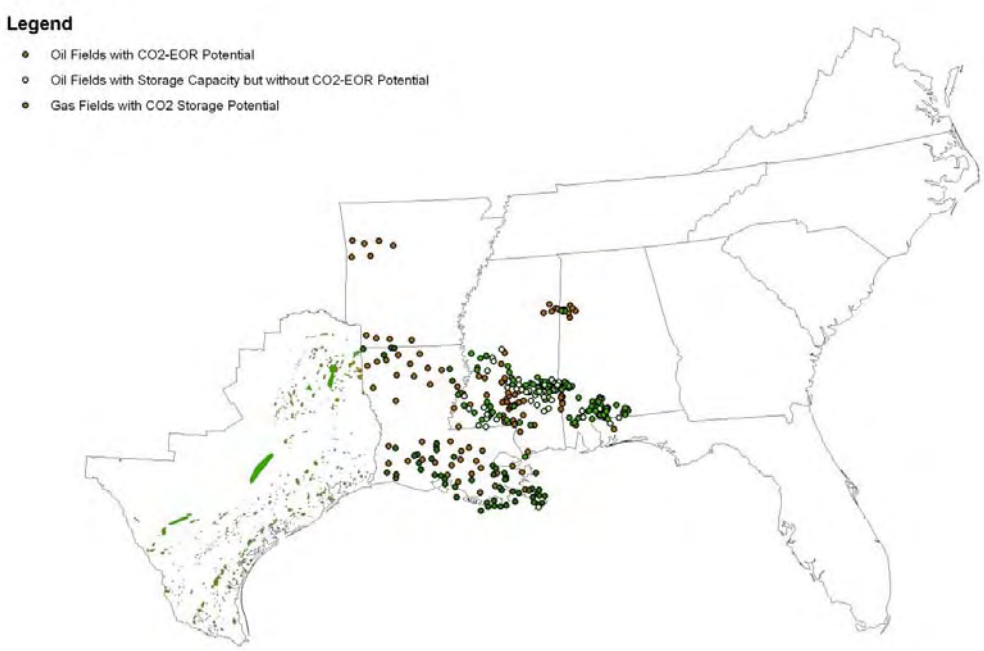
The gas fields are classified into three categories based on the depth information:

(6) Fields with CO_2 storage potential (depth > 3000 feet)
(7) Fields without CO_2 storage potential (depth < 3000 feet)
(8) Undetermined Fields (Unknown depth)

3.1.4 CO_2 Capacity Estimation Results

The methods presented above were then used to estimate the CO_2 storage capacity for oil and gas reservoirs included in the SECARB Phase I database (see Figure 3-1). Panel A of Table 3-2 summarizes the CO_2 storage capacity for oil fields aggregated by the five categories mentioned above. There are 378 oil fields in SECARB region with miscible or immiscible CO_2 EOR potential. These fields with CO_2 EOR potential have a CO_2 storage capacity of 2.3 Gt. The storage capacity of non-EOR oil fields is trivial, amounting to roughly 0.1 Gt.

Figure 3-1: Oil & Gas Fields with CO_2 Storage Capacity in Phase I Database



The CO_2 storage capacity of gas fields, screened by depth, was also estimated using the expression in equation 3.7. Panel B of Table 3-2 shows the storage capacity for gas fields aggregated by the three categories mentioned above. The result yielded 1,662 gas fields with a combined CO_2 storage capacity of 6.2 Gt.

Table 3-2: Estimates of CO_2 Storage Capacity in Oil Fields and Gas Fields

Fields Group	Number of Fields	Estimated Total Storage Capacity (Mt)
A: Oil Fields		
Oil fields with CO_2 storage potential	486	2,389
Oil fields with miscible CO_2-EOR potential	*347*	*2,134*
Oil fields with immiscible CO_2-EOR potential	*31*	*171*
Oil fields with CO_2 storage capacity no EOR potential[1]	*108*	*84*
Oil fields without CO_2 storage potential	44	0
Oil fields without depth information	1,202	0
B: Gas Fields		
Gas fields with CO_2 storage potential	1,662	6,166
Gas fields without CO_2 storage potential	88	0
Gas fields without enough information	740	0

Note:
1. Oil fields that lack API data also included.

Table 3-3 shows the CO_2 storage capacity for oil fields and gas fields, respectively, in each state. Among the 11 states in the SECARB region, 5 states have CO_2 storage capacity in both oil and gas fields and one state (AR) has CO_2 capacity only in gas fields, while the remaining 5 states have no capacity in either category. Among the states with CO_2 storage capacity in oil fields, eastern Texas has the largest share of the storage capacity: with 122 oil fields amounting to a total CO_2 storage capacity of 1.4 Gt. Among the states having gas fields with CO_2 storage potential, Louisiana and eastern Texas dominate the storage capacity. The two states also dominate the total storage capacity in hydrocarbon fields in the region. There are 922 fields with the capacity to store 2.7 Gt of CO_2 in Louisiana, and 556 fields with the capacity to store 2.6 Gt of CO_2 in eastern Texas.

Table 3-3: Estimates of CO_2 Storage Capacity in Oil Fields and Gas Fields by States

States	Oil Fields		Gas Fields	
	Number of Fields	Estimated Total Storage Capacity (Mt)	Number of Fields	Estimated Total Storage Capacity (Mt)
AL	112	66	42	154
AR	-	-	46	347
FL	3	103	2	32
GA	-	-	-	-
LA	79	585	922	2,685
MS	170	229	94	348
NC	-	-	-	-
SC	-	-	-	-
TN	-	-	-	-
TX*	122	1,406	556	2,599
VA	-	-	-	-
Total	**486**	**2,389**	**1,662**	**6,166**

Note:
* eastern Texas

3.2 CO_2 STORAGE IN SALINE AQUIFERS

Deep saline aquifers have the greatest CO_2 sequestration potential since they are the most common and most voluminous type of reservoirs. Two preliminary screening criteria are used to evaluate the CO_2 storage suitability of saline aquifers. The first screening criterion is similar to hydrocarbon reservoirs that the depth of the aquifer needs to be more than 800 m to ensure that the injected CO_2 can be kept at the supercritical phase. Second, the aquifer needs to have good seal properties so that the injected CO_2 can be sufficiently trapped in the aquifer.

If the above two screening criteria are satisfied, the CO_2 storage capacity of a saline aquifer can be calculated using the following formula:

$$Q_{aqui} = V_{aqui} * p * e * \rho_{CO_2} \tag{3.8}$$

where Q_{aqui} = storage capacity of entire aquifer (Mt CO_2)
V_{aqui} = total volume of entire aquifer (km^3)
p = reservoir porosity (%)
e = CO_2 storage efficiency (%)
ρ_{CO_2} = CO_2 density at reservoir conditions (kg/m^3)

If accurate spatial data are available for an aquifer, then the aquifer volume used in equation (3.8) can be calculated as an integral of the surface area and the thickness of the aquifer:

$$V_{aqui} = \sum_i S_i T_i \tag{3.9}$$

where S_i is the area of the raster cell,
T_i is the thickness of the cell,

The term "CO_2 storage efficiency" refers to the fraction of the reservoir pore volume that can be filled with CO_2. For the "closed" aquifer, the storage efficiency is assumed to be 2% (Holloway, 1996).

Figure 3-2 shows the aquifers in the Phase I database that meet the two screening criteria discussed above. Table 3-4 shows the estimates of CO_2 storage capacity in brine aquifers included in the Phase I database. The brine-filled volume of the aquifers in SECARB region is estimated to be 43.5×10^{12} m^3. Most of the areas with brine-filled volume are located in the Gulf Coast Region. If the saline aquifers are assumed to be "closed" then the CO_2 storage efficiency is estimated as 2%, and the CO_2 storage capacity in the aquifers would equal to 498 Gt.

Figure 3-2 Aquifers in the Phase I Database Satisfying the CO_2 Storage Screening Criteria

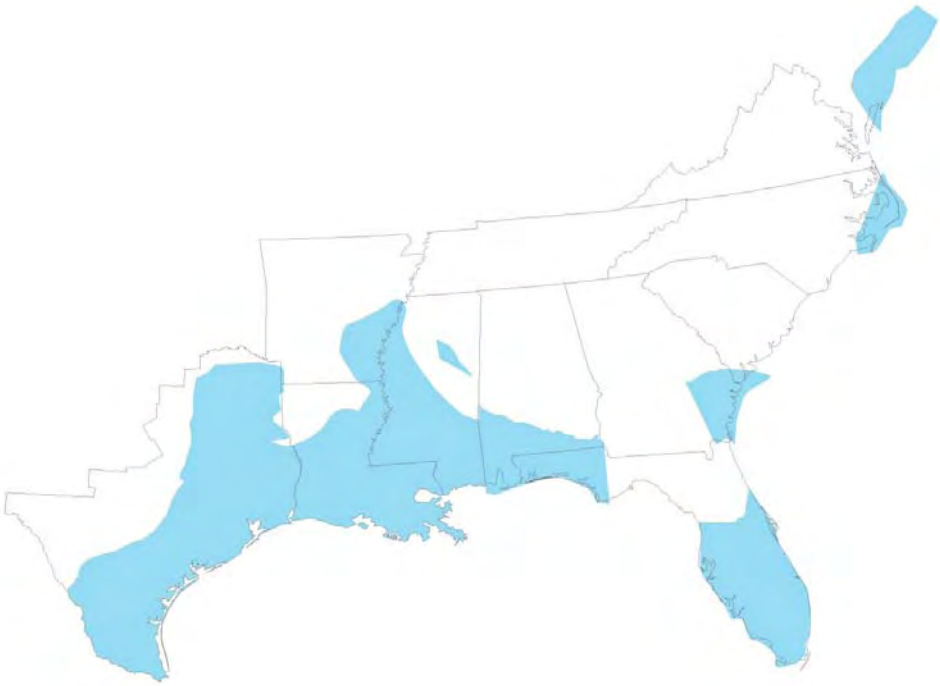


Table 3-4: Estimates of CO_2 Storage Capacity in Brine Aquifers

Basin	Formation	Brine-filled Volume (10^{12} m^3)	Capacity Estimates[1] (Gt)
Gulf Coast Region[2,3]	Upper Cretaceous	17.9	250.9
	Vicksburg & Jackson	5.3	74.2
	Miocene	3.7	51.6
	Subtotal	26.9	376.6
East Texas Basin[4]	Paluxy Sandstone	1.3	10.5
	Woodbine	1.6	14.9
Black Warrior Basin[4]	Pottsville	0.5	5.6
Alabama Gulf Coastal Plain[4]	Tuscaloosa	0.6	4.6
South Carolina Coastal Plain[4]	Cape Fear	1.0	6.5
Central Florida plain[4]	Cedar Keys/Lawson	7.6	55.5
Eastern Costal[4]	Lower Potomac	4.0	23.5
Appalachian Plain[5]		n.a	n.a
Illinois Basin[5]	St. Peter Sandstone	n.a	n.a
Total		**43.5**	**497.8**

Note:
1. CO_2 storage efficiency estimated as 2% and all the aquifer assumed as "closed".
2. There should be 9 plates in the Gulf Coast Region as to the datasets UTBEG is working for. However, only 3 out of the 9 plates can be provided with the detailed information. The report at this stage only includes these 3 plates.
3. Brine-filled volume data for Gulf Coast Region was obtained from UTBEG's estimates, which assumes an average standstone percentage of 23% an average porosty of 30%.
4. Porosity assumed uniformly distributed as the lower range of well samples.
5. CO_2 storage capacity near zero.

3.3 CO_2 STORAGE IN COALBEDS

The CO_2 storage capacity of coalbeds used for CO_2-Enhanced Coalbed Methane Recovery (ECBMR) operations can be estimated using a methodology based on work by Scott R. Reeves (2003). The original methodology developed by Reeves is useful for estimates of storage capacity at the basin level. In this study Reeves's methodology was adapted for use with data collected at the coalfield level.

The principle idea of the CO_2 disposal in coalbeds is that CO_2 can be adsorbed more readily onto the coal matrix than methane. Therefore, the CO_2-ECBMR operation involves adsorbing the injected CO_2 at the expense of methane. The displaced methane can be recovered as a free gas at production wells.

The CO_2 storage potential of a coalbed results from the two primary mechanisms listed below:

- Storage capacity via methane replacement
  In this process, the primary methane production is assumed to create a voidage in the coal reservoir, which can be replaced by CO_2 up to the original pressure of the coal reservoir.

- Incremental storage capacity via ECBMR
  The secondary methane production through CO_2 injection produces additional methane which enables some additional CO_2 storage capacity.

Coalfields are categorized as either "commercial" or "non-commercial" according to the economic feasibility of producing methane from the field. "Non-commercial" areas are areas where ECBMR and CO_2 storage are technically feasible, yet unprofitable. "Commercial" coalfields are those where ECBMR operations are both technically and financially feasible. "Non-commercial" areas are usually deeper, have thinner coals, and are less permeable than the "commercial" areas. The storage capacity of "commercial" coalfields results from both primary and incremental methane replacement, whereas the capacity of "non-commercial" coalfields is from incremental methane replacement. Accordingly, different parameters are used to calculate the storage capacity of the two types of fields via ECBMR. Section 3.3.1 and Section 3.3.2 discuss details of the methodology for estimating the CO_2 storage capacity for "commercial" methane fields and "non-commercial" methane fields, respectively.

3.3.1 CO_2 Storage in "Commercial" Methane Fields

3.3.1.1 Storage Capacity via Methane Replacement

CO_2 storage capacity available due to methane displacement can be estimated using a coal-rank based ratio that specifies the ratio of the volume of CO_2 that can be injected per volume of CH_4 produced and the primary recovery factor of methane. Due to concerns about reservoir over-pressurization or the ability to gain adequate reservoir access a Voidage Replacement Efficiency Factor (*e*) is used to reflect the percentage of void space occupied by CO_2.

$$Q_{replacement} = r * e * V_{OGIP} * PRF * \rho_{CO_2} \tag{3.10}$$

where $Q_{replacement}$ = CO_2 storage capacity via methane replacement
r = CO_2/CH_4 ratio
e = Voidage replacement efficiency
V_{OGIP} = original gas in place (volume in standard condition)
PRF = primary recovery factor of methane (%)
ρ_{CO_2} = CO_2 density (in standard condition)

According to Reeves (2003), the baseline value of e is 0.75 and the baseline value of PRF is 65%. Column (2) of Table 3-5 gives the CO_2/CH_4 ratio based on the coal rank.

Table 3-5: Coal Rank, CO_2/CH4 Ratio, and ECBM Recovery Factors

(1)	(2)	(3)	(4)
Coal Rank	**CO2/CH4 Ratio**	**ECBM Recovery Factor ("Commercial" Methane Fields)**	**ECBM Recovery Factor ("Non-Commercial" Methane Fields)**
Low-volatile (LV)	1:1	50%	25%
Medium-volatile (MV)	1.5:1	55%	32%
High-volatile A (HVA)	3:1	61%	37%
High-volatile (HV)	6:1	67%	42%
Sub-bituminous (Sub)	10:1	100%	74%

3.3.1.2 Incremental Storage Capacity via ECBMR

Additional CO_2 storage capacity due to the incremental methane production is estimated using a coal-rank based ratio and the ECBMR recovery factor (expressed as a percentage of in-place resource at the start of CO_2 injection).

$$Q_{ECBM} = r * e * V_{OGIP} * (1 - PRF) * ERF * \rho_{CO_2} \tag{3.11}$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery
r = CO_2/CH_4 ratio
e = Voidage replacement and ECBMR efficiency factor
V_{OGIP} = original gas in place (volume in standard condition)
PRF = primary recovery factor
ERF = ECBM recovery factor
ρ_{CO_2} = CO_2 density (in standard condition)

The baseline values for e and PRF are 0.75 and 65%, respectively, while the ERF depends on the coal rank. Column (3) of Table 3-5 gives the ECBM recovery factor for each type of coal ranks.

3.3.1.3 Overall Storage Capacity for "Commercial" Methane Fields

The overall CO_2 storage capacity for "commercial" methane fields is the sum of equation (3.10) and equation (3.11):

$$Q_{CO_2} = Q_{replacement} + Q_{ECBM} \tag{3.12}$$

3.3.2 CO_2 Storage in "Non-Commercial" Methane Fields

"Non-commercial' methane fields, though not economically viable for primary methane production, can generate room for CO_2 storage via CO_2-ECBMR. By substituting a zero for the PRF in equation (3.11), a modified version of the equation (3.13) can be used to estimate the CO_2 storage capacity for "non-commercial" methane fields.

$$Q_{ECBM} = r * e * V_{OGIP} * ERF * \rho_{CO_2} \tag{3.13}$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery

R = CO_2/CH_4 ratio
e = accessible portion of 'non-commercial' area
V_{OGIP} = original gas in place (volume in standard condition)
ERF =ECBM recovery factor (%)
ρ_{CO_2} = CO_2 density (in standard condition)

The default value for *e* for "non-commercial" methane fields is 0.5 (unlike 0.75 for "commercial" fields). Column (4) of Table 3-5 gives the ECBM recovery factor for "non-commercial" methane fields by coal rank, which is less than the corresponding ECBM recovery factor for "commercial" methane fields within each coal rank type.

3.3.3 The "Adopted" Approach to Estimate the CO_2 Storage Capacity for "Commercial" Methane Fields

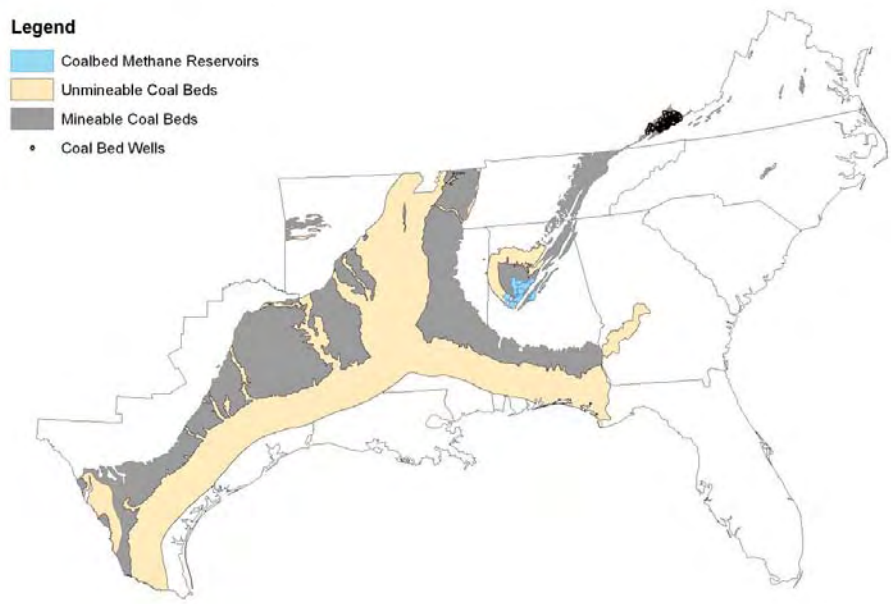
Equations (3.10) and (3.13) use data on the original gas in place in order to estimate the CO_2 storage capacity of methane fields. Just like the case with hydrocarbon fields, however, this data is generally unavailable. For "commercial" methane fields, however, data usually available pertain to the cumulative gas production to date. This cumulative gas production data is used as a lower bound of the ultimately recoverable gas—equivalent to the term "V_{OGIP}*PRF" in equation (3.10). By using this lower bound value of the ultimately recoverable gas, equation (3.14) gives a very conservative estimate of the CO_2 storage capacity for "commercial" methane fields. Since little data is available for "noncommercial" methane fields, equation (3.13) is used to estimate the CO_2 storage capacity.

$$Q_{ECBM} = r * e * \tilde{V}_{CGP} * [\frac{PRF + (1 - PRF) * ERF}{PRF}] * \rho_{CO_2} \qquad (3.14)$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery
r = CO_2/CH_4 ratio
e = Voidage replacement and ECBMR efficiency factor
$\tilde{V}_{CGP}$ = cumulative gas production (volume in standard condition)
PRF = primary recovery factor
ERF = ECBM recovery factor
ρ_{CO_2} = CO_2 density (in standard condition)

Equation (3.14) was used to estimate the CO_2 storage capacity of "commercial" methane fields using cumulative gas production data. The limitation of this approach was that it underestimated the CO_2 storage capacity for "commercial" methane fields, particularly for those in their early stage of production. Moreover, it could not be applied to "noncommercial" methane fields since these fields have no gas production. In Phase II of the study, effort will be put into collecting original gas in place data for methane fields so that the theoretically more sound formulas (3.12) and (3.13) can be used for both "commercial" and "noncommercial" methane fields.

Figure 3-3: Coalbeds in the Phase I Database



3.3.4 CO_2 Coalbed Storage Capacity Estimate Results

The primary dataset on coalfields used in this study was the USGS coal dataset (see Figure 3-3). This study only considers the unmineable coldbeds as potential CO_2 storage sites. As mentioned in the above discussion, original gas in place information (or cumulative gas production) and coal rank are required to estimate coalbed CO_2 storage potential. Since this information is not in the USGS coal dataset the CO_2 storage capacity of coalbeds throughout SECARB region was not estimated. More detailed data was available from the Alabama Geological Survey (AGS) regarding coalbed methane reservoirs in Black Warrior Basin. This data was used to estimate coalbed CO_2 storage capacity in this limited region.

Table 3-6 summarizes the CO_2 storage capacity for commercial coalbed methane reservoirs in Black Warrior Basin. The total CO_2 storage capacity is estimated to be 346 Mt, of which 257 Mt is via methane replacement and 88 Mt is via ECBMR. Considering that the Black Warrior Basin only represents a small proportion of the coalbeds in SECARB region, the CO_2 storage capacity for the coalbeds in the whole region could be very substantial. However, an accurate estimation of this capacity was not possible at this time given the limited data available.

Table 3-6: Estimates of CO_2 Storage Capacity for Coalbed Methane Reservoirs in Black Warrior Basin, Alabama

Type	Storage Capacity (Mt)
Storage Capacity via Methane Replacement	257
Incremental Storage Capacity via ECBMR	88
Total Storage Capacity	346

Note:
1. The Black River Basin, AL is the only coalbed counted in these totals.
2. Estimates were not done for the entire region due to limited data availability

3.4 REGIONAL CO_2 STORAGE SUMMARY

Table 3-7 summarizes the estimated CO_2 storage capacity for formations in the SECARB Phase I Database. The total CO_2 storage potential in the southeast region based on current information is estimated to be 507 Gt. Aquifers makeup the largest portion of this storage capacity, far surpassing the capacity of all other types of geological storage sinks.

Table 3-7: Estimates of CO_2 Storage Capacity for Formations in the Phase I Database

Field Group	Number of Fields	Total Storage Capacity (Gt)
Oil fields with CO_2-EOR potential	378	2.3
Oil fields with CO_2 storage capacity but without EOR potential	108	0.1
Gas fields with CO_2 storage potential	1662	6.2
Coalbeds[1]	n.a	0.3
Aquifers	n.a	497.8
Total		**506.7**

Note:
1. Only the Black Warrior Basin, Alabama was included in this estimate.

4 CO_2 CAPTURE COST ESTIMATION

4.1 METHODOLOGY

The study uses the "*Generic* CO_2 *Capture Retrofit*" spreadsheet prepared by *SFA Pacific, Inc*. as the basis for calculating the CO_2 capture cost for stationary CO_2 sources in the SECARB region (see Figure 4-1). These estimates vary according to three key input variables: (1) the flue gas flow rate (in tonnes per hour); (2) the flue gas composition (volume share or weight share of CO_2 in flue gas); and (3) the annual load factor.

The SFA Pacific spreadsheet provides estimates of capture cost in terms of both CO_2 captured and CO_2 avoided. CO_2 captured is the amount of CO_2 captured by the absorber and kept out of the atmosphere; assumed to be 90% of the CO_2 in the flue gas except for ammonia and gas processing facilities, for which capture factor was assumed to be 100% as their flue gas only consists of pure CO_2. However, since the CO_2 capture process requires energy for purification and compression, the CO_2 avoided term subtracts the CO_2 emitted producing this process energy from the total amount of CO_2 captured. The two terms are used differently in CO_2 sequestration analysis. The CO_2 captured term is used for calculations involving the amount of CO_2 being handled, such as for pipeline transportation costs; while theCO_2 avoided term is used for calculations involving the amount of CO_2 withheld from the atmosphere and therefore eligible for possible CO_2 emissions credits.

According to these two measurements, there are also two definitions on the per unit CO_2 capture cost. To avoid ambiguity, this report uses "CO_2 capture cost" to refer to the capture cost measured in per tonne CO_2 captured while "CO_2 avoidance cost" to refer to the capture cost measured in per tonne CO_2 avoided.

Figure 4-1: SFA Pacific CO_2 Capture Cost Tool

Generic Industrial CO2 Capture for Any Large CO2 Flue Gas Stream

April 2005 working draft by Dale Simbeck at SFA Pacific, Inc

Key assumption is that NG is use as the added energy source to make the steam & power required for CO2 capture
This avoides the loss of capacity or increased off-site CO2 emission of supplying additional electric power
Also the high demand of low pressure stripping steam for the amine CO2 stripper, favors a NG cogen boiler

Color codes: **Primary Inputs** | Secondary Inputs | **Key notes or outupts**

April 13, 2005 Version

Existing Industrial Flue Gas
2,054 metirc ton/h total
48.51 million scf/h

Weight %	Analysis	Volume %
75.00%	N2	75.86%
6.50%	CO2	4.18394545%
5.20%	H2O	8.18%
13.30%	O2	11.77%
0.00%	misc	0.00%
100.00%	Total	100.00%

0.936 million mietic tons per year CO2 (based on below input annual capacity factor)

flue gas normally vented
2,054.0 mt/h
133.5 mt/h CO2

Additional Clean-up & booster Compress

clean flue gas
2,225.6 mt/h
133.5 mt/h CO2

New CO2 Absorber
90%

CO2 depleted Flue Gas Vented
2,105.48 mt/h
13.35 mt/h CO2

171.64 mt/h
25.18 mt/h CO2
15% wt% CO2 fuel gas

NG cogen Flue Gas Vented

CO2 rich | amine solvent | CO2 lean

Thus, the CO2 Avoided to the atm
94.98 mt/h CO2

NG Energy Required for CO2 Capture steam & power

Air
162.48 mt/h
Natural Gas

New NG Boiler 95%

high pressure steam
180.24 mt/h
116.434071 MWt
0.68 MWt/mt

New Backpress Cogen ST/gen

50 psig steam
180.24 mt/h
93.18 MWt if
0.52 MWt/mt

New CO2 Stripper

1.50 tons steam/ton CO2 or
1,200 Btu/lb CO2

122.56 MWt LHV in 100% cogen
418.30 MM Btu/h LHV
464.32 MM Btu/h HHV
9.16 mt/h at
23,000 Btu HHV/lb
0.464 MM scf/h NG at
1,000 Btu/scf HHV

Electric Power via 100% cogen@
17.09 lb steam/kWh cogen

23.25 MWe total
38% 8.83 MWe misc booster fan & amine
62% 14.42 MWe CO2 compressor
MWe flue gas boostet compressor

New CO2 Drying Compress

CO2 Captured
120.16 mt/h or
2,884 mt/d
55 MM scf/d

Indirect offsite CO2 from import power generation **11.63** mt/h CO2 assuming
0.5 mt CO2 per MWh electric

Capital Costs		Unit cost basis at 60	mt/h CO2	cost/size factors	Actual unit cost at 120	mt/h CO2	millions of $ 2003 dollars	Notes
NG boiler	$	15	/lb/hr steam	75%	$13	/lb/hr steam	5.0	
cogen ST gen	$	500	/kWe	75%	$420	/kWe	9.8	
Additional cleanup	$	-	mt/h flue gas	75%	$0	mt/h flue gas	-	if SO2, NOx cleanup
Booster compressor	$	800	/kWe	75%	$672	/kWe	-	needed in many cases
CO2 absorber	$	25,000	mt/h flue gas	75%	$21,015	mt/h flue gas	46.8	
CO2 Stripper	$	200,000	mt/h CO2	75%	$168,124	mt/h CO2	20.2	
CO2 Compressor	$	1,000	/kW	75%	$841	/kW	12.1	
					Total process units		93.9	
General Facilities			**20%**	of process units			18.8	20-40% typical
Eng. Permitting & Startup			**10%**	of process units			9.4	10-20% typical
Contingencies			**10%**	of process units			9.4	10-20% typical
Working Capital, Land & Misc.			**5%**	of process units			4.7	5-10% typical
					U.S. Gulf Coast Capital Costs		136.1	
Site specific factor		**110%**	of US Gulf Coast		**Total Capital Costs**		**149.7**	CA costs are likely higher than Gulf Coast

CO2 Costs				MM $/yr	$/Mscf CO2 Capture	$/mt CO2 Cost Capture	$/mt CO2 Cost Avoided	Notes
		80%	**ann load factor**					**high ann load is critical to cost**
Variable Non-fuel O&M		**1.0%**	/yr of capital	1.5	0.09	1.78	2.25	0.5-1.5% typical
Natural Gas	**$**	**5.00**	/MM Btu HHV	16.3	1.02	19.32	24.44	$4- 7/MM Btu **industrial** rate
Carbon Tax	**$**	**10.00**	/ton Carbon	0.3	0.02	0.30	0.38	all electric power made onsite
Total Variable Operating Cost				**18.0**	1.13	**21.40**	27.08	
Fixed Operating Cost		**5.0%**	/yr of capital	7.5	0.47	8.89	11.25	4-7% typical for refining
Capital Charges		**15%**	/yr of capital	22.5	1.40	26.67	33.74	15-25% typical for private investment
			Total CO2 Costs	**48.0**	**3.00**	**56.97**	**72.07**	including return on investment

Note that the difference between capture and avoided CO2 costs is due to the energy required for CO2 capture steam & power

Source SFA Pacific, Inc. **April 13, 2005**

4.2 CO_2 CAPTURE COST FOR FOSSIL FUEL POWER PLANTS

In order to use the SFA Pacific capture cost tool with fossil fuel power plants, an assumption was made that the CO_2 capture cost for such plants varied only as a function of fuel type, design capacity, and operating factor. A further assumption was made *that power plants would operate at 80% of their designed capacity once the capture facility has been installed.* So for each fuel type the CO_2 capture cost only varies based on the plant's design capacity. The fossil power plants were grouped into three categories by fuel type: coal-fired, gas-fired, and oil-fired.[8] The study only analyzed power plants with a design capacity greater than 100MWe.

Table 4-1 provides summary statistics for the fossil fuel power plants in SECARB region by fuel type. The SECARB region hosts 316 power plants with a design capacity over 100MWe. 109 of these power plants are coal-fired, 186 are gas-fueled, and 21 are oil-fueled. The actual total CO_2 emission for these facilities in year 2000 was 862 Mt, while the adjusted (under the assumption of 80% capacity factor) annual CO_2 emission were estimated to be 1,402 Mt.

Table 4-1: Fossil Fuel Power Plants by Fuel Type (Design Capacity>100MWe)

Fuel Type	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP
# of Plants	109	186	21
Total Design Capacity (MWe)	115,412	91,822	17,298
2000 Average Operating Factor[a]	0.64	0.30	0.36
Actual 2000 Total CO_2 Emission (Million tonnes)[b]	684	143	35
Ajusted Total Annual CO_2 Emission (Million tonnes)[c]	862	442	99

Note: [a]Weigted (by design capacity) average operating factor
[b]eGRID published 2000 CO_2 emission based on the actual plant operating factor
[c]Estimated plant CO_2 emssion at 80% operating factor

Two key input variables needed to estimate the CO_2 capture cost for the fossil fuel power plants are the flue gas flow rate and the flue gas composition. Since this specific information was unavailable for all of the power facilities, two further assumptions were used to derive reasonable values for these variables. The two flue gas assumptions were that: (*1) the flue gas flow increases linearly with the design capacity of a power plant; (2) within each fuel-type category, the flue gas composition is independent of the design capacity.* Table 4-2 provides the flue gas flow rate and composition used in the data for each type of fossil fuel power plant.

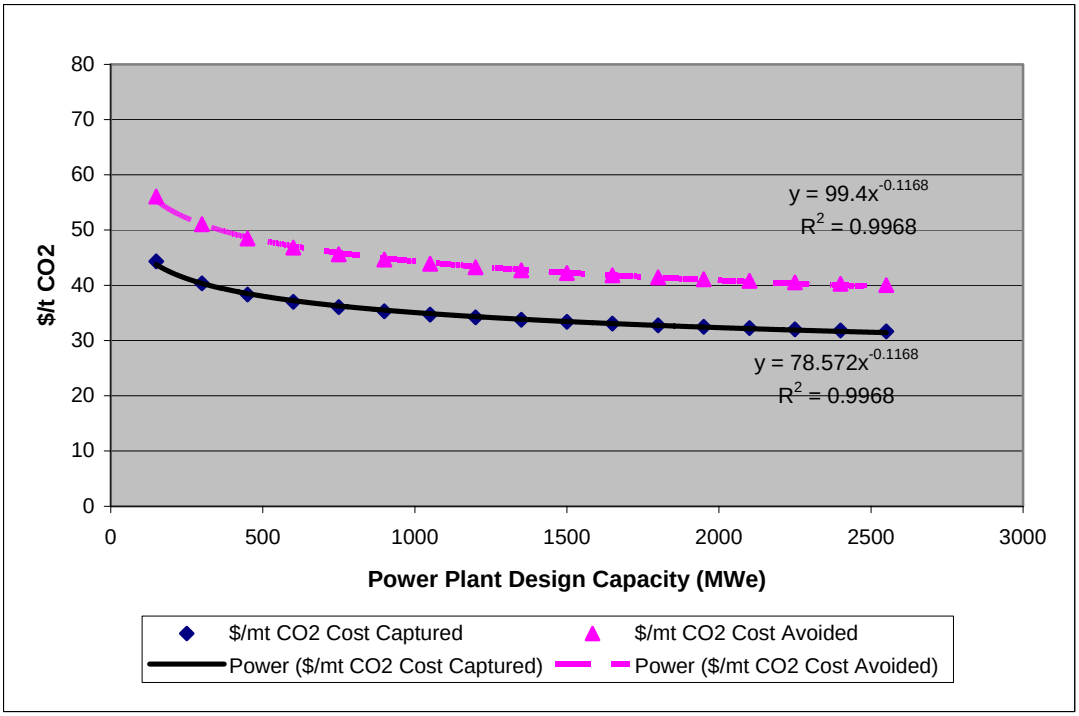
[8] There are few power plants using BL (black liquid) or MWC (municipal waste solid) as primary fuels that have a design capacity slightly above 100 MWe. But the CO_2 emissions from those plants are substantially lower than plants using oil, gas, or coal as primary fuel. Therefore, the analysis is restricted to oil-, gas-, and coal-fueled power plants with design capacity of at least 100MWe.

Table 4-2: Flue Gas Flow Rate and Composition for Coal-, Gas-, and Oil-Fired Power Plants

		Coal-fired PP	Gas-fired PP	Oil-fired PP[1]
Flow Rate (mt/h per 100MW design capacity)		4.06	5.14	4.6
Flue Gas Composition (% in Volume)				
	N_2	73.81%	75.86%	74.84%
	CO_2	15.15%	4.18%	9.67%
	H_2O	8.33%	8.18%	8.26%
	O_2	2.54%	11.77%	7.16%
	misc	0.16%	0.00%	0.08%

Note: [1]Data about oil-fired power plants are MIT Carbon Capture and Sequestration Technologies Program estimates. Others are from SFA, Pacific "*Generic CO_2 Capture Retrofit*" and *"Existing Coal Power Plant CO_2 Migration*" spreadsheets.

Figure 4-2: Estimated CO_2 Capture and Avoidance Costs for Coal-fired Power Plants



Using data derived from the SFA Pacific capture cost estimation tool, Figure 4-2 plots both the CO_2 capture cost and avoidance cost for coal-fired power plants as functions of the plant design capacity. The relationship between CO_2 capture and avoidance costs and the design capacity of the coal-fired power plant can be represented by the following two power functions (with R^2 close to 1):

$$yc = 78.57 * x^{-0.1168} \quad (4.1)$$

$$ya = 99.40 * x^{-0.1168} \quad (4.2)$$

where yc = cost per tonne of CO_2 captured ($/t)
ya = cost per tonne of CO_2 avoided ($/t)
x = design capacity of the coal-fired power plant (MWe)

Taking derivatives on both sides of Equation (4.1), the CO_2 capture/avoidance cost elasticity with respect to plant design capacity is $\frac{dy/y}{dx/x} = -0.1168$. In practical terms this means that due to economies of scale the per unit CO_2 capture/avoidance cost decreases by 0.1168 percent for every 1 percent increase in power plant design capacity.

Figure 4-3 and Figure 4-4 plot the relationship between the CO_2 capture and avoidance costs and plant design capacity for gas-fired and oil-fired power plants, respectively. Table 4-3 summarizes the estimated formula for CO_2 capture and avoidance costs as functions of power plant design capacity for each fuel type category.

Table 4-3: Formula and Range of per tonne CO_2 Capture and Avoidance Cost for Power Plants

Category	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP
# of Facilities	109	186	21
Capacity Range	109~3,969 MWe	100~2,315 MWe	112~2951 MWe
$/t CO_2 Captured Formula	$78.57x^{-0.1168}$	$144.87x^{-0.1564}$	$93.34\ x^{-0.1295}$
$/t CO_2 Avoided Formula	$99.40x^{-0.1168}$	$183.27x^{-0.1564}$	$118.08x^{-0.1295}$
Capture Cost Range ($/t CO_2 captured)	$29.8~$45.5	$43.1~$73.5	$33.2~$50.7
Avoidance Cost Range ($/t CO_2 avoided)	$37.8~$57.5	$54.6~$89.2	$42.0~$64.1

Note: x is the power plant design capacity in MWe.

Figure 4-2: Estimated CO_2 Capture and Avoidance Costs Oil-fired Power Plants

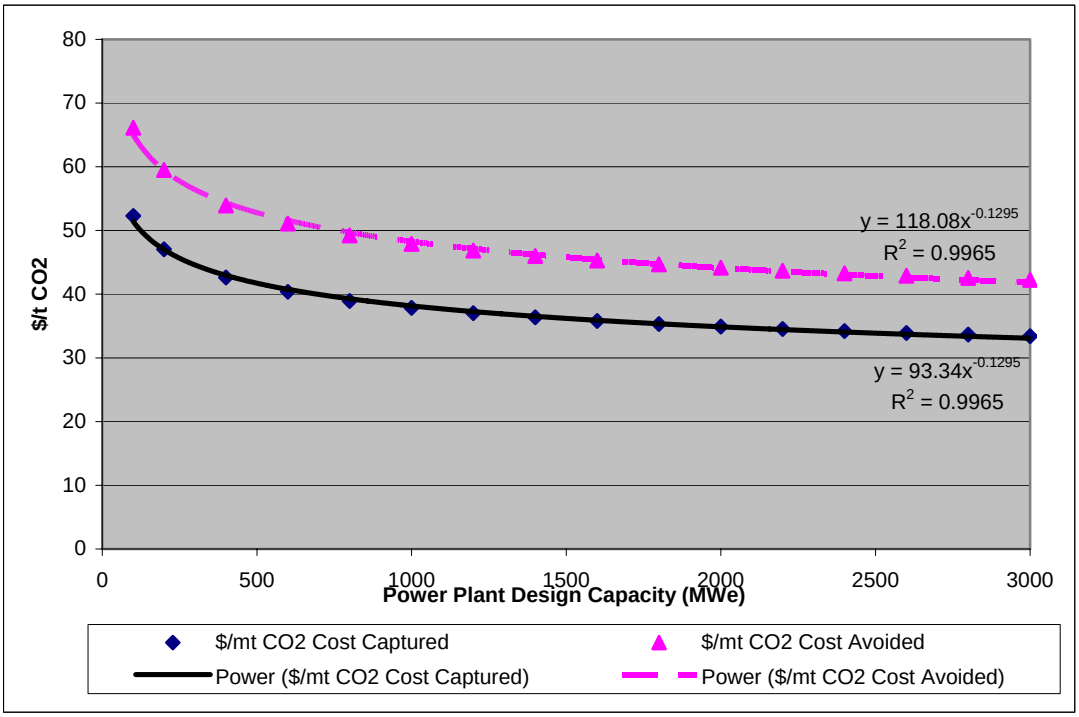
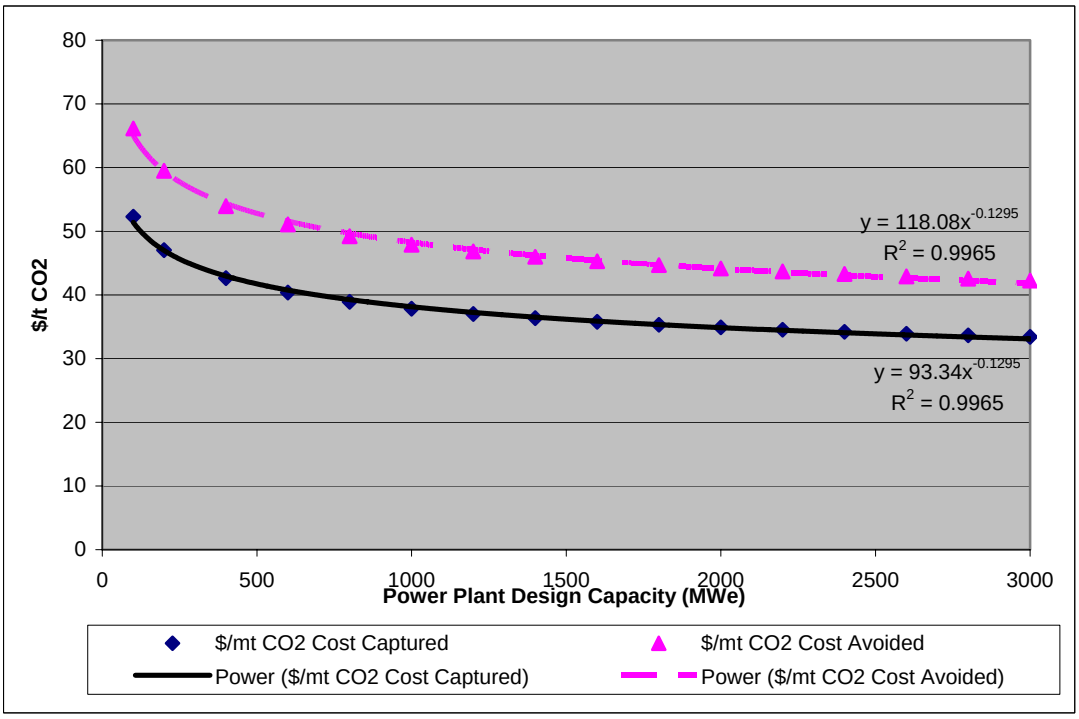


Figure 4-3: Estimated CO_2 Capture and Avoidance Costs for Ammonia Plants



The study applies the above methodology to the fossil fuel power plants with design capacity over 100 MWe in the SECARB region. Column (9) and column (10) in Appendix B present CO_2

capture cost and avoidance cost for these power plants when operated at 80% of design capacity. The capture cost varies from $29.9 per tonne for a 3,970 MWe coal plant to $70.5 per tonne for a 100 MWe gas plant. The avoidance cost varies from $37.8/t to $89.2/t for these same facilities. The capacity-weighted average *capture costs* for all facilities in the SECARB region are $33.8/t, $52.3/t, and $38.4/t for coal, gas, and oil plants respectively. The capacity-weighted average *avoidance costs* for these plants are $42.7/t, $66.2/t, and $48.6/t for coal, oil, and gas plants respectively.

4.3 CO_2 CAPTURE FOR NON-POWER STATIONARY SOURCES

The capture cost estimation tool from SFA Pacific, Inc. was adapted so that it could be used with the non-power sources in the SECARB region. As discussed in Section 4.1, three key variables were needed for the estimation: (1) the flue gas flow rate; (2) the flue gas composition; and (3) the annual load factor. The SECARB database includes seven types of non-power CO_2 sources, but flue gas composition information was only available for the following four facility types: ammonia plants, cement plants, gas processing facilities, and refineries. As a result the analysis was limited to estimating the capture cost for the four facility types listed.

Table 4-4: Assumed CO_2 Emission Factor, Flue Gas Component and Load Factor for Non-power CO_2 Sources

Facility Type	CO_2 Emission Factor	Flue Gas Component (volume)	Annual Load Factor
Ammonia	1.13t CO_2/t Ammonia	100% CO_2	100%
Cement	0.75t CO_2/t Clinker	25% CO_2, 75%N_2	100%
Gas Processing	608t CO_2/mmcfd	100% CO_2	100%
Refineries	9.9t CO_2/BPD	10% CO_2, 90% N_2	100%

Table 4-4 lists the assumed CO_2 emission rates per unit of primary product production, the flue gas composition, and the annual load factor used for each of the four types of non-power CO_2 sources evaluated. The actual flue gas flow rates were unknown, but they were estimated based on plant capacity, the CO_2 emissions factor, and the flue gas composition.

Using these assumptions with the generic SFA CO_2 capture model, Figure 4-5 through Figure 4-8Figure 4-6 plot the per unit CO_2 capture cost and avoidance cost as power functions of facility capacity for each type.

Figure 4-4: Estimated CO_2 Capture and Avoidance Costs for Cement Plants

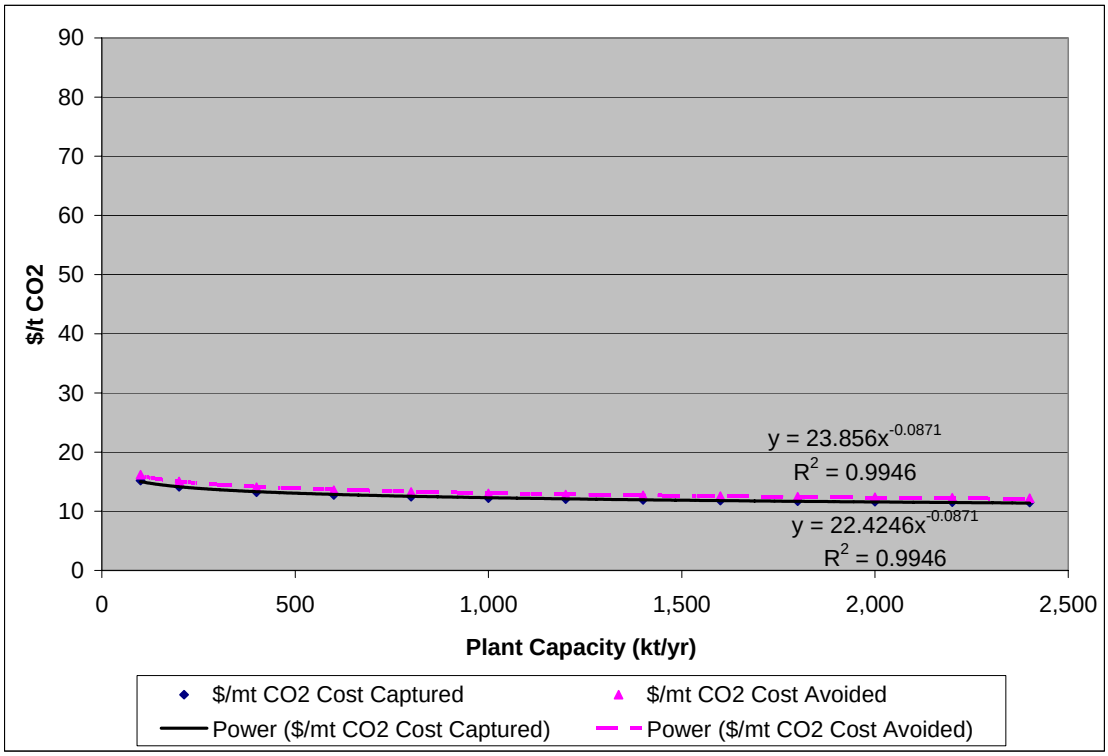


Figure 4-5: Estimated CO_2 Capture and Avoidance Costs for Gas Processing Plants

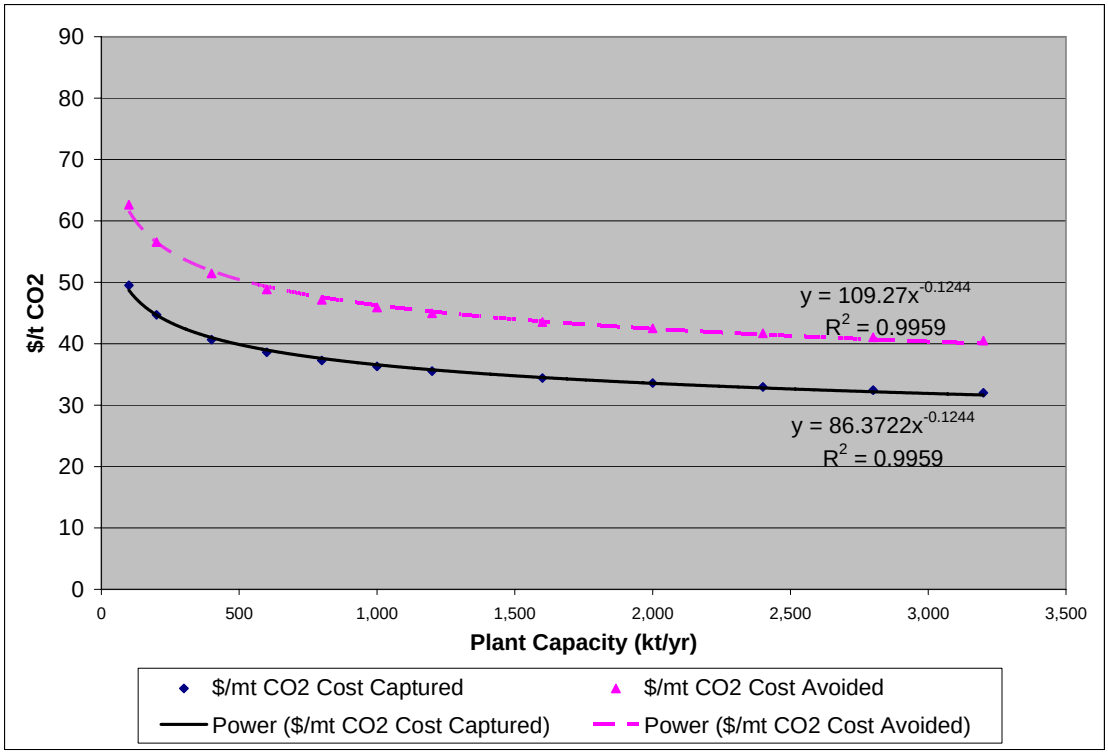


Figure 4-6: Estimated CO_2 Capture and Avoidance Costs for Refineries

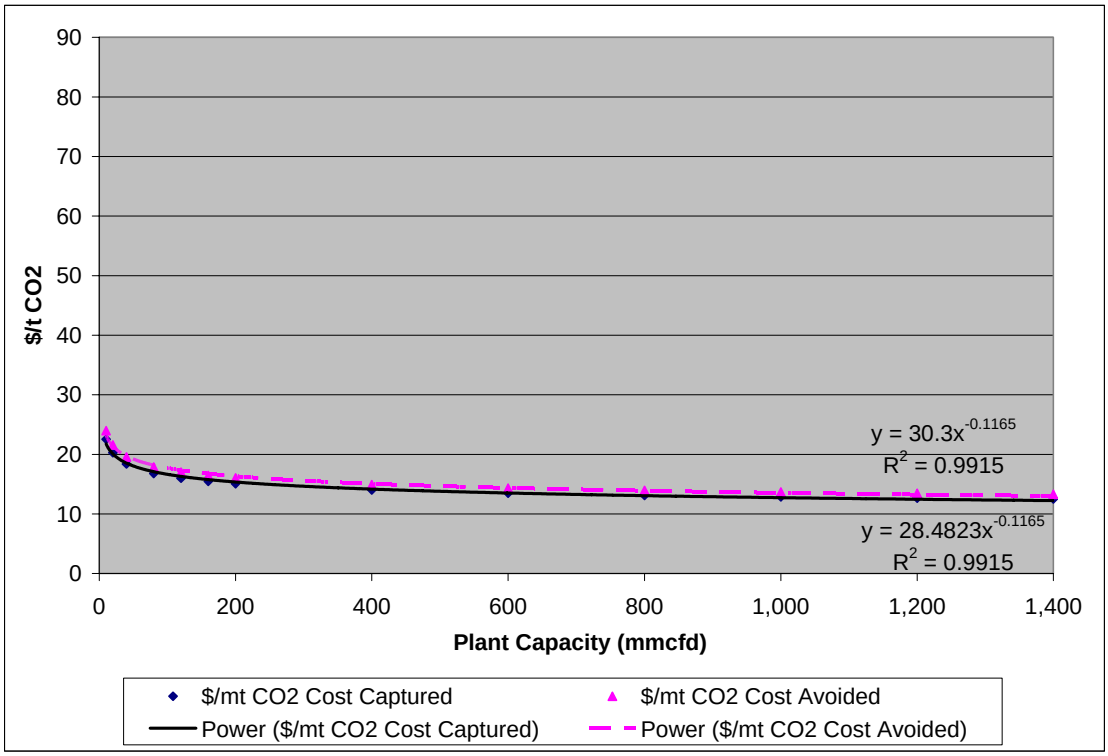
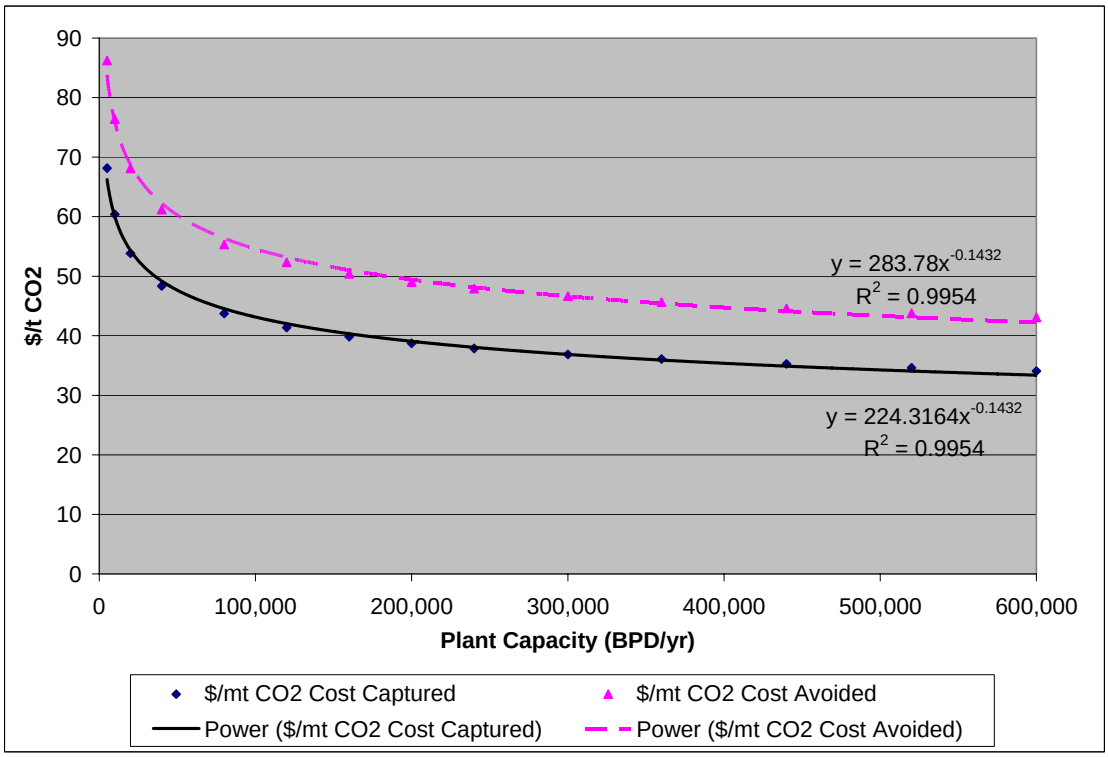


Figure 4-7: Estimated CO_2 Capture and Avoidance Costs for Refineries



Columns (6) and (7) in Appendices B to E show the estimated per tonne CO_2 capture and avoidance costs for the four non-power CO_2 sources in the region[9]. The range of per tonne CO_2 capture and avoidance costs are summarized in Table 4-5 for each category. Since both ammonia and gas processing facilities produce pure CO_2 byproduct streams, CO_2 capture at these facilities only requires gas compression but not gas separation. As a result the CO_2 capture cost at these facilities is less than at either cement or refinery facilities.

Table 4-5: Range of per tonne CO_2 Capture and Avoidance Costs for Four Non-Power Sources[9]

Category	Ammonia	Cement	Gas Processing	Refineries
# of Facilities	13	28	21	41
Capacity Range	90~2,250 kt	100~2,540 kt	300~1,350 MMCFD	5,400~557,000 BPD
Capture Cost Range ($/t CO_2 captured)	$15.2~$11.5	$48.8~$32.6	$14.7~$12.3	$65.5~$33.7
Avoidance Cost Range ($/t CO_2 avoided)	$16.2~$12.2	$61.7~$41.2	$15.6~$13.1	$82.9~$42.7

[9] Gas processing facilities with a design capacity less than 300 mmcfd were excluded.

5 CO_2 PIPELINE TRANSPORTATION COSTS

In cases where the CO_2 source is not co-located with an appropriate sink, large quantities of CO_2 will need to be transported from the source to the sink for sequestration. Underground pipelines are considered the most economical means of transporting such large quantities of CO_2, and a pipeline network would be necessary for carbon sequestration to be feasible. Pipeline construction entails significant capital costs, and this section presents models and methods to estimate the CO_2 pipeline transportation costs based on key pipeline variables.

5.1 TRANSPORT PIPELINE DESIGN CAPACITY

The pipeline design capacity is one of the first design criteria needed for cost estimation. Pipeline capacity is a factor of both pipeline diameter and operating pressure, and pipelines need to be appropriately sized for the CO_2 transportation requirements of their corresponding CO_2 emissions sources. For pipelines originating at refineries, cement plants, the pipeline design capacity is set equal to the 2002 CO_2 emission multiplied by a default capture efficiency (90%). For pure CO_2 streams originating from ammonia and gas processing facilities, the default capture efficiency is set to be 100%. For power plants, the pipeline design capacity is calculated as follows:

$$VC_{CO2} = \frac{VE_{CO2}^{2000}}{OE^{2000}} * CE_0 \tag{5.1}$$

where VC_{CO2} = Maximum CO_2 flow rate (t/yr);
VE_{CO2}^{2000} = 2000 annual CO_2 emission (t);
OE^{2000} = 2000 plant operating factor;
CE_0 = Default CO_2 capture efficiency (90%)

Equation (5.1) gives the maximum CO_2 flow rate (in terms of tonne/yr) for a power plant operating at its full design capacity. The required pipeline capacity is an overestimate since plants usually operate below their maximum design capacity.

Figure 5-1: Maximum Mass CO_2 Flow Rate as a Function of Pipeline Diameter

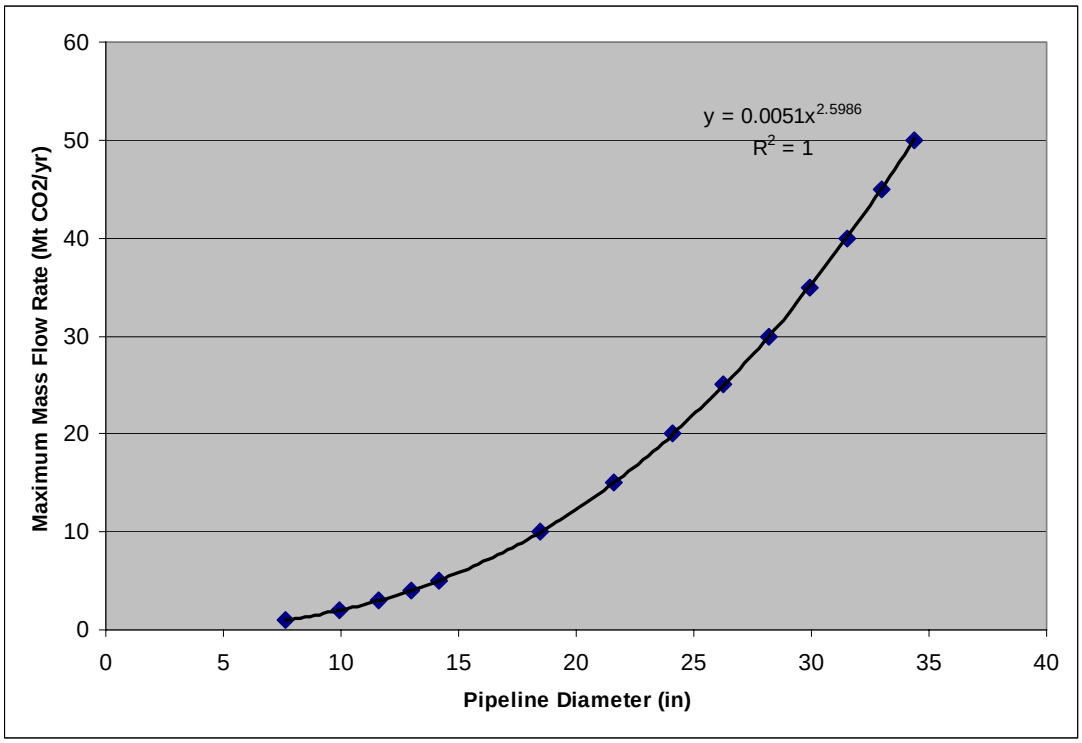


Table 5-1: Pipeline Diameter and the CO_2 Flow Rate Range

Pipeline Diameter (inch)	CO_2 Flow Rate (Mt/yr)	
	lower bound	upper bound
4		0.19
6	0.19	0.54
8	0.54	1.13
12	1.13	3.25
16	3.25	6.86
20	6.86	12.26
24	12.26	19.69
30	19.69	35.16
36	35.16	56.46

5.2 PIPELINE DIAMETER CALCULATION

Figure 5-1 plots the relationship between the maximum mass flow rate and the pipeline diameter. A power function closely models this relationship. In this study it is assumed that standard type gas industry pipelines will be used for CO_2 transportation (True, 1998). Based on the power function in Figure 5-1, Table 5-1 gives the breakdown of the CO_2 flow rate for each pipeline standard diameter within the range from 4 to 36 inches. For any given maximum CO_2 flow rate, Table 5-1 provides a look-up table to determine the appropriate pipeline diameter. Column (5) of the Appendix G provides the corresponding transport pipeline diameter for all sources located in eastern Texas used in the detailed source-sink matching analysis in Section 7.

5.3 OBSTACLE LAYER CONSTRUCTION

In addition to the diameter and capacity, the terrain being traversed by a pipeline is another significant pipeline construction cost variable. These costs vary considerably according to the local terrain and are also affected by the presence of buildings or infrastructure. Pipeline construction is more expensive in hilly areas than on flat plains. In order to reduce complications and costs, a pipeline's route should avoid passing through populated places[10], wetlands, and national or state parks. In order to account for such obstacles in the study, the locations and characteristics of these obstacles were loaded into Geographic Information System (GIS) software. Using the GIS software the costs for traversing such obstacles during pipeline construction were combined into a single obstacle data layer. This obstacle layer reflected three types of general obstacles: land slope, protected areas, and crossings and three line type obstacles: waterways, railroads, and highways.

In order to use this land obstacle data to help calculate optimal pipeline routes, the continuous obstacle data layer was rasterized into 1km by 1km cells. If there were no transportation obstacles contained within a given 1 km^2 cell, then the construction costs of a pipeline traversing the cell was assumed to be "1". From this base case construction cost, relative weights were then assigned to each obstacle in Table 5-2 according to the difficulty of traversing the obstacle. These relative weights were then added to the base case construction cost to form a combined pipeline construction cost factor.

Table 5-2: Estimated Relative Construction Cost Factor

Construction Condition		Cost Factor
Base Case		1
Slope		
	10-20%	0.1
	20-30%	0.4
	>30%	0.8
Protected Area		
	Populated Area	15
	Wetland	15
	National Park	30
	State Park	15
Crossing		
	Wateway Crossing	10
	Railroad Crossing	3
	Highway Crossing	3

Note: The relative weights are calculated as the ratios of the additional construction costs to cross those obstacles and the base case construction cost for an 8 inch pipeline.

The total pipeline construction cost factor for a cell is then the sum of the base case cost factor and the cost factors of all of the obstacles that exist in that cell. For example, the relative cost of

[10] The populated places data is from US Land Use and Land Cover (LULC) data set, which adopts the census definition of "populated place areas" that include census designated places, consolidated cities, and incorporated places within United States identified by the U.S. Bureau of the Census.

a 8 inch pipeline crossing a river in the national park would be 41: 1 (base case) + 30 (national park) + 10 (river crossing). Using the weighted cost layer calculated above, the spatial analysis function in ArcGIS was used to determine the least cost pipeline path for connecting each source and sink.

5.4 PIPELINE TRANSPORT COST ESTIMATION

The model decomposes the pipeline construction cost into two components: the basic pipeline construction cost (diameter-dependent) and the additional obstacle cost (diameter-independent). The basic pipeline construction cost is estimated to be $12,000/in/km[11]. The additional obstacle cost was calculated as the product of the relative weight assigned in Table 5-2 and the basic construction cost of an 8 inch pipeline[12]. The additional obstacle cost does not vary with the pipeline diameter, since the amount of site preparation required for pipeline construction does not vary according to pipeline size. The cumulative pipeline construction cost was then calculated as the sum of the basic construction cost and the additional obstacle cost.

For pipeline operations the pipeline O&M cost was estimated to be $3,100/km per year, regardless of pipeline diameter (Heddle, et.al., 2003). A capital charge of 0.15 was used to annualize the construction cost over the operating life of the pipeline so that the annual pipeline transportation was 0.15 of its construction cost plus the annual O&M cost.

[11] Heddle et al., (2003) estimate that the average pipeline construction cost (including obstacle crossing cost) is $20,989/in/km. For sparsely populated areas average pipeline construction costs are estimated to be $12,400/in/km.

[12] For a 100km 8 inch pipeline with 6 waterway crossings, 1 railroad crossing, 1 highway crossing, and pass 1 km wetland. The estimated construction cost is ($12,000/in/km)*(8 in)*(100km) (base case construction) + $960,000*6 (waterway crossing) + $288,000 (railroad crossing) + $288,000 (highway crossing) + $1,440,000 (wetland crossing) = $17,376,000, which is similar to the average number provided by Heddle: ($20,989/in/km)*(8in)*(100km) = $16,791,200.

6 DISTANCE BASED SOURCE-SINK MATCHING

This section presents the methodology developed to estimate the distance from each CO_2 source to its nearest sink. This methodology was applied to sources and sinks in the SECARB region in order to estimate the transportation requirements for captured CO_2 and to study how these requirements changed as a function of the sink set included in the analysis. The results from this analysis provide estimates of the distance between sources and their closest sinks, but do not consider the transportation costs or optimal pipeline routing when matching, as will be considered in Section 7.

The source-sinking matching in the SECARB region considers 316 power producing CO_2 sources and 103 non-power producing CO_2 sources[13]. Over an assumed 25 year project lifetime, 34 Gt of CO_2 would need to be sequestered[14]. After excluding sinks with less than 5 Mt of storage capacity, the regional CO_2 storage capacity was estimated to be at least 504 Gt. Since the estimated CO_2 storage capacity was significantly larger than the amount of captured CO_2, an assumption was made in this analysis that all sources could be transported and stored in the nearest sinks. The sink storage capacity constraint was considered in the analyses presented in the following section.

Table 6-1 summarizes the CO_2 to be sequestrated for the sources and CO_2 storage capacity for the sinks in the SERCARB region. Figure 6-1 presents a map of all the sources and sinks considered in this section.

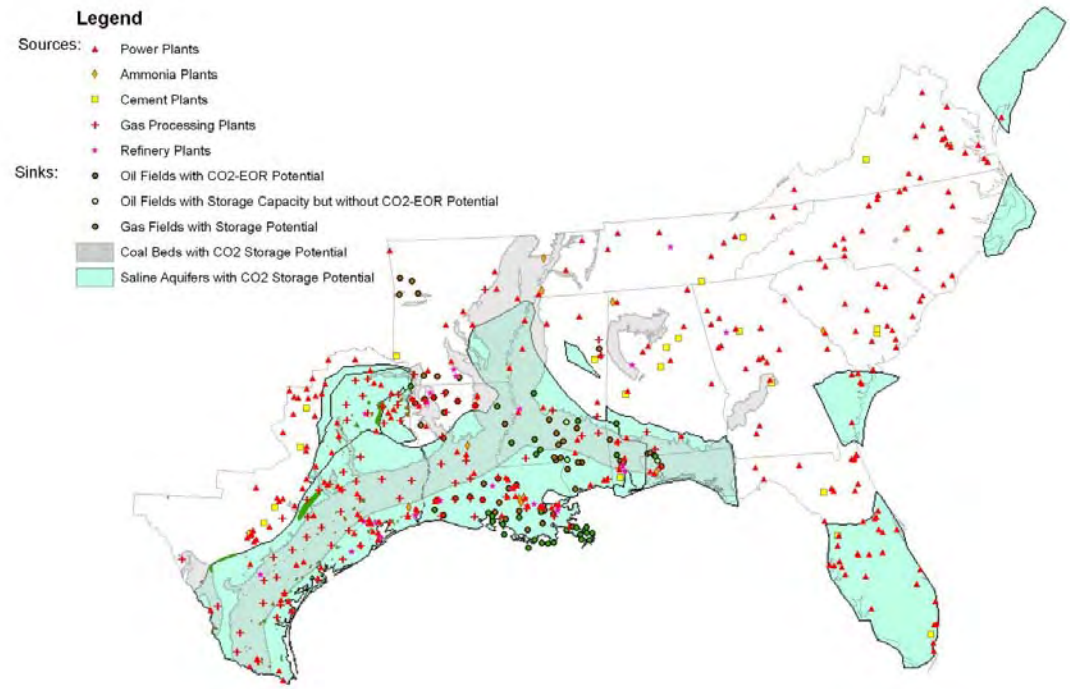
Table 6-1: CO_2 Capture Capacity for Sources and Storage Capacity for Sinks Considered in the Matching Analysis

Field Group		Number of Fields	CO_2 Capture Capacity (Gt)[1]	CO_2 Storage Capacity (Gt)
Sources	Power Plants[2]	316	31.6	-
	Non-power Stationary Sources[3]	103	2.4	-
	Total	419	**33.9**	**-**
Sinks[4]	Oil Fields w/ EOR potential	74	-	1.9
	Oil Fields w/o EOR potential and Gas Fields	246	-	3.6
	Coalbeds[5]	n.a	-	0.3
	Aquifers	n.a	-	497.8
	Total			**503.6**

Note:
1. Project lifetime 25 years.
2. Only design capacity over 100MWe included.
3. Only includes ammonia, cement, gas processing, and refineries. Also, for gas processing facilities, those with design capacity less than 300 mmdcfd were excluded.
4. Only CO_2 storage capacity over 5 Mt included.
5. Only coalbed methane data in Black Warrior Basin, Alabama from AGS included in the estimate.

[13] See note 2 and 3 of Table 6-1 for criteria used in screening CO_2 sources.
[14] The CO_2 emission was estimated under the assumption of 80% capacity factor for power plants and full production capacity factor for non-power stationary CO_2 sources. A capture efficiency of 90% is assumed for all the sources except for the pure CO_2 sources(ammonia and gas processing).

Figure 6-1: CO_2 Sources and Sinks considered in Straight-line Distance Matching



6.1 METHODOLOGY

This analysis was used to calculate the straight-line distance from each CO_2 source to the nearest sink and provides an estimate of the CO_2 storage potential within a given distance from the CO_2 sources. The analysis was performed using GIS software tools. The Straight-Line Distance function in the spatial analyst extension of ArcMap was used to calculate the shortest straight-line distance from each source in the study area to the nearest geological sink. The output from this analysis was a raster layer where the cell values were equal to the straight-line distance from each cell to the nearest sink.

6.2 STRAIGHT-LINE DISTANCE BASED SOURCE-SINK MATCHING IN SECARB REGION

Four hundred and nineteen CO_2 sources, including 316 power plants, 13 ammonia plants, 28 cement plants, 21 gas processing plants and 41 refineries, were included in the source-sink matching analysis. The annual amount of captured CO_2 from these sources was estimated at 1.4 Gt.

The distance matching analysis was performed for each of the five groups of eligible sinks: (1) oil and gas fields with EOR potential; (2) all oil and gas fields; (3) coalbeds; (4) saline aquifers; and (5) all geological sinks.

Table 6-2, Figure 6-2 and Figure 6-3 show the results for the source-sink matching in the SECARB region. Appendix B to Appendix F present the detailed results with the straight-line distance to nearest EOR site, oil & gas field, coalbed and aquifer, respectively, for each CO_2 source. It is interesting to note that the cases with the hydrocarbon reservoirs needed much larger transportation distances than the cases with the saline aquifers and coalbeds. If all of the sinks can be included in the analysis, then all the CO_2 sources can be matched to a sink within 250 km from the source.

Table 6-2: Annual CO_2 Storage Capacity (Mt/y) of Various Sinks by Straight-line Distance from Source to Sink

Sink Type	Straight Line Distance from Source to Sink		
	50 km or less	100 km or less	250 km or less
Oil & Gas Fields with EOR Potential	349	484	675
Oil & Gas Fields	507	598	726
Coalbeds	606	856	1,190
Aquifers	794	867	1,125
All Sinks	**972**	**1,143**	**1,357**

Note:
1. The total annual CO_2 storage rate was 1, 357 Mt.
2. Sinks with less than 5 Mt storage capacity were excluded from the analysis.

Figure 6-2: Marginal Straight-Line Distance to Nearest Sink (4 cases) by Annual Storage Rate for CO_2 Sources

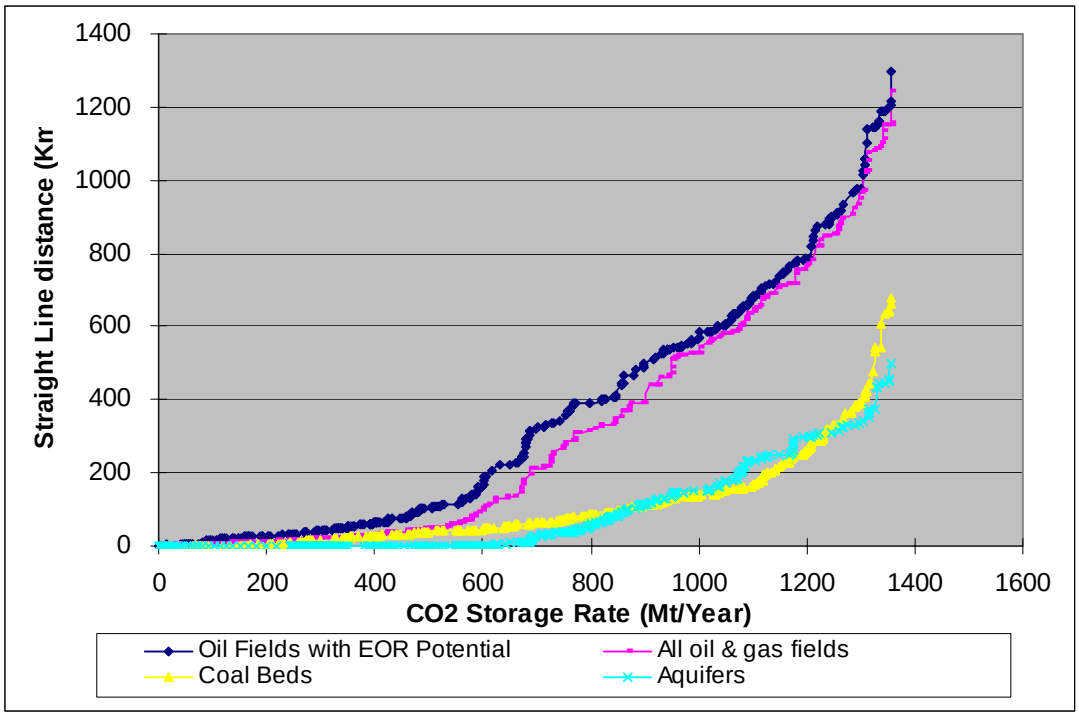
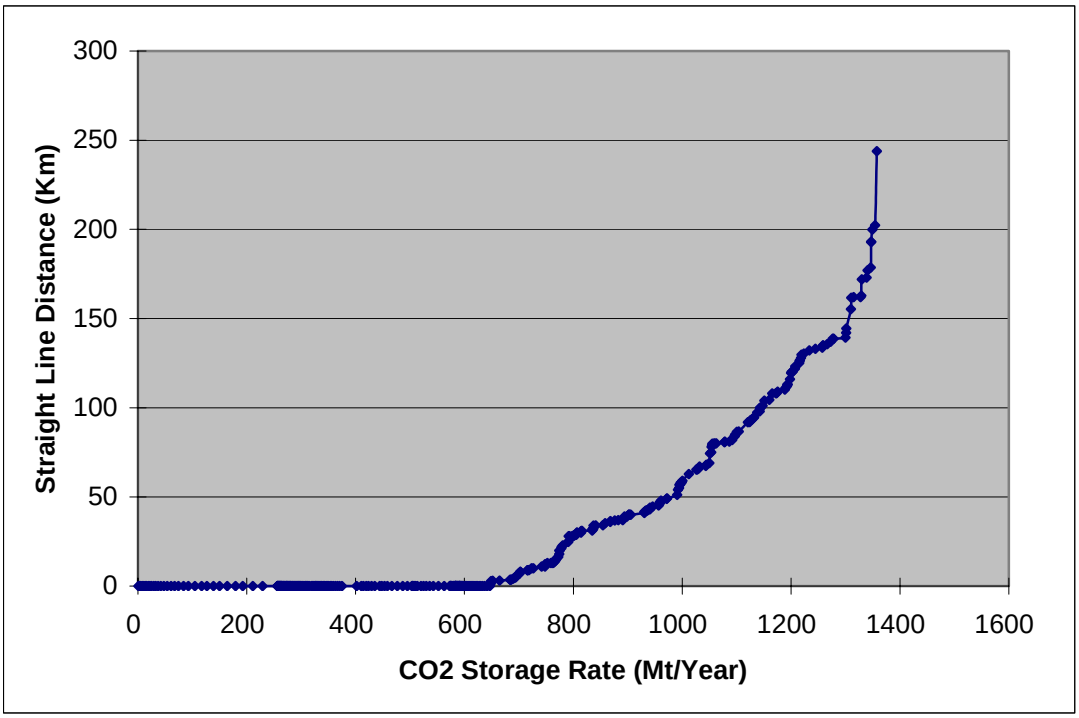


Figure 6-3: Marginal Straight-Line Distance to Nearest Sink by Annual CO_2 Storage Rate for CO_2 Sources



6.3 SOURCE-SINK MATCHING DISCUSSION

This section presented results from analyses of the straight-line distance between sources and sinks in the SECARB region. While these results are not an accurate representation of the total cost for CCS within the SECARB region, the results do provide a sense of the CCS transportation requirements for cases where there is insufficient information for a full cost evaluation. If EOR sites in the SECARB region were the only sinks available for sequestration, only half of the CO_2 sources by volume could be matched with a sink that were less than 250 km from the source. And for some sinks in VA and NC, the closest EOR sinks were over 1000 km far away. If all sink types were considered for sequestration, however then all of the CO_2 sources could be matched with appropriate sinks 250 km from the source. More than 70% of the sources (by volume) would find their nearest sinks within 50 km from the source. Around 40% of the sources were actually co-located with an appropriate sink, which was usually a saline aquifer. The actual transportation distance requirements would be larger if sink capacity constraints and transportation obstacles were considered, and these analyses are presented in the following section.

7 LEAST-COST PATH SOURCE-SINK MATCHING AND FULL COSTING ANALYSIS (EASTERN TEXAS)

In this section, estimates of the total cost of carbon capture and sequestration are calculated by combining the methods presented in sections 4 and 5 for calculating capture and transportation costs with a more detailed method of calculating pipeline paths. Whereas in the previous sections pipeline paths were calculated according to the shortest distance, in this section the pipeline paths were calculated using an iterated GIS-based least-cost path algorithm that considers typography, social, and political data for the study region. This more cumulative sequestration cost analysis, which consists of capture, transport, and injection costs, were performed for eastern Texas due to the limited availability of detailed data for the entire SECARB region. As more detailed data is collected for the other SECARB states in Phase II this least-cost path source-sink matching and full capture cost analyses will be extended to the entire SECARB region.

7.1 METHODOLOGY

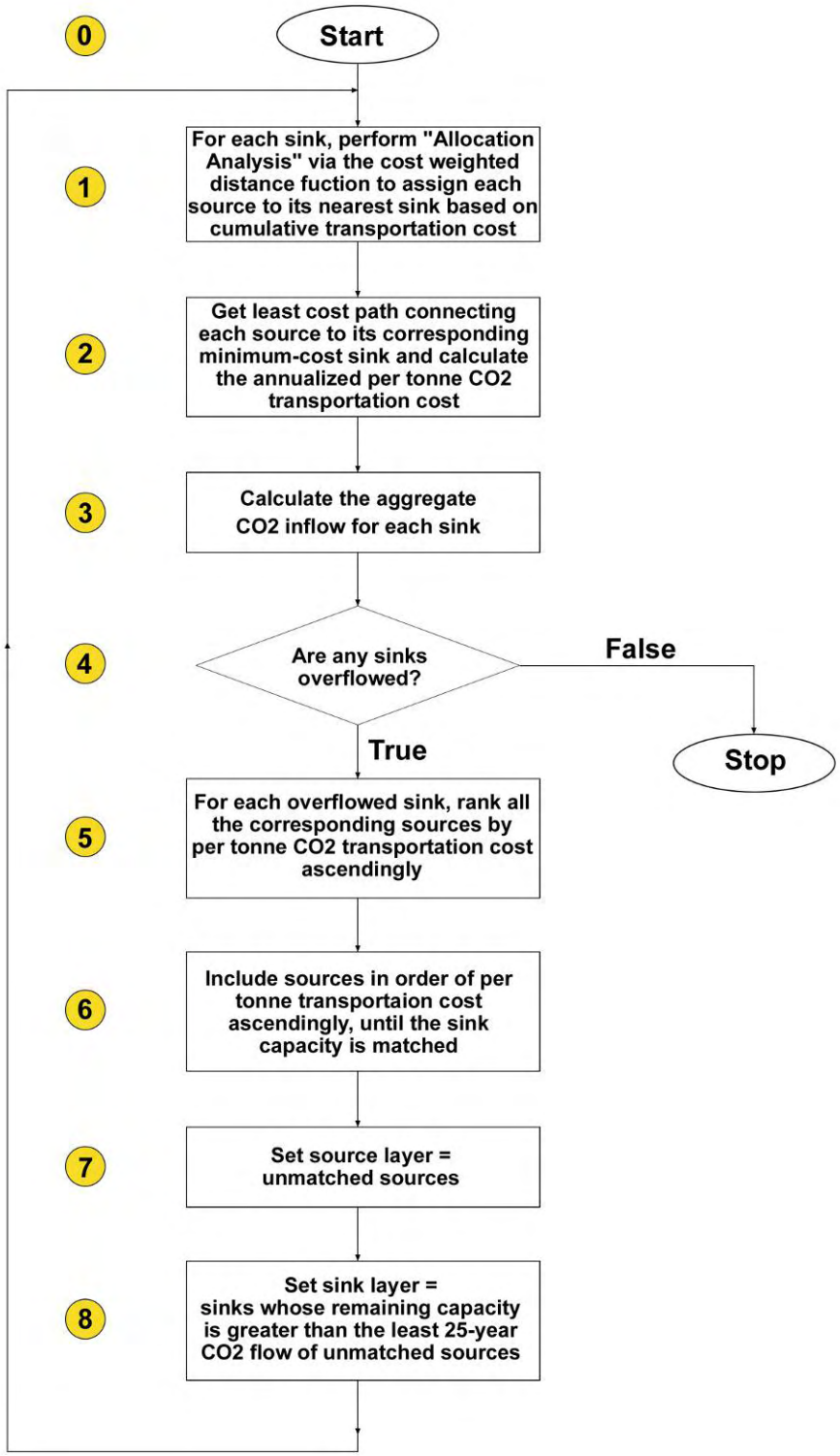
In contrast to the distance-based matching analysis performed in section 6, this section presents a method of matching sources and sinks based on least total cost. For this analysis each CO_2 source in eastern Texas was linked to a least cost geological sink based on a least-cost transportation route and an estimated injection cost. The linking algorithm also considered reservoir storage capacity and ensured that each linked sink had sufficient storage capacity for all sources matched with it.

The list of sinks used in the matching analysis included hydrocarbon fields with EOR potential, hydrocarbon fields without EOR potential and saline aquifers[15]. While all of these sinks are suitable for sequestration, the cost of sequestration varies for each sink type. The sinks can be grouped into two basic categories: (1) oil fields with EOR potential that are eligible for oil production credits, and (2) non-EOR hydrocarbon fields and saline aquifers that will have to bear the full cost for CO_2 transportation, compression, and injection. Projects were assumed to have 25 year lifetimes, and sources were only matched up to a sink if its remaining storage capacity exceeded the source's 25-year CO_2 flow.

The linking analysis was conducted in two stages: first considering cheaper sinks before proceeding to sinks with higher storage costs. In the first iteration only EOR sites were included as potential sinks, since they would purchase CO_2 from a provider. After allocating the EOR storage capacity to the appropriate sources, the matching algorithm was rerun with the regular hydrocarbon fields and saline aquifers included in the list of potential sinks. An algorithm flow chart is shown in Figure 7-1.

[15] There is no coalbed methane fields included in the sink set for eastern Texas.

Figure 7-1: Flow Chart of the Least-cost Path CO_2 Source-Sink Matching Algorithm



An iterative algorithm was developed to "optimize" the source-sink matching using the ArcGIS *"spatial analysis tool."* Figure 7-1 depicts the flow chart for this iterative matching algorithm using an example of stage 1 matching process when only transportation cost needs are considered:

- At the first step, the *"Allocation Analysis*" function was used to assign each source to its nearest sink based on the transportation cost as calculated in section 5. The allocation result provided a picture of how the sources would be optimally linked to the sinks within the region if there were no restriction on the storage capacity of each sink.

- In the second step, the *"Least Cost Path"* function was used to get the least cost path linking each source to its corresponding least-cost sink. Using the transportation cost estimation algorithm discussed in section 5.4, the capital cost and maintenance cost were calculated as the cost per tonne of CO_2 transported.

- In the third step, the 25-year CO_2 flow volumes from all sources assigned to each sink in step 1 were summed up to get the aggregate 25-year CO_2 flow.

- In step 4, the aggregate 25-year CO_2 flow calculated in step 3 was compared to the estimated CO_2 storage capacity for each sink.

    - If none of the sinks were over capacity, then the iteration ended with an approximately "optimal" matching outcome.

    - If some of the sinks were over capacity, the program continued to step 5 to evaluate which sources should be excluded from the "overfilled" sinks.

- In step 5, for each "overfilled" sink, the associated sources were ranked in ascending order by the transportation cost per tonne of CO_2.

- In step 6, the ordered sources for each "overfilled" sink were re-added to the sink's "matched source set" in ascending order of CO_2 transportation cost. Sources were added until the sink's remaining storage capacity was less than the 25-year CO_2 flow of the smallest source assigned to this sink in step 1 that had not been added to the "matched source set."

- In step 7, all of the sources that were not included in "matched source set" for any sinks were set as the new "source layer".

- In step 8, all sinks with remaining CO_2 storage capacity exceeding the 25-year CO_2 flow of the smallest source in the new "source layer" defined in step 7 was set as the new "sink layer". The program then went back to step 1 and reran the source-sink matching algorithm until all sources were matched and no sinks were "overfilled."

While the matching algorithm described above was capable of determining a near optimal solution, the algorithm might not find the absolute least cost solution. Since the algorithm did

not evaluate whether assigning one source to a relatively more costly sink could reduce overall system cost, the optimization was not truly optimal. Even though the matching algorithm used in this analysis was not "truly optimal," this is a typical problem in system optimization and the algorithm produces a reasonable result. The complexity of a "true" system optimization algorithm was beyond the scope of the Phase I analysis, but efforts in Phase II will focus on improving the algorithm functionality.

7.2 LEAST-COST PATH SOURCE-SINK MATCHING

This analysis was conducted using the CO_2 sources located in eastern Texas which included power plants, ammonia, cement, refineries, and gas processing plants. Power plants with less than 100MWe design capacity and non-power plants with less than 5 Mt of CO_2 emissions over the 25 year study period were exclude from the analysis. In total, 130 sources were included in the source-sink matching process. The project lifetime was assumed to be 25 years. Total source CO_2 flow over 25 years was about 8.9 Gt. Table 7-1 shows the CO_2 flow rate by source type.

Table 7-1: CO_2 Flow Rate by Plant Types, eastern Texas

Plant Type	Number of Plants	Annual CO_2 Flow (Mt)	25-year CO_2 Flow (Mt)
Power Plant	98	316	7,904
Ammonia	1	0	6
Cement	8	7	166
Gas Processing	8	3	82
Refinery	15	31	771
All sources	130	357	8,929

The potential sink list included EOR oil reservoirs[16], gas reservoirs, and saline aquifers with a CO_2 storage capacity of at least 5 Mt.

Eastern Texas has 122 oil fields with a total CO_2 storage capacity of 1.4 Gt. 109 of these fields, or 1.2 Gt of the capacity, were favorable for miscible EOR operations. 13 of the fields, or 0.2 Gt of the capacity, were categorized as immiscible EOR reservoirs. After screening out fields with storage capacity less than 5 Mt, 34 fields with an overall storage capacity of 1.2 Gt were included in the analysis. One hundred and one gas fields with totaled CO_2 storage capacity of 1.7 Gt were also included in the analysis after screening out those with storage capacity below 5 Mt.

The total CO_2 storage capacity for oil and gas fields included in the analysis was 2.9 Gt. Since the total 25 yr CO_2 flow rate from all sources was 8.9 Gt, aquifers were also included as potential sinks. Saline aquifers in eastern Texas, including those in eastern Texas Basin and Gulf Coast Region, were estimated to have a CO_2 storage capacity of 196 Gt.[17]

[16] There is no oil reservoir with CO_2 storage potential but no EOR potential in eastern Texas.
[17] The CO_2 storage capacity in east Texas Basin is estimated to be 26 Gt. The Gulf Coast aquifer plates cover portions of Texas, Louisiana, and Mississippi and have an estimated storage capacity of 377 Gt (see Table 3-6). We are unable to divide this storage capacity along state lines, although we can estimate storage capacity in each state

The cost surface used in this study is an aggregate transportation cost layer generated using the method presented in section 5. The cell value in this layer was calculated using the obstacle cost factor plus the construction cost factor calculated for a standard 8-inch pipeline. The raw data sources for the obstacle types are listed in Table 7-2.

Table 7-2: Data Sources of Transportation Barrier Layers

Barrier Layer	Raw Data Source
Slope	ESRI Digital Elevation Model Data
Populated area	ESRI Data & Maps
Wetland	USGS LULC Data
National Park	ESRI Data & Maps
State Park	ESRI Data & Maps
Waterway	ESRI Data & Maps
Railway	ESRI Data & Maps
Highway	ESRI Data & Maps

based on the land area. The Texan aquifers occupy 45% of the regional aquifers by area, and our estimate of 170 Gt of storage capacity assumes uniform distribution of the storage capacity over the aquifer area.

Figure 7-2: CO_2 Sources and Sinks shown over the Transportation Cost Surface, eastern Texas

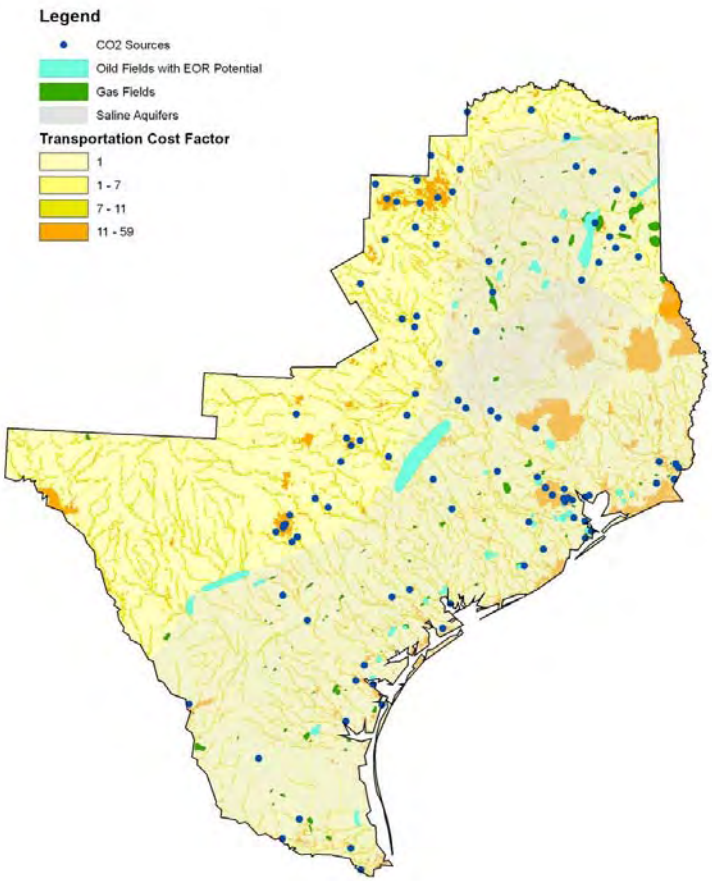


Figure 7-2 shows all the CO_2 sources, geological sinks, and transportation cost factors used in the least-cost path analysis. After the first stage of the source-sink matching analysis, 29 sources were linked to EOR sites, while 101 sources remained unmatched. Figure 7-3 and Table 7-3 present the results of the first stage analysis linking CO_2 sources to oil fields with EOR potential in eastern Texas. Figure 7-4 plots the marginal transportation distance by annual CO_2 storage rate for those sources transported to the oil fields with EOR potential. Figure 7-5 plots the marginal transportation cost by annual CO_2 storage rate for sources transported to EOR oil fields.

Figure 7-3: Source-sink Matching to Oil Fields with EOR Potential, eastern Texas

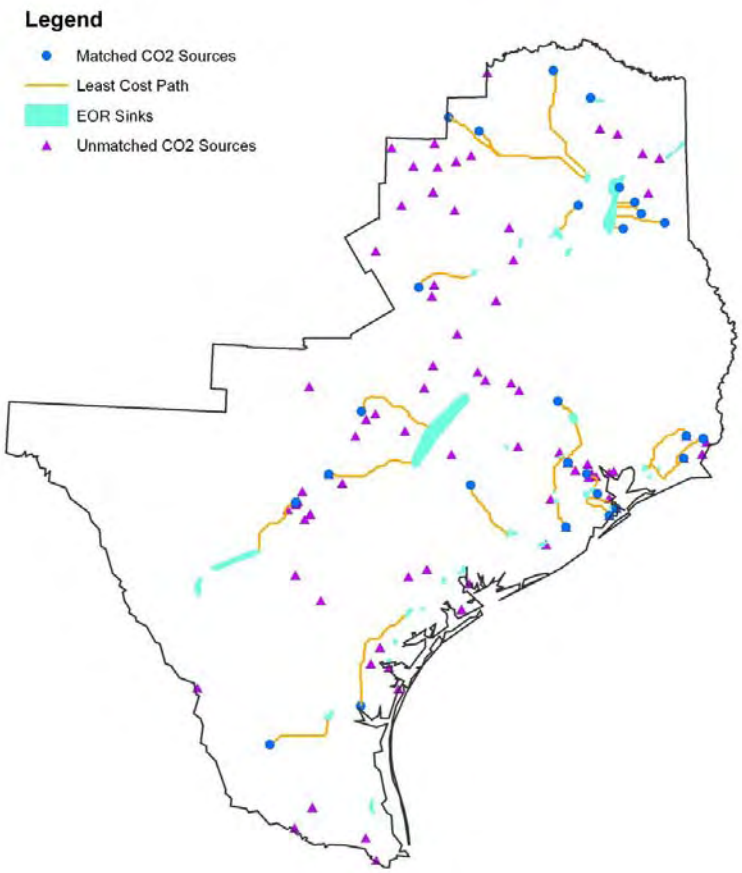


Table 7-3: Least-Cost Path analysis for CO_2 Sources Transported to Oil Fields with EOR Potential, eastern Texas

Company Name	Facility Name	Plant Type	Annual CO2 Flow (Mt)	Destination[1]	Transportation Distance (km)	Pipeline Diameter (Inch)	Construction Cost (M$)	Crossing Cost(M$)	Annual O&M Cost (M$)	Transportation cost ($/t)
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	0	6	0.00	0.00	0.00	0.00
Texas Genco	WEBSTER	Power Plant	1.90	O358	6	12	0.86	0.19	0.02	0.09
AEP NUGs	MARTIN LAKE	Power Plant	18.25	O80	30	30	10.80	0.29	0.09	0.10
Southwestern Electri	KNOX LEE	Power Plant	1.87	O80	19	12	2.74	0.19	0.06	0.27
Entergy Gulf States	LEWIS CREEK	Power Plant	2.18	O59	22	12	3.17	0.58	0.07	0.29
TXU Generation LLC	RIVER CREST	Power Plant	0.50	O319	2	8	0.19	0.86	0.01	0.33
VALERO REFINING	CO T	Refinery	1.83	O135	37	12	5.33	1.25	0.11	0.60
Sweeny Cogeneration	SWEENY COGENE	Power Plant	1.67	O322	32	12	4.61	1.82	0.10	0.64
Texas Genco	DEEPWATER	Power Plant	0.86	O358	26	8	2.50	2.02	0.08	0.88
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	12	6	0.86	2.02	0.04	1.10
Marathon Ashland Pet		Refinery	0.64	O135	37	8	3.55	1.25	0.11	1.30
BP Amoco	POWER STATION	Power Plant	0.48	O135	34	8	3.26	0.29	0.11	1.33
La Gloria Oil & Gas		Refinery	0.49	O92	38	8	3.65	2.69	0.12	2.17
Garland City of	RAY OLINGER	Power Plant	1.57	O136	136	12	19.58	1.54	0.42	2.29
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	56	6	4.03	2.11	0.17	2.57
Motiva Enterprises L	PORT ARTHUR RE	Power Plant	0.36	O8	65	6	4.68	0.86	0.20	2.87
Copano Energy LLC	Houston Central	GAS PROC	0.38	O200	73	6	5.26	1.92	0.23	3.40
Exxon Mobil	BAYTOWN TURBI	Power Plant	0.59	O59	56	8	5.38	7.30	0.17	3.52
Exxon Mobil	EXXON MOBIL CC	Power Plant	0.57	O59	56	8	5.38	7.30	0.17	3.63
Panda Energy	LAMAR POWER PI	Power Plant	1.05	O136	135	12	19.44	3.65	0.42	3.68
CEMEX		Cement	0.61	O115	96	8	9.22	5.47	0.30	4.09
TXU Generation LLC	COLLIN	Power Plant	0.67	O136	170	8	16.32	2.11	0.53	4.92
University of Texas	UNIVERSITY OF T	Power Plant	0.28	O115	99	6	7.13	2.21	0.31	6.00
ExxonMobil Corp.	King Ranch	GAS PROC	0.51	O25	129	8	12.38	6.62	0.40	6.42
E I DuPont De Nemou	SABINE RIVER W(	Power Plant	0.27	O8	99	6	7.13	3.65	0.31	7.05
Air Liquide America	SABINE COGEN LI	Power Plant	0.27	O8	99	6	7.13	3.65	0.31	7.20
Terra Industries, In		Ammonia	0.26	O8	74	6	5.33	6.24	0.23	7.44
Occidental Chemical	DEER PARK PLAN	Power Plant	0.34	O313	54	6	3.89	12.38	0.17	7.65
El Paso Field Servic	Thompsonville	GAS PROC	0.16	O317	80	6	5.76	1.54	0.25	8.18

Note: 1. Destination Code O represents Oil fields; the number represents the ID field in the SECARB sink database.

Figure 7-4: Marginal Transportation Distance by Annual CO_2 Storage Rate in Oil Fields with EOR Potential, eastern Texas

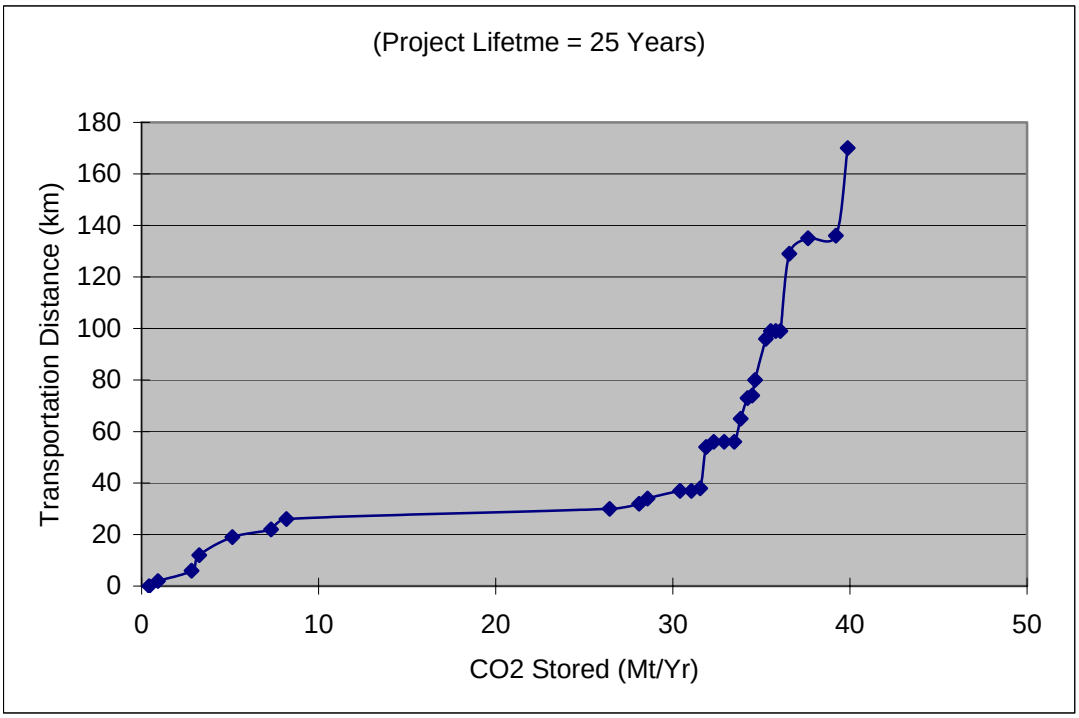
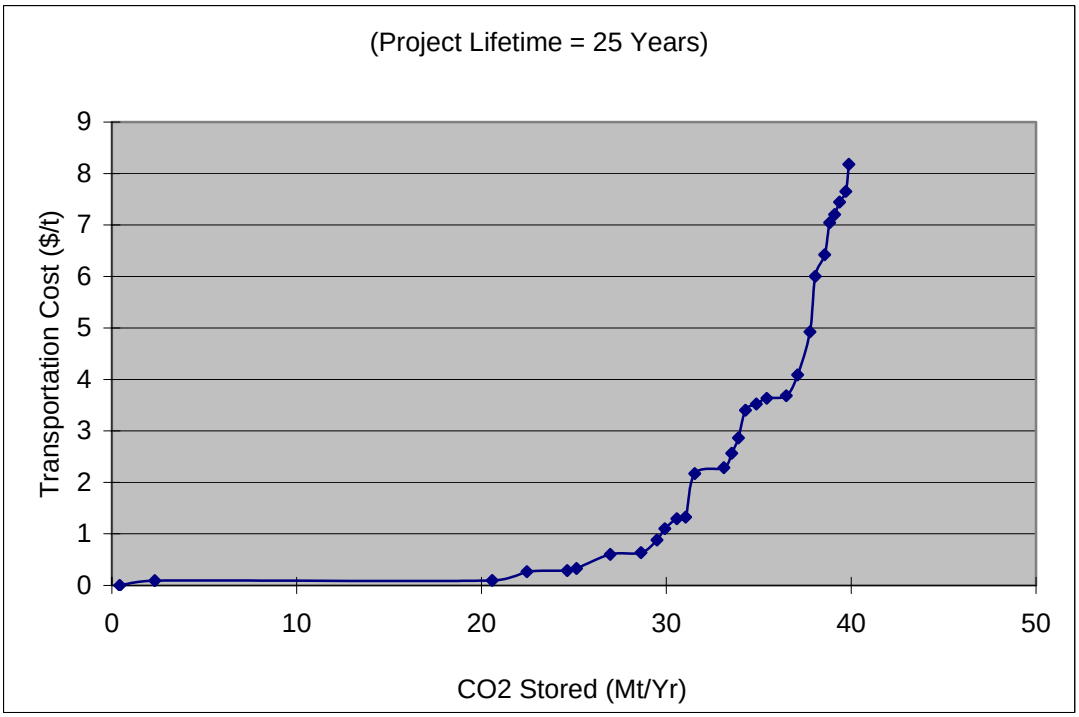


Figure 7-5: Marginal Transportation Cost in eastern Texas Oil Fields with EOR Potential



In this analysis \$16/t of CO_2 was used as an assumed EOR credit value, meaning that a CO_2 source can receive \$16/t of CO_2 used for EOR. If the transportation cost from a CO_2 source to an EOR site was less than \$16/t, then the CO_2 was allocated to that EOR site instead of an alternative non EOR sink. If the transportation costs to the closest EOR site were greater than \$16/t, then the CO_2 was considered unmatched and was allocated to the saline aquifers or gas fields during the second step of the analysis. In actuality, when the algorithm was run it turned out that all of the sources that were initially allocated to the EOR sites had transportation costs that were less than \$16/t.

After the first matching stage, 101 sources remained unmatched with appropriate sinks. The storage capacity of the gas fields is relatively small, while the aquifers have a storage capacity that is greater than the total 25-year CO_2 flow. In addition to transportation and capacity constraints, sources were allocated while considering the differential injection costs for gas fields and saline aquifers at the second stage.[18] Since there is a large saline aquifer that covers much of the study region, sources within this region were allocated directly to the saline aquifer. Next sources outside of the aquifer region were matched via the least cost method to the optimal CO_2 sink. A final check was run to compare final cost calculations for each source to alternative options to ensure that the selected pair represents the true least cost option.

[18] According to Heddle, the injection cost for gas fields is usually higher than for saline aquifers. Accordingly it was assumed that saline aquifers were preferred over gas fields for injection, and all sources located on top of saline aquifers were injected directly into the aquifer. For example, the base case provided by Heddle et al. (2003) estimated the injection cost for an aquifer would be \$0.16 per tonne of CO_2 from a power plant with a daily flow rate 7, 389 tonne, while the injection cost for a gas reservoir would be \$2.58 per tonne of CO_2 using the same flow rate.

Figure 7-6: Source-sink Matching Final Result

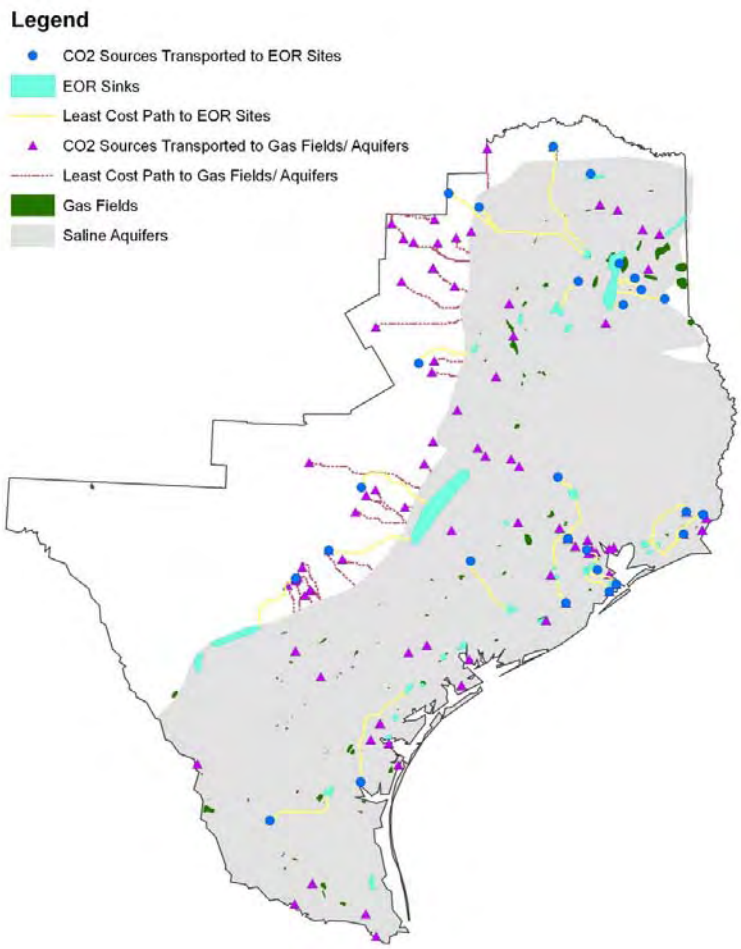


Figure 7-6 shows the final results for all of the sources in eastern Texas. Appendix G presents the corresponding destination sink for each of the CO_2 sources listed in this section. Figure 7-7 plots the marginal transportation distance by annual CO_2 storage rate for all sources including those transported to EOR sites. Figure 7-8 plots the marginal transportation cost by annual CO_2 storage rate.

Figure 7-7: Marginal Transportation Distance by Annual CO_2 Storage Rate for All Sources, eastern Texas

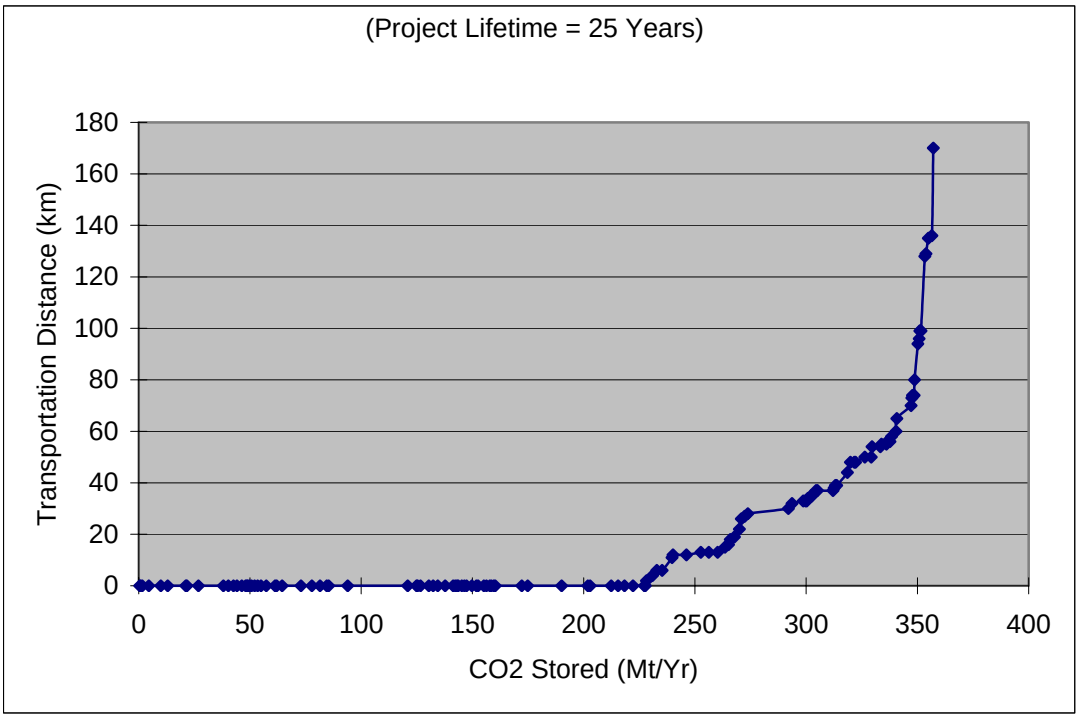
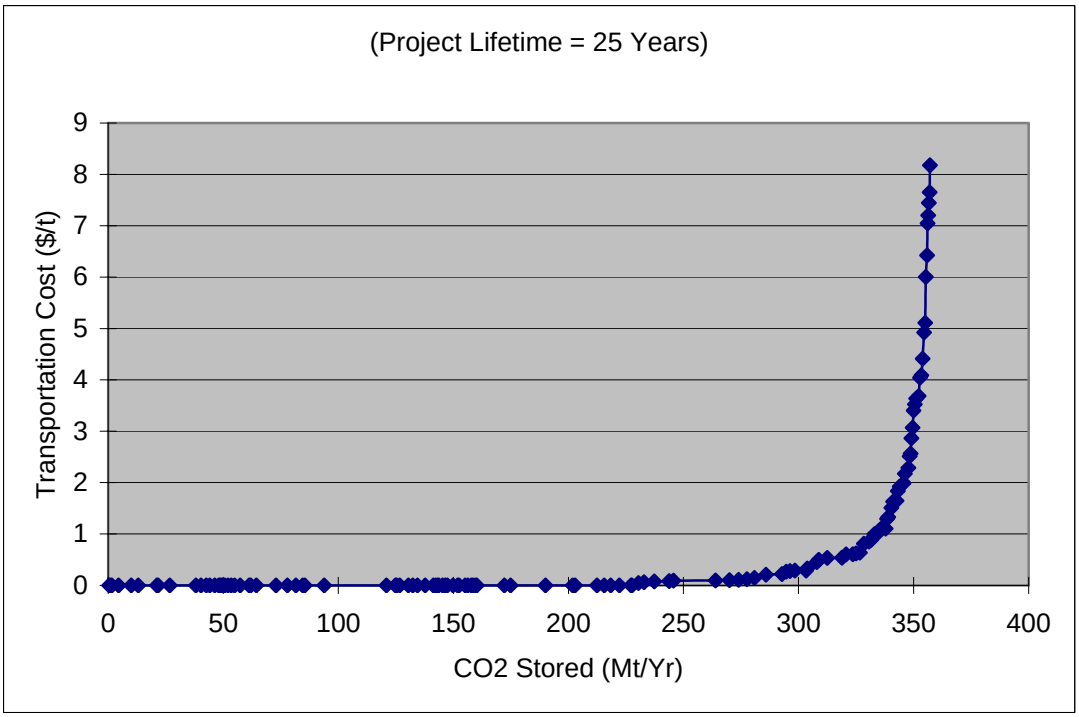


Figure 7-8: Marginal Transportation Cost for all Sources in eastern Texas



In contrast to the results from the previous section, the results from the least-cost path source-sink matching provide an optimized pipeline arrangement based on construction cost criteria. In many cases this transportation distance will be longer than the straight-line distance calculated in the previous section. But since transportation obstacle costs are included, the overall transportation cost will be less. If EOR fields were the only sequestration sinks considered (Stage I), then 12.5% of the sources could be linked to an appropriate sink. Most of these sinks were within 150 km from the CO_2 source. The total transportation costs for all sources calculated in the Stage I analysis were less than \$9/t CO_2. The assumed EOR credit was \$16/t CO_2, which reinforced the need to use the two-stage analysis strategy.

When all sources were included in the analysis, all of them could be linked to a least-cost sink within 200 km from the source. While the maximum transportation cost was around \$9/t CO_2, in most cases the transportation cost was less than \$1/t CO_2. In reality the transportation costs might be less since in some cases sources and sinks in the same region could share pipelines or pipeline routes. This would likely decrease transportation costs below the estimates presented here.

7.3 CO_2 SEQUESTRATION FULL-COST ESTIMATION

For sources matched with EOR sites the full cost estimate included costs for capture, transportation, and an EOR credit. For sources matched with gas fields or aquifers, the full cost estimate included capture cost, transportation cost, and injection cost.

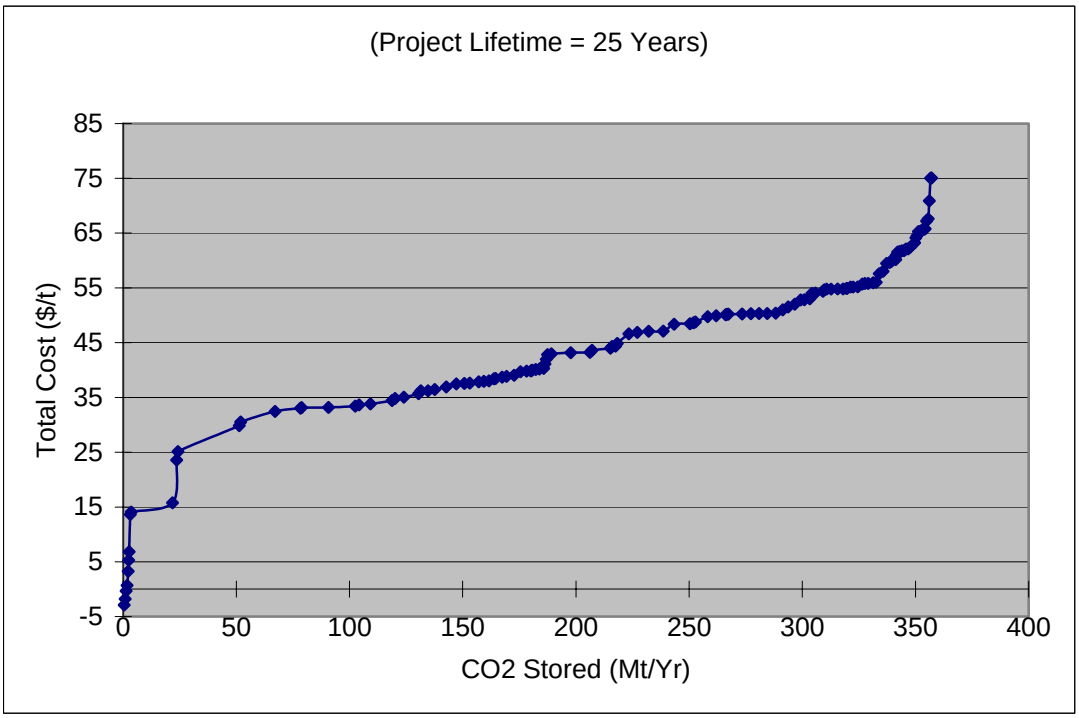
The injection cost analysis was based on methods used by Heddle, et.al. (2003). The Heddle injection cost model requires inputs for surface injection pressure, downhole injection pressure, CO_2 flow rate, and reservoir properties. Heddle, et.al. (2003) defined a base case, a high cost case, and a low cost case derived from an analysis of typical data for aquifers and gas fields. Since the spatially distributed aquifer data was unavailable at this stage, a regional mean value in the Gulf Cost was used in this analysis. For gas fields, the reservoir properties used in the analysis were referenced from the SECARB database. The surface injection pressure was assumed to be 10.30 MPa. Using the spreadsheet shown in Figure 7-9 the injection cost was calculated using the source CO_2 flow rate. A power plant with a 25-year CO_2 emission of 67.4 Mt was used as a reference case in the spreadsheet. In this reference case, the injection cost was estimated to be \$0.16 per tonne of CO_2.

Figure 7-10 and Appendix G show the results of the CO_2 sequestration full cost estimation. The results of the full cost sequestration analysis in eastern Texas indicate that 20, 100, or 200 M tonnes of CO_2 per year could be sequestered in eastern Texas at a cost of \$16/t, \$33/t, or \$43/t, respectively. This total costs could be less and the specific sequestration cost could even be negative for specific ammonia and gas processing plants with low transportation costs since their capture cost was less than the assumed EOR credit.

Figure 7-9 Injection Cost Estimation Spreadsheet

		AQUIFER - Base Case			
Inputs					
Surface inj. pressure	(MPa)	**10.30**			
Downhole inj. pressure	(MPa)	**21.30**	17.08	18.25	**17.92**
CO_2 mass flow rate	(t/d)	7,389			
	(kg/s)	86			
Reservoir properties					
Reservoir pressure	(MPa)	8.4			
Thickness	(m)	171			
Depth	(m)	1239			
Permeability	(md)	22			
Temperature	(deg C)	46.0			
Viscosity calculation					
Intermediate pressure	(MPa)	14.85	12.74	13.33	13.16
Viscosity	(mPa.s)	0.050	0.042	0.044	0.044
Well number calculation					
CO_2 mobility	(md/mPa.s)	242.4	286.8	272.6	276.5
CO_2 injectivity	(t/d/m/MPa)	5.042	5.966	5.670	5.751
CO_2 injection rate per well	(t/d)	11123	8856	9555	9363
Number wells required		0.7	0.8	0.8	**0.8**
Cost calculation					
Site screening & evaluation	($M)	1.69			
Injection equipment	($M)	0.04	0.04	0.04	0.04
Well drilling cost	($M)	0.24	0.24	0.24	0.24
Total capital cost	($M)	1.97	1.97	1.97	1.97
Normal daily expenses	($M/yr)	0.01	0.01	0.01	0.01
Consumables	($M/yr)	0.02	0.02	0.02	0.02
Surface maintenance	($M/yr)	0.01	0.01	0.01	0.01
Subsurface maintenance	($M/yr)	0.01	0.01	0.01	0.01
Total O&M costs	($M/yr)	0.04	0.04	0.04	0.04
Annual total cost	($M)	0.34	0.34	0.34	0.34
$/tonne CO_2		0.16	0.16	0.16	**0.16**
Pressure change calculation					
CO_2 temperature	(deg C)	25			
CO_2 density	(kg/m^3)	822			
Gravity head					
Elevation change	(m)	-1239			
Pressure change	(MPa)	9.99			
Friction loss					
Well diameter	(m)	0.1200			
Viscosity	($N.s/m^2$)	6.06E-05			
Reynolds number	unitless	2.26E+07	1.80E+07	1.94E+07	1.90E+07
Roughness	(ft)	0.00015			
Friction factor	unitless	0.00395	0.00395	0.00395	0.00395
Well length	(m)	1239			
Velocity	(m/s)	13.85	11.03	11.90	11.66
Pressure change	(MPa)	3.21	2.04	2.37	2.28
Downhole pressure	(MPa)	17.08	18.25	17.92	18.02

Figure 7-10 Marginal Total Cost of Capture and Sequestration in eastern Texas



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9 Appendices

Appendix A. List of Acronyms

Abbreviation	Meaning
AGS	Alabama Geological Survey
CO_2	Carbon dioxide
DOE	United States Department of Energy
ECBMR	Enhanced Coalbed Methane Recovery
eGRID	Emissions and Generation Resource Integrated Database
EIA	Energy Information Agency
EOR	Enhanced oil recovery
ERF	ECBM recovery factor
GASIS	Gas Information System
GHG	Greenhouse gas
GIS	Geographical information System
GNIS	Geographical Names Information System
Gt	giga metric tones
HV	High-volatile
HVA	High-volatile A
IEA	International Energy Agency
IFDC	International Fertilizer Development Commission
IGEM	Institute of Geology of Ore Deposits, Petrography, Mineralogy & Geochemistry
LFEE	Laboratory for Energy and the Environment (at MIT)
LULC	Land use and land cover
LV	Low-volatile
MIT	Massachusetts Institute of Technology
Mt	million metric tons
MV	Moderate-volatile
MWe	megawatt electrical
OGIP	Original gas in place
O&M	Operation and maintenance
OOIP	Original oil in place
PRF	Primary Recovery Factor
RRC	Railroad Commission
SECARB	Southeast Regional Carbon Sequestration Partnership
Sub	Sub-bituminous

tonne	metric ton
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
UTBEG	University of Texas at Austin, Bureau of Economic Geology

Appendix B. CO_2 Capture Cost Estimation and Straight-line Distance Source-Sink Matching for Fossil-Fuel Power Plants in SECARB Region

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
2739	COGENTRIX SOUTHPOR	NC	108.46	0.26	420,387	COAL	1,293,498	45.45	57.50	142	174	898	898	142
4248	COGENTRIX HOPEWELI	VA	108.46	0.36	342,024	COAL	760,053	45.45	57.50	144	58	1085	1144	58
4250	COGENTRIX PORTSMOU	VA	108.46	0.26	228,979	COAL	704,552	45.45	57.50	81	143	1150	1187	81
2746	DWAYNE COLLIER BAT	NC	114.75	0.86	1,018,239	COAL	947,199	45.15	57.12	111	128	1022	1041	111
1129	CENTRAL POWER&LIM	FL	125.00	0.92	1,029,635	COAL	895,335	44.70	56.55	0	298	510	539	0
161	GADSDEN	AL	138.00	0.42	635,483	COAL	1,210,444	44.19	55.90	263	47	236	317	47
4281	MECKLENBURG COGEN	VA	139.86	0.60	806,519	COAL	1,075,358	44.12	55.82	218	130	974	1028	130
3781	DOLPHUS M GRAINGER	SC	163.20	0.64	956,023	COAL	1,195,029	43.33	54.82	218	172	822	822	172
2815	WESTMORELAND LG&E	NC	182.32	0.83	1,326,460	COAL	1,278,516	42.78	54.12	135	138	1025	1056	135
3910	AES DEEPWATER INC	TX	184.00	0.77	1,838,231	COAL	1,909,850	42.73	54.06	0	1	7	7	0
3897	TENN EASTMAN DIV A	TN	194.30	0.71	1,022,947	COAL	1,152,616	42.46	53.71	454	74	647	750	74
1236	ARKWRIGHT	GA	213.89	0.20	486,156	COAL	1,944,625	41.99	53.12	136	29	391	391	29
1977	NELSON INDUSTRIAL S	LA	227.27	0.71	1,163,969	COAL	1,311,515	41.69	52.74	0	24	3	22	0
4282	MIRANT BIRCHWOOD P	VA	240.00	0.65	1,344,173	COAL	1,654,367	41.42	52.41	130	54	1135	1218	54
3902	WATTS BAR FOSSIL	TN	240.00	0.00	0	COAL	1,654,367	41.42	52.41	432	108	390	515	108
4237	BREMO BLUFF	VA	254.28	0.74	1,795,589	COAL	1,941,177	41.15	52.05	219	65	1021	1103	65
4249	COGENTRIX OF RICHMO	VA	270.00	0.50	1,134,672	COAL	1,815,474	40.86	51.69	155	29	1075	1142	29
3818	URQUHART	SC	277.28	0.55	1,506,944	COAL	2,191,918	40.73	51.53	109	180	563	563	109
1126	CEDAR BAY GENERATI	FL	285.00	0.79	1,911,811	COAL	1,936,011	40.60	51.36	42	284	509	528	42
3800	MCMEEKIN	SC	293.76	0.73	1,908,812	COAL	2,091,849	40.46	51.18	177	210	652	652	177
1158	INDIANTOWN COGENE	FL	330.00	0.83	2,316,185	COAL	2,232,467	39.91	50.49	0	542	753	783	0
2809	W H WEATHERSPOON	NC	342.19	0.28	949,505	COAL	2,712,870	39.74	50.28	186	94	862	862	94
1292	MITCHELL	GA	343.88	0.23	826,518	COAL	2,874,845	39.72	50.25	93	42	286	294	42
4121	TNP ONE	TX	349.20	0.72	2,708,874	COAL	3,009,860	39.65	50.16	0	5	60	65	0
1285	KRAFT	GA	355.90	0.46	1,467,952	COAL	2,552,961	39.56	50.05	0	224	578	585	0
4092	SANDOW	TX	363.00	0.88	3,387,082	COAL	3,079,165	39.47	49.93	3	4	43	43	3
2743	DAN RIVER	NC	387.97	0.27	1,178,919	COAL	3,493,095	39.16	49.55	301	112	853	918	112

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
2672	R D MORROW	MS	400.00	0.69	2,645,042	COAL	3,066,715	39.03	49.37	0	5	26	94	0
2725	CAPE FEAR	NC	405.97	0.52	1,683,226	COAL	2,589,579	38.96	49.28	206	0	885	909	0
4090	SAN MIGUEL	TX	410.00	0.83	3,869,295	COAL	3,729,441	38.91	49.23	0	17	11	46	0
3777	COPE	SC	417.36	0.76	3,043,113	COAL	3,203,277	38.83	49.13	104	250	633	633	104
3977	GIBBONS CREEK	TX	443.97	0.84	3,417,398	COAL	3,254,664	38.55	48.77	0	9	33	48	0
3820	W S LEE	SC	460.30	0.34	1,553,879	COAL	3,656,185	38.39	48.57	245	244	565	596	244
1141	DEERHAVEN	FL	471.09	0.43	1,896,848	COAL	3,529,020	38.29	48.44	92	257	459	482	92
2722	BUCK	NC	474.57	0.41	1,974,179	COAL	3,852,058	38.25	48.39	324	87	772	818	87
3769	CANADYS STEAM	SC	489.60	0.51	2,362,176	COAL	3,705,374	38.12	48.22	80	273	655	657	80
2764	LEE	NC	508.62	0.43	2,497,634	COAL	4,646,762	37.95	48.00	117	84	966	972	84
223	FLINT CREEK	AR	510.83	0.85	4,292,162	COAL	4,039,682	37.93	47.98	303	113	80	325	80
1194	POLK	FL	521.23	0.38	1,678,771	COAL	3,534,255	37.84	47.87	0	393	604	634	0
153	CHARLES R LOWMAN	AL	538.00	0.71	4,028,993	COAL	4,539,710	37.70	47.69	0	0	45	47	0
3994	J K SPRUCE	TX	546.00	0.83	4,536,490	COAL	4,372,521	37.63	47.61	13	41	51	67	13
3942	COLETO CREEK	TX	570.06	0.97	4,791,472	COAL	3,951,730	37.44	47.37	0	0	34	34	0
3795	JEFFERIES	SC	578.20	0.41	2,259,942	COAL	4,409,642	37.38	47.29	116	237	717	719	116
4091	SANDOW	TX	590.64	0.69	4,283,849	COAL	4,966,781	37.29	47.17	10	31	32	32	10
2789	RIVERBEND	NC	601.20	0.45	2,674,171	COAL	4,754,081	37.21	47.08	325	130	711	752	130
1121	C D MCINTOSH JR	FL	625.01	0.58	3,519,130	COAL	4,853,972	37.04	46.86	0	363	574	604	0
4055	PIRKEY	TX	660.40	0.75	5,311,704	COAL	5,665,817	36.81	46.56	0	36	6	30	0
1283	JACK MCDONOUGH	GA	682.10	0.61	3,342,995	COAL	4,384,256	36.67	46.39	254	139	370	402	139
3824	WILLIAMS	SC	686.54	0.72	4,704,565	COAL	5,227,295	36.64	46.35	98	261	714	717	98
4246	CLINCH RIVER	VA	712.50	0.80	4,751,106	COAL	4,751,106	36.48	46.15	501	35	675	786	35
1947	DOLET HILLS	LA	720.75	0.73	5,186,835	COAL	5,684,203	36.43	46.09	40	7	16	107	7
2771	MAYO	NC	735.84	0.74	5,827,689	COAL	6,300,204	36.34	45.98	243	97	925	979	97
2763	L V SUTTON	NC	744.94	0.40	2,916,875	COAL	5,833,751	36.29	45.91	108	170	932	932	108
3823	WATEREE	SC	771.80	0.68	4,206,893	COAL	4,949,286	36.14	45.72	162	196	689	689	162
2734	CLIFFSIDE	NC	780.90	0.59	4,167,193	COAL	5,650,431	36.09	45.66	307	202	638	687	202
3875	JOHN SEVIER	TN	800.00	0.74	5,468,726	COAL	5,912,137	35.99	45.53	450	82	585	695	82

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Dist to Nearst Sink (km)
4242	CHESAPEAKE	VA	812.39	0.63	4,898,924	COAL	6,220,856	35.93	45.45	69	155	1153	1187	69
1288	MCINTOSH	GA	817.66	0.18	1,382,520	COAL	6,144,533	35.90	45.41	0	218	582	587	0
2712	ASHEVILLE	NC	837.17	0.37	3,003,068	COAL	6,493,120	35.80	45.29	343	179	578	657	179
4247	CLOVER	VA	848.06	0.92	7,615,277	COAL	6,621,980	35.75	45.22	251	137	952	1015	137
3997	J T DEELY	TX	892.00	0.71	6,344,394	COAL	7,148,613	35.54	44.96	13	41	51	67	13
1217	STANTON ENERGY CTR	FL	929.16	0.79	6,572,178	COAL	6,655,370	35.37	44.74	0	408	619	646	0
3853	BULL RUN	TN	950.00	0.72	4,963,295	COAL	5,514,772	35.28	44.63	447	45	474	594	45
1270	HAMMOND	GA	953.00	0.60	5,456,479	COAL	7,275,305	35.26	44.61	329	108	309	389	108
3789	H B ROBINSON	SC	991.64	0.84	1,029,395	COAL	980,376	35.10	44.40	234	120	754	754	120
2677	VICTOR J DANIEL JR	MS	1000.00	0.72	7,071,914	COAL	7,857,682	35.06	44.36	0	35	60	142	0
1997	RODEMACHER	LA	1003.50	0.53	4,843,732	COAL	7,311,293	35.05	44.34	0	0	51	162	0
2660	JACK WATSON	MS	1051.36	0.61	5,850,686	COAL	7,673,030	34.86	44.10	0	64	43	129	0
3778	CROSS	SC	1147.12	0.86	8,756,646	COAL	8,145,717	34.51	43.65	125	226	712	714	125
2751	G G ALLEN	NC	1155.00	0.57	5,914,264	COAL	8,300,721	34.48	43.62	305	136	703	737	136
3920	BIG BROWN	TX	1186.80	0.82	10,834,509	COAL	10,570,252	34.37	43.48	0	4	1	16	0
1133	CRIST	FL	1229.00	0.52	6,457,296	COAL	9,934,302	34.23	43.30	0	0	27	50	0
4321	YORKTOWN	VA	1257.00	0.32	3,571,960	COAL	8,929,901	34.14	43.19	81	112	1152	1200	81
3825	WINYAH	SC	1260.00	0.70	8,447,634	COAL	9,654,439	34.13	43.18	173	205	784	786	173
165	GREENE COUNTY	AL	1288.48	0.40	4,647,240	COAL	9,294,480	34.04	43.07	66	37	92	92	37
1213	ST JOHNS RIVER POWEI	FL	1358.00	0.84	10,809,674	COAL	10,294,927	33.83	42.80	36	288	524	542	36
164	GORGAS	AL	1416.70	0.70	9,503,886	COAL	10,861,584	33.67	42.59	133	25	117	204	25
1206	SEMINOLE	FL	1429.20	0.73	10,424,329	COAL	11,423,922	33.63	42.55	49	330	529	551	49
1342	YATES	GA	1487.50	0.48	6,736,641	COAL	11,227,736	33.48	42.35	241	132	327	343	132
4144	WELSH	TX	1536.96	0.80	13,121,748	COAL	13,121,748	33.35	42.19	0	26	30	39	0
1993	R S NELSON	LA	1596.80	0.45	7,706,978	COAL	13,701,294	33.20	42.00	0	21	8	30	0
3848	ALLEN	TN	1610.80	0.38	5,238,480	COAL	11,028,380	33.17	41.96	29	0	218	319	0
4013	LIMESTONE	TX	1626.80	0.79	13,081,433	COAL	13,247,020	33.13	41.91	0	43	21	36	0
3969	FAYETTE POWER PRJ	TX	1690.00	0.80	12,514,443	COAL	12,514,443	32.98	41.72	0	0	22	22	0
229	INDEPENDENCE	AR	1700.00	0.69	12,310,474	COAL	14,273,013	32.96	41.69	104	9	213	360	9
247	WHITE BLUFF	AR	1700.00	0.68	11,920,913	COAL	14,024,603	32.96	41.69	6	3	146	227	3
3877	KINGSTON	TN	1700.00	0.66	10,723,952	COAL	12,998,729	32.96	41.69	447	63	438	563	63

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
1271	HARLLEE BRANCH	GA	1746.24	0.55	8,785,873	COAL	12,779,452	32.85	41.56	129	67	438	438	67
4243	CHESTERFIELD	VA	1799.60	0.60	9,084,140	COAL	12,112,186	32.74	41.42	148	45	1081	1143	45
154	COLBERT	AL	1826.00	0.46	8,347,215	COAL	14,516,896	32.68	41.35	161	34	134	325	34
1934	BIG CAJUN 2	LA	1833.00	0.73	14,124,989	COAL	15,479,440	32.67	41.33	0	41	21	105	0
3868	GALLATIN	TN	1918.72	0.43	7,390,039	COAL	13,748,909	32.49	41.11	377	162	352	525	162
1337	WANSLEY	GA	1956.80	0.57	9,899,030	COAL	13,893,376	32.42	41.01	236	134	321	335	134
205	WIDOWS CREEK	AL	1968.76	0.56	11,905,974	COAL	17,008,534	32.40	40.99	329	81	285	405	81
4026	MONTICELLO	TX	1980.05	0.71	14,960,317	COAL	16,856,696	32.38	40.96	0	18	13	29	0
1116	BIG BEND	FL	1998.00	0.62	11,607,158	COAL	14,976,978	32.34	40.91	0	346	554	586	0
2770	MARSHALL	NC	2000.00	0.86	13,262,502	COAL	12,337,211	32.34	40.91	351	133	717	769	133
158	E C GASTON	AL	2034.05	0.71	13,815,864	COAL	15,567,170	32.27	40.83	178	65	194	223	65
2715	BELEWS CREEK	NC	2160.14	0.65	11,727,317	COAL	14,433,621	32.05	40.54	317	110	818	881	110
4020	MARTIN LAKE	TX	2379.75	0.79	20,026,130	COAL	20,279,625	31.69	40.09	0	58	12	28	0
2795	ROXBORO	NC	2574.57	0.67	15,577,368	COAL	18,599,842	31.40	39.72	252	92	908	964	92
3863	CUMBERLAND	TN	2600.00	0.84	21,370,347	COAL	20,352,711	31.36	39.68	297	51	314	510	51
172	JAMES H MILLER JR	AL	2822.00	0.83	22,337,062	COAL	21,529,698	31.06	39.30	153	4	132	224	4
149	BARRY	AL	2834.80	0.50	12,435,918	COAL	19,897,469	31.05	39.28	0	0	14	78	0
3876	JOHNSONVILLE	TN	2911.52	0.34	8,918,108	COAL	20,983,784	30.95	39.15	251	31	268	468	31
1134	CRYSTAL RIVER	FL	3333.33	0.72	15,433,230	COAL	17,148,034	30.46	38.54	11	250	461	489	11
1249	BOWEN	GA	3540.45	0.70	21,226,831	COAL	24,259,236	30.25	38.27	307	139	333	395	139
1316	SCHERER	GA	3564.00	0.68	23,701,643	COAL	27,884,286	30.23	38.24	153	41	390	390	41
4140	W A PARISH	TX	3969.12	0.52	19,499,213	COAL	29,998,789	29.85	37.76	0	19	4	4	0
1929	ARSENAL HILL	LA	100.00	0.24	157,083	GAS	523,611	70.50	89.19	30	0	13	53	0
4083	SABINE COGEN LP	TX	101.46	0.76	281,876	GAS	296,711	70.34	88.98	0	22	5	49	0
196	SO EASTERN ELECTRIC	AL	103.14	0.04	28,718	GAS	574,363	70.16	88.76	143	80	245	245	80
4128	UNIVERSITY OF TEXAS	TX	103.43	0.35	138,293	GAS	316,098	70.13	88.72	59	31	70	70	31
1937	BORDEN CHEMICALS PI	LA	104.09	0.74	289,212	GAS	312,662	70.06	88.63	0	115	37	52	0
3948	DANSBY	TX	105.00	0.38	238,945	GAS	503,041	69.96	88.51	0	4	26	26	0
4084	SABINE RIVER WORKS	TX	105.53	0.80	303,329	GAS	303,329	69.91	88.44	0	22	5	49	0
1306	RIVERSIDE	GA	108.03	0.05	41,707	GAS	667,306	69.65	88.12	0	228	580	587	0

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
201	WASHINGTON COUNTY	AL	109.00	0.68	313,566	GAS	368,901	69.56	87.99	0	0	21	49	0
1963	KAISER ALUMINUM	LA	110.20	0.46	252,057	GAS	438,359	69.44	87.84	0	135	27	38	0
3952	DEER PARK PLANT	TX	111.06	0.79	374,057	GAS	378,792	69.35	87.74	0	1	7	7	0
4077	RIVER CREST	TX	112.50	0.19	131,822	GAS	555,038	69.21	87.56	0	8	2	2	0
1955	GEISMAR PLANT	LA	113.00	0.84	417,377	GAS	397,502	69.16	87.50	0	115	37	52	0
4025	MISSION ROAD	TX	114.00	0.06	40,043	GAS	533,907	69.07	87.38	30	60	56	62	30
1191	PENSACOLA FLORIDA P	FL	116.00	0.61	284,857	GAS	373,582	68.88	87.14	0	0	33	44	0
4039	NORTH MAIN	TX	116.25	0.14	110,426	GAS	631,003	68.86	87.11	71	127	28	140	28
3773	CHEROKEE COUNTY CC	SC	117.73	0.55	276,429	GAS	402,079	68.72	86.94	283	193	645	682	193
4061	POWER STATION 3	TX	118.13	0.36	240,223	GAS	533,829	68.69	86.89	0	73	5	6	0
2674	SWEATT	MS	119.40	0.19	161,602	GAS	680,431	68.57	86.75	25	49	77	77	25
210	BAILEY	AR	120.00	0.26	203,618	GAS	626,516	68.52	86.68	64	0	210	313	0
1322	SOWEGA POWER LLC	GA	120.00	0.09	39,497	GAS	351,080	68.52	86.68	74	42	269	280	42
188	MOBILE ENERGY SERVI	AL	121.80	0.51	396,059	GAS	621,270	68.36	86.48	0	3	21	101	0
3790	HAGOOD	SC	122.00	0.05	38,907	GAS	622,518	68.34	86.46	78	283	704	708	78
1184	ORLANDO COGEN LP	FL	122.40	0.80	405,518	GAS	405,518	68.31	86.41	0	395	606	633	0
1992	PPG RIVERSIDE	LA	124.00	0.46	220,318	GAS	383,161	68.17	86.24	0	24	3	22	0
4058	PORT ARTHUR REFINER	TX	125.35	0.64	320,516	GAS	400,645	68.05	86.09	0	37	9	28	0
1187	PASCO COGEN LTD	FL	126.60	0.62	322,473	GAS	416,094	67.95	85.96	0	307	518	548	0
235	MCCLELLAN	AR	136.00	0.33	289,635	GAS	702,144	67.19	85.00	48	0	47	128	0
1183	ORANGE COGENERATIC	FL	136.67	0.40	192,122	GAS	384,244	67.14	84.93	0	393	604	634	0
1974	MONROE	LA	137.50	0.05	51,518	GAS	824,292	67.07	84.85	13	0	2	60	0
226	HAMILTON MOSES	AR	138.00	0.07	72,516	GAS	828,757	67.04	84.81	11	0	256	293	0
3929	BRYAN	TX	138.00	0.08	81,763	GAS	817,631	67.04	84.81	0	6	25	25	0
1150	HENRY D KING	FL	142.01	0.07	73,511	GAS	840,129	66.74	84.43	0	534	746	775	0
1165	JOHN R KELLY	FL	142.71	0.05	62,138	GAS	994,212	66.68	84.36	85	264	467	490	85
1950	FORMOSA PLASTICS CC	LA	143.80	0.80	460,875	GAS	460,875	66.61	84.26	0	75	3	84	0
4097	SI RAY	TX	145.00	0.09	79,892	GAS	710,148	66.52	84.15	0	39	49	51	0
1225	TOM G SMITH	FL	146.29	0.11	125,813	GAS	915,000	66.43	84.04	0	608	819	849	0

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
183	MCWILLIAMS	AL	147.00	0.28	384995.76	GAS	1,099,988	66.24	83.79	0	4	88	88	0
2650	CHEVRON OIL	MS	147.29	0.82	432011.80	GAS	421,475	65.96	83.45	0	40	66	149	0
1926	A B PATERSON	LA	149.00	0.14	288194.88	GAS	1,646,828	65.83	83.28	0	148	27	33	0
1178	MULBERRY COGENERA	FL	153.00	0.31	165891.02	GAS	428,106	65.75	83.17	0	393	604	634	0
1940	CALCASIEU POWER LL(	LA	155.00	0.08	70410.00	GAS	704,100	65.64	83.04	0	24	3	22	0
3943	COLLIN	TX	156.25	0.22	204364.90	GAS	743,145	65.38	82.71	30	122	63	149	30
1166	LAKE COGEN LTD	FL	157.82	0.51	321531.86	GAS	504,364	65.13	82.39	0	350	560	587	0
1122	CANE ISLAND	FL	162.00	0.53	385498.10	GAS	581,884	65.00	82.24	0	424	635	664	0
3995	J L BATES	TX	166.00	0.36	375449.80	GAS	834,333	64.99	82.21	0	0	17	84	0
4094	SEADRIFT PLANT UNIO	TX	168.00	0.58	451496.27	GAS	622,753	64.59	81.71	0	28	33	33	0
4008	LAREDO	TX	168.29	0.50	521733.30	GAS	834,773	64.59	81.71	0	0	10	102	0
1946	DG HUNTER	LA	175.00	0.12	139432.10	GAS	929,547	64.51	81.61	0	0	74	153	0
1969	LOUISIANA 2	LA	175.00	0.00	50135.00	GAS	929,547	64.31	81.35	0	75	3	84	0
4089	SAN JACINTO SES	TX	176.40	0.88	690700.00	GAS	627,909	64.15	81.16	0	1	7	7	0
2783	PANDA ROSEMARY LP	NC	180.00	0.07	59874.50	GAS	684,280	64.09	81.08	135	138	1025	1056	135
227	HARVEY COUCH	AR	182.80	0.11	171519.10	GAS	1,247,412	64.01	80.98	42	13	17	62	13
1311	ROBINS	GA	183.87	0.08	104706.90	GAS	1,047,069	63.88	80.81	115	0	368	368	0
1294	MPC GENERATING	GA	185.40	0.06	98997.60	GAS	1,319,968	63.82	80.74	205	120	438	444	120
3951	DEEPWATER	TX	187.85	0.12	143445.50	GAS	956,303	63.71	80.59	0	22	10	15	0
4009	LEON CREEK	TX	189.00	0.05	68495.60	GAS	1,095,930	63.62	80.49	29	64	50	53	29
4062	POWER STATION 4	TX	191.12	0.86	612906.43	GAS	570,146	63.26	80.02	0	73	5	6	0
1111	AUBURNDALE POWER I	FL	192.78	0.63	456277.92	GAS	579,401	63.02	79.73	0	393	604	634	0
3990	HOUSTON CHEMICAL C	TX	200.00	0.86	574688.34	GAS	534,594	62.68	79.30	0	1	7	7	0
3918	BEAUMONT REFINERY	TX	204.84	0.56	1662006.44	GAS	2,374,295	62.54	79.12	0	37	9	28	0
3917	BAYTOWN TURBINE GE	TX	212.00	0.80	654346.09	GAS	654,346	62.44	78.99	0	1	7	7	0
3967	EXXON MOBIL CO USA	TX	215.00	0.87	689698.23	GAS	634,205	62.41	78.95	0	1	7	7	0
1320	SMARR ENERGY CENTE	GA	217.40	0.00	142098.80	GAS	1,123,580	62.10	78.56	159	38	379	379	38
1169	LARSEN MEMORIAL	FL	218.02	0.24	338627.23	GAS	1,128,757	61.89	78.29	0	367	578	608	0
2652	DELTA	MS	225.00	0.14	266814.60	GAS	1,524,655	61.84	78.24	0	0	167	167	0

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
1933	BIG CAJUN 1	LA	230.00	0.12	150,421	GAS	1,002,809	61.89	78.29	0	49	23	103	0
216	CECIL LYNCH	AR	231.10	0.04	108,901	GAS	2,178,026	61.84	78.24	50	7	130	245	7
3957	E S JOSLIN	TX	234.87	0.29	383,809	GAS	1,058,783	61.69	78.04	0	13	14	14	0
1137	CUTLER	FL	236.50	0.19	266,715	GAS	1,123,012	61.62	77.95	2	663	869	901	2
1964	LIEBERMAN	LA	240.00	0.21	264,491	GAS	1,007,585	61.48	77.77	14	0	15	25	0
1243	BACONTON POWER	GA	240.00	0.03	4,431	GAS	118,149	61.48	77.77	74	42	269	280	42
4003	LA PALMA	TX	242.33	0.29	423,539	GAS	1,168,384	61.39	77.66	0	23	25	28	0
4126	TRINIDAD	TX	243.36	0.19	262,494	GAS	1,105,240	61.34	77.61	0	0	15	16	0
4096	SHELL DEER PARK	TX	250.00	0.84	935,882	GAS	891,317	61.09	77.28	0	1	7	7	0
4111	TENASKA III TEXAS PAI	TX	250.00	0.68	788,323	GAS	927,439	61.09	77.28	15	57	49	49	15
2665	MOSELLE	MS	260.00	0.24	477,000	GAS	1,590,000	60.71	76.81	0	0	31	103	0
2000	ST CHARLES OPERATIO	LA	264.00	0.80	1,048,847	GAS	1,048,847	60.57	76.62	0	156	4	4	0
1223	TIGER BAY	FL	278.22	0.55	608,203	GAS	884,659	60.07	76.00	0	393	604	634	0
1239	ATKINSON	GA	281.70	0.04	98,363	GAS	1,967,259	59.96	75.85	254	139	370	402	139
4112	TENASKA IV TEXAS PAI	TX	282.60	0.63	706,816	GAS	897,545	59.93	75.81	68	114	73	106	68
3916	BAYOU COGENERATIOI	TX	300.00	0.98	1,128,743	GAS	921,423	59.37	75.11	0	1	7	7	0
4265	GORDONSVILLE ENERG	VA	300.40	0.09	135,503	GAS	1,204,474	59.36	75.09	194	43	1054	1139	43
2723	BUTLER WARNER GEN	NC	303.40	0.06	122,514	GAS	1,633,521	59.26	74.97	171	59	898	898	59
1956	GEORGIA GULF CORPOI	LA	306.00	0.75	1,101,673	GAS	1,175,118	59.19	74.87	0	87	23	63	0
1290	MID GEORGIA COGEN	GA	315.24	0.25	313,705	GAS	1,003,857	58.91	74.53	115	0	368	368	0
4004	LAKE CREEK	TX	321.63	0.32	629,962	GAS	1,574,905	58.73	74.29	28	41	49	49	28
1936	BONIN	LA	328.50	0.22	413,861	GAS	1,504,949	58.53	74.05	0	63	2	39	0
182	MCINTOSH	AL	336.00	0.07	148,787	GAS	1,700,422	58.33	73.79	0	0	21	49	0
4024	MIRANT TEXAS LP BOS	TX	340.00	0.16	326,702	GAS	1,633,511	58.22	73.65	93	118	107	107	93
4049	PARKDALE	TX	340.63	0.21	447,117	GAS	1,703,304	58.20	73.63	14	81	71	109	14
1157	INDIAN RIVER PLANT	FL	342.80	0.05	100,309	GAS	1,604,949	58.14	73.56	0	442	653	679	0
4070	RAY OLINGER	TX	345.00	0.36	784,981	GAS	1,744,402	58.09	73.48	0	94	70	119	0
2673	REX BROWN	MS	350.20	0.12	381,064	GAS	2,540,423	57.95	73.31	0	11	37	113	0
1991	PPG POWERHOUSE C	LA	357.81	0.80	1,443,285	GAS	1,443,285	57.76	73.06	0	24	3	22	0
1272	HARTWELL ENERGY LP	GA	360.00	0.13	321,760	GAS	1,980,058	#REF!	#REF!	234	200	515	543	200

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
4256	DARBYTOWN	VA	368.52	0.02	56,948	GAS	2,277,937	57.49	72.73	147	28	1084	1151	28
1153	HINES ENERGY COMPL	FL	373.15	0.83	1,164,775	GAS	1,122,675	57.38	72.59	0	393	604	634	0
3939	CLEAR LAKE COGENER	TX	377.00	0.90	1,688,152	GAS	1,500,580	57.29	72.47	0	1	7	7	0
1110	ARVAH B HOPKINS	FL	377.57	0.41	924,149	GAS	1,803,217	57.27	72.45	59	57	252	273	57
1203	S O PURDOM	FL	378.80	0.17	232,716	GAS	1,095,133	57.24	72.42	79	82	277	301	79
4251	COMMONWEALTH ATL	VA	388.88	0.03	70,067	GAS	1,868,450	57.01	72.12	67	157	1154	1188	67
4270	HOPEWELL COGENERA	VA	399.00	0.14	261,244	GAS	1,492,822	56.78	71.83	144	58	1085	1144	58
4266	GRAVEL NECK	VA	407.92	0.01	34,000	GAS	2,719,967	56.58	71.58	120	93	1112	1160	93
1261	DOYLE GENERATING F	GA	409.18	0.06	90,322	GAS	1,204,287	56.56	71.55	205	120	438	444	120
1930	BATON ROUGE COGEN	LA	422.10	0.79	1,055,404	GAS	1,068,763	56.28	71.20	0	75	3	84	0
4143	WEBSTER	TX	426.36	0.13	343,439	GAS	2,113,469	56.19	71.09	0	47	3	3	0
2669	NEW ALBANY POWER F	MS	427.20	0.02	70,099	GAS	2,803,960	56.18	71.07	75	75	101	304	75
2004	TECHE	LA	427.90	0.38	952,391	GAS	2,005,033	56.16	71.05	0	123	15	22	0
1968	LOUISIANA 1	LA	437.50	0.01	51,173	GAS	4,093,830	55.97	70.80	0	73	11	82	0
4120	THOMAS C FERGUSON	TX	446.00	0.37	886,780	GAS	1,917,363	55.80	70.59	121	94	133	133	94
4114	TEXAS CITY COGENER	TX	450.00	0.90	1,640,527	GAS	1,458,246	55.72	70.49	0	73	5	6	0
4001	KNOX LEE	TX	458.69	0.32	833,323	GAS	2,083,308	55.55	70.28	0	53	10	19	0
4108	SWEENY COGENERATI(	TX	460.00	0.68	1,579,420	GAS	1,858,141	55.53	70.25	0	54	25	26	0
4137	VICTORIA	TX	460.87	0.22	618,149	GAS	2,247,816	55.51	70.23	0	0	19	19	0
3981	GREGORY POWER FACI	TX	464.00	0.39	625,517	GAS	1,283,112	55.45	70.15	0	0	14	14	0
4234	BELLMEADE	VA	467.50	0.07	154,292	GAS	1,763,337	55.39	70.07	147	28	1084	1151	28
1149	HARDEE POWER STATI(	FL	470.05	0.28	29,370	GAS	83,913	55.34	70.01	0	412	621	652	0
2002	STERLINGTON	LA	480.78	0.33	809,093	GAS	1,961,437	55.15	69.77	37	0	25	59	0
4141	W B TUTTLE	TX	495.00	0.08	244,670	GAS	2,446,695	54.90	69.45	39	64	72	78	39
4046	OYSTER CREEK UNIT V	TX	498.05	0.66	1,269,951	GAS	1,539,335	54.84	69.38	0	1	7	7	0
3987	HIDALGO ENERGY CEN	TX	500.00	0.25	409,021	GAS	1,308,867	54.81	69.34	0	0	10	63	0
4014	LON C HILL	TX	510.87	0.35	1,172,816	GAS	2,680,722	54.63	69.11	0	4	14	16	0
3975	FRONTERA GENERATIC	TX	511.00	0.34	706,478	GAS	1,662,300	54.62	69.10	0	0	10	63	0
4042	NUECES BAY	TX	513.69	0.51	1,411,893	GAS	2,214,734	54.58	69.05	0	21	6	6	0
2649	CALEDONIA POWER FA	MS	519.18	0.03	76,963	GAS	2,052,339	54.49	68.93	40	21	18	188	18

Appendix B: (Continued)

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3991	INGLESIDE COGENERA	TX	528.00	0.63	846,313	GAS	1,074,683	54.35	68.75	0	0	14	14	0
3852	BROWNSVILLE PEAKIN	TN	529.20	0.04	135,178	GAS	2,703,564	54.33	68.73	127	9	229	408	9
4011	LEWIS CREEK	TX	542.80	0.60	1,818,204	GAS	2,424,271	54.11	68.45	0	0	19	19	0
3907	A VON ROSENBERG	TX	549.63	0.45	887,520	GAS	1,577,813	54.01	68.32	31	59	60	67	31
3989	HOLLY STREET	TX	558.00	0.25	711,016	GAS	2,275,250	53.88	68.16	51	23	62	62	23
3940	COGEN LYONDELL INC	TX	564.00	0.81	1,686,257	GAS	1,665,439	53.79	68.05	0	1	7	7	0
3869	GLEASON POWER FACIL	TN	567.90	0.01	5,333	GAS	426,624	53.73	67.97	215	12	293	498	12
1317	SEWELL CREEK ENERG	GA	570.00	0.00	37,986	GAS	2,227,142	53.70	67.93	295	120	307	367	120
1197	PUTNAM	FL	580.00	0.48	1,359,729	GAS	2,266,215	53.55	67.75	55	320	522	545	55
1989	POWER AND UTILITIES	LA	587.00	0.69	1,480,457	GAS	1,716,472	53.45	67.62	0	87	23	63	0
3766	BROAD RIVER ENERGY	SC	591.00	0.03	22,965	GAS	612,405	53.40	67.55	283	193	645	682	193
4098	SIM GIDEON	TX	639.00	0.40	1,323,358	GAS	2,646,715	52.75	66.73	7	5	19	19	5
3914	BARNEY M DAVIS	TX	647.14	0.61	2,193,268	GAS	2,876,417	52.64	66.60	0	44	7	31	0
3970	FORMOSA UTILITY VEN	TX	652.20	0.67	1,547,062	GAS	1,847,238	52.58	66.52	0	28	33	33	0
4297	REMINGTON	VA	697.00	0.01	61,636	GAS	4,930,863	52.04	65.83	203	101	1104	1206	101
1339	WEST GEORGIA GENER	GA	701.40	0.10	395,583	GAS	3,164,664	51.98	65.76	185	43	337	337	43
3958	EAGLE MOUNTAIN	TX	706.15	0.15	687,020	GAS	3,664,108	51.93	65.70	86	147	10	161	10
4038	NORTH LAKE	TX	708.61	0.31	1,236,395	GAS	3,190,697	51.90	65.66	40	111	43	139	40
4106	STRYKER CREEK	TX	713.48	0.38	1,530,830	GAS	3,222,799	51.85	65.59	0	74	15	15	0
1160	J D KENNEDY	FL	727.20	0.03	44,126	GAS	1,176,693	51.69	65.39	43	289	518	536	43
1258	DAHLBERG	GA	735.49	0.09	337,169	GAS	2,997,058	51.60	65.28	115	0	368	368	0
4258	DOSWELL COMBINED C	VA	742.40	0.23	772,758	GAS	2,687,853	51.52	65.18	148	4	1090	1163	4
231	LAKE CATHERINE	AR	752.00	0.24	1,061,320	GAS	3,537,734	51.42	65.05	69	21	113	190	21
4051	PASADENA COGENERA	TX	760.90	0.28	934,618	GAS	2,670,338	51.33	64.93	0	1	7	7	0
4150	WILKES	TX	807.39	0.34	1,475,791	GAS	3,472,449	50.85	64.33	0	27	12	25	0
2793	ROCKINGHAM POWER I	NC	809.08	0.03	398,185	GAS	10,618,277	50.84	64.31	299	104	846	908	104
2812	WAYNE COUNTY	NC	847.06	0.05	223,782	GAS	3,580,516	50.47	63.85	114	87	969	975	87
1140	DEBARY	FL	861.22	0.07	371,547	GAS	4,246,250	50.34	63.69	0	385	592	617	0
4085	SAM BERTRON	TX	875.26	0.24	1,218,280	GAS	4,060,933	50.21	63.53	0	25	6	14	0
3980	GREENS BAYOU	TX	878.40	0.12	648,993	GAS	4,326,621	50.19	63.49	0	14	17	25	0

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
2006	WATERFORD 1 & 2	LA	891.00	0.19	1,117,647	GAS	4,705,882	50.08	63.35	0	156	9	9	0
2646	BATESVILLE GENERATI	MS	891.00	0.15	295,123	GAS	1,573,987	50.08	63.35	41	8	155	257	8
4043	O W SOMMERS	TX	892.00	0.33	1,657,749	GAS	4,018,784	50.07	63.34	13	41	51	67	13
4131	V H BRAUNIG	TX	894.00	0.23	1,937,823	GAS	6,740,254	50.05	63.32	11	43	43	59	11
1949	EVANGELINE POWER S	LA	922.84	0.13	4,883,137	GAS	30,050,072	49.80	63.00	0	0	40	113	0
244	ROBERT E RITCHIE	AR	923.15	0.12	1,421,037	GAS	9,473,579	49.80	63.00	0	0	212	241	0
4005	LAKE HUBBARD	TX	927.52	0.33	1,732,061	GAS	4,198,937	49.76	62.95	0	75	69	104	0
3949	DECKER CREEK	TX	932.58	0.27	1,402,241	GAS	4,154,789	49.72	62.90	43	16	55	55	16
4110	TENASKA FRONTIER GE	TX	939.70	0.10	753,244	GAS	6,025,951	49.66	62.82	0	0	42	55	0
4031	MOUNTAIN CREEK	TX	958.49	0.27	1,558,564	GAS	4,617,967	49.51	62.63	34	93	56	118	34
1972	MICHOUD	LA	959.25	0.41	2,410,194	GAS	4,702,817	49.50	62.62	0	148	31	42	0
3779	DARLINGTON COUNTY	SC	1045.99	0.02	111,864	GAS	4,474,576	48.83	61.78	229	122	766	766	122
4007	LAMAR POWER PROJEC	TX	1090.84	0.23	336,553	GAS	1,170,620	48.52	61.38	15	57	49	49	15
3982	GUADALUPE GENERATI	TX	1142.20	0.01	96,872	GAS	7,749,735	48.17	60.94	30	51	63	78	30
4023	MIDLOTHIAN ENERGY I	TX	1156.00	0.10	216,771	GAS	1,734,164	48.08	60.82	14	56	57	67	14
4135	VALLEY	TX	1175.49	0.31	2,082,438	GAS	5,374,033	47.95	60.66	39	116	100	112	39
1965	LITTLE GYPSY	LA	1250.78	0.27	2,039,012	GAS	6,041,517	47.49	60.08	0	153	8	8	0
1159	INTERCESSION CITY	FL	1310.20	0.06	487,923	GAS	6,505,636	47.14	59.64	0	424	635	664	0
2647	BAXTER WILSON	MS	1327.60	0.32	4,081,548	GAS	10,203,870	47.05	59.52	0	0	48	59	0
4117	THE DOW CHEMICAL C	TX	1378.84	0.56	2,914,646	GAS	4,163,780	46.77	59.17	0	54	25	26	0
4125	TRADINGHOUSE	TX	1379.70	0.45	3,141,153	GAS	5,584,272	46.77	59.16	28	51	42	42	28
4109	T H WHARTON	TX	1421.52	0.32	2,268,818	GAS	5,672,046	46.55	58.89	0	0	4	4	0
3985	HANDLEY	TX	1433.35	0.24	2,123,689	GAS	7,078,964	46.49	58.81	60	115	37	131	37
2765	LINCOLN COMBUSTION	NC	1548.80	0.03	366,070	GAS	9,761,861	45.93	58.10	337	155	691	742	155
1170	LAUDERDALE	FL	1863.97	0.40	2,935,000	GAS	5,870,000	44.62	56.44	0	636	844	876	0
4082	SABINE	TX	2051.20	0.47	5,303,958	GAS	9,028,014	43.95	55.60	0	26	9	46	0
1980	NINEMILE POINT	LA	2141.62	0.32	4,372,680	GAS	10,931,701	43.66	55.23	0	155	18	22	0
2008	WILLOW GLEN	LA	2178.00	0.24	3,335,416	GAS	11,118,054	43.54	55.08	0	96	28	57	0
3934	CEDAR BAYOU	TX	2295.00	0.41	4,836,827	GAS	9,437,711	43.19	54.64	0	32	19	28	0
4047	P H ROBINSON	TX	2314.50	0.46	5,441,940	GAS	9,464,243	43.13	54.56	0	57	7	7	0

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
3801	MYRTLE BEACH	SC	111.50	0.01	21,071	OIL	1,685,714	50.69	64.13	203	163	836	836	163
3792	HILTON HEAD	SC	117.90	0.02	25,768	OIL	1,030,713	50.33	63.67	5	260	623	629	5
1314	SAVANNAH RIVER MILI	GA	140.40	0.55	563,486	OIL	819,616	49.20	62.24	0	202	566	571	0
4252	COMMONWEALTH CHE	VA	172.50	0.02	8,071	OIL	322,832	47.91	60.61	0	165	1243	1296	0
1146	G E TURNER	FL	180.98	0.03	61,583	OIL	1,642,210	47.61	60.23	0	383	592	618	0
1115	BAYBORO	FL	226.80	0.06	135,773	OIL	1,810,303	46.24	58.50	0	315	522	554	0
1154	HOOKERS POINT	FL	232.60	0.07	245,110	OIL	2,801,262	46.09	58.31	0	332	554	586	0
1211	SOUTHSIDE GENERATIN	FL	265.60	0.24	487,133	OIL	1,623,778	45.30	57.31	46	290	515	534	46
1341	WILSON	GA	321.35	0.02	64,477	OIL	2,579,066	44.20	55.92	66	160	543	543	66
1220	SUWANNEE RIVER	FL	330.60	0.15	462,772	OIL	2,468,115	44.04	55.71	128	172	369	389	128
1199	RELIANT ENERGY INDI	FL	608.54	0.23	1,010,301	OIL	3,514,089	40.69	51.48	0	442	653	679	0
1289	MCMANUS	GA	644.35	0.05	479,476	OIL	7,671,622	40.39	51.10	0	228	523	536	0
1185	P L BARTOW	FL	717.16	0.29	1,778,037	OIL	4,904,931	39.83	50.39	0	315	522	554	0
2656	GERALD ANDRUS	MS	781.47	0.35	2,478,529	OIL	5,665,209	39.39	49.84	0	0	107	107	0
1204	SANFORD	FL	1028.45	0.35	2,958,916	OIL	6,763,236	38.02	48.10	0	379	588	614	0
1145	FORT MYERS	FL	1302.30	0.25	2,433,894	OIL	7,788,462	36.87	46.65	0	475	679	712	0
1181	NORTHSIDE GENERATII	FL	1435.10	0.19	2,174,236	OIL	9,154,677	36.41	46.06	37	289	524	542	37
1195	PORT EVERGLADES	FL	1665.34	0.34	4,331,017	OIL	10,190,627	35.72	45.19	0	641	850	881	0
1172	MANATEE	FL	1726.60	0.33	4,837,988	OIL	11,728,455	35.55	44.97	0	364	571	603	0
1227	TURKEY POINT	FL	2337.85	0.71	2,712,755	OIL	3,056,625	34.18	43.24	4	676	881	913	4
1174	MARTIN	FL	2950.60	0.51	7,617,557	OIL	11,949,108	33.17	41.96	0	542	753	783	0

Appendix C. CO_2 Capture Cost Estimation and Straight-line Distance Source-Sink Matching for Ammonia Plants, SECARB Region

(1) ID	(2) Company Name	(3) State	(4) Design Capacity (Kg)	(5) Estimated Annual CO2 Emmsion(t)	(6) CO2 Capture Cost ($/t)	(7) CO2 Avoid Cost ($/t)	(8) Dist to Nearest Aquifer (km)	(9) Dist to Nearest Coalbed (km)	(10) Dist to Nearest Oil & Gas Fields(km)	(11) Dist to Nearest EOR Oil (km)	(12) Dist to Nearst Sink (km)
3	Air Products & Chemicals, I	FL	86	98,900	15.21	16.18	0	0	21	46	0
1	El Dorado Chemical Company	AL	193	221,950	14.18	15.08	153	36	131	325	36
13	Terra Industries, Inc.	TX	255	293,250	13.84	14.72	0	15	12	45	0
12	PCS Nitrogen Fertilizer, LL	TN	409	470,350	13.28	14.13	42	4	216	330	4
6	Triad Nitrogen L.L.C.	LA	465	534,750	13.13	13.97	0	120	22	38	0
2	Terra Industries, Inc.	AR	467	537,050	13.13	13.97	122	0	283	414	0
8	PCS Nitrogen Fertilizer, LL	LA	532	611,800	12.98	13.81	0	108	32	49	0
15	IMC Phosphates Company	LA	560	644,000	12.92	13.75	0	113	36	53	0
5	Triad Nitrogen L.L.C.	LA	576	662,400	12.89	13.71	0	120	22	38	0
14	Honeywell Nylon Inc.	VA	584	671,600	12.88	13.70	142	57	1087	1146	57
4	PCS Nitrogen Fertilizer, LL	GA	758	871,700	12.59	13.39	113	178	560	560	113
11	Koch Nitrogen Company	LA	1222	1,405,300	12.07	12.84	35	0	24	58	0
7	CF Industries, Inc.	LA	2250	2,587,500	11.45	12.18	0	120	22	38	0

Appendix D. CO_2 Capture Cost Estimation and Straight-line Distance Source-Sink Matching for Cement Plants in SECARB Region

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
ID	Plant Name	State	Annual Cement Production (Kt)	Estimated Annual CO2 Emission (t)	CO2 Capture Cost ($/t)	CO2 Avoid Cost ($/t)	Dist to Nearest Aquifer (km)	Dist to Nearest Coalbed (km)	Dist to Nearest Oil & Gas Fields(km)	Dist to Nearest EOR Oil (km)	Dist to Nearst Sink (km)
28	Lehigh Cement C	TX	99	74,250	48.77	61.69	44	57	59	59	44
1	Holcim (US) Inc	MS	419	314,250	40.75	51.56	20	41	32	180	20
2	Lafarge North A	GA	605	453,750	38.93	49.25	242	127	379	401	127
4	Rinker Material	FL	605	453,750	38.93	49.25	0	298	510	539	0
16	Lehigh Cement C	AL	636	477,000	38.69	48.95	195	32	181	242	32
12	Giant Cement Ho	SC	639	479,250	38.67	48.92	100	252	677	679	100
23	Florida Rock In	FL	647	485,250	38.61	48.84	84	237	441	465	84
15	CEMEX	TN	701	525,750	38.23	48.36	433	58	487	602	58
17	Tarmac America	FL	716	537,000	38.13	48.23	0	645	851	883	0
7	RC Cement Co.In	TN	735	551,250	38.00	48.08	372	123	329	443	123
8	CEMEX	GA	750	562,500	37.91	47.95	110	1	369	369	1
22	Texas Industrie	TX	771	578,250	37.78	47.79	47	65	79	91	47
25	Alamo Cement Co	TX	795	596,250	37.63	47.61	32	61	59	64	32
11	Ash Grove Cemen	AR	803	602,250	37.59	47.55	22	42	55	68	22
19	North Texas Cem	TX	840	630,000	37.38	47.28	40	85	72	96	40
10	CEMEX	AL	853	639,750	37.30	47.19	54	48	81	81	48
26	Capitol Aggrega	TX	868	651,000	37.22	47.09	32	61	59	64	32
24	National Cement	AL	886	664,500	37.13	46.97	236	42	216	283	42
21	CEMEX	TX	906	679,500	37.03	46.84	47	65	79	91	47
14	Holcim (US) Inc	SC	1002	751,500	36.57	46.26	113	239	684	685	113
5	Texas-Lehigh Ce	TX	1078	808,500	36.23	45.84	55	34	66	66	34
13	Lafarge North A	SC	1084	813,000	36.21	45.81	100	252	677	679	100
9	Roanoke Cement	VA	1120	840,000	36.06	45.62	365	126	876	972	126
3	CEMEX	FL	1190	892,500	35.79	45.28	0	298	510	539	0
27	Holcim (US) Inc	AL	1439	1,079,250	34.96	44.22	0	25	41	109	0
6	Lafarge North A	AL	1494	1,120,500	34.79	44.02	153	49	173	192	49
18	Holcim (US) Inc	TX	2024	1,518,000	33.50	42.38	40	85	72	96	40
20	Texas Industrie	TX	2536	1,902,000	32.58	41.21	40	85	72	96	40

Appendix E. CO_2 Capture Cost Estimation and Straight-line Distance Source-Sink Matching for Gas Processing Plants, SECARB Region

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
ID	State	Plant Name	Design Capacity (MMCFD) [	Estimated Annual Emmision ($)	CO2 Capture Cost ($/t)	CO2 Avoid Cost ($/t)	Dist to Nearest Aquifer (km)	Dist to Nearest Coalbed (km)	Dist to Nearest Oil & Gas Fields(km)	Dist to Nearest EOR Oil (km)	Dist to Nearst Sink (km)
31	LA	Lowry	300	182,400	14.66	15.59	0	66	6	23	0
37	LA	Sabine Pass	300	182,400	14.66	15.59	0	66	6	23	0
119	TX	Thompsonville	300	182,400	14.66	15.59	0	0	32	66	0
32	LA	Stingray	305	185,440	14.63	15.56	0	66	6	23	0
34	LA	Cow Island	500	304,000	13.81	14.69	0	98	38	38	0
58	LA	Iowa	500	304,000	13.81	14.69	0	40	4	59	0
78	TX	Houston Central	700	425,600	13.28	14.13	0	0	17	55	0
72	MS	Muldon	750	456,000	13.17	14.01	57	20	24	229	20
88	TX	East Texas	780	474,240	13.11	13.95	0	9	7	7	0
89	TX	East Texas	780	474,240	13.11	13.95	0	56	0	0	0
90	TX	East Texas	780	474,240	13.11	13.95	0	38	21	54	0
91	TX	East Texas	780	474,240	13.11	13.95	0	82	10	10	0
11	AR	Searcy	850	516,800	12.98	13.81	76	3	178	313	3
16	LA	Sea Robin	900	547,200	12.89	13.72	0	98	38	38	0
135	TX	King Ranch	925	562,400	12.85	13.67	0	24	20	30	0
134	TX	Katy	950	577,600	12.81	13.63	0	0	11	11	0
64	MS	Pascagoula	1000	608,000	12.74	13.55	0	34	59	140	0
40	LA	Bluewater	1050	638,400	12.67	13.47	0	48	4	62	0
38	LA	North Terrebonne	1250	760,000	12.41	13.20	0	141	20	29	0
59	LA	Venice	1300	790,400	12.35	13.14	0	191	9	35	0
35	LA	Eunice	1350	820,800	12.30	13.08	0	48	4	62	0

Appendix F. CO_2 Capture Cost Estimation and Straight-line Distance Source-Sink Matching for Refineries, SECARB Region

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(8)	(10)	(11)	(12)
ID	Plant Name	State	Design Capacity (BPD)	Estimated Annual Emission (t)	CO2 Capture Cost ($/t)	CO2 Avoid Cost ($/t)	Dist to Nearest Aquifer (km)	Dist to Nearest Coalbed (km)	Dist to Nearest Oil & Gas Fields(km)	Dist to Nearest EOR Oil (km)	Dist to Nearst Sink (km)
3850	Young Refining Corp.	GA	5400	53665	65.52	82.89	269	144	345	380	144
1236	Cross Oil Refining and Mktg, Inc.	AR	6800	67578	63.39	80.20	52	8	24	123	8
345	Calumet Lubricants Co. LP	LA	8300	82485	61.61	77.94	52	1	13	63	1
3	Age Refining, Inc.	TX	9112	90555	60.79	76.91	32	61	59	64	32
330	Calumet Lubricants Co. LP	LA	13020	129393	57.76	73.08	52	0	14	56	0
3353	TRIGEANT EP LTD	AL	16700	165965	55.74	70.52	0	4	23	89	0
1329	Ergon Refining Inc.	MS	23000	228574	53.24	67.36	0	0	57	61	0
319	Calcasieu Refining Co.	LA	30000	298140	51.26	64.84	0	29	13	28	0
1937	Hunt Refining Co.	AL	33500	332923	50.45	63.83	94	1	100	162	1
381	Calumet Lubricants Co. LP	LA	46200	459136	48.18	60.95	31	0	14	53	0
2646	Placid Refining Co.	LA	48500	481993	47.85	60.53	0	75	10	78	0
1995	La Gloria Oil & Gas Co.	TX	55000	546590	46.99	59.45	0	72	16	27	0
1828	Giant Yorktown Refg	VA	58600	582367	46.57	58.91	366	162	333	493	162
2023	Lion Oil Co.	AR	63000	626094	46.09	58.31	56	16	9	124	9
2275	Marathon Ashland Petro LLC	TX	72000	715536	45.22	57.20	0	71	2	2	0
3618	Valero Refining Co. Louisiana	LA	78000	775164	44.70	56.55	0	42	24	72	0
2788	Shell Chem LP	AL	80000	795040	44.54	56.35	0	0	8	87	0
3728	Valero Refining Co. Texas	TX	83000	824854	44.31	56.05	0	13	19	19	0
3510	VALERO ENERGY CORPORATI	TX	90000	894420	43.79	55.40	0	0	18	85	0
1263	Crown Central Petro Corp	TX	100000	993800	43.14	54.57	0	26	8	11	0
2474	Murphy Oil U.S.A. Inc.	LA	120000	1192560	42.03	53.17	0	157	23	41	0
3761	VALERO SAINT CHARLES REF	LA	155000	1540390	40.51	51.25	0	153	2	2	0
88	Atofina Petrochemicals Inc.	TX	175068	1739826	39.81	50.37	0	38	7	48	0
2739	PREMCOR REFINING GROUP II	TN	180000	1788840	39.66	50.17	42	4	216	330	4
469	Chalmette Refining LLC	LA	182500	1813685	39.58	50.07	0	156	23	40	0
3547	VALERO REFINING CO TEXAS	TX	204250	2029837	38.95	49.27	0	71	2	2	0
1055	CONOCOPHILLIPS	TX	217000	2156546	38.61	48.84	0	51	1	1	0
2409	Motiva Enterprises LLC	LA	226500	2250957	38.37	48.54	0	153	2	2	0
2201	Marathon Ashland Petro LLC	LA	232000	2305616	38.24	48.38	0	142	24	24	0

Appendix F: (Continued)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(8)	(10)	(11)	(12)
ID	Plant Name	State	Design Capacity (BPD)	Estimated Annual Emission (t)	CO2 Capture Cost ($/t)	CO2 Avoid Cost ($/t)	Dist to Nearest Aquifer (km)	Dist to Nearest Coalbed (km)	Dist to Nearest Oil & Gas Fields(km)	Dist to Nearest EOR Oil (km)	Dist to Nearst Sink (km)
2334	Motiva Enterprises LLC	LA	235000	2335430	38.17	48.29	0	135	25	37	0
2445	Motiva Enterprises LLC	TX	250000	2484500	37.83	47.86	0	38	7	48	0
1122	CONOCOPHILLIPS	LA	252000	2504376	37.79	47.81	0	26	10	28	0
831	CONOCOPHILLIPS	LA	253500	2519283	37.76	47.77	0	166	14	40	0
2718	Premcor Refg Group Inc	TX	255000	2534190	37.73	47.73	0	38	7	48	0
2085	Lyondell Citgo Refining Co. Ltd.	TX	270200	2685248	37.42	47.33	0	13	19	19	0
709	Citgo Petroleum Corp.	LA	324300	3222893	36.45	46.11	0	29	13	28	0
1305	Deer Park Refg Ltd Ptnrshp	TX	333700	3316311	36.30	45.92	0	29	1	11	0
1475	ExxonMobil Refg & Supply Co.	TX	348500	3463393	36.08	45.64	0	15	12	45	0
168	BP Products North America, Inc.	TX	437000	4342906	34.93	44.18	0	71	2	2	0
1386	ExxonMobil Refg & Supply Co.	LA	493500	4904403	34.32	43.42	0	78	13	77	0
1433	ExxonMobil Refg & Supply Co.	TX	557000	5535466	33.73	42.68	0	32	14	23	0

Appendix G. CO_2 Sequestration Full Cost Estimation, eastern Texas

(1) Company Name	(2) Facility Name	(3) Plant Type	(4) Annual CO2 Flow (Mt)	(5) Destination[1]	(6) Pipeline Diameter (Inch)	(7) Capture Cost ($/t)	(8) Transportation Cost ($/t)	(9) EOR Credit ($/t)	(10) Injection Cost ($/t)	(11) Total Cost ($/t)
TXU Generation LLC	RIVER CREST	Power Plant	0.50	O319	8	69.21	0.33	16.00		53.54
Garland City of	RAY OLINGER	Power Plant	1.57	O136	12	58.09	2.29	16.00		44.38
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	6	13.11	0.00	16.00		-2.89
Southwestern Electri	KNOX LEE	Power Plant	1.87	O80	12	55.55	0.27	16.00		39.82
La Gloria Oil & Gas		Refinery	0.49	O92	8	46.99	2.17	16.00		33.16
AEP NUGs	MARTIN LAKE	Power Plant	18.25	O80	30	31.69	0.10	16.00		15.79
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	6	13.11	2.57	16.00		-0.32
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	6	13.11	1.10	16.00		-1.79
Entergy Gulf States	LEWIS CREEK	Power Plant	2.18	O59	12	54.11	0.29	16.00		38.40
University of Texas	UNIVERSITY OF TEX	Power Plant	0.28	O115	6	70.13	6.00	16.00		60.13
Texas Genco	DEEPWATER	Power Plant	0.86	O358	8	63.88	0.88	16.00		48.76
CEMEX		Cement	0.61	O115	8	37.03	4.09	16.00		25.12
Texas Genco	WEBSTER	Power Plant	1.90	O358	12	56.19	0.09	16.00		40.28
El Paso Field Servic	Thompsonville	GAS PROC	0.16	O317	6	14.66	8.18	16.00		6.84
Panda Energy	LAMAR POWER PRO	Power Plant	1.05	O136	12	48.52	3.68	16.00		36.20
Terra Industries, In		Ammonia	0.26	O8	6	13.84	7.44	16.00		5.28
Air Liquide America	SABINE COGEN LP	Power Plant	0.27	O8	6	70.34	7.20	16.00		61.54
E I DuPont De Nemour	SABINE RIVER WORK	Power Plant	0.27	O8	6	69.91	7.05	16.00		60.96
Motiva Enterprises L	PORT ARTHUR REFI	Power Plant	0.36	O8	6	68.05	2.87	16.00		54.92
Exxon Mobil	BAYTOWN TURBINE	Power Plant	0.59	O59	8	62.68	3.52	16.00		50.20
Exxon Mobil	EXXON MOBIL CO U	Power Plant	0.57	O59	8	62.54	3.63	16.00		50.17
Copano Energy LLC	Houston Central	GAS PROC	0.38	O200	6	13.28	3.40	16.00		0.68
VALERO REFINING CO T		Refinery	1.83	O135	12	38.95	0.60	16.00		23.55
Marathon Ashland Pet		Refinery	0.64	O135	8	45.22	1.30	16.00		30.52
BP Amoco	POWER STATION 3	Power Plant	0.48	O135	8	68.69	1.33	16.00		54.02
Sweeny Cogeneration	SWEENY COGENERA	Power Plant	1.67	O322	12	55.53	0.64	16.00		40.17
TXU Generation LLC	COLLIN	Power Plant	0.67	O136	8	65.75	4.92	16.00		54.67

Note: 1.Destination Code O represents oil fileds, G represents gas fields. The number is taken from the ID field in the SECARB sink database.

Appendix G: (Continued)

(1) Company Name	(2) Facility Name	(3) Plant Type	(4) Annual CO2 Flow (Mt)	(5) Destination	(6) Pipeline Diameter (Inch)	(7) Capture Cost ($/t)	(8) Transportation Cost ($/t)	(9) EOR Credit ($/t)	(10) Injection Cost ($/t)	(11) Total Cost ($/t)
Occidental Chemical	DEER PARK PLANT	Power Plant	0.34	O313	6	69.35	7.65	16.00		61.00
ExxonMobil Corp.	King Ranch	GAS PROC	0.51	O25	8	12.85	6.42	16.00		3.27
Bryan City of	DANSBY	Power Plant	0.45	Aquifer	8	69.96	0.00		0.93	70.89
Bryan City of	BRYAN	Power Plant	0.74	Aquifer	8	67.04	0.00		0.57	67.61
Texas Municipal Powe	GIBBONS CREEK	Power Plant	2.93	Aquifer	16	38.55	0.00		0.14	38.69
Tenaska	TENASKA FRONTIER	Power Plant	5.42	Aquifer	16	49.66	0		0.08	49.74
ExxonMobil Refg & Su		Refinery	3.12	Aquifer	16	36.08	0		0.14	36.22
Entergy Gulf States	SABINE	Power Plant	8.13	Aquifer	20	43.95	0		0.05	44.00
ExxonMobil Corp.	Katy	GAS PROC	0.52	Aquifer	8	12.81	0		0.81	13.62
Texas Genco	T H WHARTON	Power Plant	5.10	Aquifer	16	46.55	0		0.08	46.63
Lower Colorado River	FAYETTE POWER PR	Power Plant	11.26	Aquifer	24	32.98	0		0.04	33.02
Motiva Enterprises L		Refinery	2.24	Aquifer	12	37.83	0		0.19	38.02
Premcor Refg Group I		Refinery	2.28	Aquifer	12	37.73	0		0.19	37.92
Atofina Petrochemica		Refinery	1.57	Aquifer	12	39.81	0		0.27	40.08
Exxon Mobil	BEAUMONT REFINE	Power Plant	2.14	Aquifer	12	63.02	0		0.20	63.22
AES NUGs	AES DEEPWATER IN	Power Plant	1.72	Aquifer	12	42.73	0		0.25	42.98
Texas Genco	SAN JACINTO SES	Power Plant	0.57	Aquifer	8	64.51	0		0.75	65.26
Occidental Chemical	HOUSTON CHEMICA	Power Plant	0.48	Aquifer	8	63.26	0		0.88	64.14
Shell	SHELL DEER PARK	Power Plant	0.80	Aquifer	8	61.09	0		0.53	61.62
Air Liquide America	BAYOU COGENERAT	Power Plant	0.83	Aquifer	8	59.37	0		0.51	59.88
Calpine	CLEAR LAKE COGEN	Power Plant	1.35	Aquifer	12	57.29	0		0.31	57.60
Dow Chemical	OYSTER CREEK UNIT	Power Plant	1.39	Aquifer	12	54.84	0		0.31	55.15
Dynegy Generation	COGEN LYONDELL I	Power Plant	1.50	Aquifer	12	53.79	0		0.28	54.07
Calpine	PASADENA COGENE	Power Plant	2.40	Aquifer	12	51.33	0		0.18	51.51
Texas Genco	GREENS BAYOU	Power Plant	3.89	Aquifer	16	50.19	0		0.11	50.30
Valero Refining Co.		Refinery	0.74	Aquifer	8	44.31	0		0.57	44.88
Lyondell Citgo Refin		Refinery	2.42	Aquifer	12	37.42	0		0.18	37.60
Texas Genco	CEDAR BAYOU	Power Plant	8.49	Aquifer	20	43.19	0		0.05	43.24

Appendix G: (Continued)

(1) Company Name	(2) Facility Name	(3) Plant Type	(4) Annual CO2 Flow (Mt)	(5) Destination	(6) Pipeline Diameter (Inch)	(7) Capture Cost ($/t)	(8) Transportation Cost ($/t)	(9) EOR Credit ($/t)	(10) Injection Cost ($/t)	(11) Total Cost ($/t)
ExxonMobil Refg & Su		Refinery	4.98	Aquifer	16	33.73	0		0.08	33.81
Texas Genco	SAM BERTRON	Power Plant	3.65	Aquifer	16	50.21	0		0.12	50.33
Deer Park Refg Ltd P		Refinery	2.98	Aquifer	16	36.30	0		0.14	36.44
Crown Central Petro		Refinery	0.89	Aquifer	8	43.14	0		0.47	43.61
Texas Genco	P H ROBINSON	Power Plant	8.52	Aquifer	20	43.13	0		0.05	43.18
Texas Genco	W A PARISH	Power Plant	27.00	Aquifer	30	29.85	0		0.02	29.87
BP Products North Am		Refinery	3.91	Aquifer	16	34.93	0		0.11	35.04
BP Amoco	POWER STATION 4	Power Plant	0.51	Aquifer	8	63.71	0		0.82	64.53
Texas City Cogenerat	TEXAS CITY COGENI	Power Plant	1.31	Aquifer	12	55.72	0		0.32	56.04
Dow Chemical	THE DOW CHEMICAI	Power Plant	3.75	Aquifer	16	46.77	0		0.11	46.88
CONOCOPHILLIPS		Refinery	1.94	Aquifer	12	38.61	0		0.22	38.83
AEP NUGs	VICTORIA	Power Plant	2.02	Aquifer	12	55.51	0		0.21	55.72
San Miguel Electric	SAN MIGUEL	Power Plant	3.36	Aquifer	16	38.91	0		0.13	39.04
AEP NUGs	COLETO CREEK	Power Plant	3.56	Aquifer	16	37.44	0		0.12	37.56
AEP NUGs	E S JOSLIN	Power Plant	0.95	Aquifer	12	61.69	0		0.44	62.13
VALERO ENERGY CORPOR		Refinery	0.80	Aquifer	8	43.79	0		0.53	44.32
Union Carbide	SEADRIFT PLANT UN	Power Plant	0.56	Aquifer	8	65.00	0		0.75	65.75
Formosa Plastics Cor	FORMOSA UTILITY V	Power Plant	1.66	Aquifer	12	52.58	0		0.25	52.83
LG&E Power Services	GREGORY POWER FA	Power Plant	1.15	Aquifer	12	55.45	0		0.37	55.82
Occidental Chemical	INGLESIDE COGENEI	Power Plant	0.97	Aquifer	12	54.35	0		0.44	54.79
AEP NUGs	LON C HILL	Power Plant	2.41	Aquifer	12	54.63	0		0.18	54.81
AEP NUGs	NUECES BAY	Power Plant	1.99	Aquifer	12	54.58	0		0.21	54.79
AEP NUGs	LAREDO	Power Plant	0.75	Aquifer	8	64.99	0		0.56	65.55
AEP NUGs	BARNEY M DAVIS	Power Plant	2.59	Aquifer	12	52.64	0		0.16	52.80
Hidalgo Energy Cente	HIDALGO ENERGY C	Power Plant	1.18	Aquifer	12	54.81	0		0.36	55.17
CSW Energy Inc	FRONTERA GENERA	Power Plant	1.50	Aquifer	12	54.62	0		0.28	54.90
AEP NUGs	J L BATES	Power Plant	0.75	Aquifer	8	65.13	0		0.56	65.69
AEP NUGs	LA PALMA	Power Plant	1.05	Aquifer	12	61.39	0		0.40	61.79

Appendix G: (Continued)

(1) Company Name	(2) Facility Name	(3) Plant Type	(4) Annual CO2 Flow (Mt)	(5) Destination	(6) Pipeline Diameter (Inch)	(7) Capture Cost ($/t)	(8) Transportation Cost ($/t)	(9) EOR Credit ($/t)	(10) Injection Cost ($/t)	(11) Total Cost ($/t)
Brownsville Public U	SI RAY	Power Plant	0.64	Aquifer	8	66.52	0		0.66	67.18
Texas Genco	LIMESTONE	Power Plant	11.92	Aquifer	24	33.13	0		0.06	33.19
Sempra Energy Resour	TNP ONE	Power Plant	2.71	Aquifer	16	39.65	0		0.16	39.81
AEP NUGs	MONTICELLO	Power Plant	15.17	Aquifer	24	32.38	0		0.06	32.44
Southwestern Electri	WELSH	Power Plant	11.81	Aquifer	24	33.35	0.00		0.06	33.41
TXU Generation LLC	TRINIDAD	Power Plant	0.99	Aquifer	12	61.34	0.00		0.43	61.77
TXU Generation LLC	BIG BROWN	Power Plant	9.51	Aquifer	20	34.37	0.00		0.07	34.44
Southwestern Electri	WILKES	Power Plant	3.13	Aquifer	16	50.85	0.00		0.14	50.99
TXU Generation LLC	STRYKER CREEK	Power Plant	2.90	Aquifer	16	51.85	0.00		0.15	52.00
TXU Generation LLC	LAKE HUBBARD	Power Plant	3.78	Aquifer	16	49.76	0.00		0.14	49.90
Southwestern Electri	PIRKEY	Power Plant	5.10	Aquifer	16	36.81	0.00		0.10	36.91
Duke Energy Field Se	East Texas	GAS PROC	0.43	Aquifer	6	13.11	0.00		0.98	14.09
Alcoa NUGS	SANDOW	Power Plant	2.77	Aquifer	16	39.47	0.05		0.15	39.67
TXU Generation LLC	TRADINGHOUSE	Power Plant	5.03	Aquifer	16	46.77	0.21		0.11	47.09
TXU Generation LLC	LAKE CREEK	Power Plant	1.42	Aquifer	12	58.73	0.62		0.30	59.65
AEP NUGs	SANDOW	Power Plant	4.47	Aquifer	16	37.29	0.08		0.09	37.46
Austin City of	DECKER CREEK	Power Plant	3.74	Aquifer	16	49.72	0.53		0.11	50.36
Austin City of	HOLLY STREET	Power Plant	2.05	Aquifer	12	53.88	1.10		0.21	55.19
Lower Colorado River	SIM GIDEON	Power Plant	2.38	Aquifer	12	52.75	0.06		0.18	52.99
Texas-Lehigh Ce		Cement	0.73	Aquifer	8	36.23	1.63		0.58	38.44
Texas Industrie		Cement	0.52	Aquifer	8	37.78	2.51		0.81	41.10
Guadalupe Power Part	GUADALUPE GENER	Power Plant	6.97	Aquifer	20	48.17	0.22		0.06	48.45
San Antonio Public S	W B TUTTLE	Power Plant	2.20	Aquifer	12	54.90	0.85		0.19	55.94
San Antonio Public S	A VON ROSENBERG	Power Plant	1.42	Aquifer	12	54.01	1.51		0.30	55.82
Alamo Cement Co		Cement	0.54	Aquifer	8	37.63	4.41		0.79	42.83
Capitol Aggrega		Cement	0.59	Aquifer	8	37.22	4.04		0.72	41.98
San Antonio Public S	MISSION ROAD	Power Plant	0.48	Aquifer	8	69.07	5.11		0.88	75.06
San Antonio Public S	LEON CREEK	Power Plant	0.99	Aquifer	12	63.82	1.07		0.43	65.32

Appendix G: (Continued)

(1) Company Name	(2) Facility Name	(3) Plant Type	(4) Annual CO2 Flow (Mt)	(5) Destination	(6) Pipeline Diameter (Inch)	(7) Capture Cost ($/t)	(8) Transportation Cost ($/t)	(9) EOR Credit ($/t)	(10) Injection Cost ($/t)	(11) Total Cost ($/t)
San Antonio Public S	J T DEELY	Power Plant	6.43	Aquifer	20	35.54	0.08		0.07	35.69
San Antonio Public S	O W SOMMERS	Power Plant	3.62	Aquifer	16	50.07	0.12		0.12	50.31
San Antonio Public S	J K SPRUCE	Power Plant	3.94	Aquifer	16	37.63	0.11		0.11	37.85
San Antonio Public S	V H BRAUNIG	Power Plant	6.07	Aquifer	20	50.05	0.10		0.07	50.22
Lower Colorado River	THOMAS C FERGUSC	Power Plant	1.73	Aquifer	12	55.80	1.99		0.25	58.04
TXU Generation LLC	PARKDALE	Power Plant	1.53	Aquifer	12	58.20	1.00		0.28	59.48
Exelon Generation	HANDLEY	Power Plant	6.37	Aquifer	20	46.49	0.54		0.08	47.11
Exelon Generation	MOUNTAIN CREEK	Power Plant	4.16	Aquifer	16	49.51	0.45		0.13	50.09
Holcim (US) Inc		Cement	1.37	Aquifer	12	33.50	1.02		0.31	34.83
Texas Industrie		Cement	1.71	Aquifer	12	32.58	0.81		0.25	33.64
Mirant Corp	MIRANT TEXAS LP E	Power Plant	1.47	Aquifer	12	58.22	1.65		0.29	60.16
North Texas Cem		Cement	0.57	Aquifer	8	37.38	1.84		0.74	39.96
ANP	MIDLOTHIAN ENERC	Power Plant	1.56	Aquifer	12	48.08	0.28		0.27	48.63
TXU Generation LLC	VALLEY	Power Plant	4.84	Aquifer	16	47.95	0.29		0.11	48.35
North American Energ	TENASKA IV TEXAS	Power Plant	0.81	Aquifer	8	59.93	1.92		0.52	62.37
North American Energ	TENASKA III TEXAS	Power Plant	0.83	Aquifer	8	61.09	0.50		0.51	62.10
TXU Generation LLC	NORTH MAIN	Power Plant	0.57	G287	8	68.86	3.07		3.09	75.02
TXU Generation LLC	NORTH LAKE	Power Plant	2.87	G287	16	51.90	0.61		2.30	54.81
TXU Generation LLC	EAGLE MOUNTAIN	Power Plant	3.30	G287	16	51.93	0.15		2.29	54.37

CO_2 Capture Action Plan

Deliverable 22A

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EPRI Project Manager:
Richard Rhudy

Report Prepared by
Carbon Capture and Sequestration Technologies Program
Massachusetts Institute of Technology

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BACKGROUND

This report summarizes the status of work done in Phase 1 regarding capture of CO_2 from the regional sources. The sources are summarized, selection of appropriate CO_2 capture technologies is described, description of the CO_2 capture model used in the source sink matching and then future work is described.

1 SECARB REGION STATIONARY CO_2 SOURCES

The region contains the following eight major stationary source categories:

- Power plants
- Ammonia Plants
- Cement plants
- Ethylene plants
- Ethylene oxide plants
- Gas processing facilities
- Iron & steel plants
- Refineries

Locations of the sources are shown in Figures 1-1 and 1-2.

Figure 1-1: Fossil-Fired Power Plants

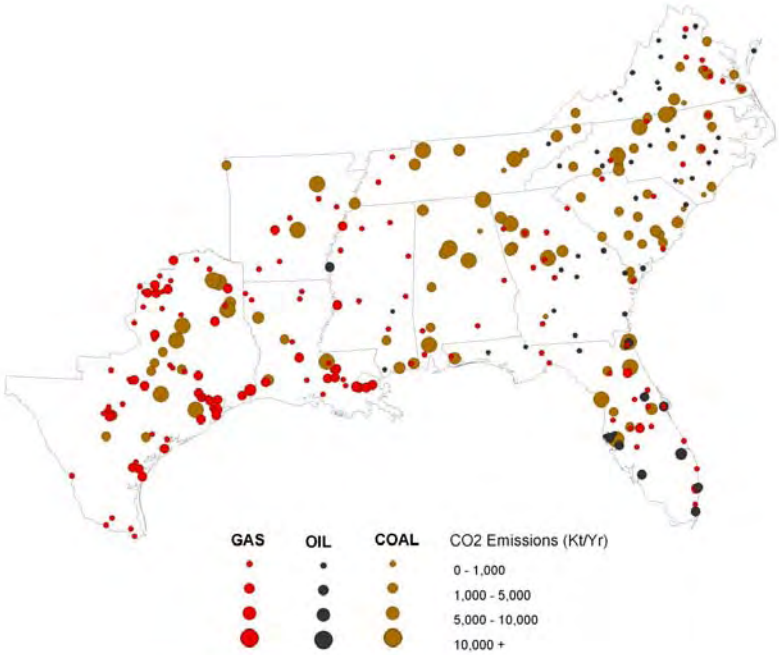
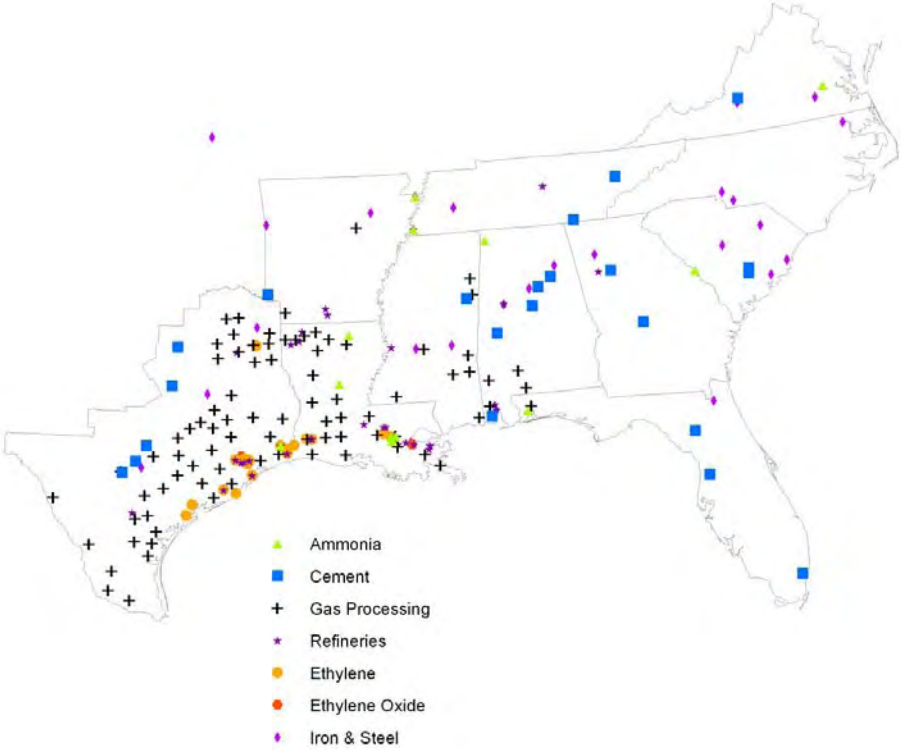


Figure 1-1: Non-Power Stationary CO_2 Sources



Emissions from the regions sources are dominated by power plant sources as shown in Table 1-1. The dominant power plant emissions are from coal-fired plants.

Table 1-1: SECARB CO_2 Sources Emission Summary

Source	Emission, Mt/y
Fossil-Fired Power Plants	
Coal	671
Gas	151
Oil	35
Refineries	63
Ethylene	50
Cement	20
Gas Processing	16
Ammonia	9
Iron & Steel	3
Ethylene Oxide	2

2 CO_2 CAPTURE PROCESS SELECTION AND COSTING

2.1 PROCESS SELECTION

In looking at the existing sources in the SECARB region, post-combustion capture was the only process that was applicable for CO_2 capture.

2.1.1 Post-combustion Capture Processes

Post-combustion capture processes have the advantage of being able to simply add on the back end of the power plant to capture CO_2 from the flue gas (see Figure 2-1). This is an advantage because of the ability to retrofit to the existing fleet of power plants (assuming the physical space is available at the plant site), almost all of which produce an atmospheric flue gas. Unfortunately, the cost associated with post-combustion capture processes today are quite large (increasing the busbar cost of electricity 50-100%), due primarily to their large parasitic energy requirements.

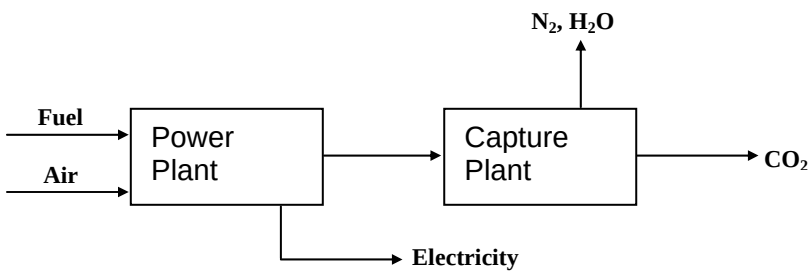


Figure 2-1: Post-combustion CO_2 capture schematic.

Recovery of CO_2 from flue gas is significantly different from other gas treating applications and therefore requires its own specialized process design. Potential processes must work for low CO_2 partial pressures and be able to tolerate oxygen and NO_x. The flue gases from coal-fired power plant boilers also contain SO_x, soot, and fly ash, which the process must be able to handle (or must be removed prior to the CO_2 capture process). Relevant design issues are:

- Low CO_2 partial pressure
- Regeneration energy
- Presence of oxygen, SO_x, NO_x, fly ash and soot
- High flue gas temperatures

The standard method used today for post-combustion capture is chemical absorption using monoethanolamine (MEA). About a dozen plants worldwide use this process on a slipstream from fossil fuel-fired plants. Long-time commercial vendors are Fluor Daniel and Lummus. Two relatively new vendors are MHI (Japan) and Kvaerner (Norway). Amine technology is the only real commercial option available. Alternative technologies have been proposed, but they have not progressed beyond laboratory or pilot scale.

The Fluor Daniel technology was originally developed by Dow. It has been applied only to gas-fired power plants. The Lummus technology was originally developed by Kerr-McGee and has been applied primarily to coal plants. The MHI technology is an offshoot of the Fluor Daniel design and has only been applied to gas plants. However, MHI claims their technology can also be applied to coal plants and are currently engaged in pilot plant tests. Kvaerner does not have their own solvent, but markets a process based on membrane contactors using amines to replace the traditional absorber and stripper in the amine process. This leads to more compact processes (good for offshore), but not necessarily any cost savings due to the costs of the membrane.

The fact that flue gas is released at atmospheric pressure severely handicaps many processes that rely on pressure driving forces. For example, in physical solvent processes, such as Selexol, CO_2 recovery is proportional to the partial pressure of the CO_2 in the feed gas. Other processes requiring pressure driving forces are molecular sieves, membranes, and cryogenic separation. Compression costs to put the flue gas into the operational range of these processes are prohibitive. Figure 2-2 shows the high energy penalty of compressing flue gas. Even compressing to only 75 psia requires over 20% of the total energy produced in the power plant. For this reason, physical absorption, pressure-swing adsorption, membranes, and cryogenic separation are not currently viable candidates for post-combustion capture.

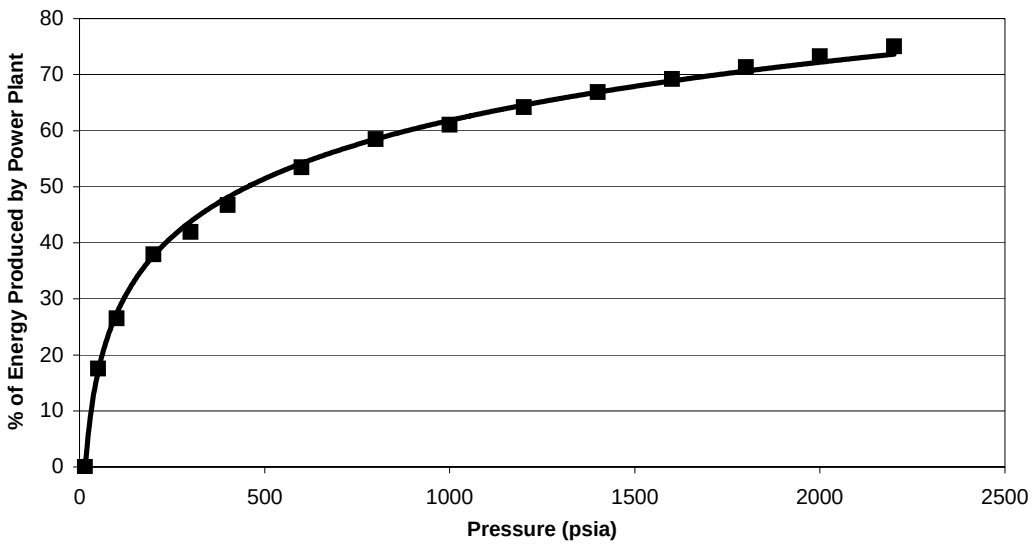


Figure 2-2: Energy required to compress flue gas from a coal-fired power plant (as a percentage of the power plant net output).

2.1.2 Improved separations (post-combustion)

This section describes post-combustion separation technologies which are not as well established as MEA separation.

2.1.2.1 Absorption

Since the amine process is the industry standard today, it is an obvious target for research. By modifying the process to fit the specific needs of CO_2 capture and sequestration from a power plant, one could improve the amine process by about 20-25% in the short-term. Some research is looking at improved packing for the amine absorber, but this will only improve the process by a couple of percent at best. Improved solvents have a potentially bigger impact, with hindered amines providing one of the best opportunities. Another option is to development novel contacting equipment to improve mass transfer and avoid some of the problems associated with vapor/liquid contacting.

Hindered amines are used as a replacement for MEA in flue gas applications. Kansai Electric Power Company (KEPCO) and Mitsubishi Heavy Industries have been developing a proprietary hindered amine called KS-1, which has a lower circulation rate, lower regeneration temperature, 10-15% lower heat reaction with CO_2 and is non-corrosive to carbon steel. The first commercial plant using KS-1 is now in operation in Malayasia.

Another option is to use membrane contactors to replace the absorber and stripper columns in the amine process. They are used to increase the mass transfer area within a given volume and to avoid some of the problems associated with vapor/liquid contacting. The membrane itself does not perform the separation, that job is still done by the amine. Kvaerner Engineering (Norway) developed the equipment and process. One of the driving forces was to make it compact enough to use offshore. A key to the development of the contactor was identifying a membrane that would work in this harsh environment. The only type of membrane that worked was Polytetrafluoroethylene (PTFE), the same membrane used in Gore-Tex. Advantages of the process include: 70-75% weight reduction and 65% space reduction for the absorber and stripper, reduced stripper reboiler duty, and reduced solvent loss. It also will be able to easily accept a wide range of new solvents. Numbers are unavailable for exact energy and cost savings. Some of the cost savings from reducing equipment sizes will be offset by the cost of the membrane. The membrane contactor is now commercially available.

2.1.2.2 Adsorption

An innovation in adsorption technology is combining lithium silicate adsorbent with a rotary heat exchanger (“wheel”). This system adsorbs CO_2 when at a temperature between 450 and 700 degrees C and releases it at higher temperatures. Lithium silicate is capable of capturing 500 times its own volume of CO_2 and is combined with the rotary heat exchanger to allow for continuous operation. Other lithium-containing oxides have been investigated, most notably lithium zirconate.

A novel adsorbent has also been developed at Oak Ridge national Laboratory named a “carbon fiber composite molecular sieve” (CFCMS). An adsorbed gas may be quickly and efficiently desorbed by the passage of an electric current, thereby allowing for a low-energy, electrical-swing separation system. Whether this adsorbent can provide the basis of a new CO_2 capture process remains to be seen.

2.1.2.3 Other processes

The above list of possible new or improved post-combustion capture processes is not exhaustive. It is only meant to give some examples of on-going research. In the future, technology could

produce whole new classes of separation processes. For example, separation processes could be developed using stimulus-responsive separation aids that rely on small changes in process operations to effect large changes in capacity using structured fluids (tailored separation aids that self-assemble reversibly to accommodate and release desired solutes). One example of a structured fluid is liquid crystals. It may be possible to use an electric current as a stimulus-response aid to make the liquid crystals adsorb or desorb CO_2, providing the basis of a low energy intensive post-combustion capture process.

2.2 CO_2 CAPTURE COST METHODOLOGY

The study uses the "*Generic* CO_2 *Capture Retrofit*" spreadsheet prepared by *SFA Pacific, Inc*. as the basis for calculating the CO_2 capture cost for stationary CO_2 sources in the SECARB region (see Figure 2-3). These estimates vary according to three key input variables: (1) the flue gas flow rate (in tonnes per hour); (2) the flue gas composition (volume share or weight share of CO_2 in flue gas); and (3) the annual load factor.

The SFA Pacific spreadsheet provides estimates of capture cost in terms of both CO_2 captured and CO_2 avoided. CO_2 captured is the amount of CO_2 captured by the absorber and kept out of the atmosphere; assumed to be 90% of the CO_2 in the flue gas except for ammonia and gas processing facilities, for which capture factor was assumed to be 100% as their flue gas only consists of pure CO_2. However, since the CO_2 capture process requires energy for purification and compression, the CO_2 avoided term subtracts the CO_2 emitted producing this process energy from the total amount of CO_2 captured. The two terms are used differently in CO_2 sequestration analysis. The CO_2 captured term is used for calculations involving the amount of CO_2 being handled, such as for pipeline transportation costs; while theCO_2 avoided term is used for calculations involving the amount of CO_2 withheld from the atmosphere and therefore eligible for possible CO_2 emissions credits.

According to these two measurements, there are also two definitions on the per unit CO_2 capture cost. To avoid ambiguity, this report uses "CO_2 capture cost" to refer to the capture cost measured in per tonne CO_2 captured while "CO_2 avoidance cost" to refer to the capture cost measured in per tonne CO_2 avoided.

Figure 2-3: SFA Pacific CO_2 Capture Cost Tool

Generic Industrial CO2 Capture for Any Large CO2 Flue Gas Stream

April 2005 working draft by Dale Simbeck at SFA Pacific, Inc

Key assumption is that NG is use as the added energy source to make the steam & power required for CO2 capture
This avoides the loss of capacity or increased off-site CO2 emission of supplying additional electric power
Also the high demand of low pressure stripping steam for the amine CO2 stripper, favors a NG cogen boiler

Color codes: **Primary Inputs** | Secondary Inputs | **Key notes or outupts**

April 13, 2005 Version

Existing Industrial Flue Gas
2,054 metirc ton/h total
48.51 million scf/h

Weight %	Analysis	Volume %
75.00%	N2	75.86%
6.50%	CO2	4.18394545%
5.20%	H2O	8.18%
13.30%	O2	11.77%
0.00%	misc	0.00%
100.00%	Total	100.00%

0.936 million mietic tons per year CO2 (based on below input annual capacity factor)

flue gas normally vented
2,054.0 mt/h
133.5 mt/h CO2

Additional Clean-up & booster Compress

clean flue gas
2,225.6 mt/h
133.5 mt/h CO2

New CO2 Absorber
90%

CO2 depleted Flue Gas Vented
2,105.48 mt/h
13.35 mt/h CO2

171.64 mt/h
25.18 mt/h CO2
15% wt% CO2 fuel gas

NG cogen Flue Gas Vented

CO2 rich | amine solvent | CO2 lean

Thus, the CO2 Avoided to the atm
94.98 mt/h CO2

NG Energy Required for CO2 Capture steam & power

Air
162.48 mt/h
Natural Gas

New NG Boiler 95%

high pressure steam
180.24 mt/h
116.434071 MWt
0.68 MWt/mt

New Backpress Cogen ST/gen

50 psig steam
180.24 mt/h
93.18 MWt if
0.52 MWt/mt

New CO2 Stripper

1.50 tons steam/ton CO2 or
1,200 Btu/lb CO2

122.56 MWt LHV in 100% cogen
418.30 MM Btu/h LHV
464.32 MM Btu/h HHV
9.16 mt/h at
23,000 Btu HHV/lb
0.464 MM scf/h NG at
1,000 Btu/scf HHV

Electric Power via 100% cogen@
17.09 lb steam/kWh cogen

23.25 MWe total
38% 8.83 MWe misc booster fan & amine
62% 14.42 MWe CO2 compressor
MWe flue gas boostet compressor

New CO2 Drying Compress

CO2 Captured
120.16 mt/h or
2,884 mt/d
55 MM scf/d

Indirect offsite CO2 from import power generation **11.63** mt/h CO2 assuming
0.5 mt CO2 per MWh electric

Capital Costs	Unit cost basis at 60	mt/h CO2	cost/size factors	Actual unit cost at 120	mt/h CO2	millions of $ 2003 dollars	Notes
NG boiler	$ 15	/lb/hr steam	75%	$13	/lb/hr steam	5.0	
cogen ST gen	$ 500	/kWe	75%	$420	/kWe	9.8	
Additional cleanup	$ -	mt/h flue gas	75%	$0	mt/h flue gas	-	if SO2, NOx cleanup
Booster compressor	$ 800	/kWe	75%	$672	/kWe	-	needed in many cases
CO2 absorber	$ 25,000	mt/h flue gas	75%	$21,015	mt/h flue gas	46.8	
CO2 Stripper	$ 200,000	mt/h CO2	75%	$168,124	mt/h CO2	20.2	
CO2 Compressor	$ 1,000	/kW	75%	$841	/kW	12.1	
				Total process units		93.9	
General Facilities		20%	of process units			18.8	20-40% typical
Eng. Permitting & Startup		10%	of process units			9.4	10-20% typical
Contingencies		10%	of process units			9.4	10-20% typical
Working Capital, Land & Misc.		5%	of process units			4.7	5-10% typical
				U.S. Gulf Coast Capital Costs		136.1	
Site specific factor	110%	of US Gulf Coast		**Total Capital Costs**		**149.7**	CA costs are likely higher than Gulf Coast

CO2 Costs			MM $/yr	$/Mscf CO2 Capture	$/mt CO2 Cost Capture	$/mt CO2 Cost Avoided	Notes
	80%	ann load factor					high ann load is critical to cost
Variable Non-fuel O&M	1.0%	/yr of capital	1.5	0.09	1.78	2.25	0.5-1.5% typical
Natural Gas	$ 5.00	/MM Btu HHV	16.3	1.02	19.32	24.44	$4- 7/MM Btu **industrial** rate
Carbon Tax	$ 10.00	/ton Carbon	0.3	0.02	0.30	0.38	all electric power made onsite
Total Variable Operating Cost			**18.0**	1.13	**21.40**	27.08	
Fixed Operating Cost	5.0%	/yr of capital	7.5	0.47	8.89	11.25	4-7% typical for refining
Capital Charges	15%	/yr of capital	22.5	1.40	26.67	33.74	15-25% typical for private investment
		Total CO2 Costs	**48.0**	**3.00**	**56.97**	**72.07**	including return on investment

Note that the difference between capture and avoided CO2 costs is due to the energy required for CO2 capture steam & power

Source SFA Pacific, Inc. **April 13, 2005**

2.3 CO_2 CAPTURE COST FOR FOSSIL FUEL POWER PLANTS

In order to use the SFA Pacific capture cost tool with fossil fuel power plants, an assumption was made that the CO_2 capture cost for such plants varied only as a function of fuel type, design capacity, and operating factor. A further assumption was made *that power plants would operate at 80% of their designed capacity once the capture facility has been installed.* So for each fuel type the CO_2 capture cost only varies based on the plant's design capacity. The fossil power plants were grouped into three categories by fuel type: coal-fired, gas-fired, and oil-fired.[1] The study only analyzed power plants with a design capacity greater than 100MWe.

Table 2-1 provides summary statistics for the fossil fuel power plants in SECARB region by fuel type. The SECARB region hosts 316 power plants with a design capacity over 100MWe. 109 of these power plants are coal-fired, 186 are gas-fueled, and 21 are oil-fueled. The actual total CO_2 emission for these facilities in year 2000 was 862 Mt, while the adjusted (under the assumption of 80% capacity factor) annual CO_2 emission were estimated to be 1,402 Mt.

Table 2-1: Fossil Fuel Power Plants by Fuel Type (Design Capacity>100MWe)

Fuel Type	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP
# of Plants	109	186	21
Total Design Capacity (MWe)	115,412	91,822	17,298
2000 Average Operating Factor[a]	0.64	0.30	0.36
Actual 2000 Total CO_2 Emission (Million tonnes)[b]	684	143	35
Ajusted Total Annual CO_2 Emission (Million tonnes)[c]	862	442	99

Note: [a]Weigted (by design capacity) average operating factor
[b]eGRID published 2000 CO_2 emission based on the actual plant operating factor
[c]Estimated plant CO_2 emssion at 80% operating factor

Two key input variables needed to estimate the CO_2 capture cost for the fossil fuel power plants are the flue gas flow rate and the flue gas composition. Since this specific information was unavailable for all of the power facilities, two further assumptions were used to derive reasonable values for these variables. The two flue gas assumptions were that: (*1) the flue gas flow increases linearly with the design capacity of a power plant; (2) within each fuel-type category, the flue gas composition is independent of the design capacity.* Table 2-2 provides the flue gas flow rate and composition used in the data for each type of fossil fuel power plant.

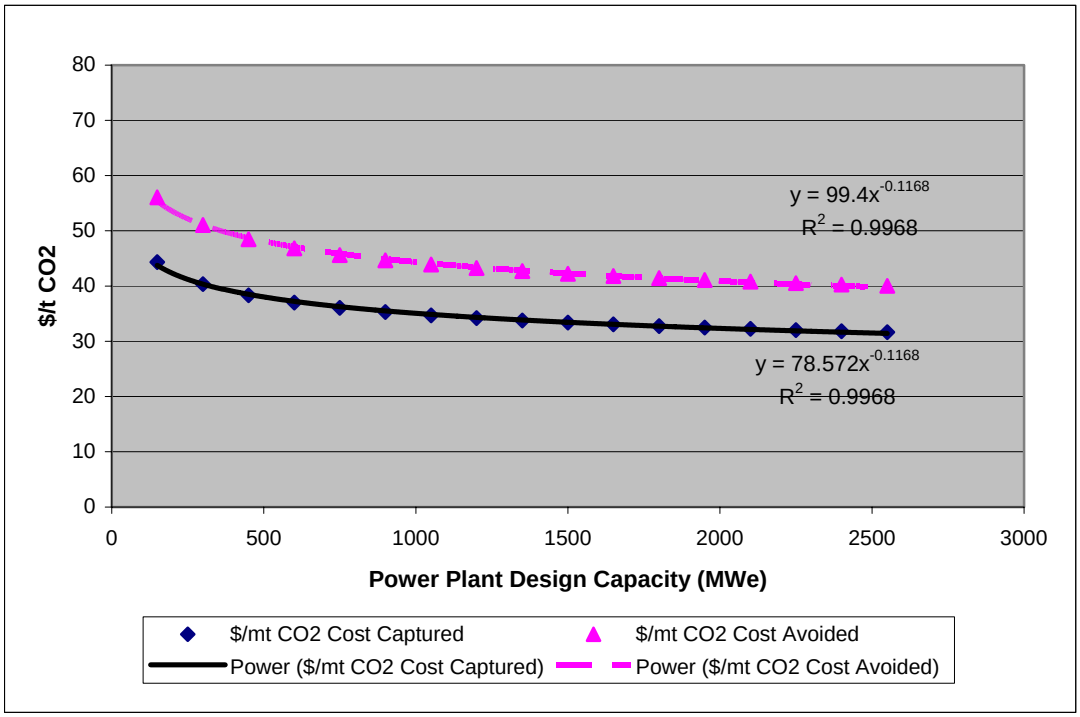
[1] There are few power plants using BL (black liquid) or MWC (municipal waste solid) as primary fuels that have a design capacity slightly above 100 MWe. But the CO_2 emissions from those plants are substantially lower than plants using oil, gas, or coal as primary fuel. Therefore, the analysis is restricted to oil-, gas-, and coal-fueled power plants with design capacity of at least 100MWe.

Table 2-2: Flue Gas Flow Rate and Composition for Coal-, Gas-, and Oil-Fired Power Plants

		Coal-fired PP	Gas-fired PP	Oil-fired PP[1]
Flow Rate (mt/h per 100MW design capacity)		4.06	5.14	4.6
Flue Gas Composition (% in Volume)				
	N_2	73.81%	75.86%	74.84%
	CO_2	15.15%	4.18%	9.67%
	H_2O	8.33%	8.18%	8.26%
	O_2	2.54%	11.77%	7.16%
	misc	0.16%	0.00%	0.08%

Note: [1]Data about oil-fired power plants are MIT Carbon Capture and Sequestration Technologies Program estimates. Others are from SFA, Pacific "*Generic CO_2 Capture Retrofit*" and "*Existing Coal Power Plant CO_2 Migration*" spreadsheets.

Figure 2-4: Estimated CO_2 Capture and Avoidance Costs for Coal-fired Power Plants



Using data derived from the SFA Pacific capture cost estimation tool, Figure 2-4 plots both the CO_2 capture cost and avoidance cost for coal-fired power plants as functions of the plant design capacity. The relationship between CO_2 capture and avoidance costs and the design capacity of the coal-fired power plant can be represented by the following two power functions (with R^2 close to 1):

$$yc = 78.57 * x^{-0.1168} \quad (4.1)$$

$$ya = 99.40 * x^{-0.1168} \quad (4.2)$$

where yc = cost per tonne of CO_2 captured ($/t)
ya = cost per tonne of CO_2 avoided ($/t)
x = design capacity of the coal-fired power plant (MWe)

Taking derivatives on both sides of Equation (4.1), the CO_2 capture/avoidance cost elasticity with respect to plant design capacity is $\frac{dy/y}{dx/x} = -0.1168$. In practical terms this means that due to economies of scale the per unit CO_2 capture/avoidance cost decreases by 0.1168 percent for every 1 percent increase in power plant design capacity.

Figure 2-5 and Figure 2-6 plot the relationship between the CO_2 capture and avoidance costs and plant design capacity for gas-fired and oil-fired power plants, respectively. Table 2-3 summarizes the estimated formula for CO_2 capture and avoidance costs as functions of power plant design capacity for each fuel type category.

Table 2-3: Formula and Range of per tonne CO_2 Capture and Avoidance Cost for Power Plants

Category	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP
# of Facilities	109	186	21
Capacity Range	109~3,969 MWe	100~2,315 MWe	112~2951 MWe
$/t CO_2 Captured Formula	$78.57x^{-0.1168}$	$144.87x^{-0.1564}$	$93.34\ x^{-0.1295}$
$/t CO_2 Avoided Formula	$99.40x^{-0.1168}$	$183.27x^{-0.1564}$	$118.08x^{-0.1295}$
Capture Cost Range ($/t CO_2 captured)	$29.8~$45.5	$43.1~$73.5	$33.2~$50.7
Avoidance Cost Range ($/t CO_2 avoided)	$37.8~$57.5	$54.6~$89.2	$42.0~$64.1

Note: x is the power plant design capacity in MWe.

Figure 2-5: Estimated CO_2 Capture and Avoidance Costs Oil-fired Power Plants

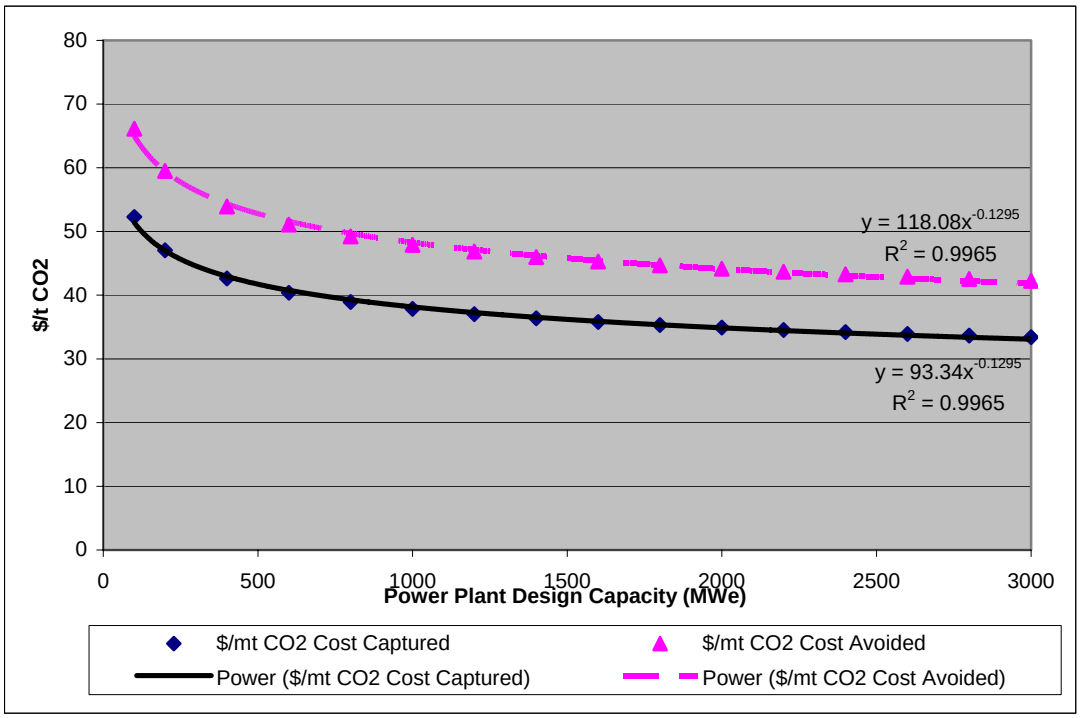
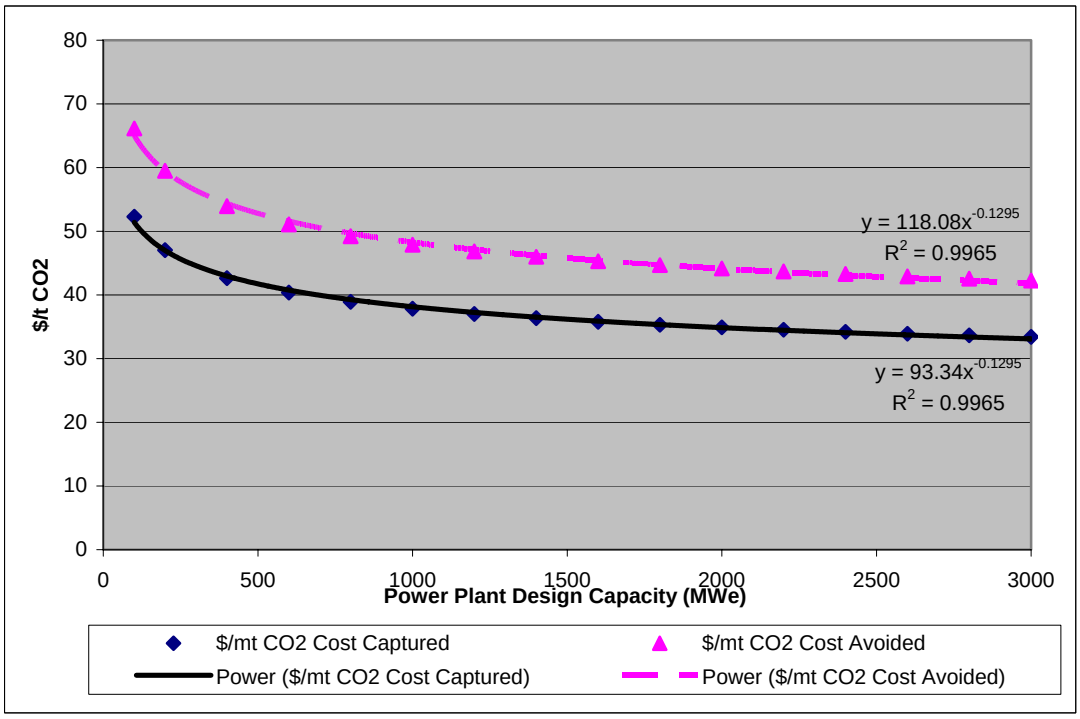


Figure 2-6: Estimated CO_2 Capture and Avoidance Costs for Ammonia Plants



The study applies the above methodology to the fossil fuel power plants with design capacity over 100 MWe in the SECARB region. The capture cost varies from $29.9 per

tonne for a 3,970 MWe coal plant to $70.5 per tonne for a 100 MWe gas plant. The avoidance cost varies from $37.8/t to $89.2/t for these same facilities. The capacity-weighted average *capture costs* for all facilities in the SECARB region are $33.8/t, $52.3/t, and $38.4/t for coal, gas, and oil plants respectively. The capacity-weighted average *avoidance costs* for these plants are $42.7/t, $66.2/t, and $48.6/t for coal, oil, and gas plants respectively.

2.4 CO_2 CAPTURE FOR NON-POWER STATIONARY SOURCES

The capture cost estimation tool from SFA Pacific, Inc. was adapted so that it could be used with the non-power sources in the SECARB region. As discussed in Section 2.1, three key variables were needed for the estimation: (1) the flue gas flow rate; (2) the flue gas composition; and (3) the annual load factor. The SECARB database includes seven types of non-power CO_2 sources, but flue gas composition information was only available for the following four facility types: ammonia plants, cement plants, gas processing facilities, and refineries. As a result the analysis was limited to estimating the capture cost for the four facility types listed.

Table 2-4: Assumed CO_2 Emission Factor, Flue Gas Component and Load Factor for Non-power CO_2 Sources

Facility Type	CO_2 Emission Factor	Flue Gas Component (volume)	Annual Load Factor
Ammonia	1.13t CO_2/t Ammonia	100% CO_2	100%
Cement	0.75t CO_2/t Clinker	25% CO_2, 75%N_2	100%
Gas Processing	608t CO_2/mmcfd	100% CO_2	100%
Refineries	9.9t CO_2/BPD	10% CO_2, 90% N_2	100%

Table 2-4 lists the assumed CO_2 emission rates per unit of primary product production, the flue gas composition, and the annual load factor used for each of the four types of non-power CO_2 sources evaluated. The actual flue gas flow rates were unknown, but they were estimated based on plant capacity, the CO_2 emissions factor, and the flue gas composition.

Using these assumptions with the generic SFA CO_2 capture model, Figure 2-7 through Figure 2-10 plot the per unit CO_2 capture cost and avoidance cost as power functions of facility capacity for each type.

Figure 2-7: Estimated CO_2 Capture and Avoidance Costs for Cement Plants

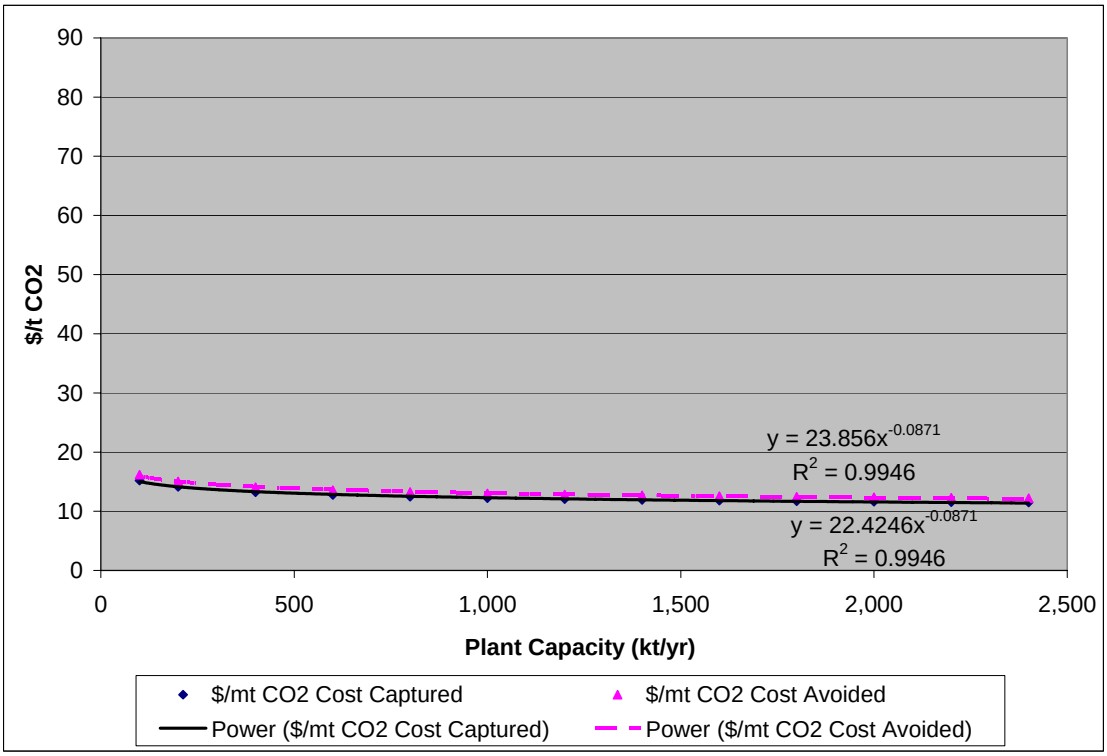


Figure 2-8: Estimated CO_2 Capture and Avoidance Costs for Gas Processing Plants

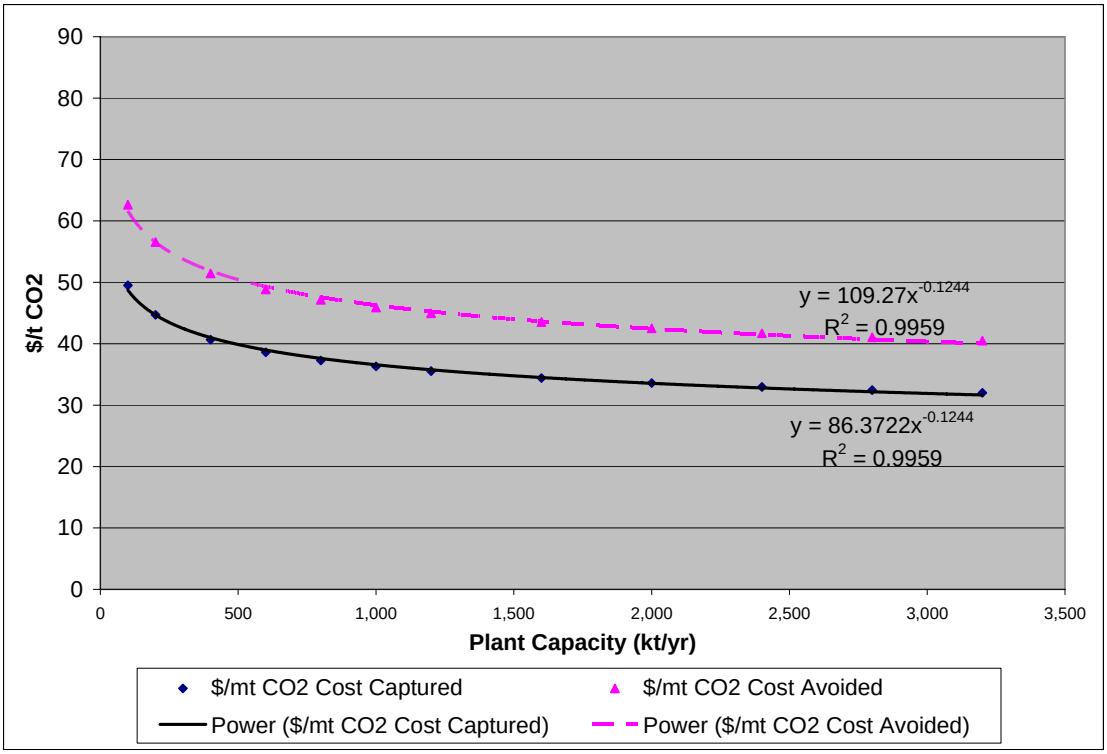


Figure 2-9: Estimated CO_2 Capture and Avoidance Costs for Refineries

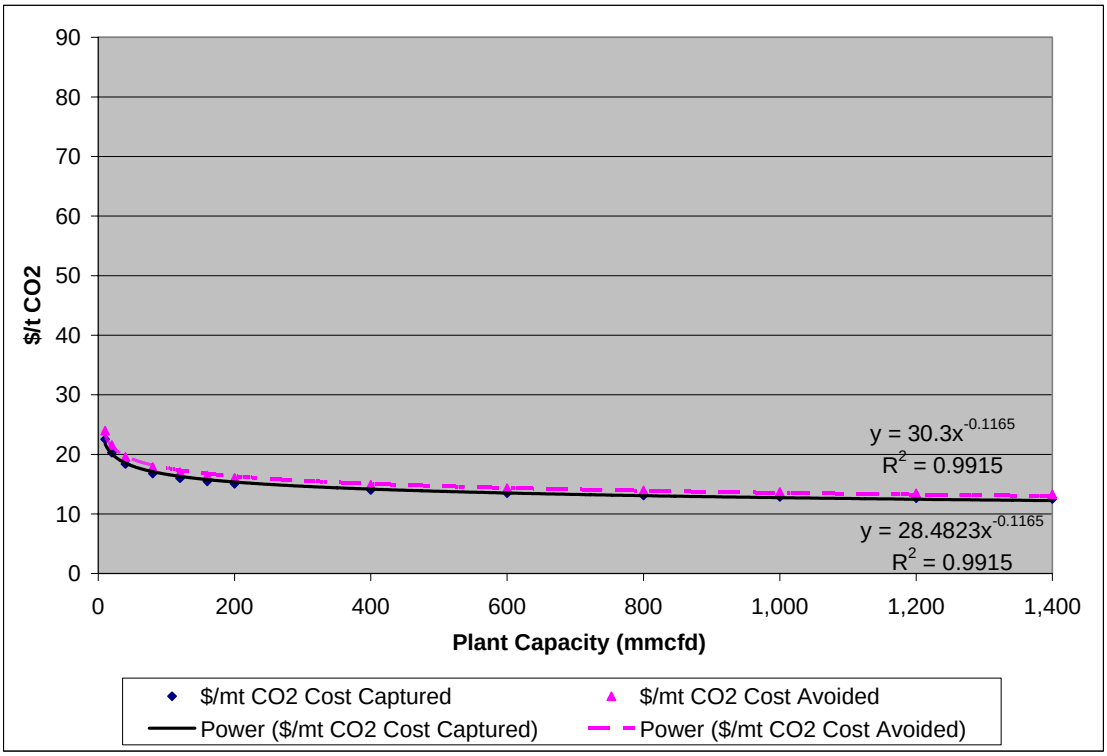
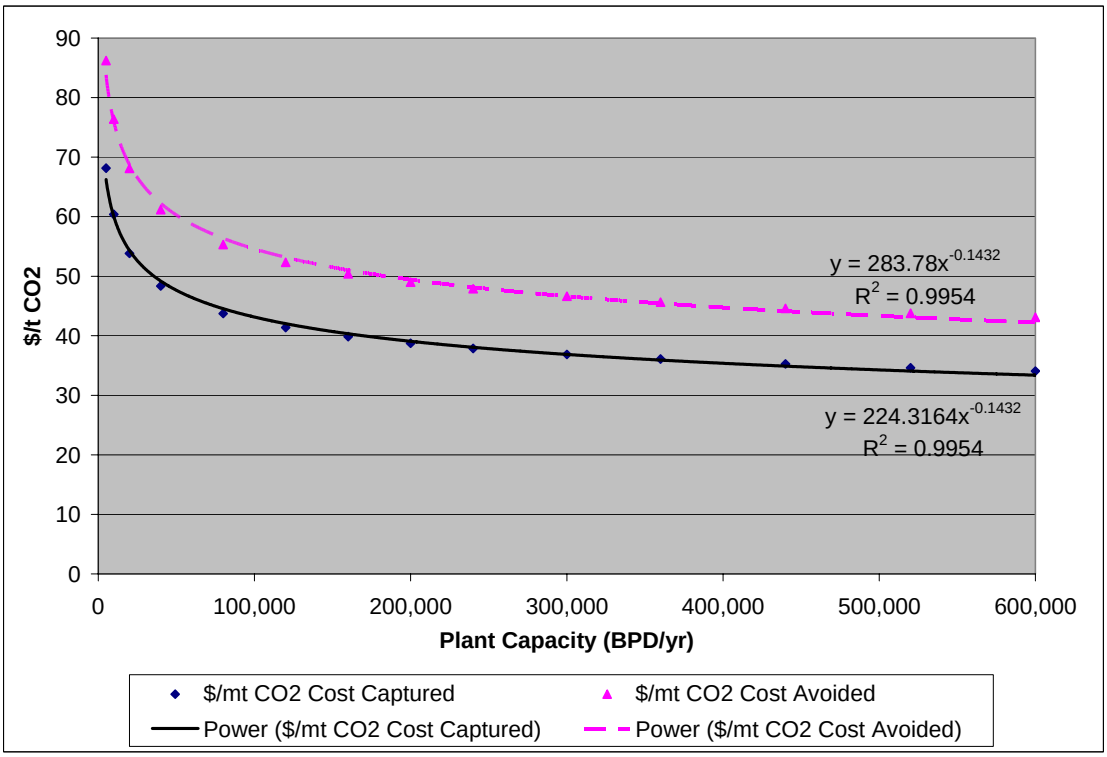


Figure 2-10: Estimated CO_2 Capture and Avoidance Costs for Refineries



The range of per tonne CO_2 capture and avoidance costs are summarized in Table 2-5 for each category. Since both ammonia and gas processing facilities produce pure CO_2 byproduct streams, CO_2 capture at these facilities only requires gas compression but not gas separation. As a result the CO_2 capture cost at these facilities is less than at either cement or refinery facilities.

Table 2-3: Range of per tonne CO_2 Capture and Avoidance Costs for Four Non-Power Sources[1]

Category	Ammonia	Cement	Gas Processing	Refineries
# of Facilities	13	28	21	41
Capacity Range	90~2,250 kt	100~2,540 kt	300~1,350 MMCFD	5,400~557,000 BPD
Capture Cost Range ($/t CO_2 captured)	$15.2~$11.5	$48.8~$32.6	$14.7~$12.3	$65.5~$33.7
Avoidance Cost Range ($/t CO_2 avoided)	$16.2~$12.2	$61.7~$41.2	$15.6~$13.1	$82.9~$42.7

[1] Gas processing facilities with a design capacity less than 300 mmcfd were excluded.

3 CO_2 CAPTURE PHASE 2 PLANS

The plan for CO_2 capture in phase 2 mainly focuses on improving the data for sources, mainly non-utility sources since the current data on these systems is the most uncertain, and updating the cost estimates based on information developed during the four year period of the phase 2 project. This would include improvements to the amine process and evaluation of developing processes that reach the level where meaningful designs and cost estimations may be made and incorporated into the spreadsheets used in phase 1. This work will be shared with the WESTCARB regional partnership as both SECARB and WESTCARB are using the same organizations to do this work and that will prevent duplication of efforts.

3.1 SOURCES

The site characterization will be updated as new information becomes available (e.g., EPA updates its EGRID database every two years) and the new data will be incorporated into into the GIS database. In addition, efforts will be made to improve the CO_2 emissions estimates for non-power sources by better estimating, both the quantity and quality (i.e., purity) of the various CO_2 emissions. The updated database of CO_2 sources will be available through the NATCARB system.

3.2 CO_2 CAPTURE PROCESS SELECTION

For a process to be considered for application in the phase 2 study effort, it must be at a meaningful developmental level and as mentioned previously, have developed process cost estimates. As part of this effort, a watch will be kept on all of the processes under development including those in the DOE carbon sequestration program, the CO_2 Capture

Project, and the EPRI Test Centers work. At a minimum, a summary of processes under development will be provided and the impact of any benefits in reduced costs will be factored into the source-sink matching effort. This will allow an evaluation of the impact of a processes without looking as if a given process is being endorsed by the SECARB partnership.

3.3 CO_2 CAPTURE COST ESTIMATION

For retrofits, the current versions of the spreadsheets may be improved by updating the costs based on more recent estimates of items like the cost of steel or construction. In addition, improvements to the amine-based solvent processes that have been demonstrated will be incorporated into the spreadsheets. As mentioned in the last section, newer, less developed processes will be estimated based on the impact of their cost improvements rather than development of new cost spreadsheets.

4 CONCLUSIONS

While the main efforts of the SECARB regional partnership in phase 2 will naturally be focused on the geologic storage pilots, with a region where stationary CO_2 sources are dominated by power plant emissions, the main effort on CO_2 capture will naturally lead to focusing on these systems. Perhaps one of the main efforts that would be useful to accomplish in phase 2 will be to work with all of the regional partnerships to develop a single set of CO_2 capture costing methodologies to assure that the studies of all of the regions are done on the same basis. The presence of the CO_2 capture working group should go a long way to facilitation of this effort.

Action Plan for CO_2 Transportation

Deliverable 22B

March 2006

EPRI Project Manager

Richard Rhudy

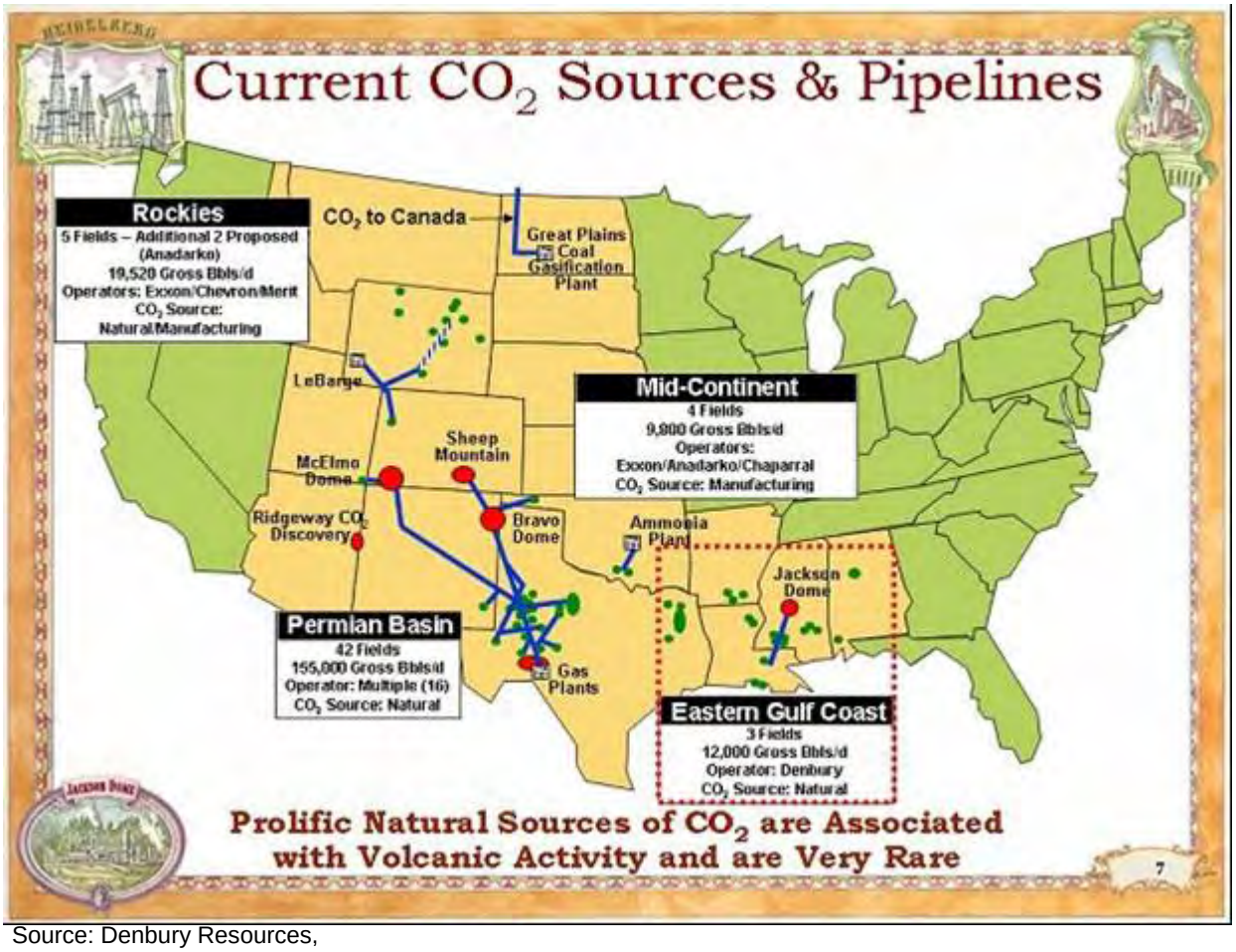
Report Prepared by:

Advanced Resources International, Inc.

MIT

Background. An important part of the overall Phase I work by SECARB has been establishing the transportation requirements and systems for delivering CO_2 from the various point sources to the large capacity geological sinks in the eleven state region.

Three CO_2 transportation options - - pipelines, barges and truck/rail - - were examined. Barge transportation of CO_2 was eliminated due to costs and limited linkage between sources and sinks. Truck and rail transportation of CO_2 was eliminated because of costs and the large volumes of CO_2 that would need to be transported. The most favorable option for transport of CO_2 within the SECARB region is through high pressure pipelines. Such pipelines already exist in significant number within the US as shown in Figure 1.

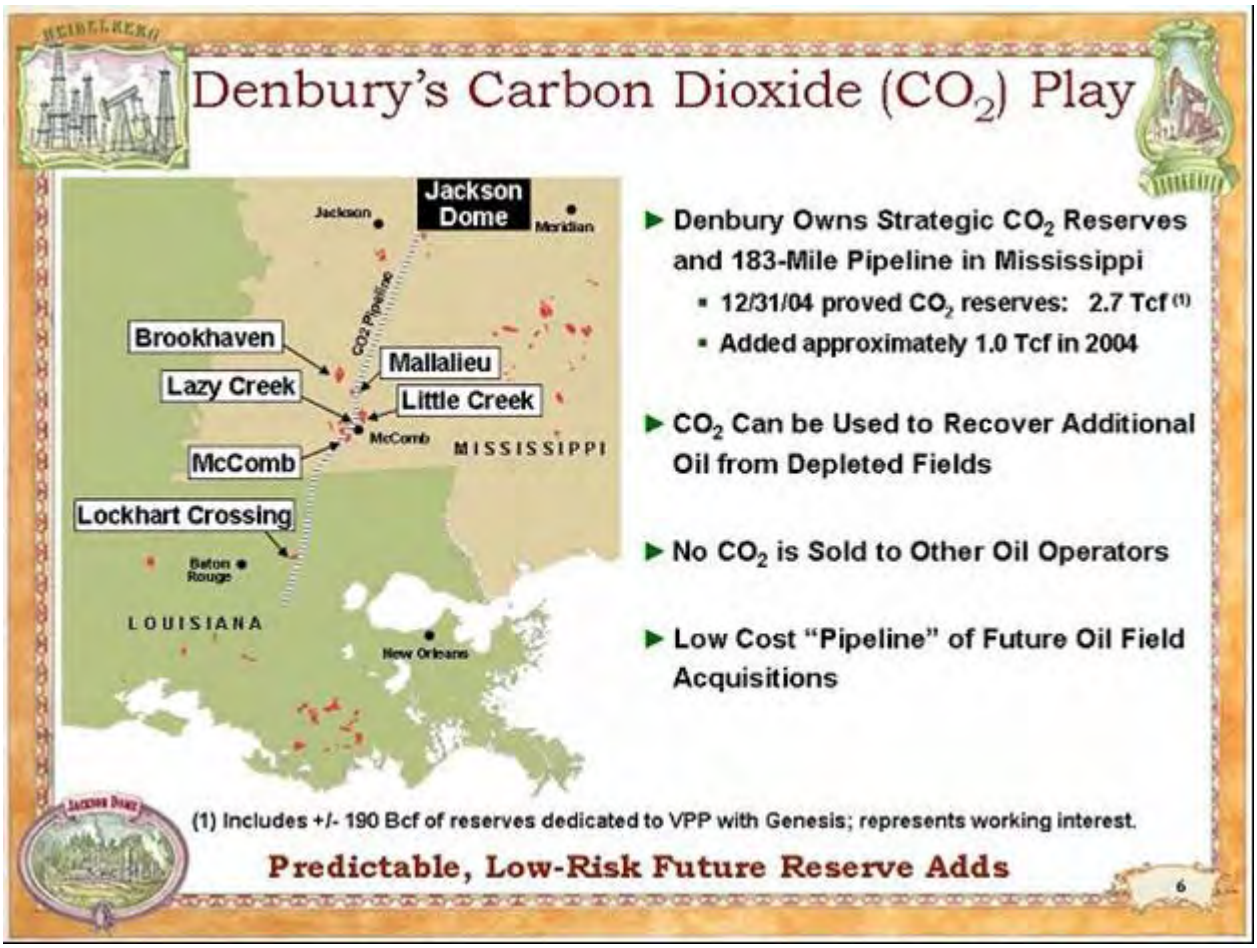


Source: Denbury Resources,

Figure 1
Current US pipelines with associated CO_2 sources.

In point of fact, there are existing CO_2 pipelines within the SECARB region.

Existing and Planned CO_2 Pipelines in the SECARB Region. The SECARB region has both natural CO_2 and an existing CO_2 pipeline system that deliver this CO_2 to oil fields for CO_2 -EOR. See Figure 2.



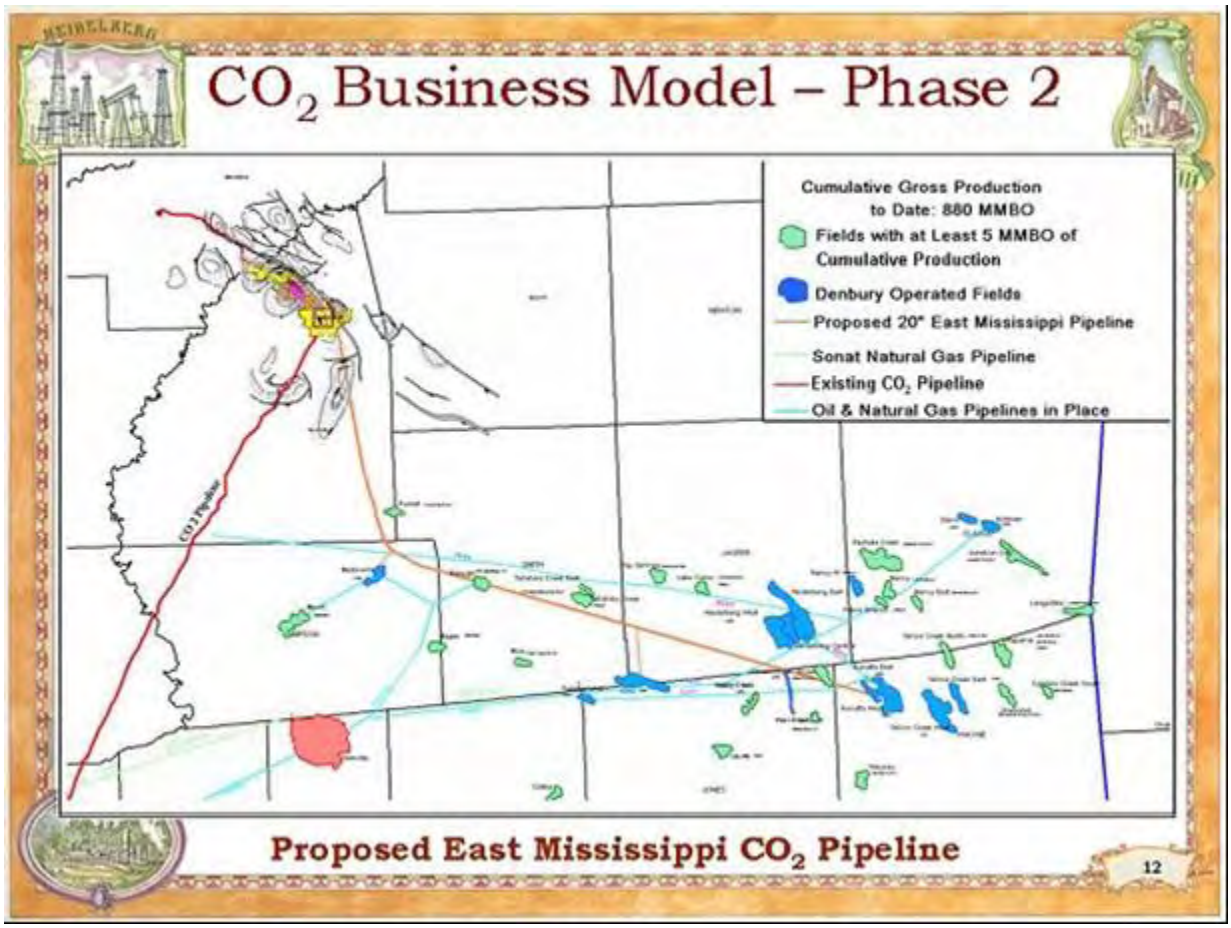
Source: Denbury Resources,

Figure 2
Denbury CO_2 pipeline in the SECARB region

.

The Jackson Dome currently holds 2.7 Tcf of natural CO_2 proved reserves. With future drilling, Jackson Dome may be able to provide up to 12 Tcf of natural CO_2 reserves, utilizing a portion of the potential CO_2 storage capacity in depleted and near-depleted oil fields.

This natural source of CO_2 is currently linked to a series of six oil fields in southwestern Mississippi and southeastern Louisiana with a 183 mile, 20-inch diameter, high-pressure pipeline, capable of transporting 440 MMcfd. In addition, Denbury Resources (the owner of the CO_2 pipeline and the CO_2 supply at Jackson Dome) has initiated construction of an 84-mile lateral capable of transporting 270 MMcfd from the natural CO_2 supply at Jackson Dome to additional oil fields in East Mississippi, Figure 3. This CO_2 pipeline system could be part of the "backbone pipeline system" for collecting CO_2 from industrial and power plants in the SECARB region and delivering this CO_2 to favorable CO_2 storage sites in the eleven state region.



Source: Denbury Resources,

Figure 3
Denbury planned CO_2 pipeline in the SECARB region

Documentation of Work to Date. To assist in the assessment and planning of CO_2 transportation and a "backbone pipeline system", the Phase I work assembled the following information:

1. ***GIS Mapping of CO_2 Sources.*** A GIS database containing the location and capacities of the major stationary sources of CO_2 was constructed for the SECARB region during Phase I. This database includes plant location, capacity, annual CO_2 emissions, the CO_2 concentration of each plant's emissions, and the cost of capturing CO_2 from the plant's emissions.

   The database was developed starting with the IEA GHG Programme preliminary data on CO_2 sources. New data was entered for power plant refineries, cement plants, ammonia plants and gas processing facilities. For power plants, the data source was the USEPA eGRID database.

2. ***GIS Mapping of CO_2 Sinks***. A GIS database containing the location and storage capacity of the main geologic sinks - - oil and gas fields, coal beds and saline aquifers - - is being constructed for the SECARB region during Phase I.

   The US DOE GASIS database was used for general information on the oil and gas fields in the region. The Geological Survey of Alabama provided a more detailed data set for oil and gas fields in Alabama and Mississippi. The University of Texas, Bureau of Economic Geology provided the oil and gas field data set for East Texas. For the coal beds data set, the Alabama Geological Survey provided the information. For Saline Aquifers, the Bureau of Economic Geology and Advanced Resources International provided the data.

3. ***Transportation System Linking CO_2 Sources with CO_2 Sinks.*** The large CO_2 sources and CO_2 sinks were linked using the "Straight-Line Distance" function on the spatial analyst extension of ArcMap. The output from this analysis is a raster layer where the cell values are equal to the straight line distance from each cell to the nearest sink. More detailed source-sink matching involving a "least-cost path" based on a calculated

transportation cost surface, an estimated injection cost and consideration of reservoir storage capacity was performed for the East Texas portion of the SECARB region.

Finally, a series of pipeline design capacity, construction and operating cost functions were used to calculate the transportation cost requirements for linking CO_2 sources with geologic sinks.

In support of planning the CO_2 transportation system for the SECARB region, the two data items indicated below were collected and provided for the transportation evaluation effort:

1. ***GIS version of the natural gas and oil pipeline systems in the SECARB region.*** This database provides information for examining potential CO_2 pipeline corridors, as well as existing oil or gas pipelines that would be converted to CO_2 collection and transportation lines. See Figure 4.

2. ***GIS version of the lakes and rivers in the SECARB region.*** This database provides information for examining the physical barriers that could influence the location and costs of the CO_2 transportation system in the region. See Figure 5.

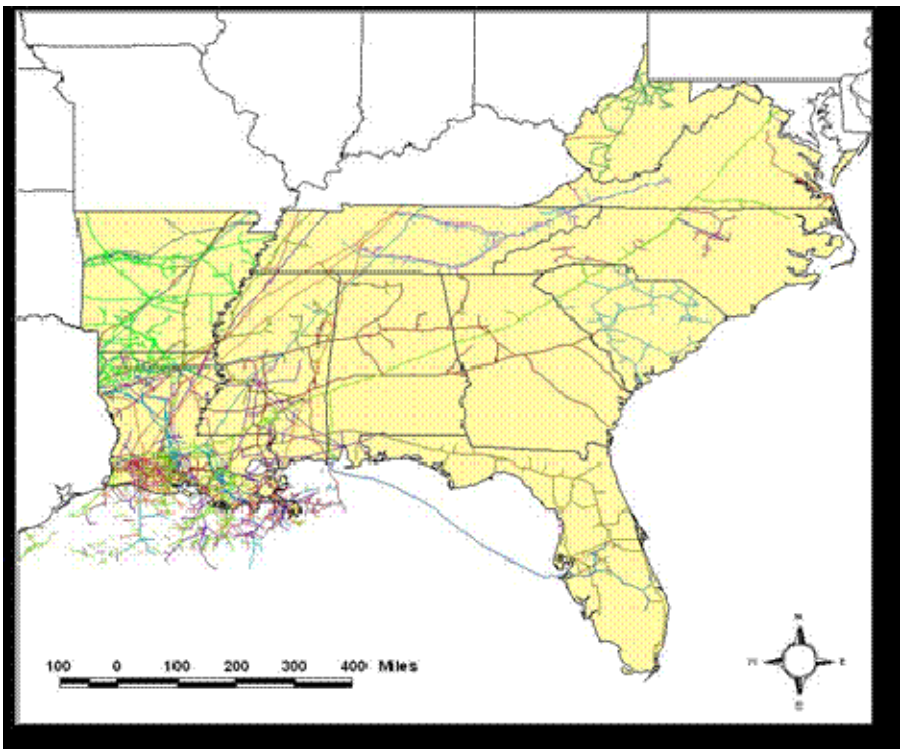


Figure 4
Oil and natural gas pipelines in the SECARB region

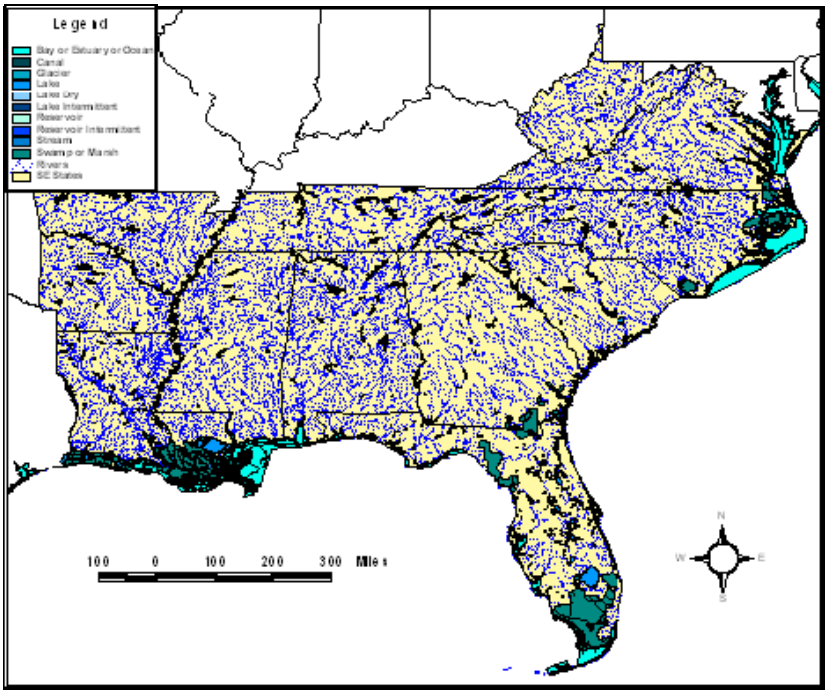


Figure 5
Rivers, reservoirs, marshes and lakes in the SECARB region

Described below is the method that was used to determine the transportation costs for the source/sink matching completed in Phase 1.

CO_2 Pipeline Transportation Costs

In cases where the CO_2 source is not co-located with an appropriate sink, large quantities of CO_2 will need to be transported from the source to the sink for sequestration. Underground pipelines are considered the most economical means of transporting such large quantities of CO_2, and a pipeline network would be necessary for carbon sequestration to be feasible. Pipeline construction entails significant capital costs, and this section presents models and methods to estimate the CO_2 pipeline transportation costs based on key pipeline variables.

Transport Pipeline Design Capacity

The pipeline design capacity is one of the first design criteria needed for cost estimation. Pipeline capacity is a factor of both pipeline diameter and operating pressure, and pipelines need to be appropriately sized for the CO_2 transportation requirements of their corresponding CO_2 emissions sources. For pipelines originating at refineries, cement plants, the pipeline design capacity is set equal to the 2002 CO_2 emission multiplied by a default capture efficiency (90%). For pure CO_2 streams originating from ammonia and gas processing facilities, the default capture efficiency is set to be 100%. For power plants, the pipeline design capacity is calculated as follows:

$$VC_{CO2} = \frac{VE_{CO2}^{2000}}{OE^{2000}} * CE_0 \qquad (1)$$

where VC_{CO2} = Maximum CO_2 flow rate (t/yr);
VE_{CO2}^{2000} = 2000 annual CO_2 emission (t);
OE^{2000} = 2000 plant operating factor;
CE_0 = Default CO_2 capture efficiency (90%)

Equation (1) gives the maximum CO_2 flow rate (in terms of tonne/yr) for a power plant operating at its full design capacity. The required pipeline capacity is an overestimate since plants usually operate below their maximum design capacity.

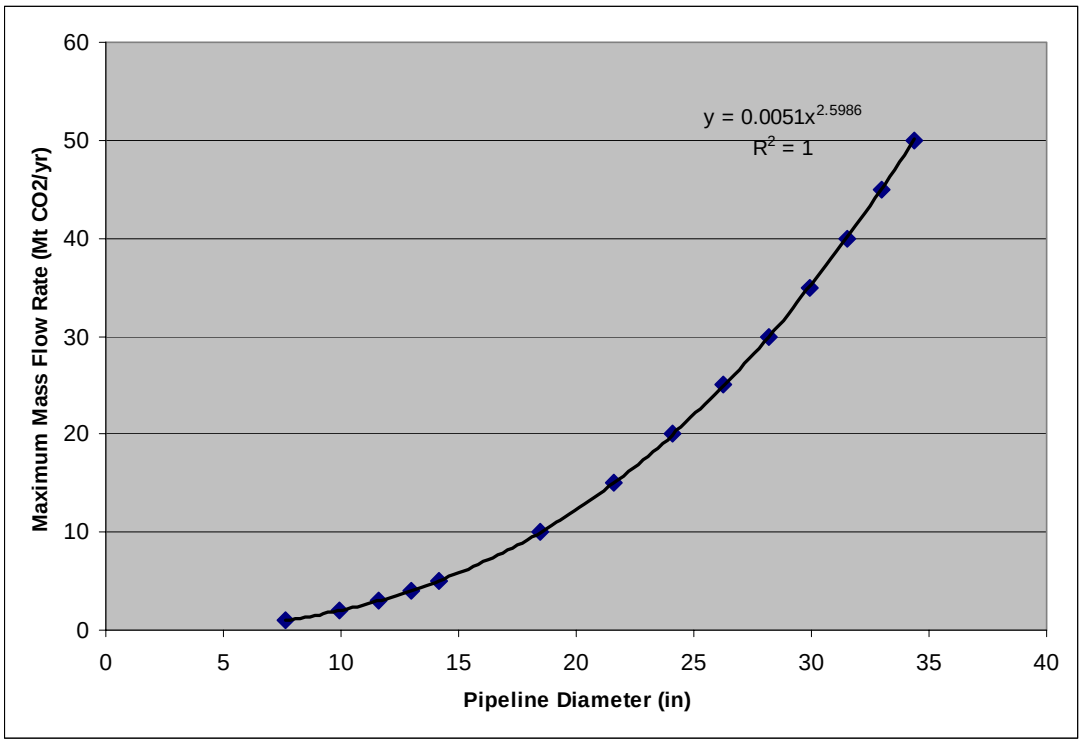


Figure 6
Maximum Mass CO_2 Flow Rate as a Function of Pipeline Diameter

Pipeline Diameter (inch)	CO_2 Flow Rate (Mt/yr)	
	lower bound	upper bound
4		0.19
6	0.19	0.54
8	0.54	1.13
12	1.13	3.25
16	3.25	6.86
20	6.86	12.26
24	12.26	19.69
30	19.69	35.16
36	35.16	56.46

Table 1
Pipeline Diameter and the CO_2 Flow Rate Range

Pipeline Diameter Calculation

Figure 6 plots the relationship between the maximum mass flow rate and the pipeline diameter. A power function closely models this relationship. In this study it is assumed that standard type gas industry pipelines will be used for CO_2 transportation (True, 1998). Based on the power function in Figure 6, Table 1 gives the breakdown of the CO_2 flow rate for each pipeline standard

diameter within the range from 4 to 36 inches. For any given maximum CO_2 flow rate, Table 1 provides a look-up table to determine the appropriate pipeline diameter.

Obstacle Layer Construction

In addition to the diameter and capacity, the terrain being traversed by a pipeline is another significant pipeline construction cost variable. These costs vary considerably according to the local terrain and are also affected by the presence of buildings or infrastructure. Pipeline construction is more expensive in hilly areas than on flat plains. In order to reduce complications and costs, a pipeline's route should avoid passing through populated places[1], wetlands, and national or state parks. In order to account for such obstacles in the study, the locations and characteristics of these obstacles were loaded into Geographic Information System (GIS) software. Using the GIS software the costs for traversing such obstacles during pipeline construction were combined into a single obstacle data layer. This obstacle layer reflected three types of general obstacles: land slope, protected areas, and crossings and three line type obstacles: waterways, railroads, and highways.

In order to use this land obstacle data to help calculate optimal pipeline routes, the continuous obstacle data layer was rasterized into 1km by 1km cells. If there were no transportation obstacles contained within a given 1 km^2 cell, then the construction costs of a pipeline traversing the cell was assumed to be "1". From this base case construction cost, relative weights were then assigned to each obstacle in Table 2 according to the difficulty of traversing the obstacle. These relative weights were then added to the base case construction cost to form a combined pipeline construction cost factor.

Construction Condition		Cost Factor
Base Case		1
Slope		
	10-20%	0.1
	20-30%	0.4
	>30%	0.8
Protected Area		
	Populated Area	15

[1] The populated places data is from US Land Use and Land Cover (LULC) data set, which adopts the census definition of "populated place areas" that include census designated places, consolidated cities, and incorporated places within United States identified by the U.S. Bureau of the Census.

	Wetland	15
	National Park	30
	State Park	15
Crossing		
	Waterway Crossing	10
	Railroad Crossing	3
	Highway Crossing	3

Note: The relative weights are calculated as the ratios of the additional construction costs to cross those obstacles and the base case construction cost for an 8 inch pipeline.

Table 2
Estimated Relative Construction Cost Factor

The total pipeline construction cost factor for a cell is then the sum of the base case cost factor and the cost factors of all of the obstacles that exist in that cell. For example, the relative cost of a 8 inch pipeline crossing a river in the national park would be 41: 1 (base case) + 30 (national park) + 10 (river crossing). Using the weighted cost layer calculated above, the spatial analysis function in ArcGIS was used to determine the least cost pipeline path for connecting each source and sink.

Pipeline Transport Cost Estimation

The model decomposes the pipeline construction cost into two components: the basic pipeline construction cost (diameter-dependent) and the additional obstacle cost (diameter-independent). The basic pipeline construction cost is estimated to be $12,000/in/km[2]. The additional obstacle cost was calculated as the product of the relative weight assigned in Table 2 and the basic construction cost of an 8 inch pipeline[3]. The additional obstacle cost does not vary with the pipeline diameter, since the amount of site preparation required for pipeline construction does not vary according to pipeline size. The cumulative pipeline construction cost was then calculated as the sum of the basic construction cost and the additional obstacle cost.

[2] Heddle et al., (2003) estimate that the average pipeline construction cost (including obstacle crossing cost) is $20,989/in/km. For sparsely populated areas average pipeline construction costs are estimated to be $12,400/in/km.

[3] For a 100km 8 inch pipeline with 6 waterway crossings, 1 railroad crossing, 1 highway crossing, and pass 1 km wetland. The estimated construction cost is ($12,000/in/km)*(8 in)*(100km) (base case construction) + $960,000*6 (waterway crossing) + $288,000 (railroad crossing) + $288,000 (highway crossing) + $1,440,000 (wetland crossing) = $17,376,000, which is similar to the average number provided by Heddle: ($20,989/in/km)*(8in)*(100km) = $16,791,200.

For pipeline operations the pipeline O&M cost were estimated to be $3,100/km per year, regardless of pipeline diameter (Heddle, et.al., 2003). A capital charge of 0.15 was used to annualize the construction cost over the operating life of the pipeline so that the annual pipeline transportation was 0.15 of its construction cost plus the annual O&M cost.

Transportation Efforts in Phase 2

As described in detail in the source/sink matching report, this information was used to develop a least-cost path source-sink matching and full costing analysis for Eastern Texas. This evaluation was confined to Eastern Texas due to the limited availability of detailed data for the entire SECARB region. The Eastern Texas study did not consider any benefit in transportation from developing backbone CO_2 transport pipeline systems. In Phase 2, an evaluation of the impact of such a backbone will be evaluated. Also, the work in phase 2 of this project will focus on improving the algorithms for calculating the optimum or lowest cost transportation system. Costs for transportation will be reviewed and topography and existing rights-of-way will be incorporated in determining paths between sources and sinks.

Making Carbon Sequestration a Paying Proposition

Fengxiang X. Han and Jeff Lindner
Diagnostic Instrumentation and Analysis Laboratory
Mississippi State University
205 Research Blvd
Starkville, MS, 39701

Executive Summary

Atmospheric CO_2 has increased from a preindustrial concentration of about 280 ppm to about 367 ppm at present. It is evident that the rapid increase in CO_2 concentrations has been occurring since the onset of industrialization. The increase has closely followed the increase in CO_2 emissions from the use of fossil fuels. Global energy usage predictions in the next century indicate a continued increase in carbon emissions and rising atmospheric CO_2 concentrations. Global warming caused by increasing amounts of greenhouse gases in the atmosphere is the major environmental challenge for the 21st century. Reducing worldwide emissions of CO_2 requires multiple mitigation pathways, including reductions in energy consumption, more efficient use of available energy, the application of renewable energy sources, and sequestration. Sequestration is a major tool for managing carbon emissions. In a majority of cases CO_2 is viewed as waste to be disposed; still, however, there are a number of potential opportunities that render sequestration economically viable.

Government policy is a key factor in creating value and establishing long-term market systems for CO_2 emission reductions. This includes emissions caps, trading, and possible taxes. A number of sequestration opportunities have direct economic benefits such as reforestation, furniture and housing, enhanced oil recovery (EOR) and coal-bed methane (CBM). Alternately, a number of sequestration activities will not provide an opportunity for short-term gain. Rather, for CO_2 injection into deep saline aquifers, mineralization and biomineralization, economic benefits will be indirect arising from second order benefits directly related to the improvement or stabilization of the environment. In such cases the primary economic gains will likely arise from trading and taxes. This report will analyze both categories of opportunities, which mostly fall into either terrestrial carbon sequestration or geological sequestration. Other potential opportunities where additional research is needed to assess the economic potential are identified.

Part I. Terrestrial Sequestration as a Paying Proposition

1. Reforestation

Forests are biological scrubbers by removing/sequestering CO_2 from the atmosphere. Carbon sinks in U. S. forests could sequester 50% (0.78 Pg/y) of all North American emissions (Katul et al., 2004). Intensive management practices and long growing seasons indicate that forests within the Southeaster region of the country can become a dominant sink.

Reforestation constitutes a low-cost sequestration option when compared to presently available capture and storage paths. Economic benefits are possible through the value of forest products and through the long-term social and environmental benefits that include improved soil and air quality, reduced surface runoff and erosion, and ecosystem health. Costs and benefits are a measure of the value of whatever must be sacrificed to prevent or reduce the chances of a negative environmental impact. Sequestration costs are typically expressed as the ratio of economic input to carbon mitigation output ($ per metric ton of C, or of CO_2). The amount of carbon sequestered is determined by forest management practices, such as tree species, geographic location and characteristics, and the disposition of forest products (Stavins and Richards, 2005). The cost includes that associated with additional land, planting and management, and secondary costs or benefits such as non-climate environmental impacts or timber production (Stavins and Richards, 2005). For a reforestation program of 300 million tons of annual carbon sequestered in the U.S., the costs have been estimated to range from $7.5 to $22.5 per metric ton of CO_2 (Stavins and Richards, 2005). This range depends upon underlying biological and economic assumptions and analytical methods employed. Through the incentive program at high payment levels, in the range of $25 - $125 per metric tons for permanently sequestered carbon, reforestation becomes a dominant source of additional carbon sequestration. Land can be drawn from pasture and cropland into forest land (Lewandrowski et al., 2004).

The annual forest carbon sink in the southeast and south-central United States is estimated as 76 Tg C/year, accounting for 40.2% of total annual C sink in the region and 27% of the total annual carbon accumulation in U. S. forests (Table 1) (Han et al., 2005). Total annual U.S. forest carbon accumulation from 1952 to 1992 was 281Tg C/year (US Department of Energy, 1999). The contribution of the regional forest C accumulation to the overall US forest carbon accumulation is in proportion to the ratio of forest lands in the region (193,973 thousand acres compared to 641,536 thousand acres) (USDA, 2003). Katul et al. (1999) reported that forests in the southeast U. S. are a dominant C sink, accounting for 50% of the carbon sequestered in North America. The current value (76Tg C/year) of annual carbon accumulation as forest biomass in the region is in agreement with other estimates (Delcourt and Harris, 1980).

Table 1 Current annual terrestrial biomass C pools (Tg C/year) in the Southeast and Southcentral USA (USDA, 2003).

State		Biomass C		Total Terrestrial C
	Forest	Crop	Pasture	as biomass
AL	8.7	1.3	1.3	11.3
AR	6.5	22	2.9	31.4
FL	5.4	0.3	0.7	6.4
GA	11	3.7	1.6	16.3
LA	5.9	8.7	0.7	15.3
MS	7.8	7.0	1.3	16.1
NC	8.5	7.4	1.8	17.8
SC	3.7	1.9	0.7	6.4
TN	4.3	5.2	4.7	14.3
TX	7.8	21	8.9	38.0
VA	6.3	6.3	3.2	15.8
Sum	76.0	85.3	27.8	189.1

Reforestation does not require the use of capture technology. Currently monoethanolamine (MEA) solvent absorption has been employed to scrub CO_2 from industrial streams. Other techniques are expected to be used at power plants with integrated coal gasification combined cycles (IGCC); however, such plants are not yet widespread (David and Herzog, 2000). Separation, capture, and compression costs have been estimated as 75-80% of the total cost, them remainder being transportation and injection (Herzog, 2001). Advances in technology are expected to result in decreases in sequestration costs from \$183/ton C (\$50/ton of CO_2) in 2000 to \$146/ton C (\$40/ton of CO_2) in 2012 (David and Herzog, 2000).

Specific savings for the region can be calculated based on costs avoided. The use of current separation and capture technology for anthropogenic carbon (equivalent to the amount of carbon annually sequestered in forest biomass in the region, 76 Tg C/year) when directed to a non-forest sequestration option, would amount to an expenditure of \$13.9 billion/year at \$183/ton C or \$11.1 billion/year at \$146/ton C. The estimate of Stavins and Richards, (2005) of from \$27.5 to \$82.35/ton of C indicates the cost effectiveness of reforestation.

2. Best Agricultural Production

Increasing the total carbon content of soils is considered as an indirect method resulting in long-term environmental and social benefits. Genetically modified crops/plants with high biomass (especially in root systems) facilitate soil C accumulation. Best management strategies include soil erosion management, conservation tillage practices, restoring wetlands, restricting the use of organic soils, restoration of degraded soils, crop residue management, utilization of an appropriate crop rotation system, application of organic manure and bio-byproducts, and increasing agricultural production (Lal et al., 1999).

Soil organic matter is an important dynamic component which strongly influences physical, chemical and biological properties of soils. Soil organic matter increases soil water and nutrient holding capacity, decreases nutrient and herbicide/pesticide release into runoff, improves soil structure and water infiltration. Maintenance of soil organic matter is a key to sustainable agriculture and a central indicator of soil quality and health.

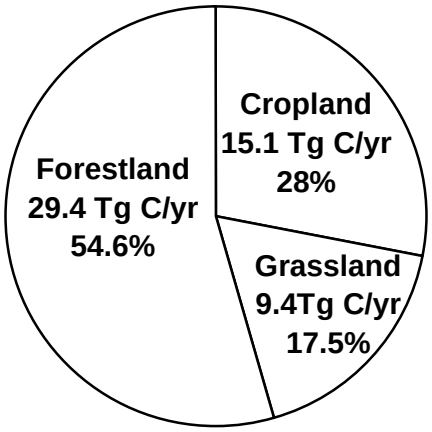
Soil organic matter storage is affected by soil management. Conservation tillage is effective in increasing soil organic carbon storage. About 37% of the U.S. farm land is now managed with conservation systems. About 48-60% of arable land in the southeastern U.S. is managed by conservation tillage (Lal et al, 1999). Long-term conservation tillage and no-tillage increase soil organic carbon storage. Adoption of conservation tillage in the U.S. has a total C sequestration potential of 350-1400 Tg C by the year 2020 (Lal et al., 1999). The overall annual potential of U.S. cropland for C sequestration through best management practices as listed above is estimated to be about 123-295 Tg C/year (Lal et al., 1999). Farmers and landowners would find it cost effective to adopt changes in soil and crop management through an incentive program at payment levels below $10 per metric tons (Lewandrowski et al., 2004).

In the Southeastern of U.S., total land area in the region totals 1583 thousand km^2. There are 377, 471 and 736 thousand km^2 of cropland, grassland and forestland, respectively. Texas has the largest cropland (26.7% of total land in TX) and grassland (65.4%), while the remaining states are dominated by forest cover (60 to 70%).

Best management practices in the region could enhance carbon sequestration on these lands by 53.9Tg C/year, accounting for 9.3% of current total annual greenhouse gas emission in the region (Table 2) (Han et al., 2005). The potential for forestland, cropland, and grassland was estimated as 29.4, 15.1 and 9.4Tg C/year, respectively (Figure 2). The potential in agricultural soils including grass land of the region could represent 13-52% of the potential in US agricultural soils estimated by Bruce et al. (1998) and Lal et al. (1998). Lal et al. (1999) reported that the total C sequestration potential in US cropland could offset 8.5-9.8% of total US greenhouse gas emissions.

Table 2 Potentials of terrestrial carbon sequestration (Tg/yr) in the southeast and southcentral USA (Han et al., 2005).

State	Total Carbon Emission	Potential Terrestrial C Sequestration				% of potential increase
		Cropland	Grassland	Forestland	Sum	
AL	37.6	0.72	0.15	3.55	4.42	11.8
AR	NA	1.63	0.16	2.98	4.78	
FL	55.9	0.59	0.44	2.37	3.40	6.1
GA	44.8	0.43	0.11	3.73	4.26	9.5
LA	68.3	0.89	0.13	2.22	3.23	4.7
MS	25.1	1.05	0.16	3.01	4.22	16.8
NC	34.3	0.95	0.07	3.02	4.04	11.8
SC	NA	0.41	0.04	2.01	2.46	
TN	30.3	1.21	0.09	2.15	3.45	11.4
TX	173	6.49	7.94	1.91	16.3	9.4
VA	35.0	0.70	0.12	2.49	3.31	9.5
Sum	505	15.1	9.4	29.4	53.9	
Average						9.3



Potential Annual C Sink: 53.9 Tg C/yr

Figure 2 The potential terrestrial carbon sequestration in the region.

A substantial cost savings is recognized through the use of best agricultural practices. Assuming that 100% of the carbon sequestration potential within the region is realized corresponds to an offset of $7.87 billion. Of this value $4.3 billion is thought to be available from forest operations. Whereas the inclusion of annual crops such as grasses and crops has little short-term benefit, improving

agricultural practices described above will improve the quality of soil carbon and the eventual terrestrial storage capacity.

Among the 11 states, Texas has the highest potential of terrestrial carbon sequestration (16.3Tg C/year) due to the greatest contribution from both cropland (6.5Tg/year) and grassland (7.9Tg/year) (Table 2) (Han et al., 2005). However, Alabama, Arkansas, Georgia, Mississippi, and North Carolina could have the potential of 4-5Tg C/year, where the forestland is the biggest contributor (between 2 and 4 Tg/year). Cropland in Arkansas could also contribute 1.6Tg C/year. However, a huge area of histosol in Florida may become a significant carbon source under cultivation.

3. Furniture and Housing

Carbon sequestered as furniture and housing can also have long term economic benefit. Annual carbon storage in housing, furniture, manufacturing, packaging and shipping in 1998 was estimated as 13.9Tg C in the southeastern U.S. region (Table 3). Texas has the highest carbon storage in housing and furniture (3.0 Tg C), followed by Florida (2.7Tg C), while Mississippi and Arkansas exhibit the lowest storage ~ (0.43Tg C) based primarily on population density.

Table 3 Carbon sequestration in the housing and furniture sector of the southeast and south-central U. S.

State	C in Furniture/Housing
	(Tg C/year)
AL	0.72
AR*	0.43
FL	2.73
GA	1.25
KY	0.64
LA	0.67
MS	0.43
NC	1.33
SC*	0.65
TN	0.9
TX	3.04
VA	1.08
Sum	13.86

Carbon storage in housing and furniture were taken from three categories: construction, manufacturing, and packaging and shipping. The construction sector accounts for 67% of the carbon pool, while manufacturing and packaging/shipping sectors represent 31 and 2%, respectively. Carbon storage in new residential construction in the region represents 64% of the construction carbon pool while that in residential upkeep and improvements accounts for 36%. Increases in the mass of carbon sequestered in housing and furniture will be driven by population. Assuming that the average “life” or a home is 70 years

allows for longer carbon sequestration periods as compared to direct use of trees for heating or pulpwood.

4. Biomineralization

One of the major criticisms of terrestrial carbon sequestration is its relative impermanence. Uptake of carbon by plants, and its incorporation into the plant or into the soil as organic carbon, will sequester carbon for periods as short as decades. Current terrestrial carbon sequestration technologies exclusively focus on organic carbon in biomass and soils. Mineral carbon sequestration has been generally neglected; however, with the proper selection of plants, another mechanism – one denoted here as “phytomineralization” – can be used to sequester carbon for periods as long as millions of years. This process bolsters the case for terrestrial sequestration. Unfortunately, the primary economic viability of this process is restricted to reduction in emissions as opposed to the generation of a product with significant market potential.

Phytomineralization refers to the processes by which some plants convert atmospheric CO_2 into mineral deposits. Calcium and silicon are the two most common elements involved in phytomineralization (biomineralization) by higher plants. Calcium deposition is far more abundant and widespread (Arnott, 1974), which produces deposits of calcium oxalate and calcium carbonate. These deposits can be amorphous or crystalline and are found in stems, leaves, roots and flowers. Hundreds of plant species (forest trees, shrubs, subshrubs, herbs, and crop plants) are known to mineralize free carbon dioxide (Cailleau et al., 2004). The great benefit of phytomineraliation is therefore long-term environmental benefits with low costs.

Studies on phytomineralization of carbon in terrestrial ecosystems are just beginning. The tropical iroko tree (Milicia excelsa) in the Ivory Coast of Africa had a high ability of accumulating mineral carbon as calcium carbonate in ferralitic soil; about 500 kg and 100 kg of mineral carbon (excluding organic carbon) was found inside and around an 80-year-old iroko stump (Cailleau et al., 2004; Braissant et al., 2004). It is estimated that the annual mineral carbon sink deficit due to deforestation in the Ivory Cost alone is more than 0.15Tg C/year. This study shows the great promise of phytomineralization of forests/soils in enhancing cost-effective terrestrial carbon sequestration.

Although the mechanisms of biomineralization/phytomineralization processes in higher plants have been studied, continental and global scale application of phytomineralization in terrestrial ecosystems and its integration technology to capture CO_2 and combat global warming have not been formally attempted. Studies match potentially available sinks with specific soils and climates. Along with greenhouse and field-scale experiments are needed.

Part II. Geological Sequestration as a Paying Proposition

1. Enhanced Oil Recovery

CO_2 injection into depleted oil wells is the fastest-growing enhanced oil recovery (EOR) process in the U.S. Total active CO_2 EOR projects increased from about 20 in 1980 to about 70 in 2004 and CO_2 oil production linearly increased from about 10,000 bpd in 1985 to about 65,000 bpd in 2004 (USDOE, 2004). CO_2 EOR oil production in the U.S. could double by 2010 and quadruple by 2020 with CO_2 incentives (DOE, 2004).

The growth of CO_2 EOR in the past two decades has resulted in substantially reduced costs. Kinder Morgan CO_2 Co. L.P. estimated that total operating expenses (exclusive of CO_2 costs) at $2-3/bbl (DOE, 2004). The direct target of CO_2 enhanced oil recovery is an increase in oil production, yet added benefits arise for sequestering CO_2. Currently the two largest companies involved with EOR in the U. S. are Kinder Morgan and Denbury Resources Ltd. Both firms rely on natural sources of CO_2. In the case of Denbury, the CO_2 originates from the Jackson dome and is of sufficient purity for beverages and food applications.

A successful demonstration of CO_2 tertiary recovery was performed in central Kansas by utilizing the effluent from a nearby ethanol plant (DOE, 2004). The estimated incremental oil production resulting was noted as being possibly as high as 600 million barrels. This translates into the equivalent of 5-10 years of additional field production. As market prices increase a commensurate number of tertiary recovery plays are expected. The main problem becomes one of transmitting the CO_2 to fields that are not already served by the few existing pipelines in the country. In Kansas alone, CO_2 EOR is expected to aid recovery from as many as 6000 mature fields. Linkage of, for example, an ethanol plant along with co-generation and EOR was estimated to result in an $88 million benefit (DOE, 2004).

2. Coal Bed Methane

Coal seam sequestration is defined as the storage of CO_2 from anthropogenic sources in deep un-mineable coals for geologically significant times with or without the recovery of natural gas (White et al., 2003). Laboratory experiments have shown that CH_4 was rapidly displaced from coal when CO_2 was injected (Fulton et al., 1980; Reznik et al., 1984). Actually methane can be replaced by many other gases as well, such as N_2. Sequestration of CO_2 in coal seams with recovery of natural gas is an attractive approach to sequester atmospheric CO_2 with additional economic values.

The technology to pump CO_2 into geological media has been used commercially for many decades. In 1993, a small CO_2 pilot injection to recover CH_4 was performed in the Fruitland Coal Formation in southern Colorado (White et al.,

2003). Similarly, a flue gas was injected into San Juan Basin coal and produced methane (White et al., 2003). A large scale field test was performed in northern New Mexico. After five years of injecting CO_2, there was been no significant breakthrough of CO_2 at the CH_4 production wells after injecting 57 million m^3 of CO_2, CH_4 production was dramatically improved (White et al., 2003). This field test showed that CH_4 production was increased by CO_2 injection and that the injected fluid was sequestered. In addition, some international projects with CO_2 injection enhancing coal bed methane have been initiated (White et al., 2003).

The overall capacity of gassy coal worldwide to adsorb CO_2 is estimated to be between 225 and 964Gt of CO_2 (Gunter et al., 1988; Kuuskraa et al., 1992; Stevens et al., 1999). On the thirteen major worldwide coal basins, the San Juan coal basin has the highest CO_2 sequestration potential (1400 x 10^6 t) (White et al., 2003). On the other hand, the global coalbed CH_4 resources are estimated in the range from 84.1 to 262 Tm^3 (Kuuskra et al., 1992). CH_4 in U.S. coals is estimated at 1.13 x 10^{13} m^3 (11.3 Tm^3) (ICF Resources, 1990). Other estimates on U.S. coalbed methane capacity are in the range of 7.77-18.3 Tm^3 (Gunter et al, 1997). Many of these coalbeds are near fossil fuel-fired electric power-generating stations with convenient CO_2 sources. This results in a great availability of CO_2 sources, less cost for transport and operation.

Economic analysis of CO_2 ECBM production in the Black Warrior coalbed methane fairway in Alabama shows a great promise for commercial application because (1) the coalbed methane industry represents a substantial market for CO_2 and (2) coal-fired power plants are the nearby sources that produce CO_2 in enough quantity to facilitate enhanced methane recovery at a large scale (Pashin et al., 2001). Pipeline CO_2 currently costs $9-23 per thousand cubic meters (Mcm), coalbed methane prices are higher than $100/Mcm. Assuming that coal sorbs twice as much CO_2 as methane, this adds $18-24/Mcm to current costs, which give most operators $35/Mcm (Pashin et al., 2001). Conventional methods only recover 20-60% of the in-place coalbed methane resources (Stevens et al., 1999), while CO_2 injection may considerably enhance methane production. This will justify considerable investment. Furthermore, enhanced coaled methane recovery may extend the productive life of all coalbed methane fields by 40% (Pashin et al., 2001).

3. Deep Saline Aquifers

Deep saline aquifers are a promising option for large scale CO_2 sequestration. There are widespread deep saline aquifers in the world. The global potential storage capacity is estimated at 350-11,000Gt of CO_2 (Bruant et al., 2002, Holloway, 1997). An earlier estimate indicated the total capacity of deep saline aquifers in the U. S. as between 5.5 and 550Gt of CO_2 (Bergman and Winter, 1995). More recent estimates tend higher.

A number of saline aquifers are located in the Southeast region. In addition, a great majority of fossil fuel fired power plants are located near these structures. This would have a tendency to reduce transportation costs, however, costs associated with capture, purification, compression, and injection will still be in effect. No saleable product is expected to arise from geological sequestration in deep saline aquifers. Thus, much like phytomineralization, the primary benefit will consist of lowered emissions.

4. Others Economic Possibilities

4.1. Flue Gas Mineralization

Mineralization of carbon dioxide is the process to converting gas phase CO_2 to carbonate minerals. The process currently focuses on reactions of Ca, Fe, and Mg silicates, such as olivine and serpentine, with gaseous carbon dioxide to form carbonates. Recent studies have been expanded to other minerals, including Ca and Fe-rich rocks and minerals such as wollastonite and basalt.

To date the produced minerals do not represent a significant commercial venture aside from sequestering CO_2. Significant quantities of ore will be required and this further necessitates that any carbonization plants be in close proximity to existing power generating facilities or to pipelines. Two potential carbon mineralization locations have been identified within the southeastern region. One is the ultramfic carbonation region, an olivine deposit in western North Carolina, which is estimated around 200 Mt of reserves (Roskill, 1990). The olivine supply from this reserve may meet the ore demand for 1-2 years and convert CO_2 from all power plant point sources within a 200-mile distance (north Georgia, central North Carolina, South Carolina and Virginia) (O'Connor et al., 2003). Reducing the distance to a 100 mile radius reduces the use of the precursor to 120 Mt/year. In some cases serpentine resources may have to be substituted for olivine. The other potential carbon mineralization site is in central Texas, where serpentine from the Llano Uplift is expected to meet an estimated ore demand of 200-400 Mt/year for CO_2 from lignite power plant point sources (O'Connor et al., 2003). The reserve may consist of over 1Gt of serpentine (Barnes et al., 1950) and represent a 5-10 year supply at full scale mineral sequestration.

There may be promise for in situ mineral sequestration, especially for the layered structure of basalts. This can save the huge cost for tremendous tonnages of ex situ mineral required for carbon mineralization sequestration. Actually the natural gas storage within anticline structures and injection of CO_2 into deep saline aquifers show some promise for involving carbon mineralization. Still costs associated with transport and injection along with those applicable to direct mineralization will be in effect.

The initial overall cost of direct mineralization is estimated at $252/ton C ($69/ton CO_2) (O'Connor et al. 2003). The cost is somewhat higher than the use of MEA;

however, current and future research is aimed at making mineralization more cost effective. Additionally, whereas the minerals generated by the process have little or no opportunity for cost recovery, such chemicals may find uses through continuing materials science efforts.

4.2. Oil Shale and Tar Sands

Oil shale are fine grained sedimentary rocks containing relatively large amounts of organic matter from which significant amounts of “oil” and combustible gas can be extracted by destructive distillation. Oil shale exists worldwide with large deposits in Australia, Brazil, Canada, China, Estonia, France, Russia, Scotland, South Africa, Spain, Sweden and the USA. Global resources of oil shale are conservatively estimated at 2.6 trillion barrels (EMD Oil Shale Committee, 2005). Sixty two percent of the world’s potentially recoverable oil shale with an oil content of 242 billion tonnes is concentrated in the USA (Youngquist, 2001). The largest of the deposits is located in the 42700 km^2 Eocene Green River formation (89%) in north-western Colorado, north-eastern Utah and south-western Wyoming. There is also the Devonian-Mississippi black shale (11%) in the eastern United States. Costs of mining and extracting energy feed stocks from shale exceed standard petroleum development costs. An increase in the cost of oil in the 1980’s as well as currently has allowed corporations to re-evaluate the development of shale resources. The interaction of shale deposited with CO_2 sequestration is currently being addressed (Nuttal, et al., 2005)

Tar sands (oil sands) are impregnated sand that yields mixtures of liquid hydrocarbon. Oil sands are deposits of bitumen, viscous oil which must be converted into an upgraded crude oil before it can be processed. Oil sands must be mined or recovered in situ. Oil sand recovery processes include extraction and separation processes to remove the bitumen from the majority of sand and water. By 2005, oil sand production accounts for about 50% of Canada’s total crude oil output and 10% of North American production. Oil sands occur in more than 70 countries. The two largest are Canada and Venezuela. Cyclic steam stimulation and steam assisted gravity drainage are currently used for in situ recovery techniques. Other techniques include thermal injection through vertical and horizontal wells, solvent injection and CO_2 methods. With improved techniques, CO_2 emitted from oil sand operations will be reduced.

4.3 CO_2 Hydrates

Gas hydrates have the capability to capture and separate CO_2 from gas mixtures and store large quantities of CO_2 in water that is hydrogen-bonded as solid structures. The feasibility of designing a process for producing methane gas hydrates has been tested in the Diagnostic Instrumentation and Analysis Laboratory and Department of Chemical Engineering at Mississippi State University. Whereas the majority of clathrates work that has been performed to date has focused on CH_4 hydrates some limited work was conducted on CO_2

hydrates. Various surfactants and biosurfactants were tested in the laboratory to form CO_2 hydrates. Rogers and Ding (2005) found that CO_2-philic surfactant dramatically improved CO_2 capture and CO_2-hydrate formation rate was substantially increased by increasing concentrations of CO_2-philic surfactant. A total 67.7% reduction of CO_2 gas from the gas mixtures was realized. Therefore, CO_2 hydrate holds a promise for possible development of practical process to capture, separate, and store CO_2 for efficient transportation.

Another potential application is to inject CO_2 into deposits of natural gas hydrates in the sub-surface of the oceans. In this manner it may be possible to exchange CO_2 for CH_4 and therefore sequester CO_2 and generate a saleable product (Smith et al., 2001). Some estimates indicate that natural gas hydrates in sediments (porous media) below arctic and sub-seafloor formations contain more energy than other fossil fuel deposits. The simultaneous sequestration of carbon dioxide and the production of methane through this process may represent a potentially efficient and cost-effective option for CO_2 sequestration (Smith et al., 2001). Additional research is needed to fully provide proof of concept for the metathesis reaction.

Conclusions

Many terrestrial and geological sequestration opportunities are expected to provide a direct economic benefit over that obtained by merely reducing the atmospheric CO_2 loading. Among the most promising methods for the region include re-forestation and coal bed methane.

Tertiary CO_2 flooding is an on-going commercially viable activity. Further development of the Eastern Mississippi fields by Denbury is planned and additional flooding opportunities are likely for Louisiana and Eastern Texas. Still, the viability of CO_2 EOR is currently based on access to natural sources as opposed to CO_2 obtained from fossil-fired power plants. Thus, some questions may arise based on differences in gas composition and, specifically, the behavior of trace gas constituents. Denbury had previously estimated that CO_2 flooding is economic at an oil price of $19 bbl (Denbury, 2005). Addition of current separation and capture costs would clearly increase the break even point; however, the cost of oil is expected to remain above $19 bbl and likely over $40 bbl for the foreseeable future.

Other sequestration options, including the direct injection of CO_2 in deep saline aquifers, mineralization, and biomineralization are not expected to lead to direct economic gain. More detailed calculations are needed for assessing the ultimate changes in the environment and the associated indirect cost savings for atmospheric stabilization. Similar comments apply to the direct conversion of methane hydrates; here, however, additional research will be needed to attain proof of concept.

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Southeast Regional Carbon Sequestration Partnership
(SECARB)

Action Plans for the SECARB Geographic Region

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Action Plans

As part of SECARB's Action Plan, the team will continue to refine Phase I concepts and will begin to validate, through field testing, sequestration technologies and corresponding infrastructure approaches related to regulatory, permitting, and outreach. The multi-partner collaborations that developed during Phase I will continue in Phase II.

SECARB's Action Plans embrace three diverse field tests. Each field test can be broken down into five activities: project definition, design, implementation, operations, and closeout/reporting. In addition, the Action Plans include work in continued characterization; cross-cutting services for education and outreach; regulatory issues and permitting; monitoring, measurement and verification technology deployment; geographical information systems data presentation; and project management.

During the first year of activity, the project field teams will assess respective geologic formations to identify site-specific opportunities for field validation. As part of this down-selection process, the teams will conduct environmental reviews and determine what actions are required to gain approval for site-specific field investigations.

6.1 Field Test 1 (FT1): Gulf Coast Stacked Storage Action Plan

FT1 is an expansion of work completed under Phase I by SECARB. The project focuses on oil and gas reservoirs and brine formations to demonstrate advanced methods of CO_2 injection and monitoring for EOR and long-term geologic storage. Because of the large number of potential EOR projects as well as the large number of saline reservoirs, the Gulf Coast is the area of focus for this field test. Figure 1 shows the target area.

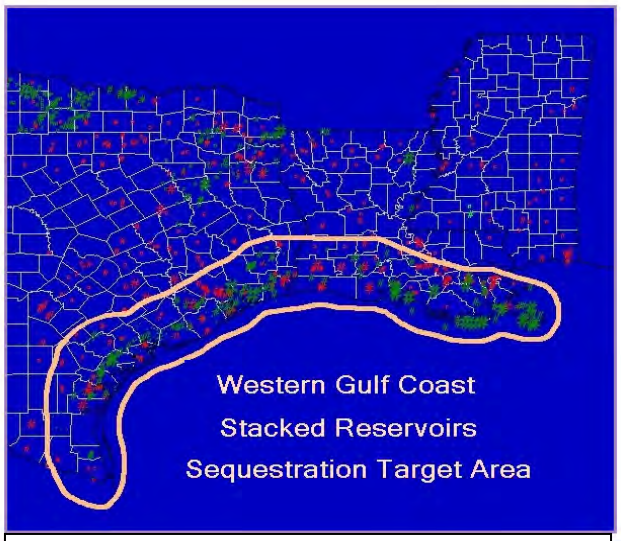

Figure 1 – Target Area for the Gulf Coast Stacked Storage Project

6.1.1 Project Definition

This field test is designed to evaluate the potential for injecting CO_2 into multiple horizons, coupling an EOR effort to provide an economic benefit to the project with sequestration efforts in saline reservoirs "stacked" in close proximity.

Each field under evaluation will have an initial reservoir characterization completed, and a preliminary CO_2 injection simulation will be performed. Candidate fields will be narrowed to one site for the field test. Field-wide simulation will be performed for the amount of CO_2 to be injected, and the models recalibrated for any changing reservoir parameters. As FT1 goes into full field injection, the simulation model will be validated and updated as necessary through injection and post injection phases, with a final summary on how accurately the simulation predicts CO_2 injection flow and

subsequent oil volumes produced.

Public outreach is key to a successful Phase II CO_2 injection project. As archived in the Frio Brine Pilot project (Hovorka, 2004), SECARB envisions significant interaction and education of the local and regional stakeholders in this process. These parties will include several NGO's, such as the Environmental Defense Fund, National Resources Defense Council, Houston Sierra Club, and Texas Nature Conservancy. In addition, communication with local residents, schools, newspapers, and governmental institutions will occur.

6.1.2 Design

The Gulf Coast team will determine preinjection baseline characterization of CO_2 concentrations that are considered normal. Subsurface characteristics of oil and brine reservoirs also must be determined prior to drilling in order that fluid changes are verified at depth after injection. Specific reservoir characteristics, such as structural dip, depositional stratigraphy and internal fluid type with specific temperature and pressures will be determined. Technical design of the pilot CO_2 injection project will occur over the first two years of the project. The design will focus on assessing an optimal operating oil-field site for both oil reservoir injection and brine injection over time.

6.1.3 Implementation

The field team will reuse existing infrastructure (road, well, and well pads) as much as possible to minimize environmental impact and reduce cost. New surface installations will be minor and include one or two new wells, most likely placed on existing pads, and an array of low-impact, surface monitoring stations with small cement pads or markers for repeat surface surveys. SECARB will work with regional experts to ensure that the engineering is excellent and all regulatory and health and safety requirements are met.

Observational wells will be installed to observe CO_2 concentration changes and associated pressure and temperature variations during injection. A critical aspect is the impact of CO_2 at depth on fault-seal integrity. The injection well will undergo completion to ensure hole integrity, to guarantee that the CO_2 is injected into the correct reservoir interval, and that the interval of interest can be traced to other well bores. Workover of any existing production wells and using idle wells for monitoring will be employed as needed to maintain seal integrity of the reservoir while minimizing project costs. Surface access will be obtained to facilitate the installation of shallow, vadose-zone monitoring wells to validate that no CO_2 has infiltrated from the injection level to the shallow-drinking-water or surface-water zones. The reservoir container will be characterized to determine optimal injection criteria as well as logging responses expected during injection in monitoring and producing wells. The core analysis performed will address these issues.

6.1.4 Operations

Injection operations will be similar to those performed at the Frio Brine Pilot site. At the site, the CO_2 will be repressurized to the required reservoir conditions utilizing Praxair injection equipment and processes. The experiment is planning on injection of up to 15,000 tons of CO_2 over a five-month period at 3,000 tons per-month. Longer-term

considerations of using low-pressure pipeline facilities at specific sites will be considered where practical but are not anticipated to be economically feasible for the field test, only for post-test, full-injection implementation.

In the stacked storage experiment, SECARB will build on the Frio Brine Pilot experience to define effective monitoring strategies for the interaction of CO_2 injection with faults; distribution of pressure in the near and far field during and after injection; and impact on fluid flow and deformation. It is critical to conduct a successful CO_2-EOR project in order to fund injection at a scale sufficient to support the monitoring strategy. The following tools will be assessed prior to field activity, and those proving viable will be fielded:

- a cased, low-angle observation bore hole that crosses the sealing fault and accesses CO_2 plume development and sweep;
- pressure, temperature, and environmental management tools permanently installed with the casing of this observation well;
- a suite of open- and cased-hole logs repeated through time in all available well bores to monitor plume evolution and observe any changes above the injection zone;
- an array of tilt meters on the surface and/or down hole;
- injected suites of partitioning and nonpartitioning tracers in brine and CO_2 to track fluid interactions and migration;
- near-surface monitoring for gas composition and tracer; and
- ecosystem monitoring for any impact related to CO_2 leakage.

In addition, SECARB will assess the feasibility of detecting CO_2 using down hole, crosswell or surface geophysics in the selected well configuration. If these seismic methods could contribute, SECARB will seek additional funding to field the instrument. Three groups of instrument designers will work with the team during the first year: Lawrence Livermore National Lab; Lawrence Berkeley National Lab; and the Diagnostic Instrumentation Analysis Laboratory (DIAL) at Mississippi State University (MSU).

Risks to the success of this project are in three main areas: health and safety; tool failure; and leakage of CO_2 out of the reservoir interval. Health and safety aspects will follow all current Occupational Safety and Health Administration (OSHA) and state regulations for the transport of CO_2, its injection, and operation of all associated equipment. The ability to acquire meaningful measurements for each experiment will determine the project's success. Pre-drilling modeling of reservoir conditions and collection of previously determined production and reservoir data will be utilized to define reservoir and bore hole conditions to allow the proper calibration of tools to those conditions. Much of the experiment will focus on the placement of both down hole and surface monitoring tools that will be state of the art in detecting small changes in CO_2 concentrations.

SECARB will determine the preferred method of transporting CO_2 to the selected field. Two options include compressed liquid via truck or barge and low-pressure gas via existing pipeline. CO_2 will be an essentially pure commercial product. SECARB will continue to evaluate emerging capture options, both in industrial and power plant

settings, which are critical to long-term applications of the technology.

Injection of CO_2 (a key milestone) will start only after an environmental review has been conducted. The project plan calls for a minimum of 7,500 tonnes of CO_2 and up to 15,000 tonnes of CO_2 for injection. The injection operator will maintain the safety environment for the project and will collect all injection data as to volume, rate, and pressures utilized. This information will validate injection and production models for tracking injection fronts and production efficiencies across the field. SECARB will perform post-injection assessments. Information collected will be utilized in validating injection and producing models for tracking injection fronts and production efficiencies across the field. Monitoring will continue for an extended time after injection, both in the subsurface to determine storage of the CO_2 and at the surface to ensure that escape of CO_2 from the subsurface injection area does not occur. During the course of the project, the SECARB team will engage local media, interested governmental bodies, and local residents.

6.1.5 Closeout/Reporting

At the conclusion of the project, a post operation discussion of activities and results will be presented to DOE and other interested parties. Discussions will continue with the local operator on continued use of the field site for experimentation on other possible projects and to determine whether EOR aspects were successful enough for the operator to move to a full-phase recovery project. If this does occur, then interaction with the operator and supplier of CO_2 for longer range storage projects will continue.

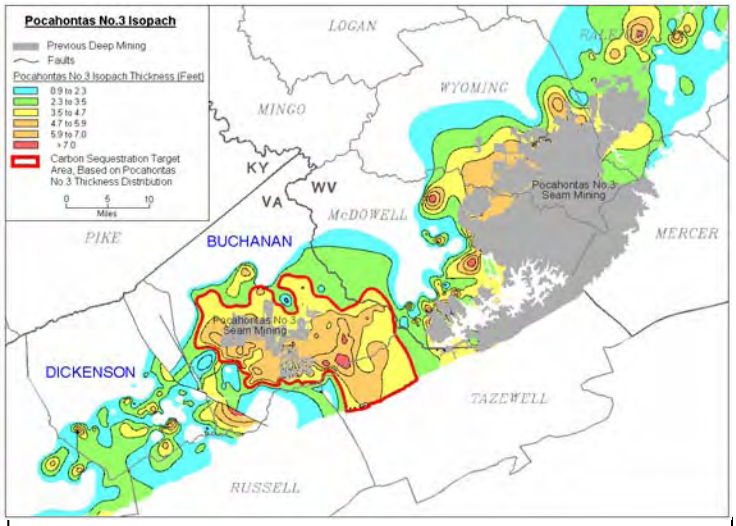

Figure 2 – Pocahontas No. 3 Seam Thickness Isopach

6.2 Field Test 2 (FT2): Coal Seams Action Plan

The action plan focuses on coal seams with high methane content and unminable coal seams in the vicinity of existing coal fields extending from the Appalachian range (Karmis, 2005), southwesterly into the Black Warrior Basin (Pashin, 2004) and towards the Gulf Coast. This field test will demonstrate CO_2 injection for ECBM in the southeastern United States. Also, this field test will investigate CO_2 sequestration in unminable coal seams and address a breakthrough concept for sequestering a full range of coal-fired power plant emissions. Two field test areas have been identified, one in the Central Appalachian Basin of Virginia, West Virginia, and Kentucky and one in the Black Warrior Basin of Alabama. These areas are shown in Figures 2 and 3 respectively.

6.2.1 Project Definition

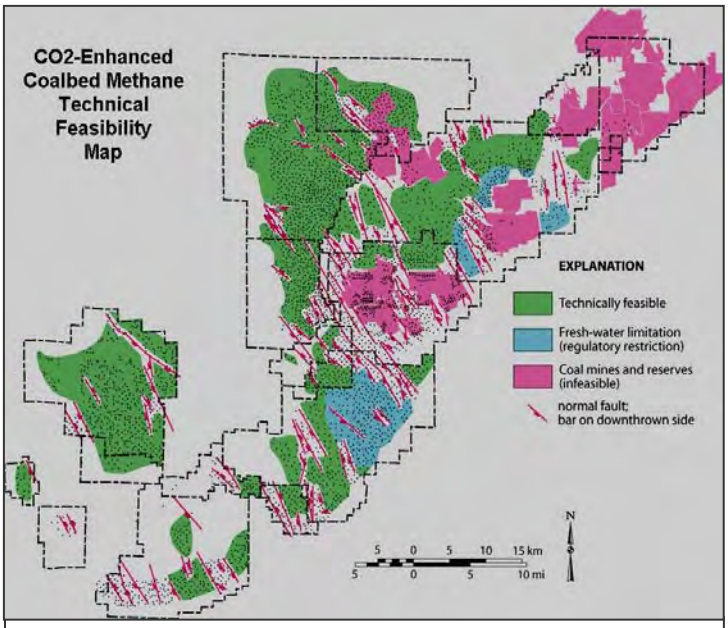

Figure 3 – Sequestration Target Areas for the Warrior Basin in Alabama

Geological assessment of coal seams and GIS development will continue. The Black Warrior Basin has been assessed in detail; however, similar assessments are lacking for some areas of the Central Appalachian Basin and for the coal fields of the Alabama thrust belt. Regional characterization activities will focus on sequestration potential of CBM reservoirs in the Cahaba and Coosa coal fields of the Alabama thrust belt, where no assessments of sequestration and ECBM potential are available. Regional geologic mapping for the Central Appalachian Basin will be expanded into neighboring counties in Kentucky and southern West Virginia.

SECARB will review characterization study results to determine optimum sites for core hole drilling and testing for pilot injection of CO_2. Approximately four well sites in both Central Appalachia and Alabama will be reviewed for possible selection as pilot sites. The results of geological characterization will be used to select the final test sites and to determine the precise well design and monitoring plan.

Reservoir modeling is an important component in understanding the mechanisms at work in carbon sequestration within coal seams. As such, the process will require the gathering of production history and detailed geologic information for each of the prospective pilot locations. A history match will be synthesized from these data. Multiple sensitivity runs then will be conducted concerning the injection of CO_2 (rate, pressure, and duration) and production controls at offset producers (rate, pressure), which should contribute to the design aspect of the pilot by providing estimates of the necessary CO_2 volumes, expected operating conditions, and a baseline expectation.

The public outreach and education activities for the Coal Seam Project should be initiated early and span the entire schedule, beginning with the assembly of an advisory committee at the start of the project that will include a broad range of stakeholders, including gas producers, utilities, regulators, and landowners. A vigorous technology transfer program will be conducted throughout Phase II and will include development of a project website, presentations at technical meetings, and publications. A local outreach program in both Alabama and Central Appalachia will develop a grassroots group to enlighten citizens in the area on the positive benefits the sequestration program offers. A speaker's bureau will be created to engage and educate elected officials (local, regional, state), chambers of commerce, civic organizations, and educational communities through printed publications and PowerPoint presentations.

6.2.2 Design

Four types of reservoir modeling efforts provide the basis for design:

- review of the selected primary injection site's basins;
- rigorous history matching and assessment of the preferred CO_2 injection sites;
- mid-course reservoir modeling to assess the performance of the project against expectations; and
- post-project history matching and performance prediction of the CO_2 sequestration pilots and their implications to CO_2 storage in the basins.

After the locations of the test sites are determined, three core holes will be drilled around each production well and the specific pilot design will be determined on the basis of the baseline reservoir models.

6.2.3 Implementation

This program will make use of existing CBM wells. Therefore, the principal construction requirements under this program will be the drilling of core holes and the installation of monitoring apparatus. Field work will not begin until an environmental review has been completed. Three core holes will be drilled around the production well immediately after the location of the test site is finalized. These holes will be about 75 to 150m from the production well, and the precise locations will be determined on the basis of the baseline reservoir models. After the cores are removed for analysis, the core holes will be converted into monitor wells. A similar monitoring design was employed at the Rock Creek test site in the Black Warrior Basin, which was used to develop CBM completion technology (Spafford and Stubbs, 1989; Koenig, 1989). Isolation packers and slim hole monitoring equipment will be installed to observe reservoir pressure and gas composition. Shortly thereafter, shallow slant holes will be drilled and monitoring equipment will be installed to analyze gases in near-surface fractures.

Risk analyses will be performed and include review of the feasibility of the proposed pilot tests and assessment of environmental risks. Integration of geologic, geophysical, laboratory, reservoir, and production data will be necessary to complete this task. Monitoring and verification implementation will focus on two approaches: (1) deep well monitoring; and (2) shallow subsurface monitoring. To prepare for field testing, the core holes will be converted to deep monitor wells by an oilfield service company, and three shallow wells will be drilled for shallow monitoring in the Black Warrior Basin pilot. Baseline data will be collected for a minimum of three months before injection-falloff and production testing begins. Monitoring equipment will be installed in the shallow wells to monitor CO_2 levels. Baseline data on natural CO_2 levels will be measured for at least three months prior to deep well testing. Any required leases, surface owner agreements, state drilling permits, and Class II permits from the EPA will be obtained prior to implementation.

6.2.4 Operations

A sequence of parallel tests will be performed in Alabama and Central Appalachia in order to allow proper evaluation of each basin. These tests will be staggered to allow for

proper funding and minimize replication among the proposed pilot tests. Pilot project operations will constitute a series of injection-falloff and production tests similar to those performed by the Alberta Research Council (Law, 2004). The total amount of CO_2 required for each injection program is estimated to be 1,000 tons. However, higher injection volumes are anticipated for the horizontal multi-lateral injection pilot in the Central Appalachian region. Reservoir pressure and gas composition will be monitored in the deep monitor wells throughout the injection testing. Deep monitoring will continue for at least three months after the injection tests are completed. Similarly, gas composition will be monitored in the shallow monitor wells at the Alabama site throughout the injection tests, and shallow monitoring also will continue for at least three months after the injection tests are completed to ensure that no leakage occurs.

Injection operations at each of the proposed coal seam test sites will comprise a series of injection-falloff and production tests similar to those performed by the Alberta Research Council in Canada and China (Law, 2004). Prior to injection, a production and pressure-buildup test will be performed in three separate coal zones to analyze pressure response and permeability near the production well. Next, a 10- to 15-ton slug of CO_2 will be injected into each coal zone to determine the pressure-falloff response of the reservoir to CO_2, and then a second set of production tests will be performed. After this, a larger slug of up to 100 tons of CO_2 will be injected and pulsed injection tests performed. Additional injection tests will follow this step, and the size and timing of these tests will be determined on the basis of the initial results of production and injection-falloff testing. A final production test will be performed to analyze changes in reservoir properties after the injection tests are complete. The total amount of CO_2 required for each injection program is estimated to be 1,000 tons. However, the test procedure and CO_2 requirement may be changed somewhat for the multi-lateral horizontal test after initial modeling is complete.

Monitoring and verification will focus on deep well monitoring and shallow subsurface monitoring. After the three core holes are drilled at each test site, they will be converted into deep monitor wells. Packers will be installed to isolate three separate coal zones. Slim hole equipment for observing reservoir pressure and gas composition will be installed between the isolation packers to monitor reservoir pressure and gas composition (CO_2 and CH_4). Baseline data will be collected for a minimum of three months before injection-falloff and production testing begins, and data will continue to be collected during the well testing and for at least three months after the testing is completed. Pressure response and gas composition will be mapped using the data from the observation wells, and reservoir models will be refined on the basis of the data.

Southern Company Services (SCS) will perform surface and shallow subsurface monitoring in Alabama consisting of approximately 30 surface sampling stations and three shallow wells that will be drilled directionally. Infrared gas analyzers with accumulation chambers will be used to measure CO_2 flux using the methods of Ghafurian et al. (1998) and Galdiga and Greibrokk (2000). The three wells will be drilled into bedrock below the soil zone to analyze gases in fractures and to minimize false-positive CO_2 readings caused by bacterial action within the soil profile. Baseline data on natural CO_2 levels will be measured for at least three months prior to deep well testing, and testing will continue for at least eight months after the injection-falloff and production tests are completed. One shallow monitor well will be drilled near the production well to test for leakage near the injection site, another will be installed above the main hydraulic

fractures that extend laterally from the production well, and a third will be installed in a location remote to the production well and other monitor wells.

The principal risks associated with the injection experiments are leakage of CO_2 and dilution of CH_4 with CO_2 in nearby production wells. The small amount of CO_2 required for the injection tests will minimize risk by limiting the probability of leakage. Also, the small amount of CO_2 to be injected under this program should not travel more than 150 meters from the well bore and thus should not affect the quality of gas produced in nearby wells. The deep monitoring program for gas composition will be sufficient to determine if communication of gas between coal zones occurs. The shallow monitoring program, similarly, will be used to determine if seepage of injectate at the surface is a problem at the Alabama pilot. If surface seepage is a problem there, then injection rates will be reduced, or the injection tests will be terminated. If communication between coal zones occurs, injection pressures and volumes will be adjusted to minimize communication.

CO_2 will be purchased from a commercial source. Transportation to the well site will be by tanker trucks, which hold up to 30 tons of CO_2. The CO_2 will be warmed to surface temperature and injected directly from the trucks. The CO_2 that is used in the injection tests will be relatively pure and contain no significant impurities that will impact the project results. An identified supplier of bulk liquid CO_2 is Praxair in Marietta, Ohio. From Marietta, the CO_2 will be shipped by tanker truck to the proposed pilot area in Central Appalachia.

A sequence of parallel tests will be performed in Alabama and Central Appalachia in order to allow proper evaluation of each basin. These tests will be staggered to allow for proper funding and minimize replication among the proposed pilot tests. Pilot project operations will constitute a series of injection-falloff and production tests similar to those performed by the Alberta Research Council (Law, 2004). The total amount of CO_2 required for each injection program is estimated to be 1,000 tons. However, higher injection volumes are anticipated for the horizontal multi-lateral injection pilot in the Central Appalachian region. Reservoir pressure and gas composition will be monitored in the deep monitor wells throughout the injection testing. Deep monitoring will continue for at least three months after the injection tests are completed. Similarly, gas composition will be monitored in the shallow monitor wells at the Alabama site throughout the injection tests, and shallow monitoring also will continue for at least three months after the injection tests are completed to ensure that no leakage occurs.

6.2.5 Closeout/Reporting

The Coal Seam team will interpret the results of deep and shallow monitoring and refine reservoir models using the injection-falloff and production data and obtain a history match. A base forecast will be supplied to understand the potential movement of CO_2 over geologic time. Various sensitivity parameters will be reviewed, such as caprock permeability and vertical permeability within the coals to aid in the understanding of long-term storage and migration of CO_2 within coal seams. The results of injection testing will identify best practices for CO_2 sequestration, vertical versus horizontal well injection efficiencies, ECBM, monitoring, and regulation. Well tests and model results will be used to revise procedures for assessing sequestration capacity and ECBM potential in other coal basins. The proposed injection tests for CO_2 constitute an early step in realizing the

acid-gas sequestration potential of coal. Modeling efforts and analysis of regulatory factors also will explore the possibility of sequestering multiple acid gases in coal, a breakthrough technology with the potential for low cost, permanence, and large global capacity.

6.3 Field Test 3 (FT3): Saline Formation Action Plan

Field Test 3 focuses on the ultimate goal of locating suitable geologic sequestration sinks in proximity to large coal-fired power plants. Funds will be used specifically for investigating the geologic formations in proximity to EPRI's proposed Test Center. The Test Center team will assemble the available deep well logs, core analyses, and other geological data to build a geologic and reservoir model. The team will use its COMET2 reservoir simulator to estimate CO_2 injectivity plus long-term CO_2 storage capacity and fate. The team also will run the models for a longer time period to fully assess the CO_2 storage potential of the saline aquifers in this area.

6.3.1 Project Definition

The Test Center team will specify the well pad and infrastructure criteria, prepare the drilling, casing and completion plan, define the surface facility requirements, identify the reservoir characterization and testing plan for the injection and monitoring wells, and conduct numerous other pilot test site planning and preparation tasks. The team will: (1) support Southern Company and the local plant management involved in the test site project with initial information and distribution materials on the proposed project; and (2) work with Southern Company to prepare an action plan for informing the public and gaining their acceptance.

The FT3 team will build a detailed geological and reservoir model of the proposed test site, including conducting a sequence of reservoir simulations to estimate injectivity, storage capacity, and the long-term fate of injected CO_2. The project will assemble the available deep well logs, core analyses, and other geological data to build a geologic and reservoir model of the proposed saline aquifer test site. The Test Center team will use the COMET2 reservoir simulator to estimate the CO_2 injectivity and the long-term CO_2 storage capacity and fate of the injected CO_2 of the site. The team will run the model to match the injection rate and flow performance of CO_2 injection at the test site to conduct a "history match" that will provide confidence in the CO_2 storage properties of the Eutaw formation in the plant area. Next, the model will be executed for much longer time periods and for a larger geographic area to predict the CO_2 storage potential of the Eutaw saline aquifer in this portion of the SECARB region.

To help define the CO_2 storage potential of the area, a sequence of four reservoir modeling efforts will be conducted during Phase II. These will be:

- initial "screening modeling" to verify the selection of the primary site;
- rigorous assessment of the preferred CO_2 injection site after obtaining actual reservoir data from the slim hole monitoring well;
- numerous sensitivity runs to establish injectivity and storage; and
- mid-course reservoir modeling to assess the performance of CO_2 injectivity and flow prediction.

FT3 will assist Southern Company and the local plant management with initial information and distribution materials on the proposed project. FT3 will work with Southern Company to clearly define roles for Southern Company's management staff, SECARB, and the pilot project plant staff for informing the public and gaining their acceptance. The team will provide periodic updates of the project to Southern Company and SECARB staff in a form that can be readily submitted to the public at large. FT3 will design plans using insights from the successful public outreach and education efforts by the DOE/NETL sponsored BEG Frio saline aquifer project in Texas and the American Electric Power's Mountaineer CO_2 sequestration project in West Virginia. FT3 also will ensure that the project complies with the public involvement requirements set forth for NEPA and regulatory permitting. In addition to providing information to the public using local newspapers and media advertising, FT3 will help Southern Company hold public education programs at libraries, schools, and local businesses and provide information to and personal visits with local and state officials interested in the saline aquifers CO_2 sequestration project in the SECARB region.

6.3.2 Design

FT3 will procure and transport approximately 3,000 tons of CO_2 and inject it over 30 days of operation. The total volume of CO_2 injected will depend on the costs which are projected to be $100 per ton. The Test Center team will set forth the CO_2 storage and monitoring protocols for the saline aquifer's field test site including, as appropriate, "shooting" of baseline and subsequent seismic, pressure, and fluids sampling by the observation wells and the linkage of reservoir simulation-based projections of the movement and fate of CO_2 with actual observations. The MMV protocol description includes the costs of installing and operating each protocol. Test site permitting will ensure that NEPA, EA and EIS requirements are met and that valid permits are obtained. For the saline aquifer test site, the team will (1) provide a roadmap for permitting saline aquifer test sites in the region; (2) consult with federal and state regulatory permitting agencies for guidance and information; (3) satisfy the local, state, and federal permitting requirements to conduct the project, including transportation, storage, monitoring, and risk assessment; and (4) track changes to the regulatory requirements for sequestration in the region.

6.3.3 Implementation

The first step will be to conduct an environmental review, followed by characterization of the reservoir. A slim hole reservoir characterization well will be used to acquire subsurface data to conduct the detailed pre-injection well drilling characterization of the test site. Later, this well will be used to provide future reservoir access for monitoring and observing the flow and storage of CO_2 in the Eutaw saline aquifer. As part of the slim hole well reservoir characterization effort, a full suite of geophysical logs will be obtained, pressure transient testing on reservoir zones of interest will be conducted, and the formation and overburden stress evaluated.

The well logging will provide vital information on the porosity and net reservoir thickness of the Eutaw formation in the test site area, which is essential for estimating the CO_2 storage potential in the test site area. The pressure transient testing will provide a first-order estimate of the reservoir permeability necessary for calculating CO_2 injectivity in the test site area. The confining stresses of the shale formations adjacent to the primary

CO_2 injection zones will be evaluated to provide an assessment of the competence of the reservoir seal.

After drilling, logging, and testing of the slim hole well in the Eutaw formation, the next step will identify the specific location and prepare the well pad for the CO_2 injection well. This process will involve examining the surface characteristics of the area, identifying the need for new roads or alternative site access, and establishing the size, disposal requirements, and environmental impacts of establishing the well site. It also will involve arranging for site clearance, well pad construction, and protective fencing. The final step is to procure the well drilling, well completion, and surface equipment for the test site.

Site-specific reservoir characterization will be conducted beginning with a slim hole reservoir characterization of wells along with well testing and analysis to acquire detailed subsurface data. A suite of geophysical logs will be obtained, and pressure transient testing on reservoir zones of interest will be conducted. The confining stresses of formations adjacent to the primary CO_2 injection zones will be evaluated. The Test Center team expects three months for site preparation, well drilling, and installation of facilities. The team will define and conduct the work designed to establish the baseline conditions for the field test site, including a high resolution 2-D seismic survey, soil sampling, reservoir fluid sampling, and the characterization of the reservoir seal and bounding layers.

6.3.4 Operations

As part of this effort, the FT3 team will specify the CO_2 injection and testing plan for the injection and monitoring wells. The current plans are to inject approximately 3,000 tons of CO_2 and to observe its movement and storage in the saline aquifer formation. The team will review these plans with the outside experts to ensure that the injection and monitoring expectations are sound. Particular attention will be given to avoiding and reducing well bore corrosion problems from the acidic CO_2 and water solution during the injection of CO_2.

The FT3 team will set forth the CO_2 storage and monitoring protocols for the saline aquifers field test site. This will include, as appropriate, baseline and subsequent seismic surveys, pressure, and fluids sampling by the observation wells, and the comparison of reservoir simulation-based projections of the movement and fate of CO_2 with actual observations. The team will define and supervise the implementation of work designed to establish the baseline conditions for the field test site. This will include conducting a high-resolution 2-D seismic survey, soil sampling, reservoir fluid sampling, and the characterization of the reservoir seal and bounding layers. The current plan is to shoot two ten-mile 2D seismic lines over the field test site, to provide the important “baseline.” This will be followed by shooting two additional ten-mile seismic lines after CO_2 injection to track the movement and storage of the CO_2. The fluid sampling plan will include taking fluid measurements in the monitoring well to gain an understanding of CO_2 saturation in the field test site area.

Risk analysis will include examination of the pilot project operation and assessment of future environmental risks. This task will be conducted and performed as an EA, reviewing the potential risks relevant to a given pilot site(s). Integration of geologic, geophysical, laboratory, reservoir, and production data will be necessary to complete

this task. Highlights of this analysis should consider caprock integrity, quality of stored CO_2, movement profile, MMV, and duration of storage, with significant portions of this information being derived from the reservoir modeling. More specifically, this task will review and assess the potential economic and environmental risks involved in pilot and large-scale CO_2 injection projects due to contamination of offset wells, carbonic acid induced corrosion, contamination of groundwater or other horizons, and possible facility incidents. Land, regulatory, safety, operational, gas processing, and logistical issues that could present obstacles to pilot or large-scale implementation projects also will be reviewed.

The FT3 team's preliminary plan is to purchase 3,000 tons of CO_2 and transport it under pressure to the test site. While we have yet to establish the source of CO_2, FT3 has identified a number of viable options, including ethanol plants, refineries, fertilizer plants, and gas processing plants in the area. We also are familiar with Denbury's plans to extend their CO_2 transportation line south. This provides the test site a back-up source of CO_2 should industrial sources of CO_2 not be available or too costly.

Based on the volume of CO_2 to be injected, the test site will operate actively for 30 days, with monitoring and passive operations to follow. Selected MMV protocols, including a second high resolution 2-D seismic survey, will ensure that the sampling plan, frequency and number of samples taken, and the overall operations of MMV at the saline aquifer test site meet the protocol design. Mid-course reservoir modeling will assess the performance of the project and its implications to CO_2 storage in the basins.

The Test Center team will provide detailed analysis to establish the economic and CO_2 storage implications for the overall SECARB region learned from the performance of the test site. The economic model will be used to extrapolate the results from the pilot to basin-scale. The Test Center team will prepare the saline aquifers test site chapter and develop the MMV protocols and performance chapter for the SECARB Final Report.

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Submitting Organization:	Augusta Systems, Inc. 3592 Collins Ferry Road, Suite 200 Morgantown, WV 26505 (304) 599-3200 telephone (304) 599-3480 facsimile

Patrick R. Esposito II, J.D.
patrickesposito@augustasystems.com

Patrick R. Esposito, Ph.D., P.E.
pesposito@augustasystems.com

Janet M. Wood
jwood@augustasystems.com

Jesse E. Gandee
jgandee@augustasystems.com

Jackie P. Williams II
jwilliams@augustasystems.com

Augusta Systems, Inc. submits this report, which includes information and activities conducted by Augusta Systems in consultation with the SSEB. The report includes information and analysis in response to deliverables 29 and 30 under this project and updates information from deliverables 1 and 5.

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ABSTRACT

United States (U.S.) President George W. Bush has developed the President's Global Climate Change Initiative (GCCI) to assist U.S. businesses and public entities in meeting the need to decrease carbon dioxide (CO_2) and other greenhouse gas (GHG) emissions in a voluntary manner. The GCCI has a goal of 18 percent reduction in GHG intensity, which involves the relationship of GHGs to the gross domestic product, by 2012. To assist with President Bush's initiative, Federal government departments and agencies are utilizing various technologies and approaches, including, in the case of the U.S. Department of Energy, a program led by the National Energy Technology Laboratory focused on multi-state, regionally-based partnerships, known formally as Regional Carbon Sequestration Partnerships (RCSPs), to advance and demonstrate carbon sequestration technology options to assist to the Nation's ability to meet the GCCI goal.

The Southeast Regional Carbon Sequestration Partnership (SECARB), which is one of seven RCSPs funded for Phase I activities, is the Southern States Energy Board (SSEB)-led framework to address opportunities for carbon sequestration technology deployment in the Southeastern U.S. The Partnership represents eleven southeastern states, including Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Texas, and Virginia. Partners include state government agencies, research universities, energy companies, private consultancies, and nonprofit entities with presences and interests in the SECARB and SSEB regions.

As part of its mission, SECARB has developed action plans to overcome the issues identified in the preliminary assessment of regulatory, safety, permitting, and accounting frameworks within the region to allow for wide-scale deployment of promising terrestrial and geologic sequestration approaches, including, with reference to geologic sequestration, specific capture, transport, injection, and storage approaches. During its two years of Phase I activities, SECARB has worked to advance this goal and the overall mission.

To develop the action plans, Augusta Systems performed a variety of research and analysis activities. To provide context for regulatory, safety, and permitting frameworks, Augusta Systems investigated emerging, potentially SECARB-applicable GHG accounting frameworks. In addition, Augusta Systems collected and analyzed the relevant state and federal statutes and regulations applicable to sequestration regulatory, permitting, and safety matters. This research involved direct examinations of applicable statutes and regulations related to both geologic and terrestrial sequestration applications, as well as interaction with state legislators and regulators responsible for enacting and implementing regulatory regimes. Also, Augusta Systems participated, on behalf of SECARB, with the Interstate Oil and Gas Compact Commission Task Force on Geologic Carbon Sequestration to ensure that SECARB approaches would converge with recommended national approaches.

This report documents the efforts of the SECARB regulatory and accounting team during the Phase I SECARB activities. Areas of the report focus on: Introduction; Emissions Management Goal Drivers; Regulatory, Permitting, Safety, and Accounting Frameworks; Action Plan Development and Activities; and, Conclusions. The Phase I efforts, which meet the requirements of SECARB Subtask 3.1 and 6.6, focused on efforts to assess relevant information and develop the Action Plans for Regulatory, Permitting, Safety, and Accounting Frameworks.

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EXECUTIVE SUMMARY

To assist United States (U.S.) President George W. Bush with his President's Global Climate Change Initiative (GCCI), which seeks to reduce U.S. greenhouse gas emissions on a voluntary basis, Federal government departments and agencies are utilizing various technologies and approaches, including, in the case of the U.S. Department of Energy, a program led by the National Energy Technology Laboratory focused on multi-state, regionally-based partnerships, known formally as Regional Carbon Sequestration Partnerships (RCSPs), to advance and demonstrate carbon sequestration technology options to assist to the Nation's ability to meet the GCCI goal.

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I. INTRODUCTION

With projections indicating that the use of fossil energy for power generation will double by 2030 with a corresponding increase in global emissions of carbon dioxide (CO_2) from human activities of up to 60 percent by as early as 2020, there is a heightened focus within the international community to structure and develop solutions to assist in carbon management. United States (U.S.) President George W. Bush has developed the President's Global Climate Change Initiative (GCCI) to assist U.S. businesses and public entities in meeting the need to decrease CO_2 and other greenhouse gas (GHG) emissions in a voluntary manner. The GCCI has a goal of an 18 percent reduction in GHG intensity, which involves the relationship of GHGs to the gross domestic product, by 2012.

To assist with President Bush's initiative, Federal government departments and agencies are utilizing various technologies and approaches, including, in the case of the U.S. Department of Energy (USDOE), a program led by the National Energy Technology Laboratory (NETL) focused on multi-state, regionally-based partnerships, known formally as Regional Carbon Sequestration Partnerships (RCSPs), to advance and demonstrate carbon sequestration technology options to assist to the Nation's ability to meet the GCCI goals.

The Southeast Regional Carbon Sequestration Partnership (SECARB), which is one of seven RCSPs funded for Phase I activities, is the Southern States Energy Board (SSEB)-led framework to address opportunities for carbon sequestration technology deployment in the Southeastern U.S. The Partnership represents eleven southeastern states, including Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Texas, and Virginia. Partners include state government agencies, research universities, energy companies, private consultancies, and nonprofit entities with presences and interests in the SECARB and SSEB regions.

As part of its mission, SECARB has a goal to develop action plans to overcome the issues identified in the preliminary assessment of regulatory, safety, permitting, and accounting frameworks within the region to allow for wide-scale deployment of promising terrestrial and geologic sequestration approaches, including, with reference to geologic sequestration, specific capture, transport, injection, and storage approaches. In support of this mission, Augusta Systems has performed research and analysis of the relevant state and federal statutes and regulations applicable to sequestration regulatory, safety, and permitting matters. This research involved direct examinations of applicable statutes and regulations related to both geologic and terrestrial sequestration applications, as well as interaction with state legislators and regulators responsible for enacting and implementing regulatory regimes. Also, Augusta Systems participated, on behalf of SECARB, with the Interstate Oil and Gas Compact Commission Task Force on Geologic Carbon Sequestration to ensure that SECARB approaches would converge with recommended national approaches. In addition, Augusta Systems investigated emerging, potentially SECARB-applicable GHG accounting frameworks.

This report documents the efforts of the SECARB regulatory and accounting team during the initial year and a half of the Phase I SECARB activities, which focused on meeting the requirements of SECARB Subtask 3.1, as well as initiating efforts to

develop Action Plans for Regulatory, Safety, Permitting and Accounting Frameworks called for in SECARB Subtask 6.6.

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II. EXPERIMENTAL

Due to the nature of the project, no experimental methods, materials, or equipment were or are necessary.

III. RESULTS AND DISCUSSION

A. Overview

SECARB, which, as noted, is one of seven RCSPs funded for Phase I activities, is the SSEB-led framework to address opportunities for carbon sequestration technology deployment in the Southeastern U.S. The Partnership represents eleven southeastern states, including Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina and Tennessee, Texas, and Virginia.

Partners include state government agencies, research universities, energy companies, private consultancies, and nonprofit entities with presences and interests within the SECARB region and the SSEB, which is the only interstate compact in the United States that is constituted by both federal and state laws, that has governors, state legislators, and a Presidential appointee comprising its board of directors, and is empowered by its charter to address energy and environmental issues. Among the Technical Team partners are: the SSEB; Electric Power Research Institute (EPRI); a Mississippi State University (MSU) team led by the Diagnostic Instrumental Analysis Laboratory (MSU-DIAL); Augusta Systems, Inc. (Augusta Systems); Massachusetts Institute of Technology (MIT); the University of Texas at Austin, Bureau of Economic Geology (Texas-BEG); the Virginia Polytechnic Institute and State University (Virginia Tech); Winrock International; Geological Survey of Alabama; Advanced Resources International (ARI); Applied Geo Technologies, Inc., a business of the Mississippi Band of Choctaw Indians; the Tennessee Valley Authority (TVA); RMS Strategies; and, The Phillips Group.

As part of its mission, SECARB has a goal to develop action plans to overcome the issues identified in the preliminary assessment of regulatory, safety, permitting, and accounting frameworks within the region to allow for wide-scale deployment of promising terrestrial and geologic sequestration approaches, including, with reference to geologic sequestration, specific capture, transport, injection, and storage approaches. Through the efforts of the SECARB team, SECARB has worked to advance this goal and the overall mission during the first phase of the RCSP initiative. As a result of the unique structure of the SSEB, which is the nation's only regionally-focused, Federal-state energy compact, which engages state government entities and private businesses in sustainable dialogues on emerging energy and environmental technology issues, SECARB is well-positioned to research and develop regulatory, permitting, and accounting frameworks for and associated multi-year action plans to assist in the wide-scale deployment of carbon sequestration technologies and approaches. During the initial phase of SECARB, Augusta Systems and the SSEB have worked to advance this goal and the overall mission.

To provide context for the regulatory, safety, and permitting analysis, Augusta Systems investigated emerging, potentially SECARB-applicable GHG accounting frameworks. As no universally-accepted accounting standard exists for GHG emissions and emissions reduction accounting, this research focused on tracking the methodologies and protocols presently in practice internationally and nationally, with a focus on developed accounting standards, registry program requirements, and trading program rules. This study included the current requirements of and contemplated amendments to the USDOE Voluntary Reporting of Greenhouse Gases Program, established under Section 1605(b) of the Energy Policy Act of 1992. SECARB also examined methodologies and protocols under emerging voluntary GHG emissions reduction trading platforms; state GHG emissions and emissions reduction registry programs in the U.S; and, various international efforts, including the World Business Council for Sustainable Development and the World Resources Institute's "Greenhouse Gas Protocol."

Augusta Systems has performed research and analysis of the relevant state and federal statutes and regulations applicable to sequestration regulatory, safety, and permitting matters. This research involved direct examinations of applicable statutes and regulations related to both geologic and terrestrial sequestration applications, as well as interaction with state legislators and regulators responsible for enacting and implementing regulatory regimes. This research and analysis on geologic sequestration related to direct carbon dioxide injection into geologic formations; enhanced hydrocarbon recovery using carbon dioxide; and, governance of the associated deep well injection classes. Also, Augusta Systems participated, on behalf of SECARB, with the Interstate Oil and Gas Compact Commission (IOGCC) Geological CO_2 Sequestration Task Force (the IOGCC Task Force) to ensure that SECARB approaches would converge with recommended national approaches.

Key analysis regarding terrestrial sequestration focused on permitting and regulatory barriers and/or incentives to various field applications that could be implemented. The research and analysis activity also used selected scholarly articles and papers related to regulatory and permitting issues for analogous practices.

In another effort to ensure that all RCSPs, including SECARB, engaged in regulatory, safety, permitting, and accounting framework analysis and development activities with an appropriate base of background knowledge about carbon sequestration regulatory and legal activities, NETL coordinated and managed RCSP Regulatory Compliance and Liability Issues Working Group meetings. As a result of these quarterly meetings and calls, as well as the IOGCC-led effort, SECARB and the other partnerships are working to ensure that common regulatory and accounting approaches are being developed throughout the RCSPs.

Thus, the Action Plans for Regulatory, Safety, Permitting, and Accounting Frameworks have taken into account the present state of developments in each of these areas and will leverage the resources of the SSEB to connect efforts state regulators. This report documents the efforts of the SECARB regulatory and accounting team during the two years of the Phase I SECARB activities.

B. Drivers – Emissions Management Goals

Sequestration, both in its geologic and terrestrial forms, is gaining importance as the leading practical and cost-effective technology solution to combat the specter of global climate change and other environmental concerns that loom large on today's business and political landscape. Driven by the efforts of public bodies, ranging from the multinational Carbon Sequestration Leadership Forum (CSLF) and Intergovernmental Panel on Climate Change (IPCC) of the United Nations (UN) to the localized Regional Greenhouse Gas Initiative (RGGI) of nine northeastern U.S. states and the voluntary rules-based Chicago Climate Exchange (CCX), efforts have been set in motion to reduce GHG emissions through a variety of mechanisms, including sequestration as an option, in most instances. These regulatory initiatives are mirrored by private drivers of GHG emissions management, including financial risk and Sarbanes-Oxley disclosure requirements, being put in place by banking and insurance institutions. To provide context for the drivers of sequestration technology and approach deployment and their associated regulatory, safety, permitting, and accounting frameworks, a brief overview of the market drivers and the accounting protocols will be provided below.

1. Markets and Market Makers

With Kyoto Protocol being adopted in 2008 in the European Union (E.U.) and other countries, not including the U.S., and other measures, there are additional regulatory and voluntary drivers for GHG emissions management activities, including sequestration projects, by enterprises that are present today. For instance, in the E.U., significant action by member states has already taken place and will be expanding in the coming years. As two examples, both Denmark and the United Kingdom had adopted trading mechanisms to allow for financially viable solutions in order to meet new emissions standards for several years. More notably, this year, the European Commission moved forward to launch a regulated system, the E.U. Emissions Trading Scheme, for GHG emissions trading with mandatory application to E.U. member states and select industrial sectors, which has given rise to a sister organization to CCX, the European Climate Exchange (ECX).

Similarly, in the United States, there have been overtures from national policymakers and business leaders that voluntary, market-based solutions offer a realistic answer to reduce GHG emissions. For instance, in 2002, over 225 companies filed voluntary GHG emissions management reports through the USDOE Voluntary Report of Greenhouse Gases Program, which is better known as the "1605(b) Program," its citation in the Energy Policy Act of 1992. Most major energy companies and many industrial companies are annual filers under this program. Among the notable participants are AES Corporation, American Electric Power, ChevronTexaco, Cinergy, CONSOL Energy, Consolidated Edison, Dominion, Dow Chemical, Duke Energy, Entergy, NiSource, PG&E Corporation, Southern Company, Tennessee Valley Authority, and Xcel Energy, to name just a few. Again, another example of the broad-based support for this vision among energy and industrial players is the CCX voluntary emissions trading platform, which boasts over 100 members as of late September 2005.

Further, over half of the individual states within the U.S. have developed or are developing strategies to reduce GHG emissions. For instance, Massachusetts, New Hampshire, and Oregon, have all mandated certain GHG emissions reductions for energy companies. Moreover, as referenced, a group of nine northeastern state

governors have formed RGGI and committed to developing a regional cap-and-trade program for carbon emissions by 2009, which is presently being discussed as a "staff working group proposal." In addition to the regulatory and voluntary mechanisms put in place by public entities, many enterprises are initiating action in order to meet the demands of their insurance carriers regarding GHG emissions management standards, or create an aura of sustainability in the minds of shareholders and customers.

Each of these efforts to form self-regulating or government-regulated markets for GHG emissions management will impact the development and implementation of sequestration technologies and approaches. In addition, each market or market-maker contributes certain nuances to the debate regarding accounting for GHG emissions and GHG emissions reductions, including those derived from sequestration. More information on accounting frameworks follows.

2. Accounting Frameworks

Closely related to these markets, market-makers, and regulatory, permitting, and safety frameworks are accounting frameworks for carbon sequestration which allow for adequate recording, documentation, and verification of the carbon sequestration activities, whether terrestrial or geologic in nature. Presently, GHG accounting comes in two forms – just like the above-referenced markets – voluntary or mandatory. In the SECARB region, to-date, voluntary reporting has been the universally accepted form of accounting practices, although mandatory approaches must also be assessed for consistency in case mandatory measures should arise locally, on a state basis, or nationally. Regardless of the compliance mechanism approach, it appears that the most significant issues regarding carbon sequestration accounting center on a few key elements – baselines, minimum legal requirements, additionality, measurement, monitoring, and verification.

Voluntary reporting is valuable as it provides a way to present information about an enterprise's GHG emissions and/or emissions reduction activities to its customers or constituents, who are interested in GHG emissions. The communication of voluntary reports and achievements can be valuable in that it provides public information that may influence future GHG policy formulation, and more importantly, prompt enterprises to pursue GHG mitigation projects in the years to come, including those focused on terrestrial and geologic carbon sequestration.

Under this research phase, SECARB partner Augusta Systems analyzed Federal, state, and private sector accounting frameworks, including, most notably, the U.S. national voluntary GHG reporting program, the Voluntary Reporting of Greenhouse Gases Program (VRGGP) of the U.S. Department of Energy (USDOE), the new Georgia registry legislation, and the emerging Chicago Climate Exchange and "Greenhouse Gas Protocol" of the World Business Council for Sustainable Development and World Resources Institute (WBCSD/WRI). Details of each analysis follow.

a. USDOE 1605(b) Program

In 1992, the U.S. Congress established the VRGGP in order to meet U.S. commitments under the United Nations Framework Convention on Climate Change (UNFCCC). The VRGGP was established under Section 1605(b) of the 1992 Energy Policy Act, which has become known as the 1605(b) program. The 1605(b) program

provides a mechanism for reporting GHG emissions and emissions reductions, including those produced from carbon sequestration projects. Presently, the 1605(b) program is being revised to better meet the emerging needs of the voluntary GHG trading market and the expanding role of carbon sequestration in the GHG emissions management arena. As this national program would, potentially, impact accounting frameworks within the SECARB region, a summary of the present 1605(b) program will be presented, as well as information on the proposed revisions made public to-date.

i. Existing Program

Under the enacting legislation for the 1605(b) program, the USDOE through its Energy Information Administration (EIA), and in collaboration with the U.S. Environmental Protection Agency (USEPA), was required to publish procedures for the accurate voluntary reporting of information on: (1) GHG emissions on an annual basis for the baseline period 1987 through 1990, and for subsequent calendar years; (2) annual reductions of GHG emissions achieved through any measure; and, (3) reductions in GHG emissions achieved voluntarily, including via carbon sequestration, or as a result of plant or facility closings, or as a result of Federal or individual state requirements.

Final guidelines and supporting materials were developed, with stakeholder input, for the six sectors identified by the 1605(b) program, which are: Electricity Supply; Residential and Commercial Buildings; Industrial; Transportation; Forestry; and, Agricultural. The initial guidelines provide reporting flexibility by allowing the participant to utilize existing GHG emissions and emissions reduction information, and to select appropriate quantification methods based upon the nature of their reduction or offset projects. To prompt action by participants, the support documents included examples of project analyses for the various sectors, appendices of conversion tables, and default emissions factors for various fuels and for electricity on a state-by-state basis.

Participants are encouraged to submit comprehensive reports, which can include information on GHG emissions levels and emissions reduction projects, including terrestrial and carbon sequestration projects. It is important to note that the present 1605(b) program definition of “carbon sequestration” is limited to terrestrial projects. Geologic sequestration projects are dealt with under another project type definition. For project reporting, every GHG emissions reduction project report must include specific information to assist in analyzing the benefits of the projects. For instance, it is required that every report provide an established reference case that serves as a basis for comparison with a specific project. Further, the report must provide identification of the effects of the project, and an estimation of the GHG emissions for both the reference case and the specific GHG emissions reduction or carbon sequestration project.

To aid in the development of these data sets, the 1605(b) program guidelines and supporting documents provide detailed information regarding the appropriate processes under which an entity should obtain data and define the methods for estimating a specific project’s effect on GHG emissions reduction and carbon sequestration results. The guidelines outline the acceptance of three types of data – physical, default, and reporter-generated. Based on these three categories of data, the guidelines recognize two categories of projects: standard projects, which rely on physical and default data, and reporter-designed projects, which use relative default data and measured, or engineering data, developed by the entity. The GHG emissions reduction outcomes or sequestered carbon emissions of an entity’s project must be determined

and recorded. By requiring these elements, the report contains detailed information relative to the impact of the project, which can be reviewed by a third party to determine the validity of the emissions reduction effort.

In summary, the 1605(b) program provides enterprises with an opportunity to record their GHG emissions reduction and carbon sequestration achievements, and communicate these achievements to colleagues, customers, and the general public. By nature of its voluntary and uncomplicated structure, the 1605(b) program provides an unrestrictive opportunity to encourage enterprises to engage in GHG emissions reduction activities. However, the 1605(b) program was not without its detractors, as the program's reporting mechanisms did not, in the eyes of many, truly allow for detailed accounting procedures and did not adequately address geologic sequestration project reporting and accounting. The following section describes the on-going efforts of the USDOE, the U.S. Department of Agriculture (USDA), and the USEPA to improve the 1605(b) program.

ii. Emerging Changes to 1605(b) Program

During 2002, USDOE, USDA, and USEPA initiated a series of actions to facilitate comments and suggestions for enhancements and improvements to the 1605(b) program from stakeholders. In July 2002, the three federal agencies initiated a call for public comments to improve the guidelines. In addition, the three Federal agencies conducted a series of workshops to enable interested persons to help improve the 1605(b) program guidelines. Following these activities, the Federal agencies moved forward to produce two levels of new proposed guidelines – General Guidelines[1] and Technical Guidelines.[2]

The enhanced General Guidelines, which are currently in an Interim Final form, are intended to improve the accuracy and completeness of GHG emissions data in the national registry created by 1605(b). These enhanced General Guidelines were publicly released in draft form in 2004 and have recently been released in an interim final form since March 2005. The Technical Guidelines were released in draft form at the end of March 2005 as well and both of these Guidelines, when effective, will collectively modify and replace the current guidelines for the 1605(b) program. The Technical Guidelines will specify methods and factors to be used in measuring and estimating GHG emissions, emissions reductions, and carbon sequestration. Thus, these Technical Guidelines will play the most critical role of the two guideline sets in the development of the accounting framework for SECARB.

Due to the fact that these General Guidelines will provide the structure for the more specific Technical Guidelines, these initial proposed revisions are significant to the SECARB accounting framework research. The key elements of the proposed revised guidelines follow. More specifically, these General Guidelines are summarized into sections examining entity reporting requirements, certification and verification, and reporting and registering emission reductions (including carbon sequestration).

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[1] United States Department of Energy (USDOE), USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Interim Final General Guidelines, *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/generalguidelines.html*

[2] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*

With respect to entity reporting requirements, the General Guidelines feature two mechanisms for differently sized entities. Large entities, i.e. those with average annual emissions over 10,000 tons of CO_2 equivalent, would be required to provide an inventory of total emissions and calculate net reductions associated with entity-wide efforts, as well as demonstrate that the reported reductions represent an actual net decrease in entity-wide emissions, as calculated by one or more of the methods allowed by the General Guidelines. Meanwhile, smaller entities, i.e. those with average annual emissions of less than 10,000 tons of CO_2 equivalent, would be eligible to register emission reductions associated with specific activities without completing an entity-wide inventory or reduction assessment.[3]

As certification and verification standards of the 1605(b) program could impact SECARB accounting frameworks, the certification and verification recommendations for the new General Guidelines merit examination. Under the proposed new General Guidelines, an agency head, CEO, or other responsible official is required to certify that the reporting entity accurately follows the revised guidelines for determining emissions, emission reductions, and sequestration achievements with sufficient records maintained for at least three years to enable independent verification. In addition, entities are encouraged to obtain independent verification of the accuracy of their reports and compliance with USDOE guidelines. It is also important to note that the required reports sent to EIA should be sufficiently detailed to enable EIA to review and confirm the final emission reduction calculations for each method and output measure utilized, and to review and confirm the rates of conversion used for each category of GHG covered and for electricity-related use or emissions avoidance by region.[4]

With reference to reporting and registering emissions reductions, including those achieved via carbon sequestration, there are a number of significant points to consider, including legal rights and ownership, as well as emissions intensity metrics. Notably, as legal rights to sequestration opportunities or other emissions management activities may be in question given current laws, the proposed new General Guidelines state that owner of the facility, land, or vehicle that generated the emission reductions or sequestration is the entity presumed to have the right to report and register any emission reductions or sequestration unless otherwise agreed. Also, entities are required to coordinate with other entities that share ownership of particular operations to ensure no double counting occurs. With reference to emissions intensity metrics, the proposed General Guidelines recommend the use of emission intensity indicators as the basis for determining emission reductions however, the USDOE Technical Guidelines will set procedures to calculate emission reductions, including lists of possible output indicators, calculation methods for determining reductions associated with terrestrial and geologic sequestration, methods and emission factors for calculating avoided emissions, and project-based methods. Also, it is important to note that, entities could report reduction in emissions intensity, absolute reductions in emissions, increased carbon storage, avoided emissions, and project emission reductions.[5]

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[3] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Interim Final General Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/generalguidelines.html*

[4] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Interim Final General Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/generalguidelines.html*

[5] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Interim Final General Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/generalguidelines.html*

As could be surmised, to register emission reductions, reporting entities with substantial emissions (average annual emissions of 10,000 or more tons of CO_2 equivalent) must provide an inventory of their total emissions and calculate the net reductions associated with entity-wide efforts to reduce emissions or sequester carbon. Entities with average annual emissions of less than 10,000 tons of CO_2 equivalent (small emitters) are eligible, under certain conditions, to register emission reductions associated with specific activities without completing an entity-wide inventory or entity-wide reduction assessment. Also, the revised General Guidelines enable entities to report (but not register) emission reductions achieved prior to 2003 as well as report emission reductions achieved during or after 2003 that do not qualify for registration. The guidelines also permit entities to report (but not necessarily register) emission reductions associated with specific actions or with specific parts of the entity, even if these reports are not accompanied by entity-wide emissions and reductions reports. Moreover, and germane to sequestration, an entity responsible for the destruction or sequestration of emissions may report or register such reductions, or may assign the reporting rights for such reductions to other entities, such as the entity that initially captured the gas. However, under the proposal, there will be no issuance of "transferable credits" that will have value under any future climate policy.

In terms of the proposed revised Technical Guidelines, the changes to the existing program are substantial and related to the detailed manner in which registering or reporting, as the case may be, of emissions reductions or offsets should take place. As with the existing program terrestrial sequestration opportunities, both in terms of agricultural and forestry-based are well-defined. In this proposed revised regime, the two types – "Agricultural Emissions and Sequestration" and "Forestry Emissions" are each dealt with independently.[6] In a marked enhancement to the existing program, geologic sequestration is provided with its own "Engineered Sequestration" section, whereas, previously, the topic of geologic sequestration merited only nominal attention and not as "sequestration.".[7] More information from the Draft Technical Guidelines in each of these areas follows.

While GHG emissions may result from livestock and/or crop production, opportunities abound in the agricultural sector for GHG emissions reductions. Terrestrial carbon sequestration occurs when the land management practices, including tillage practices and crop rotations, increase the amount of organic carbon contained in soil and/or promote growth of long-lived perennial biomass (e.g., trees and permanent grasses). [8] Measurement of sequestered carbon under the Technical Guidelines to ensure proper registering and reporting can be performed via estimation and measurement mechanisms.[9] The Technical Guidelines provide detailed information and examples of the acceptable methods for chronicling carbon emissions, flux, and

[6] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*
[7] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*
[8] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*
[9] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*

sequestration via both estimation and measurement, including soil storage and changes.[10]

Moving to the coverage of forestry-based sequestration approaches, the proposed revised Technical Guidelines provide well-detailed information about the accounting approach for this type of sequestration.[11] Here, the terrestrial storage is defined by net flows of carbon between forests and the atmosphere. Net carbon storage in forests increases when the amount of carbon withdrawal from the atmosphere exceeds the release of carbon to the atmosphere. Given this, accounting for carbon stocks and flows is the primary focus of these accounting rules and guidelines, which provide both estimation methodologies and calculations based upon the area of forest land included in the entity or activity, and the amount of carbon per unit of area. Under the Technical Guidelines, it is anticipated that carbon flows from forests and forestry operations will typically estimated using changes in an inventory of carbon stocks, which is defined as a stock-based approach; however, an alternative is also provided in that the guidelines would allow for direct estimation of annual flows of carbon using CO_2 flux monitoring methods or models of the impacts of certain forestry practices on carbon flows into and out of forest carbon pools.[12] The Technical Guidelines also establish that land use change and permanence of sequester carbon are important factors to be chronicled and factored into registered and reported emissions reductions.[13]

With regard to "Engineered Sequestration," which again pertains to geologic sequestration, the Technical Guidelines indicate that it is generally the reporter's responsibility to identify all emissions of CO_2 that occur from facilities owned or controlled by the reporter.[14] For inventory reporting purposes, any CO_2 produced and emitted to the atmosphere as a result of combustion or reforming processes or withdrawal from natural or man-made geologic reservoirs is considered an emission, while any CO_2 captured, transported, stored, converted into products, or injected into the ground is considered sequestered and potentially eligible for registering or reporting.[15] Reporters that engage in CO_2 capture and storage shall account, within its inventory, for all CO_2 emissions to the atmosphere that occur within the reporter's entity boundary, including any leakage of CO_2 during the capture process as well as from the geologic storage site and fugitive emissions from processing plants and pipelines, injection wells, and enhanced resource recovery sites.[16] Further, it is noted that, if a reporter injects CO_2 into a geologic formation as part of an enhanced oil recovery (EOR) project, and withdraws CO_2 from that or another reservoir for oil production, the extracted CO_2 should only be counted towards the inventory if it is released as fugitive emissions, while extracted and

[10] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*
[11] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*
[12] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*
[13] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*
[14] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*
[15] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*
[16] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*

recycled CO_2 would not be included in the inventory. [17] Estimations for leakages and vented CO_2 are included within the Technical Guidelines. In addition, the document includes information on accounting for emissions resulting from energy used to advance the sequestration activity, as well as physical leakage to the atmosphere.

In terms of accounting, when CO_2 is injected into a geologic formation, the Technical Guidelines expect that CO_2 will be sequestered permanently, barring any physical disruption of the reservoir and injection wells.[18] When an engineered sequestration project is undertaken for the sole purpose of emissions mitigation, the accounting is fairly straightforward as the amount of CO_2 emitted may be determined to be the amount of CO_2 lost as fugitive emissions during the capture, transport, and injection of CO_2. [19] Once injection of the captured CO_2 is completed and the wells are sealed, the reporter will be responsible for any potential physical leakage of carbon dioxide occurring every year thereafter. [20] As for accounting protocols, the Technical Guidelines indicate that while tools exist to assist with estimation, there are no existing calculation protocols that specifically address GHG emissions from engineered sequestration practices, although existing protocols for other industries may be utilized and may provide guidance in calculating emissions from various aspects of engineered sequestration. [21]

Once the revised General and Technical Guidelines take effect following incorporation of augmentation based upon public comments, which is likely during June 2006 based upon current timelines, the 1605(b) program will serve as the primary public emission and emission reduction reporting mechanism for participants in USEPA's Climate Leaders program and in USDOE's Climate VISION program and serve as a guidepost for state and regional accounting protocols in the U.S. regions.

2. State-Based Accounting

While the 1605(b) program has been in operation for a sufficient period to allow for the thoughtful consideration of enhancements and revisions, state voluntary reporting programs are only beginning to appear. Although a number of states are moving forward to initiate and adopt voluntary GHG registries, including Georgia in the SECARB region, a smaller number (California, New Hampshire, and New Jersey) have active state voluntary GHG registries, which include opportunities for reporting and registering emissions reductions achievements, including those produced via carbon sequestration projects, both terrestrial and geologic. Also, as noted, the northeastern RGGI is still being developed. However, it should be noted that the staff working group proposal appears to be interested in limiting the types of GHG offsets that could be applied to meeting the goals of RGGI. In fact, within the domain of carbon sequestration, only

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[17] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*

[18] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*

[19] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*

[20] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*

[21] USDOE, USDOE 1650(b) Program Enhancements Website, Proposed Guidelines, Draft Technical Guidelines at *www.pi.energy.gov/enhancingGHGregistry/proposedguidelines/technicalguidelines.html*

afforestation is specifically noted on the initial draft.[22] Fortunately, the RGGI proposal, does contemplate the approval of other types of offset projects, which could enhance prospects for sequestration deployment, both in its geologic and terrestrial incantations, to assist RGGI in meeting its goals.

In the SECARB region, however, less activity has occurred and most existing state enactments tend to deal only with the technology and approaches presently enjoying expansion – terrestrial sequestration. For instance, the State of Georgia, under its recently enacted Senate Bill 356, established the Georgia Carbon Sequestration Registry Act, which supported the use of terrestrial sequestration, but is seemingly silent on geologic sequestration opportunities. The launch date for the Georgia Registry has not been established at this time. Thus, the SECARB region does not yet have in place accounting mechanisms on a regional or a state level that would hinder or assist in the wide-scale deployment of geologic or terrestrial sequestration projects.

3. Private Sector Initiatives

In addition to analysis on Federal and state reporting and registry mechanisms that could impact the SECARB accounting framework action plans, Augusta Systems also examined the requirements of reporting, registering, and accounting under the Chicago Climate Exchange, as well as the WBCSD/WRI GHG Protocol. For reference, the WBCSD/WRI Greenhouse Gas Protocol may provide the most comprehensive method and process for GHG and carbon sequestration accounting activities produced to-date, and as such will serve as a vital resource for accounting framework developments by SECARB. In general, the most significant issues regarding carbon sequestration accounting for private sector initiatives tend to key on the same points as public sector initiatives – baselines, minimum legal requirements, additionality, measurement, monitoring, and verification.

Due to the global acceptance of the GHG Protocol as the de-facto standard approach and reference point for GHG emissions management activity accounting on a multi-national basis, the two major elements of the GHG Protocol – The Corporate Accounting and Reporting Standard (Corporate Standard) and The Project Accounting Standard (Project Standard) warrant coverage herein.

The Corporate Standard provides a step-by-step guide for companies to use in quantifying and reporting their GHG emissions.[23] The first edition of the Corporate Standard, published in September 2001, enjoyed broad adoption and acceptance around the globe by businesses, non-governmental organizations (NGOs), and governments. Many industry, NGO, and governments used the standard as a basis for their accounting and reporting systems. A revised edition of the Corporate Standard was recently published and is the result of the culmination of a two-year multi-stakeholder dialogue – utilizing experience gained from the first edition. The Corporate Standard provides standards and guidance for companies and other types of organizations preparing a GHG emissions inventory. The standard and guidance were designed, in part, to help companies prepare a GHG inventory that represents a true and fair account

[22] Regional Greenhouse Gas Initiative (RGGI) Website, RGGI Staff Working Group Package Proposal at www.rggi.org.

[23] World Business Council for Sustainable Development / World Resources Institute (WBCSD/WRI) Greenhouse Gas (GHG) Protocol, A Corporate Reporting and Accounting Standard (Revised Edition) at http://www.ghgprotocol.org/includes/getTarget.asp?type=d&id=MTM3NTg

of their emissions, via standardized approaches and principles and to increase consistency and transparency in GHG accounting and reporting among various companies and GHG programs. Thus, the Corporate Standard is composed of "standards" – which must be achieved in order to fully comply with the Corporate Standard – and "guidance" – which do not necessarily have to be achieved in order to fully comply with the Corporate Standard. Since the Corporate Standard is very general and not specific to sequestration projects, unlike the Project Standard,[24] more overage will be donated to the latter rather than the former.

In general, the Project Standard provides guidance on how to quantify the reductions associated with GHG emission reduction and carbon sequestration projects. The guidelines are typically targeted at project developers, but will also be relevant to external program administrators designing or operating GHG crediting programs. The guidelines address the setting of project assessment boundaries, baseline selection and additionality, and the calculation of reductions on an ex-ante basis (before the project is implemented). The objectives of the Project Standard are to:

- Simplify GHG project quantification, while improving quality and credibility through the use of standardized methodologies and GHG accounting principles;
- Reduce transaction costs and uncertainty for project developers;
- Increase investor confidence in GHG projects; and,
- Promote greater consistency between different projects and GHG trading programs with regard to the quantification of GHG projects. [25]

To ensure consistency in the way project reductions are calculated, it is important that emissions trading and crediting programs converge on consistent quantification methods like those in the Project Standard. This will reduce transaction costs for project developers and facilitate the development of an integrated global GHG market in the future. For instance, if one program is significantly less rigorous than the other and the systems are linked, the less rigorous one will distort the emission trading market and create a loss in the overall environmental integrity. Even if no transfer of credits is allowed between programs there are lower transaction costs, more certainty and credibility if different programs use a similar approach.

Essentially, the Project Standard requires eight steps to quantity GHG project-based emissions reductions, including those achieved via carbon sequestration. More specifically, the Project Standard requires that the interested parties:

- Describe the project and primary effect(s);
- Check the eligibility of the primary effect for acceptance under prevailing standards;
- Check that the primary effect is additional to other regulated legislative requirements;
- Undertake a preliminary evaluation of secondary effects (life cycle effects, leakage, activity shifting, and market leakage) to ascertain impact;
- Select the baseline scenario;

[24] WBCSD/WRI GHG Protocol, Project Accounting Standard (Road Test Document) at http://www.ghgprotocol.org/includes/getTarget.asp?type=d&id=MTM3OTU

[25] WBCSD/WRI GHG Protocol, Project Accounting Standard (Road Test Document) at http://www.ghgprotocol.org/includes/getTarget.asp?type=d&id=MTM3OTU

- Identify and assess the relevance of secondary effects;
- Calculate the project reduction and classify based on ownership; and,
- Develop a monitoring plan. [26]

The Project Standard was recently "road tested" in its initial draft form. Presently, the road test comments are being incorporated into what is anticipated to be a final version of the GHG Protocol for Project Accounting is scheduled to be completed in November 2005.

Given the similarities between the private, state and local, national, and international accounting approaches, it appears that while all existing reporting, registering, and accounting methodologies are still developing, there is some level of commonality among the existing accounting framework standards that can feed the development of regulatory, safety, and permitting framework analysis.

B. Regulatory, Safety, and Permitting Frameworks

Phase I regulatory, safety, and permitting frameworks issues analysis focused on two key areas – geologic sequestration and terrestrial sequestration issues. Activities in both areas are discussed below.

1. Geologic Sequestration

As terrestrial sequestration activities have been initiated and are beginning to emerge as a standard bearer for GHG emissions management projects, the relatively less well-known and less practiced domain of geologic carbon sequestration merits substantially more examination and analysis at this time to ensure that appropriate regulatory, safety, permitting, and accounting frameworks emerge around the arena. To support this effort, USDOE NETL has provided funding support to the above-referenced the IOGCC Task Force, which was formed by IOGCC with funding support from USDOE and empowered with two primary objectives:

- Examine the technical, policy, and regulatory issues related to safe and effective storage of CO_2 in the subsurface (oil and natural gas fields, coal-beds and saline formations), whether for enhanced hydrocarbon recovery or long-term storage; and
- Produce of a final report containing (a) an assessment of the current regulatory framework likely applicable to geologic CO_2 sequestration, and (b) recommended regulatory guidelines and guidance documents. The Final Report and the documents contained therein will lay the essential groundwork for a state-regulated, but nationally consistent, system for geologic sequestration of CO_2 in conformance with national and international law.[27]

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[26] WBCSD/WRI GHG Protocol, Project Accounting Standard (Road Test Document) at http://www.ghgprotocol.org/includes/getTarget.asp?type=d&id=MTM3OTU

[27] Interstate Oil and Gas Compact Commission Geological CO_2 Sequestration Task Force, Final Report, January 2005.

Per direction of USDOE, Augusta Systems, on behalf of SECARB, has worked to support the IOGCC effort through idea generation, analysis, drafting, and technical editing, and, when possible, worked to adopt its anticipated recommendations. Thus, in many instances, this report will cite the IOGCC Task Force's report as it potentially provides a common platform for geologic sequestration regulatory, permitting, and safety frameworks.

In an examination of geologic sequestration both under SECARB and the IOGCC effort, a clear question emerged regarding the future regulatory, safety, and permitting frameworks – How linked will geologic sequestration regulatory, safety, and permitting frameworks, especially with reference to the injection and long-term storage activities, be to the Federal Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) program? More specifically, there are four principal sub-level questions:

- Will CO_2 be defined as a commodity, waste, or pollutant under Federal, state, or Federal and state laws and regulations, including UIC regulations?
- Will geologic carbon sequestration injection and storage activities be wholly subject to existing UIC regulations?
- Will new UIC classes or definitions emerge to facilitate geologic sequestration injection and storage activities?
- Will long-term geologic sequestration projects without enhanced hydrocarbon recovery components be subject to UIC at all?

Clearly, SECARB and even the IOGCC Task Force do not hold the final authority on this matter, or else the conclusions of this report could be more concrete. With the USEPA holding authority for UIC rules, regulations, and interpretations, it seems that the USEPA will be ultimate arbiter of these matters. To assist in defining the options for the SECARB region, and perhaps the nation, however, SECARB has produced this examination. A brief overview of the present regulatory, safety, and permitting environment for potential geologic sequestration activities follows.

a. Natural Analogues

It has been suggested that four analogues exist for regulatory guidance regarding geologic carbon sequestration – naturally occurring CO_2 contained in geologic formations; CO_2 enhanced oil recovery (EOR) operations, storage of natural gas in geologic formations, and the injection of hydrogen sulfide (H_2S) into underground formations.[28] In some states, and more specifically states with hydrocarbon production and/or storage activities, there is a rich legacy of regulatory, permitting, and safety regimes in place that would assist in wide-scale deployment of geologic carbon sequestration approaches and technologies.[29]

Of these analogues, perhaps the most significant are those of the naturally occurring CO_2, which shows the capabilities of geologic formations to retain vast quantities of CO_2 over time, and the EOR operations, which demonstrate the safe and well-regulated transport and injection of CO_2 into geologic formations.

Although CO_2 is a non-hazardous gas at normal atmospheric conditions, CO_2 can exist in three forms:

- As the above-referenced gaseous state;
- As a supercritical fluid that has physical properties between a liquid and a gas at pressures greater than 1073 pounds per square inch (psi) at less than 87.7 degrees Fahrenheit; and,
- As a solid form most commonly referred to as dry ice, at temperatures below 109 degrees Fahrenheit.[30]

Given a situation in which normal geologic pressure and temperatures would exist, it has been assumed that deep injection of CO_2 (i.e. greater than 2,500 feet below the surface) would result in the CO_2 existing as a supercritical fluid. In other instances related to geologic sequestration (i.e. capture, transport, injection, and shallow storage, if ever), it is likely that CO_2 would be in a gaseous form. Thus, geologic sequestration regulatory, safety, and permitting frameworks would relate to the gaseous and supercritical fluid states.

Options for geologic sequestration abound, but the geologic sinks with the highest potential geologic carbon sequestration include deep unmineable coal seams, depleted or nearly depleted sandstone/limestone oil and gas reserves, oil and gas bearing shales, active and abandoned storage fields, saline formations, salt caverns/beds, and hydrates. Thus, the focus on regulatory, safety, and permitting analysis for geologic sequestration would be focused on these areas.

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[28] Interstate Oil and Gas Compact Commission Geological CO_2 Sequestration Task Force, Final Report, January 2005.
[29] Interstate Oil and Gas Compact Commission Geological CO_2 Sequestration Task Force, Final Report, January 2005.
[30] Interstate Oil and Gas Compact Commission Geological CO_2 Sequestration Task Force, Final Report, January 2005.

b. Examination of Regulatory, Safety, and Permitting Issues

More specifically, the regulatory, safety, and permitting framework analysis and action plan development would principally focus on four key areas:

- Capture;
- Transport;
- Injection; and,
- Storage.[31]

i. Capture

Capture of CO_2 from anthropogenic, or man-made, sources is presently being performed in the SECARB region, and in some instances with processing activities to enhance purity, to feed EOR and enhanced gas recovery (EGR) projects and can be anticipated to increase in frequency as geologic sequestration becomes deployed on a more significant scale. At present, the existing regulations are likely of limited utilization for future geologic sequestration, which will include elements of capture and separation of CO_2 from flue gas streams and other point sources. Thus, it would seem that the future of capture regulations will rely upon the answer to whether CO_2 will be defined as a commodity, waste, or pollutant under Federal, state, or Federal and state laws and regulations, including UIC regulations.

ii. Transport

The arena of CO_2 transport is a little more complex today, but also more applicable to the future world of wide-scale geologic sequestration. Transport of CO_2 is currently conducted through pipelines, generally, and with the support of three primary mechanisms:

- High pressure, or supercritical phase (i.e. above 1180 psi);
- Lower pressure gas transmission; and,
- Refrigerated liquid transmission (also commonly used for rail and truck transport).

The SECARB region is fortunate, and perhaps unique as compared to a number of other RCSPs, because the region already has a functioning CO_2 transport infrastructure. CO_2 pipelines exist in Louisiana and Mississippi. Denbury Resources, Inc. (Denbury), is selling CO_2 commercially (primarily to the food and beverage industry), and currently seems to be expanding its supply. Denbury may also be a major consumer of CO_2 for enhanced oil recovery. Several SECARB Technology Coalition Members and others in the SECARB region have publicly expressed interest in the use of CO_2 for recovery of coal bed methane gas. The latter two are particularly important in the region because of the extensive oil production along the Gulf Coast, and the coal beds in Mississippi, Alabama, and Tennessee.

[31] These key areas of analysis have been selected both for reasons of sound regulatory analysis and practical considerations. For reference, the IOGCC Task Force and the Carbon Sequestration Leadership Forum Legal, Regulatory, and Financial Issues Task Force have both selected similar breakdowns for their analysis efforts.

The CO_2 infrastructure in the region includes pipelines and other transportation infrastructure, separation and purification capabilities, and a network of equipment suppliers. These existing pipelines are regulated by the Office of Pipeline Safety (OPS) of the U.S. Department of Transportation (USDOT).[32] U.S. states may also be involved in the regulatory process for these CO_2 pipelines under partnership agreements with OPS. In most instances, regulatory responsibilities the smaller diameter gathering lines for the CO_2 tend to fall to the states. Moreover, rail and truck transportation tend to be regulated primarily by state entities.

While the existing SECARB infrastructure is robust, the opportunity to leverage this infrastructure may not be as significant. Presently, the CO_2 pipelines assets tend to be closely controlled, and without options for open access-based utilization.

iii. Injection and Storage

Injection and storage, like transport, has a robust history, both in terms of practices and regulations, to rely upon for the future of sequestration. Due to the fact that the regulatory, safety, and permitting frameworks for injection and storage will likely be linked closely, these two topic areas will be discussed together.

In terms of practices, the American Petroleum Institute (API), American Gas Association (AGA), and the American Society for Testing and Materials (ASTM) have established materials selection standards for well casing and down hole equipment, wellhead equipment, cement types and other relevant oilfield equipment and facilities that meet prevailing standards in states under UIC laws and regulations. Logically, these established practices and industry standards would adequately address materials standards for geologic carbon sequestration.

While clarity may exist with regard to industry standards for well construction, maintenance, and operation, less agreement is found regarding the rules and regulations for the potential geologic sinks. While present state regulations would generally permit injection of CO_2 into depleted oil and natural gas reservoirs, for EOR, EGR, and enhanced coalbed methane (ECBM) purposes, and into deep saline formations, the treatment of salt cavern utilization is less consistent. In fact, in some SECARB states, including Alabama, salt cavern storage would not be permitted by existing statutes.

Although the USEPA has indicated that CO_2 regulation is beyond its mandate under the Clean Air Act, the USEPA may play a significant role in voluntary GHG management programs as USEPA could have the primary authority for structuring geologic sequestration program requirements, and in some instances, applying them. This would be dependent upon whether geologic carbon sequestration is governed under the UIC Program of the SDWA. Based upon the IOGCC Task Force recommendations and the general consensus of other interested parties, it seems that at a minimum the USEPA will play this role, at least with respect to geologic sequestration activities related to enhanced hydrocarbon recovery. More details on the SDWA, the UIC Program, and their applicability to the arena of geologic sequestration follows.

[32] 49 C.F.R. 195.

The SDWA of 1974 requires that the USEPA determine the need for and to promulgate regulations sufficient to protect underground sources of drinking water (USDWs). A USDW is any aquifer that contains a volume of water such that it is a present, or viable future, source for a public water system, contains water with less than 10,000 parts per million total dissolved solids, and is not exempted.[33] Section 1421 of the SDWA mandates that the USEPA establish rules for UIC programs, which apply to certain types of wells for which five classes exist as shown in Figure 1 below.[34] Under SDWA Section 1423, states may, although need not, acquire primacy for enforcement.[35] The goal of the USEPA UIC Program is to protect public health through the protection of USDWs.[36] USEPA estimates indicate that the nation's most accessible freshwater is stored in geological formations, known as aquifers, which in many instances, USEPA estimates indicate that these resources are utilized to recharge 41 percent of streams and rivers and serve as resources for 89 percent of public water systems in the U.S.[37] Underground injection is the practice of placing fluids underground, in porous formations of rock, soils, or rock and soils, through wells.

Figure 1. Summary of UIC Well Class Applicability.

UIC CLASS	SUMMARIZED APPLICATION
Class I	Deep disposal of hazardous and non-hazardous fluids (including industrial and municipal wastes) beneath the lowermost USDW and are further regulated under the Resource, Conservation, and Recovery Act (RCRA)
Class II	Injection of brines and other fluids associated with oil and gas production, including crude oil (storage), drilling fluids, and drilling muds
Class III	Injection of fluids associated with solution mining of minerals with fresh water (salt), sodium bicarbonate (uranium), or steam (sulfur)
Class IV	Injection of hazardous or radioactive wastes into or above a USDW (which have been banned except as part of authorized clean up activities)
Class V	All underground injection not included in Classes I-IV, which generally inject non-hazardous fluids or above a USDW and are on-site disposal systems, such as storm water runoff, industrial wastewater, car wash water, sanitary waste, agricultural waste, and aquifer recharge, as well as experimental wells

Source: USEPA, "USEPA's Program to Regulate the Placement of Waste Water and other Fluids Underground, December 1999.

All injection wells are not waste disposal wells – some Class V wells inject surface water to replenish depleted aquifers or to prevent salt water intrusion.[38] Some Class II wells inject fluids for enhanced recovery of oil and natural gas (i.e. EOR and EGR), and others inject liquid hydrocarbons that constitute the nation's strategic fuel reserves, including the Strategic Petroleum Reserve.[39]

[33] United States Environmental Protection Agency (USEPA), Drinking Water Pocket Guide #2: Protecting Drinking Water Through Underground Injection Control, January 2002.
[34] SDWA § 1421; 42 U.S.C.A §300h.; 40 CFR Parts 144-148.
[35] SDWA § 1421; 42 U.S.C.A §300h-2; 40 CFR Parts 144-148.
[36] USEPA, "UIC Program Overview," Sequestration Workshop, February 2-3, 2004.
[37] USEPA, "USEPA's Program to Regulate the Placement of Waste Water and other Fluids Underground, December 1999.
[38] USEPA, "USEPA's Program to Regulate the Placement of Waste Water and other Fluids Underground, December 1999.
[39] USEPA, "USEPA's Program to Regulate the Placement of Waste Water and other Fluids Underground, December 1999.

Of these five classes, only three are potentially applicable to the arena of geologic carbon sequestration – Class II, in cases of enhanced hydrocarbon recovery, and potentially Classes V and I, which are both invoked under the Frio Injection Project presently being conducted by the University of Texas, Bureau of Economic Geology invokes both approaches, which is explained in greater depth in this same section.

Responsibility for UIC regulation is divided between the Federal government, as represented by the USEPA, and state governments. The USEPA roles include setting UIC Program requirements and national standards, approving and overseeing U.S. state delegations, providing assistance to state entities administering UIC activities, overseeing direct implementation programs in certain states, and supporting and advancing sound science. U.S. state and tribal roles for the 33 states, Guam, Commonwealth of the Mariana Islands, and Puerto Rico, that have primacy authority for all or part of the UIC program, which includes responsibility for application, review, authorization, and monitoring.[40] In seven other states, including SECARB state Florida, primacy is shared between the states and the USEPA. In addition, the USEPA administers UIC programs for the remaining 10 states, including SECARB states of Tennessee and Virginia, and all other Federal jurisdictions and Tribal lands.[41] Most of the minimum requirements that affect the siting of the injection well, the construction, operation, maintenance, monitoring, testing, and, finally, the closure of the well, are designed to address USDW functions. A detailed listing of the regulatory relationship between the Federal government and the states in the SECARB region follows in Figure 2. For reference, it is these entities that will play a crucial role in the development and implementation of regulatory, permitting, and accounting frameworks in the SECARB region.

[40] USEPA, Drinking Water Pocket Guide #2: Protecting Drinking Water Through Underground Injection Control, January 2002.
[41] USEPA, "USEPA's Program to Regulate the Placement of Waste Water and other Fluids Underground, December 1999.

Figure 2. SECARB State Regulatory Primacy for UIC Program.

SECARB STATE	PRIMACY	REGULATORS
Alabama	State	Classes I, III-V -- Alabama Department of Environmental Management Class II -- Alabama State Oil and Gas Board
Arkansas	State	Classes I, III-V -- Arkansas Department of Environmental Quality Class II -- Arkansas Oil and Gas Commission
Florida	Shared	Classes I, III-V -- Florida Department of Environmental Management Class II -- EPA Region 4
Georgia	State	Classes I-V -- Georgia Environmental Protection Division
Louisiana	State	Classes I, III-V -- Louisiana Department of Natural Resources Class II -- Louisiana Office of Conservation
Mississippi	State	Classes I, III-V -- Mississippi Department of Environmental Quality Class II -- Mississippi Oil and Gas Board
North Carolina	State	Classes I-V -- North Carolina Department of Environment and Natural Resources
South Carolina	State	Classes I-V -- South Carolina Department of Natural Resources
Tennessee	Federal	Classes I-V -- USEPA Region 4
Texas	State	Classes I, III-V -- Texas Natural Resource Conservation Commission Class II -- Texas Railroad Commission
Virginia	Federal	Classes I-V -- USEPA Region 3
Tribal Lands in SECARB	Federal	Classes I-V -- USEPA Region 4 or 6 (in Arkansas, Louisiana, and Texas) (*Note: No Tribal Lands Region 3 SECARB state, Virginia)

Source: USEPA, Drinking Water Pocket Guide #2: Protecting Drinking Water Through Underground Injection Control, January 2002.

According to recent USEPA estimates, there are between UIC 650,000 to 850,000 wells in the U.S. as of February 2004. For reference, approximate UIC well counts by SECARB state follows in Figure 3.

Figure 3. UIC Well Numbers by SECARB State.

SECARB STATE	NUMBER OF UIC WELLS
Alabama	797
Arkansas	1,247
Florida	75,674
Georgia	780
Louisiana	3,990
Mississippi	5,377
North Carolina	4,489
South Carolina	6,314
Tennessee	4,747
Texas	59,246
Virginia	16,267

Source: USEPA, "UIC Program Overview," Sequestration Workshop, February 2-3, 2004.

Based upon existing rules and regulations, it seems logical that geologic carbon sequestration projects, which function as EOR and EGR activities, would be permitted under UIC as Class II wells. It is less clear, however, how other long-term storage carbon sequestration projects would be permitted. Viewpoints range from the IOGCC preference for regulating and permitting these sites under natural gas storage laws to restating USEPA regulations regarding Class V well definitions or adding another UIC class.[42] Another less viable, and potentially more costly, option is the utilization of the Class I UIC definition, which appears to be preferred by another faction of geologic carbon sequestration scholars.[43] In fact, the Frio Injection Project presently being conducted by the University of Texas, Bureau of Economic Geology, as noted, invokes both approaches. While the project was permitted as a Class V UIC well due to its experimental nature, the consensus in Texas is that future, non-experimental long-term geologic carbon sequestration wells would be permitted under a UIC Class I regime.

In addition to the governing regime for the regulatory, permitting, and safety issues of geologic sequestration injection and storage, matters of long-term liability and stewardship exist which cannot be easily ignored. One approach to this matter could mirror the various state mine land restoration programs, which would require bonding or trust fund deposits to be posted with the relevant state regulatory agency to ensure that the long-term stewardship of geologic carbon sequestration sites would continue past the life of operating companies. Based upon early stakeholder input on this subject, it seems that this type of approach would address public concerns without undue harm to the economics of geologic sequestration, and, in doing so, serve as an asset to wide-scale geologic sequestration deployment.

2. Terrestrial Sequestration

While the geologic sequestration regulatory, safety, and permitting frameworks will require substantial shepherding to ensure that the regulations protect the public interest and are at the same time not unduly burdensome on terrestrial sequestration project stakeholders, the arena of terrestrial sequestration regulatory, safety, and permitting frameworks is advancing without assistance from entities like SECARB. Witness, for example, the investments being made in the Lower Mississippi River Valley by power companies, including Entergy and American Electric Power, and nonprofit organizations, including the Conservation Fund, among others. This is not to say, however, that SECARB will not play a beneficial role in attempting to streamline various state enactments in this domain, as with its present mission, SECARB would do so.

In general, most laws and regulations related tangentially to terrestrial sequestration in the SECARB states provide limited guidance to regulatory, safety, and permitting practices, but instead focus on attempting to stimulate voluntary terrestrial sequestration activities. As a result, much of the guidance for terrestrial sequestration activities in the SECARB region results from state conservation policies or economic development enactments. As a result of the potential terrestrial sequestration options in the region, four areas that relate to potential terrestrial sequestration projects – mine

[42] Interstate Oil and Gas Compact Commission Geological CO_2 Sequestration Task Force, Final Report, January 2005.
[43] Wilson, Elizabeth J., David W. Keith, and Malcolm Wilson, "Considerations for a Regulatory Framework or Large-Scale Geological Sequestration of Carbon Dioxide: A North American Perspective," Presented at Vancouver, BC, Canada, September 2004.

reclamation, reforestation, farm practices, and brownfield restoration – were examined in greater depth.

a. Mine Land Reclamation

As a result of Federal mining laws, all SECARB states have required mining companies to submit reclamation plans to the state governments explaining the post-mining utility of lands that have been excavated for mineral resources. These plans typically explain the vegetative cover that will be planted in the land and the man-made structures that will conserve water and land resources. Some of the states such as Florida and Arkansas have regulations on the type of plants and trees to be used in the reclamation process and the manner in which vegetation is to be planted. As terrestrial sequestration can be additional value-add options for mine land reclamation projects, state focuses on encouraging this practice could be helpful to the goal of wide-scale terrestrial sequestration.

b. Reforestation and Afforestation

Similar value-add opportunities exist for terrestrial sequestration in the area of reforestation and afforestation to combat emerging problems with land erosion resulting, in some instances, from development and industrial processes. To augment this situation, many SECARB states have employed programs to diminish the costs associated with replanting trees and conserving land resources. Therefore, the SECARB states provide technical assistance services or provide cost-sharing grant opportunities to develop appropriate preliminary planning to implement reforestation and afforestation practices. For example, some SECARB states provide private land-owners with tree seedlings at cost of planting the trees. Many of the state governments maintain tree nurseries for the rational of diminishing the costs associated with developing immature trees. In addition, many SECARB states utilize the educational systems to develop reforestation technical assistance and site preparation. Further, these states provide, in some instances, technical assistance through “Stewardship Programs” for maintenance of forestry resources. This program is also used for information resources and networking for forest land owners to optimize the value of their resources.

c. Brownfield Restoration

SECARB states have also adopted a focus on brownfield restoration as a land management activity, which in some instances can positively impact terrestrial sequestration prospects. Most SECARB states, with North Carolina as a notable exception to the rule, have diminished the liability associated hazardous waste for future generations following the initial clean-up process, which could include for purposes of terrestrial sequestration.

The incentives associated with brownfield redevelopment do not always apply to terrestrial sequestration activities in the SECARB states. Often, in terms of terrestrial sequestration, these governmental incentives are dependent on the definition of "development". Some of the states observe the creation of public parks as an activity worthy of these tax incentives. The development of public parks could sequester carbon, but the intention of these laws is often more focused on development of brownfields into commercial property, not necessarily GHG reduction projects. Thus, alterations to brownfield restoration laws could be required in order to allow this mechanism to become a more viable option for terrestrial sequestration.

d. Farm Practices

Moving to the domain of soil sequestration, select SECARB states have advanced programs that assist in on-farm, soil management-based terrestrial sequestration. While several SECARB states encourage agricultural management practices that enhance terrestrial sequestration, two SECARB states – Georgia and North Carolina – have provided incentives for farmers to employ conservation-oriented farm preparation activities, e.g. no-tillage farm practices, which can directly result in marketable, verifiable carbon sequestration achievements. For reference, the state governments provide capital equipment for farm owners using this form of site preparation. In addition, North Carolina state government also provides technical assistance for farmers that utilize no-tillage practices.

e. Other References to Terrestrial Sequestration

To date, SECARB state terrestrial sequestration enactments have focused on laws and regulations that provide opportunities for terrestrial sequestration, but that do not directly contemplate terrestrial sequestration. In limited instances, however, terrestrial sequestration projects are specifically referenced in state codes and forestry entities are empowered with the authority to assist private and public parties, in some instances, with terrestrial sequestration projects. For instance, the Arkansas Forestry Commission is endowed with these privileges under a recent enactment.[44] Other non-SECARB states, including Oklahoma, seem to have set the precedent for this approach with its "Carbon Sequestration Enhancement Act" from several years earlier.

While common approaches to terrestrial sequestration are developing, there remains a void in terms of a universal approach to terrestrial sequestration regulatory, permitting, and safety frameworks that would encourage such activities in the SECARB region.

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[44] Code of Arkansas, §22-5-506 (2003).

D. Action Plan Development and Activities

During SECARB Phase I regulatory, safety, permitting, and accounting team activities, the efforts culminated with activities focused on two major areas – early action plan activities and action plan development activities. More information on these areas follows.

1. Early Action Plan Activities

As a Federal-state energy compact, the SSEB hosts a number of activities for SSEB members during the course of a calendar year, including an SSEB Annual Meeting, an SSEB Chairman's Forum, and a meeting at the Southern Legislative Conference. As a significant benefit to SECARB, these meetings, as proposed in the SECARB proposal to NETL, have been utilized to facilitate early engagement of partners and stakeholders alike in SECARB, which will need to be involved in the final development of the SECARB regulatory, safety, permitting, and accounting frameworks and action plans.

During SECARB Phase I, the SECARB team utilized the SSEB as a vehicle for engaging and informing opinion leaders and stakeholders in the southeast on SECARB and its goals. Information about SECARB was disseminated through various SSEB communications and events, including the SSEB Chairman's Forum, the SSEB Annual Meeting, the Southern Legislative Conference Annual Meeting, meetings of the SECARB Technical Team and Technology Coalition and the Carbon Sequestration PEIS public scoping meeting held in the SECARB region, among others.

The initial meeting of the SECARB Technical Team and Technology Coalition occurred in January 2004 in Atlanta, Georgia. The meeting served to report on the status of subcontracts for SECARB, the work effort accomplished following the NETL RCSP Kick-off Meeting in November 2003, and to solicit input from Technology Coalition stakeholders for the coming months of the activity. A copy of the agenda from the event is attached as Appendix A.

As a result of the decision of SSEB 2004 Chairman, West Virginia Governor Bob Wise, to host an SSEB Chairman's Forum focused on carbon management, entitled "Regional Meeting on Defining Priority Actions for Voluntary Carbon Management Activities in the South," SECARB had another opportunity to present to stakeholders the plans and initial efforts of SECARB. Speakers at the SSEB Chairman's Forum included representatives from USDOE, NETL, the United States Environmental Protection Agency, the United States Department of State, state governments, private industry, the SECARB Technology Coalition, and the SECARB Technical Team. A copy of the agenda from the SSEB Chairman's Forum is attached as Appendix B. Notably, this event featured an update on regulatory and accounting research activities for the Technical Team and Technology Coalition, which serves as a de-facto partnership advisory board for SECARB.

In August 2004, Augusta Systems and the SSEB, on behalf of SECARB, provided remarks to a meeting of the Southern Legislative Conference regarding the

carbon sequestration issues of potential interest to legislators in SECARB and other southern states. A copy of a briefing document distributed along with a Power Point presentation delivered by Augusta Systems is attached as Appendix C. For reference, the oral presentation and Power Point Presentation included features on carbon management overview, SECARB regulatory and accounting research activities, voluntary and regulatory efforts at carbon management by U.S. states, and SECARB plans for action plan development and implementation, and a mechanism for feedback from SECARB and SSEB state legislative representatives.

In addition, the SSEB and SECARB provided comments during the NETL Carbon Sequestration PEIS public scoping meeting. A copy of these comments is provided for reference as Appendix D.

2. Action Plan Development

During Year 2 SECARB activities, the SECARB regulatory and accounting team focused on performing Action Plan development activities. Key issues examined during the action plan development were to ensure that the efforts of SECARB leveraged the work being performed by other organizations, including USDOE, IOGCC, CSLF and others questions integrated into the development of the Draft Action Plan include:

- Whether CO_2 be defined as a commodity, waste, or pollutant under Federal, state, or Federal and state laws and regulations, including UIC regulations?
- What Federal and/or state standards should be devised for measurement of CO_2 concentration at the point of capture to ascertain and verify the quality and purity of the CO_2?
- Whether the Federal and state entities with existing CO_2 pipelines continue business-as-usual with regulating, permitting, and enforcing safety as CO2 pipelines enjoy greater proliferation under wide-scale sequestration endeavors?
- Whether geologic carbon sequestration injection and storage activities be wholly subject to existing UIC regulations?
- Whether new UIC classes or definitions emerge to facilitate geologic sequestration injection and storage activities?
- Whether long-term geologic sequestration projects without enhanced hydrocarbon recovery components be subject to UIC at all?
- How will the existing Federal and state land management and restoration, timber management, and farm management legislation be augmented to include comprehensive plans to encourage terrestrial sequestration?
- How will the 1605(b) guideline enhancements, state registry activities, and private sector standards develop and allow for reconciliation to create reliable accounting frameworks?
- How quickly can effective measurement, monitoring, and verification technologies be developed that will provide reliable data to advance regulatory and accounting activities, both for terrestrial and geologic carbon sequestration activities?

As SECARB will be coalition-builder for the region, SECARB has highlighted these issues as the significant matters to be addressed during implementation of the

Phase II Action Plan which follows. In addition, SECARB has determined the potential paths and strategies to respond to these issues, but to ensure that a regional consensus emerges from SECARB, the judgments and paths on the regional response forged by SECARB will be produced through the Action Plan in lieu of unilateral decision-making.

Thus, the SECARB activities for the regulatory, safety, permitting, and accounting framework activity efforts focused on developing frameworks that incorporated available resource information and analysis to forge a flexible Action Plan that would allow for the integration of new findings and pronouncements during the course of SECARB Phase II.

3. Action Plan for Regulatory, Safety, Permitting, and Accounting Frameworks

As international, national, state, and local policies and regulations related to GHG emissions management and carbon sequestration are debated and structured during the coming years, SECARB Phase II is uniquely positioned to assist in the structuring and coalition-building efforts related to wide-spread sequestration deployment in the four-year span of SECARB Phase II, as limited efforts have taken place to-date within the region to initiate regulations regarding sequestration to complement the emerging voluntary GHG emissions management activities led by industry in response to the Climate VISION program and GCCI. Thus, the Action Plan for Regulatory, Safety, Permitting, and Accounting Frameworks for SECARB region sequestration efforts will attempt to focus the SECARB stakeholders around common policies and regulations that will ensure opportunities for wide-spread sequestration in the coming decades.

More specifically, the Action Plan for Regulatory, Safety, Permitting, and Accounting Frameworks focuses on:

- Forming a SECARB Regulatory, Safety, Permitting, and Accounting Frameworks Working Group;
- Continuing Assessment of the Changing Landscape on Regulatory, Safety, Permitting, and Accounting Matters;
- Assisting the SECARB Field Project Teams with National Environmental Policy Act (NEPA), Environmental Impact Statement (EIS), and other Filings;
- Facilitating Outreach on the Findings of the Regulatory, Safety, Permitting, and Accounting Frameworks Working Group and SECARB Field Projects; and,
- Publishing the SECARB Model Guidance for Sequestration Regulatory, Safety, Permitting, and Accounting Frameworks.

Details on each element of the Action Plan follow.

a. Forming a SECARB Regulatory, Safety, Permitting, and Accounting Frameworks Working Group

A major area of focus for the SECARB Phase II regulatory, safety, permitting, and accounting frameworks activities will include working with SECARB partners, technical coalition team members, and other state government and private sector

stakeholders to form a working group to assist in the drafting of model regulatory statutes, leveraging existing state statutes and regulations to provide for the opportunity for commonality and certainty to emerge in the arena of carbon sequestration within SECARB, the southern region and integrated on a national basis.

To frame the context for the SECARB Regulatory, Safety, Permitting, and Accounting Framework Group drafting activities, the initial meeting will involve both geologic and terrestrial topics and include specific questions as follows.

Geologic Sequestration

- Should CO_2 be defined as a commodity, waste, or pollutant under Federal, state, or Federal and state laws and regulations, including UIC regulations?
- Should geologic carbon sequestration injection and storage activities be wholly subject to existing UIC regulations?
- Should new UIC classes or definitions emerge to facilitate geologic sequestration injection and storage activities?
- Should long-term geologic sequestration projects without enhanced hydrocarbon recovery components be subject to UIC at all? If not, should existing natural gas storage statutes be amended and utilized?
- What Federal and/or state standards should be devised for measurement of CO_2 concentration at the point of capture to ascertain and verify the quality and purity of the CO_2?
- Should the Federal and state entities with existing CO_2 pipelines under their jurisdiction continue business-as-usual with regulating, permitting, and enforcing safety as CO2 pipelines enjoy greater proliferation under wide-scale sequestration endeavors?
- How quickly can effective and economic measurement, monitoring, and verification technologies be developed that will provide reliable data to advance regulatory and accounting activities for terrestrial sequestration activities? What impact will the maturity and cost have upon accounting standards?
- For geologic sequestration efforts, how should the 1605(b) program and its guidelines, the GHG Protocol, and other U.S. state registry, reporting, and accounting models be utilized to ensure consistency for stakeholders and not duplicate efforts?

Terrestrial Sequestration

- How will the existing Federal and state land management and restoration, timber management, and farm management legislation be augmented to include comprehensive plans to encourage terrestrial sequestration?
- How quickly can effective and economic measurement, monitoring, and verification technologies be developed that will provide reliable data to advance regulatory and accounting activities for geologic sequestration activities? What impact will the maturity and cost have upon accounting standards?
- For terrestrial sequestration efforts, how should the 1605(b) program and its guidelines, the GHG Protocol, and other U.S. state registry, reporting, and accounting models be utilized to ensure consistency for stakeholders and not duplicate efforts?

With the above-referenced matters to be contemplated by the working group likely to be detailed and prolonged conversations, the majority of these meetings will be conducted via email and teleconference, to minimal cost to SECARB and USDOE. However, Augusta Systems will also facilitate group and one-on-one meetings with Federal and State regulatory permitting agencies and other interested parties to support the working group and ensure that a common approach can be found. When possible these meetings will be arranged to coincide with standing SSEB meetings in order to minimize travel costs to the project.

b. Continuing Assessment of the Changing Landscape on Regulatory, Safety, Permitting, and Accounting Matters

On a continuous basis during SECARB Phase II, Augusta Systems will examine new regulatory developments, on an international, national, state, and local basis, to update the existing base of knowledge assembled within this Phase I report.

c. Assisting the SECARB Field Project Teams with NEPA, EIS, and other Filings

In addition, Augusta Systems will work with the field project leads for the carbon sequestration activities to take place in Texas, Virginia, and Deep South (either in Mississippi, Alabama, or Tennessee) to document project permitting requirements to conduct sequestration projects and NEPA requirements for conducting environmental assessments and/or EIS required for the proposed sequestration technology validation projects. Assisting the field project implementation leads with NEPA and EIS filings will be critical to ensure commonalities of approach within the SECARB region and provide regulatory, safety, permitting, and accounting guidelines for future sequestration projects, given that the five states of interest have markedly different regulatory schemes in place for UIC applications that could be embraced by the SECARB region for geologic sequestration endeavors in long-term storage applications. For instance, Virginia and Tennessee, though both regulated through USEPA for UIC applications are subject to different USEPA Regional Offices. Moreover, the state-based UIC applications of Alabama, and Mississippi, and Texas are not entirely similarly structured in terms of UIC regulation, as can be witnessed in Figure 2 above.

d. Facilitating Outreach on the Findings of the Regulatory, Safety, Permitting, and Accounting Frameworks Working Group and SECARB Field Projects

Also, Augusta Systems, working in support of SECARB Phase II and in conjunction with the SSEB, will facilitate outreach efforts on the findings of the regulatory, safety, permitting and accounting framework working group and the sequestration field projects to state and federal regulators in the region who represent entities that will be guiding policies and practices related to sequestration. To minimize costs of outreach efforts, the activities will be conducted with standing SSEB meetings including those at the Southern Legislative Conference and Southern Governors Association meetings.

e. Publishing the SECARB Model Guidance for Sequestration Regulatory, Safety, Permitting, and Accounting Frameworks

Perhaps most importantly, during Phase II activities, Augusta Systems, assisted by the SSEB, will provide regulatory, safety, permitting, and accounting frameworks based upon the on-going analysis, experiences drawn from projects implemented in the SECARB region during Phase II and other sequestration projects, to produce a SECARB Model Guidance for Sequestration laws and regulations within the region to address both geologic and terrestrial carbon sequestration. This Model Guidance will feature sections that provide background information as well as draft laws and regulation suitable for adoption by the SECARB member states.

4. Phase II Activities

Thus, in Phase I, SECARB developed action plans to overcome issues identified in the preliminary assessment of regulatory, safety, permitting, and accounting frameworks to allow for wide-scale deployment of promising terrestrial and geologic sequestration approaches, including specific capture, transport, injection, and storage approaches for geologic sequestration. During Phase II, Augusta Systems will implement SECARB action plans on regulatory, safety, permitting, and accounting matters. This implementation includes: drafting of model regulations in cooperation with stakeholders; continuing assessments of the changing regulatory landscape on international, state, and local bases (as conditions warrants); interacting with federal and state regulatory agencies and other stakeholders to provide education and outreach regarding action plan activities and field projects; assisting field project teams with NEPA and EIS filings; and providing regulatory, permitting and accounting guidelines for future sequestration projects. At the conclusion of Phase II, SECARB, through the efforts of Augusta Systems, will provide regulatory, permitting and accounting guidelines for projects implemented during Phase II and commercially-ready future sequestration projects.

IV. CONCLUSION

Phase I of SECARB regulatory, safety, permitting, and accounting framework activity efforts focused on meeting the requirements of SECARB Phase I Subtask 3.1, which focused on conducting a thorough analysis of the existing environment that could impact the carbon sequestration regulatory, safety, permitting, and accounting frameworks in the SECARB region, as well as Subtask 6.6, which called for the development of the Action Plan for Regulatory, Safety, Permitting, and Accounting Frameworks. As the carbon sequestration arena is a rapidly developing field, multiple, complimentary efforts are underway that will ultimately affect the implementation of the SECARB Action Plan for the Regulatory, Permitting, Safety, and Accounting Frameworks.

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LIST OF ACRONYMS AND ABBREVIATIONS

CCS	Carbon Capture and Storage
CCX	Chicago Climate Exchange
CEED	Center for Energy and Economic Development
CO_2	Carbon Dioxide
CSLF	Carbon Sequestration Leadership Forum
DIAL	Diagnostic Instrumentation and Analysis Laboratory
ECBM	Enhanced Coalbed Methane
ECX	European Climate Exchange
EGR	Enhanced Gas Recovery
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EPRI	Electric Power Research Institute
GCCI	Global Climate Change Initiative
GHG	Greenhouse Gas
IOGCC	Interstate Oil and Gas Compact Commission
MIT	Massachusetts Institute of Technology
MSU	Mississippi State University
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
OPS	Office of Pipeline Safety
PEIS	Programmatic Environmental Impact Statement
PSI	Pounds Per Square Inch
RCSP	Regional Carbon Sequestration Partnership

SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
SGA	Southern Governors Association
SLC	Southern Legislative Conference
SSEB	Southern States Energy Board
TVA	Tennessee Valley Authority
UIC	Underground Injection Class
UNFCCC	United Nations Framework Convention on Climate Change
U.S.	United States
USDOE	United States Department of Energy
USEPA	United States Environmental Protection Agency
USDOT	United States Department of Transportation
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

APPENDICES

APPENDIX A – JANUARY SECARB MEETING

Southeast Regional Carbon Sequestration Partnership

Technical Team and Technology Coalition Meetings

Grand Hyatt Atlanta – In Buckhead
Atlanta, Georgia

January 14-15, 2004

AGENDA

Wednesday, January 14, 2004

"Administrative and Project Management Meeting for

Lead Technical Team Members"

9:00 a.m. Welcome and Introductions

Mr. Kenneth J. Nemeth, Executive Director
Southern States Energy Board

Task 1, 2 & 3 Progress Reports and Crosscutting Activity Reports

- *Regulatory Compliance and Liability Issues*
- *Public Outreach and Education*
  Mr. Patrick R. Esposito, II, Chief Operating Officer
  Augusta Systems, Incorporated

- *Capture and Separation Technologies*
  Dr. M. John Plodinec, Director, Diagnostic Instrumentation Analysis Laboratory
  Mississippi State University

- *Geologic Sink Characterization and Infrastructure Requirements*
  Dr. Patrick R. Esposito, Sr., Chief Executive Officer
  Augusta Systems, Incorporated

- *Terrestrial Sink Characterization and Infrastructure Requirements*
  Mr. John Kadyszewski
  Winrock International

- *GIS/Database Development*
  Mr. Richard Rhudy, Project Manager
  Electric Power Research Institute

Review of *Work Responsibility Matrix* with Key Team Leaders (some via phone)

Southeast Regional Carbon Sequestration Partnership Website, www.secarbon.org

Goals for January 15th Presentation to Coalition Members

Governor's Forum Discussion

12:30 p.m. Lunch on Your Own

"Technical Team Working Session"

2:00 p.m. Welcome and Introductions

Mr. Kenneth J. Nemeth, Executive Director
Southern States Energy Board

Introduction of Lead Technical Team
Dr. Gerald R. Hill, Senior Technical Advisor
Southern States Energy Board

Goals for January 15th Meeting
Dr. Patrick R. Esposito, Sr., Chief Executive Officer
Augusta Systems, Incorporated

3:45 p.m. Task 1, 2 & 3 Input Requirements

Breakout Sessions for Working Groups

Action Items for Technical Team

5:30 p.m. Adjourn

6:00-7:00 p.m. Networking Session for SERCSP Technical Team and Technology Coalition Members

Location: Buckhead Ballroom 2

Thursday, January 15, 2004

"Technology Coalition Briefing and Working Session"

8:00 a.m. Welcome

Mr. Kenneth J. Nemeth, Executive Director
Southern States Energy Board

Introduction of Coalition Members and Team Leaders
Dr. M. John Plodinec, Director, Diagnostic Instrumentation Analysis Laboratory
Mississippi State University

Project Overview
Dr. Patrick R. Esposito, Sr., Chief Executive Officer
Augusta Systems, Incorporated

Task 1, 2 & 3 Status Report and Crosscutting Activity Reports

- *Regulatory Compliance and Liability Issues*
- *Public Outreach and Education*

  Mr. Patrick R. Esposito, II, Chief Operating Officer

Augusta Systems, Incorporated

- *Capture and Separation Technologies*
  Dr. M. John Plodinec, Director, Diagnostic Instrumentation Analysis Laboratory
  Mississippi State University

- *Geologic Sink Characterization and Infrastructure Requirements*
  Dr. Patrick R. Esposito, Sr., Chief Executive Officer
  Augusta Systems, Incorporated

- *Terrestrial Sink Characterization and Infrastructure Requirements*
  Mr. John Kadyszewski
  Winrock International

- *GIS/Database Development*
  Mr. Richard Rhudy, Project Manager
  Electric Power Research Institute

U.S. Department of Energy Report
Dr. Karen Cohen, DOE Project Manager
U.S. Department of Energy

- *Regional Partnership Working Groups*
- *Carbon Sequestration Atlas*

GIS Overviews

- *Terrestrial*
  Mr. John Kadyszewski
  Winrock International

- *Geological*
  Mr. Howard Herzog
  Massachusetts Institute of Technology

12:00 p.m. Lunch on Your Own

1:30 p.m. Roundtable Discussion: Perspectives for Phase II Carbon Sequestration
Mr. Richard Rhudy, Project Manager
Electric Power Research Institute

Panel Discussion of Coalition Representatives

Action Items for Project Team

Announcement of April 2004 Chairman's Forum on
Carbon Management in the Southern States
Dr. Patrick R. Esposito, Sr., Chief Executive Officer
Augusta Systems, Incorporated

3:00 p.m. Adjourn

APPENDIX B – SSEB CHAIRMAN'S FORUM MEETING

Southern States Energy Board

2004 Chairman's Forum on Carbon Management in the Southern States

"Regional Meeting on Defining Priority Actions for Voluntary Carbon Management Activities in the South"

Washington Plaza
Washington, DC
Thursday, May 20, 2004

8:00 am **Continental Breakfast and Registration**

8:30 am **Welcome and Introductions**

Presiding: The Honorable Jimmy Skipper
House of Representatives, State of Georgia
Vice Chairman, Southern States Energy Board

Dr. Patrick R. Esposito
Chairman, Governor's Energy Task Force, State of West Virginia
Governor's Alternate, Southern States Energy Board

The Honorable Brian C. Griffin
Federal Representative, Southern States Energy Board

8:45 am **Overview of Carbon Management**

Mr. Mark Maddox
Acting Assistant Secretary for Fossil Energy
United States Department of Energy

Mr. Jeffrey R. Holmstead
Assistant Administrator for Air and Radiation
United States Environmental Protection Agency

Mr. John F. Turner
Assistant Secretary, Bureau of Oceans and International Environmental Scientific Affairs
United States Department of State

10:00 am **Break**

10:15 am **Perspectives on Carbon Management**

Presiding: Dr. M. John Plodinec, Director
Diagnostic Instrumentation and Laboratory, Mississippi State University

- Federal Government Perspective
  Dr. Robert Wright
  Power Systems Portfolio Manager, Office of Fossil Energy
  United States Department of Energy

- Historical Perspective
  Mr. Roger Ballentine
  President
  Green Strategies, Inc.

- Industry Perspective
  Mr. Dwight H. Evans
  Executive Vice President
  Southern Company

- Public Perspective
  Mr. David Hawkins
  Director, Climate Center
  Natural Resources Defense Council

12:00 pm **Luncheon**

Keynote Presentation: "The Road to Sensible Carbon Sequestration:
An Insurance Policy for the Future"

Mr. Ben Yamagata
Executive Director
Coal Utilization Research Council

1:30 pm **Carbon Management in the South: Technologies and Approaches**

Presiding: The Honorable Tommy Robertson
Senate, State of Mississippi

- Terrestrial Sequestration Approaches
  Mississippi River Valley Activities
  Mr. Lawrence A. Selzer
  President and Chief Executive Officer
  The Conservation Fund

- Accounting and Monitoring Approaches
  Ecolytics – A GHG Emissions System
  Mr. Patrick R. Esposito II
  Chief Operating Officer
  Augusta Systems, Inc.

- Methane Management Approaches
  Mr. Richard Winschel
  Director, Coal Utilization
  CONSOL Energy, Inc.

- Geologic Sequestration Approaches
  CO_2 Test Center Project
  Mr. Richard G. Rhudy
  Project Manager
  Electric Power Research Institute

3:00 pm **Break**

3:15 pm **Carbon Management in the South: Technologies and Approaches** (*continued)*

Presiding: The Honorable Jerry Paul

House of Representatives, State of Florida

Executive Member, Southern States Energy Board

- Biobased Approaches
  Mr. Steve Segrest
  The Common Purpose Institute

- Nuclear Power Contributions
  Dr. Tim Valentine
  Legislative Fellow
  United States Senator Lamar Alexander's Office, State of Tennessee

- Distributed Generation Approaches
  Mr. Dave Walls
  Director, New Business and Technology
  Navigant Consulting, Inc.

- Combustion Approaches/Cleaner Fossil Fuel Systems
  Mr. Brian C. Griffin
  President
  Clean Energy Systems, Inc.

4:30 pm **Break**

4:45 pm **Determining Priority Actions for Voluntary Carbon Management in the South**
A discussion hosted by:
The Honorable Bob Wise
Governor, State of West Virginia
Chairman, Southern States Energy Board

5:30 pm **Closing Remarks**
Mr. Kenneth J. Nemeth

6:00 pm **Adjournment to Networking Reception**

APPENDIX C – SOUTHERN LEGISLATIVE CONFERENCE BRIEFING

Southern Legislative Conference Briefing:
Considerations for Legislators Interested in Voluntary Carbon Management

Introduction

State legislators have an important role to play in encouraging voluntary greenhouse gas (GHG) and carbon management activities in the Southern States region. With the region accounting for roughly 44% of the United States (U.S.) GHG emissions and a current Federal government position that focuses on voluntary GHG and carbon management approaches and encourages state action to facilitate the achievement of Federal goals, it is clear that the Southern States must play a leading role in the facilitation of activities that allow voluntary carbon management initiatives to take hold. The Southern States Energy Board (SSEB) is assisting the U.S. Department of Energy (USDOE) by leading the Southeast Regional Carbon Sequestration Partnership (SECARB), which is working to foster the development of potential model state legislation on carbon sequestration, a leading field of carbon management approaches, and GHG emissions management on a region-wide basis. As this effort and others move forward, there are proactive steps that state legislators can take on this matter today.

What's Happening in States?

Throughout the United States, state legislators have taken the lead in drafting and advancing legislation to assist in facilitating voluntary GHG and carbon management activities in their states. Notable types of legislation, as well as the states in which these concepts have been adopted, include:

- Development of studies and creation of advisory bodies on carbon management (various states including Idaho and South Dakota);
- Adoption of voluntary GHG and carbon emissions registries (examples include California, Georgia, and New Hampshire); and,
- Passage of legislation to encourage terrestrial sequestration activities (Oklahoma and others).

Conclusions

As GHG and carbon emissions management will be a significant issue in the coming years, state legislators have a unique opportunity to impact the arena of carbon management. With the Federal government supporting development of innovative approaches and technologies, including those focused on carbon sequestration, state legislators can work to assist their resident businesses and individuals with adopting and implementing voluntary carbon management activities and programs. The SSEB and its partners in SECARB are ready to assist legislators in the Southern States in efforts to adopt cost-effective approaches to GHG and carbon emissions management. Leading options include:

- Authorizing and funding state studies on GHG and carbon emissions management approaches;
- Implementing legislation to establish voluntary GHG emissions management registries;
- Implementing legislation encouraging, or even providing incentives for, investments in voluntary GHG or carbon emissions reduction or offset projects that can be facilitated by initiatives like the Carbon Offset Opportunity Program (www.offsetopportunity.com) and others, or traded through programs like the Chicago Climate Exchange (www.chicagoclimatex.com) and others;
- Working with national and regional efforts, such as those related to SECARB, to ensure that terrestrial sequestration projects, including those activities which include aspects of mine land reclamation, no till farming, soil conservation, brownfield restoration, among others, are legally permissible and economically feasible in states; and,
- Working with national and regional efforts, such as those related to SECARB and the parallel efforts of the Interstate Oil and Gas Compact Commission, to ensure that geologic sequestration activities, including those related to the capture, separation, transportation, injection, and storage phases, are legally permissible and economically feasible in states.

For more information

For more information on options and approaches to allow state legislators to proactively assist with voluntary carbon management activities, please contact Kenneth Nemeth, of the Southern States Energy Board, by email at nemeth@sseb.org or telephone at 770.242.7712, or Patrick Esposito, of Augusta Systems, by email at pesposito@augustasystems.com or by telephone at 304.599.3200.

APPENDIX D – SECARB COMMENTS AT USDOE PEIS MEETING

(Please note: This document features the comments of Dr. Gerald R. Hill, of SECARB and the SSEB, at the USDOE Programmatic Environmental Impact Statement Public Scoping Meeting in Atlanta, Georgia on June 2, 2004.)

Comments of
DR. GERALD R. HILL
Public Scoping Meeting
NORCROSS, GA – JUNE 2, 2004
U.S. Department of Energy
Programmatic Environmental Impact Statement
Carbon Sequestration Program

INTRODUCTION

My name is Dr. Gerald Hill. I am Senior Technical Advisor to the Southern States Energy Board. The Southern States Energy Board, or "SSEB", is located at 6325 Amherst Court, Norcross, Georgia 30092.

I am speaking on behalf of SSEB, and in support of Carbon Sequestration Programs. We believe that the potential environmental benefits of carbon sequestration are significant and, therefore, the demonstration and deployment of enabling technologies to implement the Program should proceed.

SSEB is a non-profit interstate compact organization created in 1960 and established under Public Law 87-563 and 92-400 of the United States Congress. The Board's mission is to enhance economic development and the quality of life in the South through innovations in energy and environmental programs and technologies.

Sixteen southern states and two territories comprise the membership of SSEB. Each jurisdiction is represented by the governor and a legislator from the House and Senate. A Federal Representative is appointed by the President of the United States.

SSEB is chaired by a Governor who is instrumental in setting priorities for the Board's activities.

In September 2002, West Virginia Governor Bob Wise became SSEB Chairman and declared carbon management to be a priority. On May 20, 2004 Governor Wise convened a Chairman's Forum on Carbon Management in the Southern States.

SSEB's carbon management forum was attended by over 100 people. Presentations were made by government officials, private sector experts, and public interest advocates. A highlight of the two-day forum was a May 21st meeting of the Technology Coalition of the Southeast Regional Carbon Sequestration Partnership, or "SECARB".

In DOE's announcement of tonight's carbon sequestration meeting it was stated that:

> "*Major initiatives to demonstrate the key elements of the Program may require collaboration with Federal agencies, state and regional governments, and private sector partnerships.*"

I am please to note that the groundwork for future collaboration on demonstration projects has been initiated.

SECARB is one of seven regional partnerships that work with the National Energy Technology Laboratory to assess issues related to the capture, transport and storage of carbon dioxide emissions from fossil fuel sources. Nine months of work by SECARB, and discussions with the SECARB Technology Coalition, provide the basis for specific comments I will make this evening.

CAPTURE, TRANSPORT AND STORAGE

I would like to discuss each of the three points noted here (carbon dioxide capture, transport and storage) in the context of current industry experience and potential environmental impacts.

(1) Carbon dioxide capture (or separation) is an accepted and historic practice world-wide. Both food grade and industrial grade CO2 are produced and consumed within world economies. The DOE program of demonstration and deployment will simply expand the available sources of CO2 to include fossil fuel emissions. Expanding potential sources to include fossil fuel emissions has the environmental benefit of offsetting others production processes.

(2) Carbon dioxide transport is an accepted and historic practice world-wide. Food grade and industrial grade CO2 are transported via pipeline, tanker truck and rail on a regular basis. The CO2 that originates from fossil fuel emissions can be transported in the same manner. The specifications will be the same, primarily relating to moisture content and oxygen content (to prevent corrosion of pipes or vessel surfaces) and the presence of other trace constituents (depending on whether the CO2 is intended for food-grade applications or various industrial applications). Transporting CO2 that is captured from fossil fuel emissions sources will not introduce new or unknown environmental impacts to the pipeline, tanker truck or rail industries.

(3) Carbon dioxide storage occurs naturally in terrestrial and geologic systems.

(a) Terrestrial systems are being evaluated as potential sinks for sequestering CO2 emissions as stored carbon. Building up soil carbon content or increasing the inventory of stored carbon in croplands and forest lands is viewed as a viable and immediate opportunity for reducing greenhouse gas (GHG) intensity. The US Department of Agriculture has noted that the south central and southeast regions of the United States have the highest potential for carbon storage in terrestrial systems. Utilizing terrestrial systems as sinks for carbon will have a positive environmental benefit upon the reduction in greenhouse gas intensity.

(b) Geologic systems are being evaluated as potential sinks for storing CO2 emissions. Injecting CO2 into underground formations has been occurring for the past twenty years. Specifically, CO2 from natural underground formations or from commercially available separation units is injected into oil/gas wells in order to increase the output of the wells. This practice is called enhanced oil recovery, or “EOR”. The potential market for CO2 used in enhanced oil recovery is large. The Texas Bureau of Economic Geology has evaluated over 3300 wells and determined that about 1800 are suitable for EOR, with CO2 injection being a

candidate technology for many of these wells. The use of CO2 that is captured from fossil fuel emission sources will not introduce new or unknown environmental impacts to the EOR industry. In fact, it will have the added environmental benefit of removing large volumes of CO2 from the atmospheric inventory and also will reduce the amount of CO2 that is being extracted from natural formations or produce by commercial separation units.

In addition, CO2 injection can be used for recovering coal bed methane. In this practice CO2 is pumped into coal seams and methane is liberated from the seams. The southeast region has many thin seams of coal that could store CO2 and produce methane. Recovering methane by utilizing CO2 emissions from fossil fuel facilities can provide positive economic benefits to the southeastern region, while increasing the supply of pipeline-grade natural gas. Additional work is needed in order to fully understand the mechanisms of coal bed methane recovery using CO2. The potential economic benefits of methane production and the potential environmental benefits of CO2 sequestration in coal seams are both very high. Therefore, work should continue in the demonstration and deployment of these technologies, including the evaluation of environmental impacts.

A third category of geologic storage is the sequestration of CO2 in deep saline formations. Unlike enhanced oil recovery or coal bed methane production, this category of storage has no economic drivers within the region. It is, however, a viable option for storing huge volumes of CO2 emissions from fossil fuel facilities. The oil industry and industries that extract materials from salt brine have practiced underground injection for decades. The activity is regulated by the US Environmental Protection Agency and state agencies within the Underground Injection Control, or “UIC”, program. The potential environmental benefits of CO2 sequestration in deep saline formations are very high. Therefore, work should continue in the demonstration and deployment of these technologies, including the evaluation of environmental impacts.

REGULATORY, PERMITTING AND SAFETY FRAMEWORK

Clearly, at its inception, the Underground Injection Control program could not have anticipated the injection of fossil fuel CO2 emissions. Consequently, there exists the potential for regulatory uncertainty. It is essential that the regulatory, permitting and safety framework for CO2 injection evolve on its own merit.

The framework must not be inappropriately or inaccurately constrained by UIC programs designed for unrelated activities. We are asking DOE, as part of the Programmatic Environmental Impact Statement process, to call attention to potential regulatory barriers to the demonstration and deployment of CO2 sequestration options and related technologies.

SSEB further requests that the US Environmental Protection Agency consider proactive steps, including but not limited to, the creation a new regulatory framework (or perhaps a new UIC category) for CO2 injection and storage.

The federal and state regulatory frameworks should facilitate, not block, the demonstration and deployment of technologies that can increase our ability to produce domestic oil and gas (including coal bed methane gas). We have an opportunity to generate positive economic activity in the region, while reducing our dependence on

foreign sources of oil and gas. At the same time we can facilitate the development of a regulatory structure that will provide clear guidance for storing CO2 from fossil fuel emissions.

MEASUREMENT, MONITORING AND VERIFICATION

The ability to measure, monitor and verify performance of carbon sequestration technologies is an essential component of any demonstration or deployment program. Existing tools need to be modified for CO2 sequestration applications. New tools will be needed for deployment efforts. Measurement and verification systems will be needed to support voluntary reporting programs such as the US DOE 1605(b) initiative. Future trading platforms and regulatory programs will require measurement and verification. Also, monitoring systems will be needed to assess real-time performance of equipment as well as long-term performance of storage options.

Analytical tools and methods must be demonstrated under conditions that reasonably represent actual field conditions for carbon sequestration. The potential environmental benefits of demonstrating analytical systems and methods are great and, under carefully controlled field conditions, the environmental risks can be very low. Therefore, DOE should move forward in an aggressive fashion to ensure that the proper measurement, monitoring and verification tools are made available as soon as possible.

BREAKTHROUGH CONCEPTS

A major objective of the carbon sequestration program is to demonstrate and deploy technologies that can achieve environmental benefits and remain economically viable. For this reason, the carbon sequestration program must maintain a level of flexibility that allows breakthrough concepts to be tested and verified. The potential environmental benefit of a quantum leap breakthrough in carbon sequestration solutions is enormous. Therefore, the programmatic EIS must incorporate sufficient flexibility to test and verify breakthrough concepts in order to realize potential environmental benefits.

SUMMARY

In summary, please allow me to recap key points that SSEB would ask the Department to consider as it develops a Programmatic Environmental Impact Statement:

Capture:

- Expanding potential sources to include fossil fuel emissions has the environmental benefit of offsetting others production processes.

Transport:

- Transporting CO2 that is captured from fossil fuel emissions sources will not introduce new or unknown environmental impacts to the pipeline, tanker truck or rail industries.

Storage:

- The use of CO2 that is captured from fossil fuel emissions sources will not introduce new or unknown environmental impacts to the EOR industry.

- The potential economic benefits of methane production and the potential environmental benefits of CO2 sequestration in coal seams are both very high.

Therefore, work should continue in the demonstration and deployment of these technologies, including the evaluation of environmental impacts.

- The potential environmental benefits of CO2 sequestration in deep saline formations are very high. Therefore, work should continue in the demonstration and deployment of these technologies, including the evaluation of environmental impacts.

Measurement, monitoring and verification:

- The potential environmental benefits of demonstrating analytical systems and methods are great and, under carefully controlled field conditions, the environmental risks can be very low.

Regulatory, permitting and safety framework:

- Federal and state regulatory frameworks should facilitate, not block, the demonstration and deployment of technologies.

Breakthrough concepts:

- The programmatic EIS must incorporate sufficient flexibility to test and verify breakthrough concepts in order to realize potential environmental benefits.

FURTHER INFORMATION

Thank you for the opportunity to speak this evening. For those who would more information about SSEB and SECARB, log on to www.sseb.org and click on the Southeast Regional Carbon Sequestration Partnership.

SECARB CO_2 Sequestration GIS Analysis

March 2006

Carbon Capture and Sequestration Technologies Program
Massachusetts Institute of Technology

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EXECUTIVE SUMMARY

This report presents the GIS analysis part for the Phase I study of the Southeast Regional Carbon Sequestration Partnership (SECARB) in characterizing the CO_2 sequestration potential for the region. The following three components of CO_2 sequestration are evaluated in the study:

- CO_2 source analysis
- CO_2 storage capacity estimation
- CO_2 source-sink matching and sequestration cost

As a first step, the study collected the information regarding the stationary CO_2 sources in the SECARB region. The data was compiled and stored as a database in the SECARB GIS server. The database includes information for 862 facilities from eight categories with total annual emissions estimated at just over 1 Gt[1] of CO_2. Table ES-1 and Table ES-2 summarize the CO_2 emissions from major stationary sources in the SECARB region by facility type and by state, respectively. Power plants are the single largest source of CO_2 emissions, accounting for about 85 percent of the emissions from the stationary sources in the database. The SECARB region, especially Louisiana and eastern Texas, hosts a variety of non-power stationary CO_2 emission facilities and has a higher than national average proportion of non-power stationary CO_2 emissions. Eastern Texas, Florida, Alabama, and Louisiana—all are Gulf Coast states—rank highest in terms of the CO_2 emissions in the region.

Table ES-1: CO_2 Emissions from Stationary Sources by Facility Type

Type of Plant	Facilities #	CO_2 Emissions[1] (Mt/yr)
Ammonia	15	9
Cement	28	20
Ethylene	24	50
Ethylene Oxide	11	2
Gas Processing	164	16
Iron & Steel	32	3
Power Plants	547	859
Refineries	41	62
Total	**862**	**1,020**

Note:
[1]Power plants data are 2000 actual data but others are estimated emissions based on plant production capacity in various years (see Section 2 for details).

[1] 1 Gt is one billion metric tons. 1 Mt is one million metric tons.

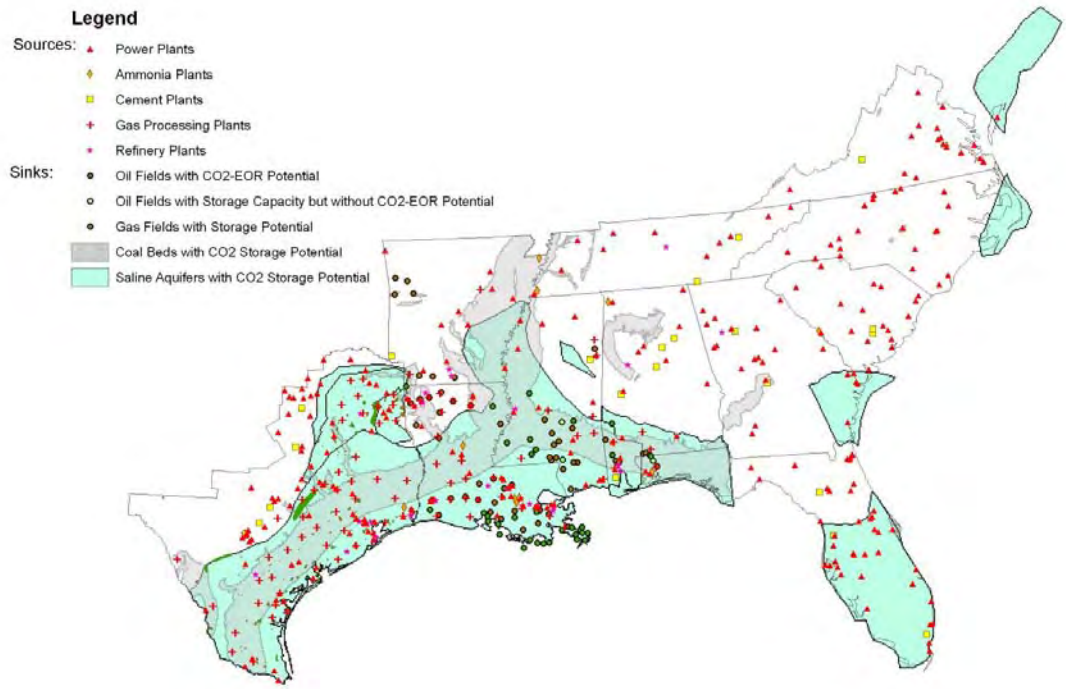
Table ES-2: CO_2 Emissions from Stationary Sources by State

State	Facilities #	CO_2 Emissions (Mt/yr)
AL	48	96
AR	26	35
FL	85	120
GA	65	89
LA	139	95
MS	42	29
NC	51	79
SC	32	44
TN	25	68
TX[1]	298	320
VA	51	43
Total	**862**	**1,020**

Note:
[1]eastern Texas only, consisting of Railroad Commission District 1-6.

The study identified three types of potential geological storage sinks for CO_2 sequestration in the SECAB region: hydrocarbon (oil & gas) reservoirs, saline aquifers, and coalbeds. A similar survey was conducted for candidate CO_2 sinks and the information was also stored in the SECARB database. The database was based on the best information available during Phase I and will be continually updated in Phase II as more detailed data sets are developed. The storage capacity estimation methods in the JOULE II report (Holloway, *et.al.*, 1996) were adapted as the baseline models in estimating the CO_2 storage capacity for hydrocarbon reservoirs and saline aquifers, while the methodology developed by Reeves (2003) was used as the baseline model in estimating the CO_2 storage capacity for coalbeds. When necessary, these baseline models were modified to accommodate incomplete data sets contained in the current database. The modified models were then applied to estimate the CO_2 storage capacity for each candidate CO_2 sink.

Figure ES-1: CO_2 Sources and Sinks in the SECARB Region



After identifying the CO_2 sources and candidate sinks, the study then evaluated the CO_2 sequestration potential in the SECARB region by analyzing the matching between sources and sinks. Figure ES-1 shows the distribution of CO_2 sources and sinks that were considered in the source-sink matching analysis. Table ES-3 summarizes the CO_2 capture capacity from these sources (over 25 years) and the CO_2 storage capacity for these sinks by category. After excluding sources with CO_2 emissions below certain scales[2], the source data set considered in the matching analysis was restricted to 316 power plants and 103 non-power facilities. Over an assumed 25 year project lifetime, a total amount of 34 Gt of CO_2 from these facilities would need to be sequestrated. After excluding sinks with less than 5 Mt of storage capacity[3], the regional CO_2 storage capacity was estimated to be at least 504 Gt[4].

[2] Power plants with design capacity less than 100 MW_e and gas processing plants with design capacity below 300mmcfd are excluded.

[3] 5 Mt is the minimum capacity requirement for a sink to store the 25-year cumulative amount of CO_2 that can be captured from any facility in the interested source set.

[4] Due to incomplete datasets, the study didn't evaluate the CO_2 storage capacity in coalbeds except for Black Warrior Basin (see Section 3.3 for details).

Table ES-3: CO_2 Capture Capacity for Sources and Storage Capacity for Sinks Considered in the Matching Analysis

Field Group		Number of Fields	CO_2 Capture Capacity (Gt)[1]	CO_2 Storage Capacity (Gt)
Sources	Power Plants[2]	316	31.6	-
	Non-power Stationary Sources[3]	103	2.4	-
	Total	419	**33.9**	**-**
Sinks[4]	Oil Fields w/ EOR potential	74	-	1.9
	Oil Fields w/o EOR potential and Gas Fields	246	-	3.6
	Coal Beds[5]	n.a	-	0.3
	Aquifers	n.a	-	497.8
	Total			**503.6**

Note:
1. Project lifetime 25 years.
2. Only design capacity over $100MW_e$ included.
3. Only includes ammonia, cement, gas processing, and refineries. Also, for gas processing facilities, those with design capacity less than 300 mmdcfd were excluded.
4. Only CO_2 storage capacity over 5 Mt included.
5. Only coalbed methane data in Black Warrior Basin, Alabama from AGS included in the estimate.

Table ES-4: Annual CO_2 Storage Capacity (Mt/y) of Various Sinks by Straight-line Distance from Source to Sink

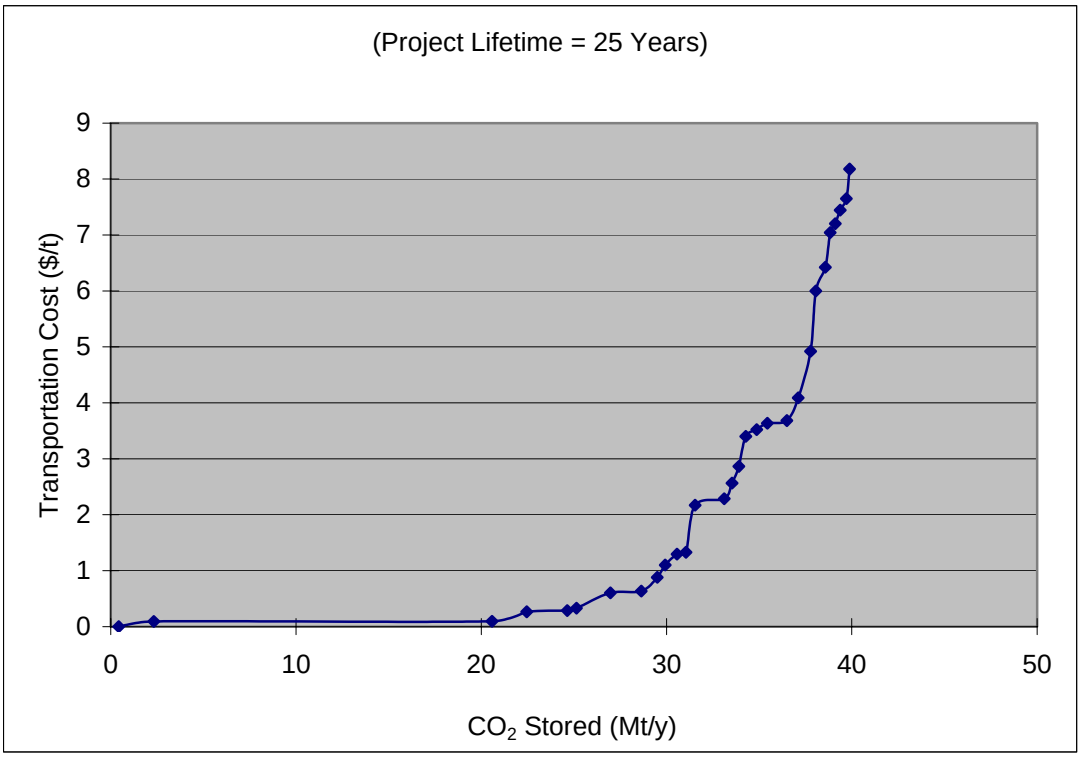
Sink Type	Straight Line Distance from Source to Sink		
	50 km or less	**100 km or less**	**250 km or less**
Oil & Gas Fields with EOR Potential	349	484	675
Oil & Gas Fields	507	598	726
Coalbeds	606	856	1,190
Aquifers	794	867	1,125
All Sinks	972	1,143	1,357

Note:
1. The total annual CO_2 storage rate was 1, 357 Mt.
2. Sinks with less than 5 Mt storage capacity were excluded from the analysis.

As a preliminary analysis, the study performed a straight-line distance based matching for the entire SECARB region, connecting each source to its closest sink in terms of straight-line distance. In this preliminary exercise, neither the optimal pipeline path nor the sink's storage capacity constraints were considered. The straight-line distance matching analysis was performed for each of the four different groups of eligible sinks and a combination of them altogether. Table ES-4 summarizes the matching results based on the straight-line distance in terms of annual CO_2 storage capacity by marginal straight-line distance. If EOR sites were the only sinks used for sequestration, only half of the CO_2 sources (by volume) could be matched with a sink that is less than 250 km from the source. If all sink types were considered for sequestration, however, then all of the CO_2 sources could be matched with appropriate sinks within 250 km from the source. More than 70% of the sources (by volume) would find their nearest sinks within 50 km. Note that the 1,357 Mt/y in Table ES-4 is larger than the 1,020 Mt/y in Table ES-2. This is because in the matching exercise we assumed 80% capacity factors, while Table ES-2 used actual capacity factors for the year reported.

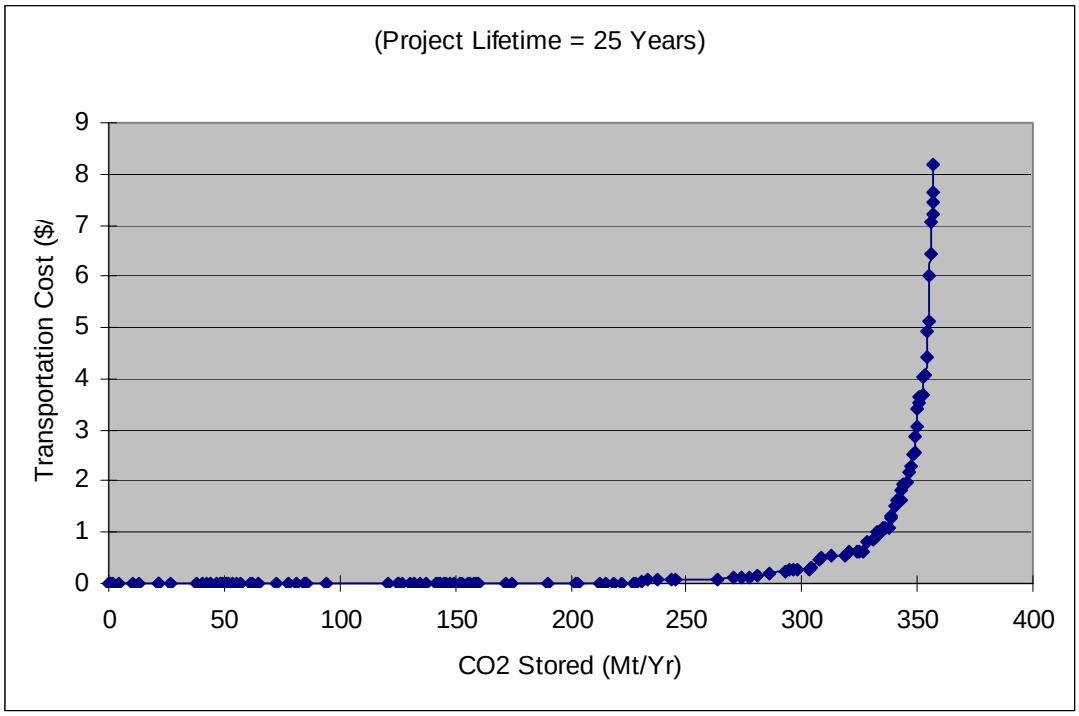
The study also conducted a GIS-based method of matching sources and sinks considering the optimal pipeline route selection and sink's capacity constraint. The pipeline construction costs vary considerably according to local terrains, number of crossings (waterway, railway, highway), and the traversing of populated places, wetlands, and national or state parks. In order to account for such obstacles, the locations and characteristics of these obstacles were loaded into the spatial database and were used to construct a single aggregate transportation obstacle layer. In contrast to the distance-based matching analysis, this least-cost matching analysis links each CO_2 source to a least cost geological sink based on sum of the transportation cost associated with the least-cost path and the injection cost subject to the sink's capacity constraint. An iterative algorithm was used to approximate an optimal system solution. Due to the limited availability of detailed sink data for the SECARB region, this least-cost matching analysis was only performed for eastern Texas where the data sets are relatively rich.

Figure ES-2: Marginal Transportation Cost in eastern Texas Oil Fields with EOR Potential



The least-cost source-sink matching analysis for eastern Texas was conducted in two stages. In the first stage, only EOR sites were included as candidate sinks. The cost calculation assumed a credit of \$16/t CO_2 for EOR injection in place of the injection cost. With the assumption of a constant CO_2 credit, the optimization algorithm only considers minimizing the overall transportation of the network system. Figure ES-2 shows the marginal transportation cost in oil fields with EOR potential. The annual CO_2 storage rate in EOR sites is estimated to be 40 Mt. While the maximum transportation cost is around \$8.2/t CO_2, about 30 Mt CO_2 can be transported to EOR sites annually at transportation cost less than \$1/t CO_2.

Figure ES-3: Marginal Transportation Cost for all Sources in eastern Texas



After allocating the EOR storage capacity to appropriate sources, the remaining unmatched sources were assigned to hydrocarbon fields without EOR potential and saline aquifers in the second stage. Figure ES-3 shows the marginal CO_2 transportation cost in all sinks. Extending the sinks to include non-EOR hydrocarbon fields and saline aquifers, the annual CO_2 storage rate in eastern Texas becomes 357 Mt, among which about 330 Mt can be transported to a sink with transportation cost less than $1/t CO_2. Figure ES-4 shows the pipeline routes connecting each source to its assigned sink by the least-cost matching. Some sources right on top of aquifers were still assigned to EOR sites as the EOR credit and the saved injection cost outweigh the added transportation cost.

Figure ES-4: Source-sink Matching Final Result

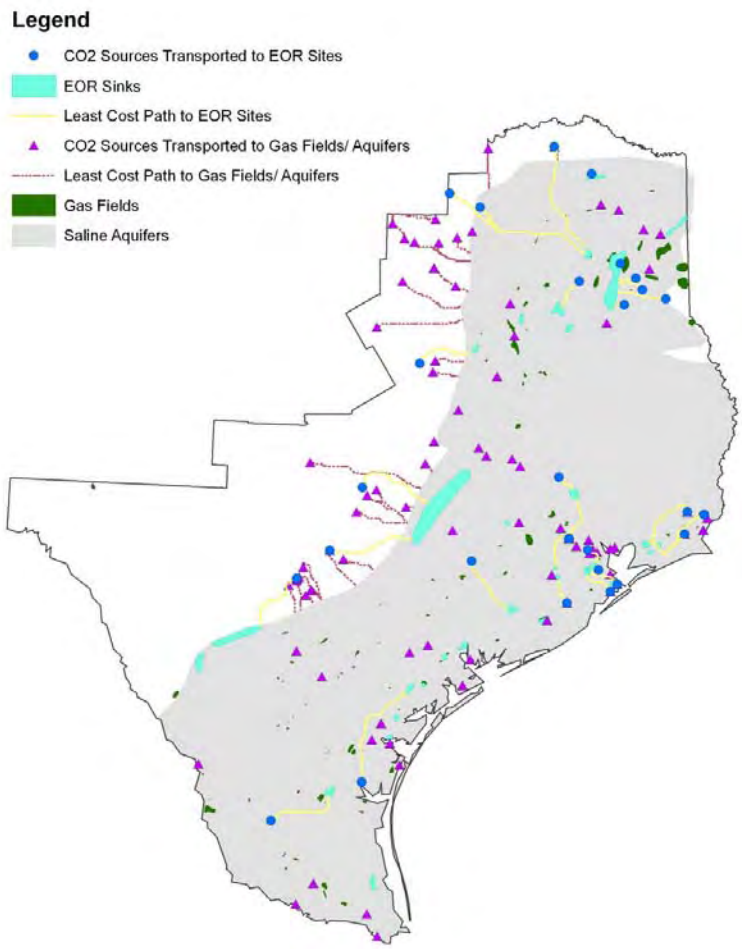


Figure ES-5: Marginal Total Cost of Capture and Sequestration in eastern Texas

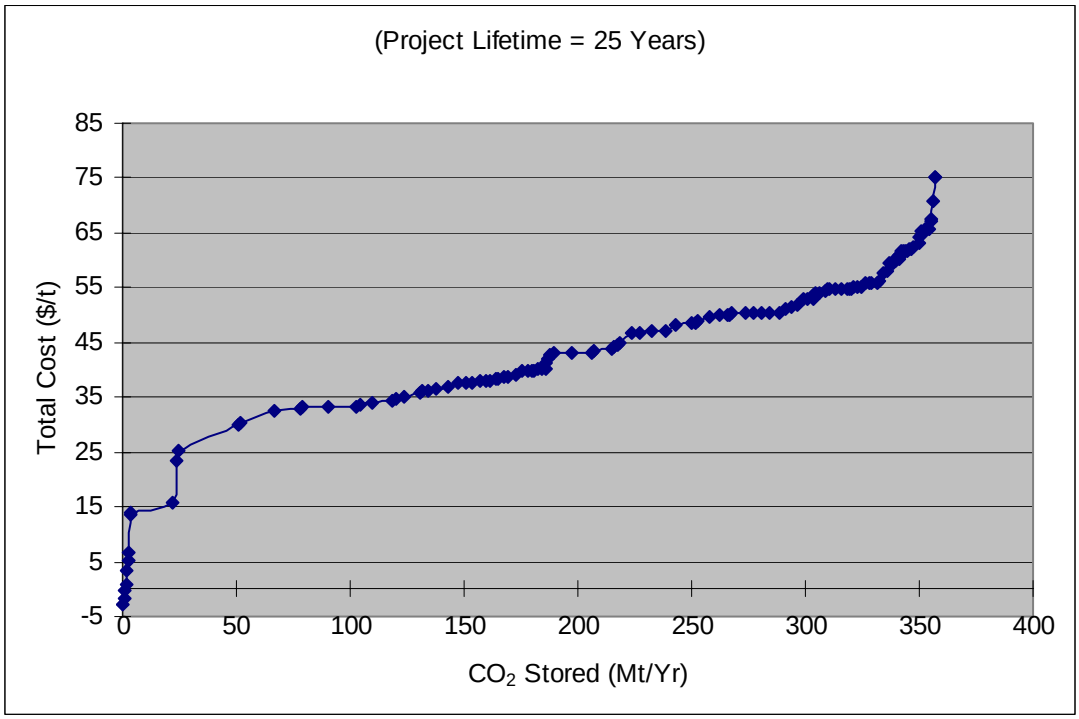


Figure ES-5 shows the full marginal capture and sequestration cost. For sources matched with EOR sites, the full cost estimate includes costs for capture and transportation, net of an EOR credit. For sources matched with non-EOR hydrocarbon fields or aquifers, the full cost estimate included costs for capture, transportation, and injection. The results of the full cost analysis in eastern Texas indicate that 20, 100, or 200 M tonnes of CO_2 per year could be sequestered for marginal costs of $16/t, $33t, or $43/t, respectively. The sequestration cost could be negative for certain ammonia and gas processing plants with low transportation costs since their capture cost was less than the assumed EOR credit.

1 OVERVIEW

This report presents the GIS analysis part of the Phase I study of the SECARB regional partnership. In this report GIS software and other tools were used to characterize the SECARB region and assess its carbon sequestration potential. The SECARB member states include Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and eastern Texas[5].

In this report:

- Section 2 presents a summary of stationary CO_2 sources and the levels of emissions within the SECARB region.
- Section 3 presents a first-order scoping analysis to determine the maximum CO_2 storage capacity of the carbon sinks within the SECARB region.
- Section 4 documents methods for determining the CO_2 capture costs from the types of CO_2 sources included in the study.
- Section 5 presents a methodology for estimating the requirements and costs of transporting CO_2 from the sources to the storage reservoirs.
- Section 6 presents an initial matching between CO_2 sources and sinks in the SECARB region based on minimum straight-line distance.
- Section 7 presents a detailed source-sink matching analysis which is used to develop CO_2 sequestration marginal abatement cost curves. This analysis is restricted to eastern Texas due to the limited availability of more expansive datasets. This type of analysis will be expanded to the entire SECARB region in Phase II.

It must be emphasized that this is only an initial analysis. It was based on the best information available during Phase I of the regional partnerships. This effort will be continued and improved in Phase II using more sophisticated tools and more detailed data sets.

[5] In this report 'eastern Texas' was defined as Railroad Commission (RRC) District 1 to 6.

2 STATIONARY CO_2 SOURCES IN THE SECARB REGION

This report summarizes the CO_2 source database that has been created for the SECARB GIS analyses. The database contains the location and capacities of the major stationary sources of CO_2 in the SECARB study area. It also includes annual CO_2 emissions. CO_2 emissions from power plants were given in the US Environmental Protection Agency (USEPA) eGRID database. For other CO_2 sources, the emissions were estimated using emissions factors based on annual production.

The database contains the following eight major stationary source categories:

- Power plants
- Ammonia Plants
- Cement plants
- Ethylene plants
- Ethylene oxide plants
- Gas processing facilities
- Iron & steel plants
- Refineries

2.1 FACILITY DATA SOURCES

The USEPA eGRID database was used exclusively for the power plant data cited within this report. For other major CO_2 sources, the ECOFYS database developed for the IEA GHG program was used as an initial starting point. Records within the ECOFYS database were then upgraded using the sources listed in Table 2-1. Specifically, new data sources were used for ammonia plants, cement plants and refineries. Updated data was also used for gas processing facilities. No changes were made to the data sources for ethylene, ethylene oxide, and iron and steel plants because the ECOFYS database already contained the most recent and accurate datasets available for these sources. See Table 2-1 for details on the data sources used for each emissions source category.

Table 2-1: Data Sources

Category	Data Source	Details
Power plants	US Environmental Protection Agency (USEPA) eGRID Database (2002) http://www.epa.gov/cleanenergy/egrid/index.htm	- Best data source identified - Plants located - CO2 emissions estimated - Database to be updated when 2004 data released
Ammonia plants	International Fertilizer Development Center Report "North America Fertilizer Capacity" (October, 2004) http://www.ifdc.org/New_Design/Publications/Market_Reports/index.html	- Best data source identified - Plants located - Plant capacities estimated
Cement plants	"U.S. and Canadian Portland Cement Industry: Plant Information Summary," Portland Cement Association, 2002. http://www.cement.org/bookstore/	- Best data source identified - Plants located - Plant capacities estimated
Gas processing facilities	Oil and Gas Journal Worldwide Gas Processing Survey (2003) http://orc.pennnet.com/surveys/aboutsurveys.cfm USGS Organic Geochemistry Database http://energy.cr.usgs.gov/prov/og/ (well CO2 levels)	- Best data sources identified for gas processing capacity and well CO_2 levels - Processing capacities of plants estimated
Refineries	US Department of Energy – Energy Information Administration (2004) http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html	- Best data source identified - Plants located - Plant capacities estimated
Ethylene plants	From Ecofys: *Ethylene Report*, Oil & Gas Journal, April 23, 2001	- Best data source identified - Plants located - Plant capacities estimated
Ethylene oxide plants	From Ecofys: ChemWeek Website; http://www.chemweek.com, 2001	- Best data source identified - Plants located - Plant capacities estimated
Iron and steel plants	From Ecofys: *World Steelworks Survey*, SteelEye, 2001	- Best data source identified - Plants located - Plant capacities estimated

The eGRID and ECOFYS databases contain geographic coordinate information for the vast majority of the stationary CO_2 emissions sources in the SECARB region. In cases where this data was unavailable, the USGS Geographical Names Information System database (GNIS) was used to lookup the missing data.

2.2 CO_2 EMISSION FACTORS

Except for the eGRID database, the data sources in Table 2-1 provide production capacity numbers but do not have information on CO_2 emission rates. In order to convert these capacity numbers to CO_2 emission rates, emission factors for each of the source categories were identified. These are outlined in Table 2-2.

It is important to note that the CO_2 emissions estimated from applying these emission factors are very approximate. They are useful for comparing the total emissions from each source type, but may not be an accurate estimate of emissions from any individual source.

Table 2-2: CO_2 Emission Factors

Category	Emission Factor	Units	Source
Power	n/a	n/a	CO_2 emissions explicitly given in eGRID database
Ammonia	1.13	kg CO_2/kg Ammonia	International Fertilizer Development Center (IFDC)
Cement	0.75	kg CO_2/kg Clinker	Hanle, "CO_2 Emissions Profile of the US Cement Industry," US EPA, 2004
Gas Processing	608	tCO_2/mmcfd/yr	ECOFYS, based on 4% average inlet gas CO_2 concentration
Refineries	9.9	tCO2/BPD/yr	ExxonMobil "Report on Energy Trends, Greenhouse Gas Emissions and Alternative Energy," 2004 - Calculated as the company-wide average refinery emission rate
Ethylene	2.43	kg CO_2/kg Ethylene	ECOFYS
Ethylene Oxide	0.51	kg CO_2/kg Ethylene Oxide	ECOFYS
Iron and Steel	0.1468	Kg CO_2/kg Steel	US EPA, "Direct Emissions from Iron and Steel Production," 2002

2.3 SUMMARY OF SOURCE CATEGORIES

2.3.1 Power Plants

The database used 2002 USEPA eGRID data for power plant capacities, locations, operating factors, and CO_2 emission rates. The database only contains fossil power plants that are fired by coal, oil, or gas. The CO_2 emissions for these power plants were directly reported in the eGRID data and no emission factors were used to calculate total emissions.

The USEPA eGRID database is the best available database of power plant emissions information. The database is updated and re-released on a periodic basis. The analyses within this report are based on the most recent version of the database available during Phase I study, which was released in May 2003 and contains updated data from the year 2000. Table 2-3 summarizes the fossil power plants in the study area by state. Figure 2-1 shows the geographical distribution and the CO_2 emissions for fossil power plants in the SECARB region.

Table 2-3: Power Generation Capacity and CO_2 Emissions by Fuel and State (2000)

State	Gas			Oil			Coal		
	Number	Capacity (MW)	CO_2 Emissions (Mt)	Number	Capacity (MW)	CO_2 Emissions (Mt)	Number	Capacity (MW)	CO_2 Emissions (Mt)
AL	15	1,030	1.9	0	0	0	10	14,904	88
AR	12	2,637	3.4	1	8	0	3	3,911	29
FL	42	10,045	12.4	23	15,218	31.4	13	12,732	74
GA	19	4,501	2	25	1,205	1.1	16	15,804	84
LA	54	14,795	31.1	0	0	0	4	3,360	18
MS	22	4,621	6.6	3	807	2.5	4	2,498	16
NC	7	3,747	1.2	12	118	0	29	14,548	78
SC	8	2,029	0.5	3	246	0	14	7,637	41
TN	5	1,132	0.3	0	0	0	13	12,990	65
TX*	126	47,793	89.6	1	11	0	17	19,197	143
VA	12	3,781	1.6	13	435	0.1	21	6,855	37
Total	**322**	**96,110**	**151**	**81**	**18,048**	**35**	**144**	**114,435**	**671**

* eastern Texas

Figure 2-1: Fossil-Fired Power Plants

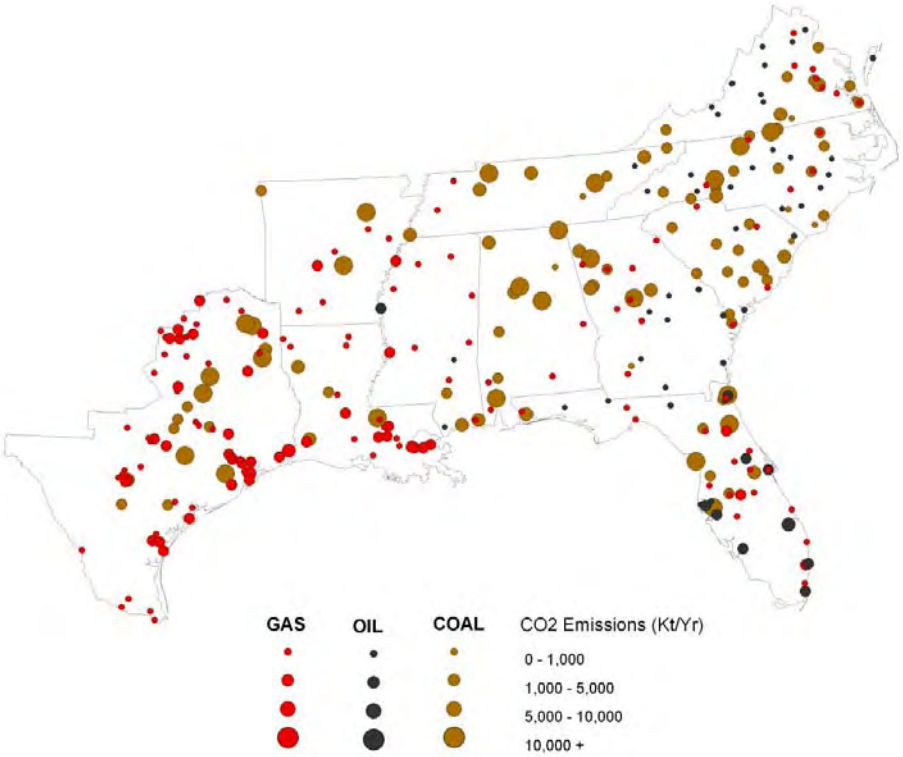
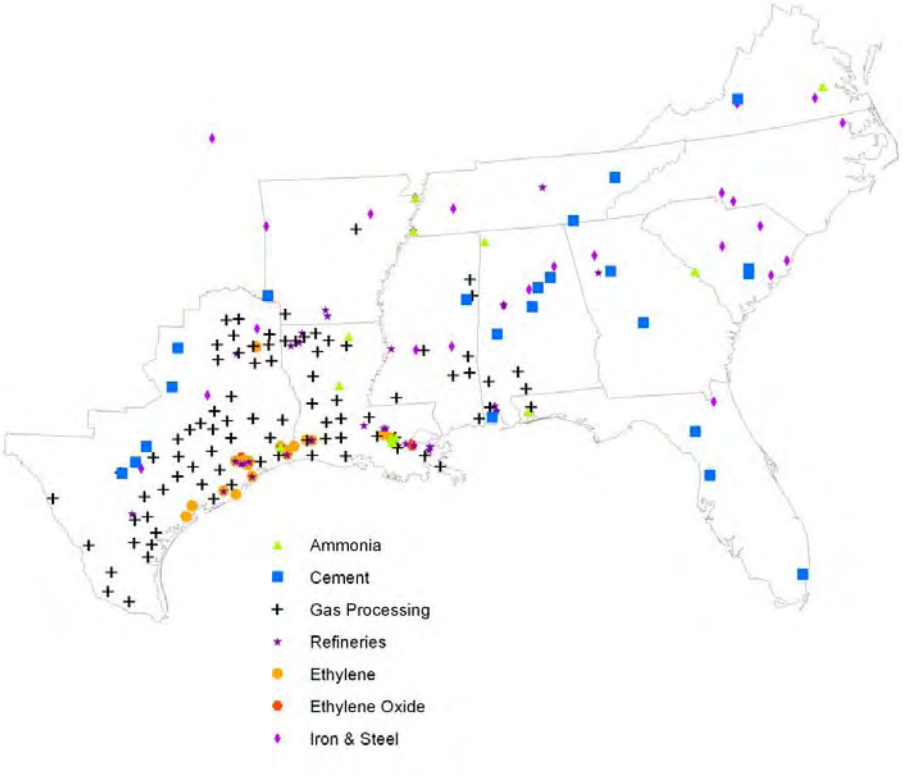


Figure 2-2: Non-Power Stationary CO_2 Sources



2.3.2 Non-Power Stationary CO_2 Sources

The SECARB region also hosts a variety of non-power stationary CO_2 sources. Figure 2-2 shows the geographical distribution of the non-power stationary CO_2 sources included in the database. The following of this section briefly summarizes each type of these non-power stationary CO_2 sources in the database.

Ammonia Plants

The ammonia plant database was updated with the latest available numbers from the International Fertilizer Development Commission (IFDC). The most recent numbers were released in October 2004. This database was cross-referenced with the ECOFYS database to determine the locations of facilities. In addition, the USGS GNIS database was used to locate facilities not included in the ECOFYS database. Table 2-4 summarizes the ammonia facilities in the study area by state.

Table 2-4: Ammonia Plant Capacity and Estimated CO_2 Emissions by State

State	Number	Capacity (kt/yr)	Estimated CO_2 Emissions (kt/yr)
AL	1	193	218
AR	1	467	527
FL	1	86	97
GA	1	758	856
LA	8	5,605	6,334
MS	0	0	0
NC	0	0	0
SC	0	0	0
TN	1	409	462
TX*	1	255	288
VA	1	584	660
Total	**15**	**8,357**	**9,443**

* eastern Texas

Cement Plants

The cement plant database was revised with new data from the Portland Cement Industry Association. The most recent database (December 2001) was used. This database was cross-referenced with the ECOFYS database to determine the locations of facilities. In addition, the USGS GNIS database was used to locate facilities not included in the ECOFYS database. Table 2-5 summarizes the cement production facilities in the study area by state.

Table 2-5: Cement Plant Capacity and Estimated CO_2 Emissions by State

State	Number	Capacity (kt/yr)	Estimated CO_2 Emissions(kt/yr)
AL	5	5,308	3,981
AR	1	803	602
FL	4	3,158	2,369
GA	2	1,355	1,016
LA	0	0	0
MS	1	419	314
NC	0	0	0
SC	3	2,725	2,044
TN	2	1,436	1,077
TX*	9	9,917	7,438
VA	1	1,120	840
Total	**28**	**26,241**	**19,681**

* eastern Texas

Refineries

The online database of the Energy Information Agency (EIA) of the US Department of Energy (DOE) was used to revise capacity estimates of refineries in the study area. The ECOFYS database was used for plant locations, with the USGS GNIS used to verify and update the location of new facilities. Table 2-6 summarizes the refineries in the study area by state.

Table 2-6: Refinery Capacity and Estimated CO_2 Emissions by State

State	Number	Capacity (1000 barrels / stream day)	Estimated CO_2 Emissions(kt/yr)
AL	3	130	1,289
AR	2	97	955
FL	0	0	0
GA	1	34	332
LA	16	2,452	24,275
MS	1	227	2,242
NC	0	0	0
SC	0	0	0
TN	1	120	1,188
TX*	16	3,002	29,719
VA	1	250	2,475
Total	**41**	**6,311**	**62,475**

* eastern Texas

Gas Processing Facilities

The database for gas processing facilities used data from the 2003 Oil and Gas Journal Gas Processing survey. This database was cross-referenced with the ECOFYS database to determine the locations of facilities. In addition, the USGS GNIS database was used to locate facilities not included in the ECOFYS database. Table 2-7 summarizes the gas processing facilities in the study area by state. The estimated CO_2 emissions in Table 2-7 are calculated using the CO_2 emission factor given in Table 2-2.

Table 2-7: Gas Processing Capacity and Estimated CO_2 Emissions by State

State	Number	Capacity (MMCFD)	Estimated CO_2 Emissions(kt/yr)
AL	9	766	466
AR	2	872	531
FL	1	90	55
GA	0	0	0
LA	47	10,015	6,092
MS	9	1,876	1,141
NC	0	0	0
SC	0	0	0
TN	0	0	0
TX*	96	12,455	7,577
VA	0	0	0
Total	**164**	**26,074**	**15,862**

* eastern Texas

However, the CO_2 emission rate from gas processing facilities is highly dependent on the percentage of CO_2 in the gas being processed by each facility. Initial analysis indicate that gas processing facilities in the SECARB region are likely to emit less CO_2 than is estimated in this study using the ECOFYS emissions factor. In order to better estimate these emissions, the USGS organic geochemistry database has been obtained. This database contains the CO_2 concentrations of the gas wells in the study area. Phase II analyses will provide better CO_2

emissions estimates for the gas processing facilities by revising the CO_2 emissions factors using the USGS organic geochemistry database.

Ethylene, Ethylene Oxide, and Iron and Steel Plants

The ECOFYS database contained the most detailed and up to date datasets for ethylene, ethylene oxide, and iron and steel plants. ECOFYS got the ethylene information the Oil & Gas Journal's *Ethylene Report* (April 2001), the ethylene oxide information from the ChemWeek (www.chemweek.com), and the iron and steel information from the 2001 *World Steelworks Survey*. The information from these databases was not supplemented with any additional sources. Table 2-8 summarizes the plant capacity and the estimated CO_2 emissions for these three types of non-power CO_2 sources by states.

Table 2-8: Ethylene, Ethylene Oxide, and Iron and Steel Plants Capacity and Emissions Estimate by State

State	Iron and Steel			Ethylene			Ethylene Oxide		
	Number	Capacity (kt/yr)	CO_2 Emissions (kt/yr)	Number	Capacity (kt/yr)	CO_2 Emissions (kt/yr)	Number	Capacity (kt/yr)	CO_2 Emissions (kt/yr)
AL	5	3,739	549	0	0	0	0	0	0
AR	4	2,115	310	0	0	0	0	0	0
FL	1	356	52	0	0	0	0	0	0
GA	1	712	105	0	0	0	0	0	0
LA	1	712	105	5	3,547	8,619	4	1,730	882
MS	2	401	59	0	0	0	0	0	0
NC	3	890	131	0	0	0	0	0	0
SC	4	2,992	439	0	0	0	0	0	0
TN	3	1,602	235	0	0	0	0	0	0
TX*	6	2,271	333	19	16,870	40,994	7	2,255	1,150
VA	2	1,647	242	0	0	0	0	0	0
Total	**32**	**17,437**	**2,560**	**24**	**20,417**	**49,613**	**11**	**3,985**	**2,032**

* eastern Texas

3 SECARB CO_2 STORAGE CAPACITY ANALYSIS

This section presents the theoretical principles supporting the baseline estimation of CO_2 storage capacity in the SECARB region. Methods were developed to estimate the CO_2 storage capacity of three different types of geological sinks:

- Hydrocarbon (oil & gas) reservoirs
- Saline aquifers
- Coalbeds

These methods were integrated into software tools for use with ArcGIS modeling software. These standardized capacity tools were then used with the collected SECARB data to estimate the total CO_2 storage capacity of the geological sinks in the study region.

Table 3-1: Data Source for Geologic Sinks

Category	Data Source	Details
Oil & Gas Fields (Texas, Louisiana)	University of Texas at Austin, Bureau of Economic Geology (UTBEG)	- Fields outlines - Fields located - Cumulative production - Reservoir depth - API gravity - Reservoir pressure
Oil & Gas Fields (Alabama, Mississippi)	Alabama Geological Survey (AGS)	- Fields located - Cumulative production - Example reservoir depth - API gravity - Example reservoir pressure
Oil & Gas Fields (Other States)	Gas Information System (GASIS)	- Fields located - Cumulative production - Reservoir depth - API Gravity - Reservoir Pressure
Coalbeds	United States Geological Survey (USGS)	- Coalbeds located - Coalbeds outlines
	Alabama Geological Survey (AGS)	- Coalbeds located - Coalbeds outlines - Reservoir depth - Cumulative gas production - Coal rank
	Virginia Center for Coal and Energy Research, Virginia Tech	- Coalbeds outlines - Coalbeds located - Coalbed wells located
Saline Aquifers	the University of Texas at Austin, Bureau of Economic Geology (UTBEG)	- Aquifers outlines - Aquifers located - Depth - Thickness - Reservoir porosity

Table 3-1 provides a summary of the data used to construct the SECARB database for each geologic sink category. The GASIS database provides general information on the oil and gas

fields in much of the SECARB region, but more detailed databases were used when available. Texas and Louisiana oil and gas data was prepared by the University of Texas at Austin, Bureau of Economic Geology (UTBEG). The oil and gas information for Alabama and Mississippi was prepared by the Alabama Geological Survey (AGS). The UTBEG saline aquifer CO_2 storage analysis dataset was also used in this report. The general USGS coalbed data was supplemented with detailed coalbed methane reservoir information provided by the AGS.

The storage capacity estimation methods in the JOULE II report (Holloway, *et.al.*, 1996) were adapted as the baseline models in estimating the CO_2 storage capacity for hydrocarbon reservoirs and saline aquifers, while the methodology developed by Reeves (2003) was used as the baseline model in estimating the CO_2 storage capacity for coalbeds. These baseline models were modified to accommodate the availability of information in the existing data set.

3.1 CO_2 STORAGE IN HYDROCARBON RESERVOIRS

3.1.1 CO_2 Storage Capacity of Hydrocarbon Reservoirs

A significant amount of pore space is vacated in underground hydrocarbon reservoirs when hydrocarbons are produced from the reservoir. CO_2 can be stored in the pore space left vacant by the hydrocarbon production. The CO_2 storage capacity of each reservoir depends on the amount of hydrocarbon fuel produced from the reservoir, with the total expected future storage capacity dependant on the total expected hydrocarbon production. In order to estimate storage capacity an assumption was made in this study that the entire underground volume of the hydrocarbons produced from a reservoir can be replaced by CO_2. Therefore, the future CO_2 storage capacity of a hydrocarbon reservoir can be calculated from *the underground volume of the ultimately recoverable oil and gas*.

Not every hydrocarbon reservoir is suitable for CO_2 storage, and reservoirs were only analyzed for CO_2 storage if the initial pressure and temperature were above the critical point of CO_2. If the pressure and temperature of the reservoir were unknown, the reservoirs were only analyzed if they were at a depth of 3,000 feet or greater. The generalized theoretical formula adopted in estimating the CO_2 storage capacity of a hydrocarbon field with depth over 3,000 feet can be expressed as:

$$Q_{CO2} = (V_{Uoil} + V_{Ugas}) * \rho_{CO_2} \tag{3.1}$$

where Q_{CO2} = CO_2 storage capacity (Mt CO_2)
V_{Uoil} = underground volume of the ultimately recoverable oil (km^3)
V_{Ugas} = underground volume of the ultimately recoverable gas (km^3)
ρ_{CO_2} = CO_2 density at the reservoir conditions (kg/m^3)

The CO_2 density at the reservoir conditions was calculated using correlations from V. V. Altunin (1975) that assumes the CO_2 density is a function of the pressure and temperature of the reservoir[6].

The underground volumes of oil and gas in equation (3.1) are calculated from the standard volumes of oil and gas based on the following conversion formula:

$$V_{Uoil} = V_{oil(st)} * B_o \tag{3.2}$$

$$V_{Ugas} = V_{gas(st)} * B_g \tag{3.3}$$

where $V_{oil(st)}$ = volume of oil at standard conditions (km^3)
$V_{gas(st)}$= volume of gas at standard conditions (km^3)
B_o = oil formation volume factor
B_g = gas formation volume factor

In this study, a default B_o of 1.2 is applied for oil. B_g is estimated using the following equation:

$$B_g = (4.8\,P + 93.1)^{-1} \tag{3.4}$$

where P = the reservoir pressure (MPa).

Data on the underground volume of the ultimately recoverable oil and gas in a field is generally not available, so equation (3.1) usually cannot be directly applied to estimate the CO_2 storage capacity of hydrocarbon fields. But in cases information on the amount of original oil in place (OOIP) or original gas in place (OGIP) is known, the ultimately recoverable oil or gas can be estimated as a proportion of OOIP or OGIP.

$$V_{Uoil} = V_{OOIP} * p_{oil} \tag{3.5}$$

$$V_{Ugas} = V_{OGIP} * p_{gas} \tag{3.6}$$

where V_{OOIP} = underground volume of original oil in place (km^3)
V_{OGIP} = underground volume of original gas in place (km^3)
$p_{oil/gas}$ = volume percentage of OOIP/OGIP that are recoverable (%)

According to the JOULE II report, the average underground volumes of the ultimately recoverable oil and gas are approximately 35% of OOIP and 80-90% of OGIP, respectively. Therefore, when OOIP and OGIP information is available, equation (3.1), together with equations (3.5) and (3.6) give the formula to estimate the CO_2 storage capacity in hydrocarbon fields.

[6] The CO_2 density was calculated using a computer code developed by Victor Malkovsky of the Institute of Geology of Ore Deposits, Petrography, Mineralogy and Geochemistry (IGEM) of the Russian Academy of Sciences, Moscow. We converted his FORTRAN code into Visual Basic.

3.1.2 The Adopted "Conservative" Approach

In most cases, information on the OOIP and OGIP for a reservoir is also not available. The best data that is available is the cumulative oil and gas production up to the date when the data was collected. To make use of this data, the cumulative production of oil and gas was used to replace the ultimately recoverable oil and gas in equation (3.1). This methodology will result in an underestimation of the CO_2 storage capacity, particularly for fields that are in early stages of production. However, this approach provides the ability to calculate consistent estimates of the CO_2 storage capacity for most of the oil and gas fields using available data. Using this methodology, equation (3.1) can be rewritten as:

$$\tilde{Q}_{CO2} = (\tilde{V}_{Uoil} + \tilde{V}_{Ugas}) * \rho_{CO_2} \tag{3.7}$$

where $\tilde{Q}_{CO2}$ = CO_2 storage capacity (Mt CO_2)

$\tilde{V}_{Uoil}$ = underground volume of the cumulative oil production (km^3)

$\tilde{V}_{Ugas}$ = underground volume of the cumulative gas production (km^3)

Equation (3.7) was then used as the baseline formula in estimating the CO_2 storage capacity for hydrocarbon reservoirs.

3.1.3 Categorizing the CO_2 Storage Potential for Hydrocarbon Reservoirs

Oil and gas reservoirs were classified into different types in terms of their depths and API gravities. Reservoirs that are at least 3000 feet[7] deep are under enough pressure for supercritical CO_2 injection, so this depth is used as an initial criterion for determining whether hydrocarbon fields have CO_2 storage potential. The API gravity, a measurement of oil density which indicates CO_2 miscibility, is used to determine the EOR potential for oil fields. Oil fields with API gravity more than 25° are classified as fields with miscible CO_2-EOR potential. Oil fields with API gravity between 17.5^o and 25° are classified as fields with immiscible CO_2-EOR potential. Based on these criteria, the oil fields can be divided into five categories:

(1) Fields with miscible CO_2-EOR potential (depth > 3000 feet, API>25)
(2) Fields with immiscible CO_2-EOR potential (depth > 3000 feet, 17.5<API<25)
(3) Fields with CO_2 storage potential but no EOR potential (depth > 3000 feet, API<17.5)
(4) Fields without CO_2 storage potential (depth < 3000 feet)
(5) Undetermined Fields (depth or API missing)

[7] 3,000 feet (approx. 914 m) is chosen as a conservative depth threshold. Some studies suggest using 800 m as depth threshold. The result does not differ much from using 800 m as the depth threshold as few fields have depth between 800 m and 914 m.

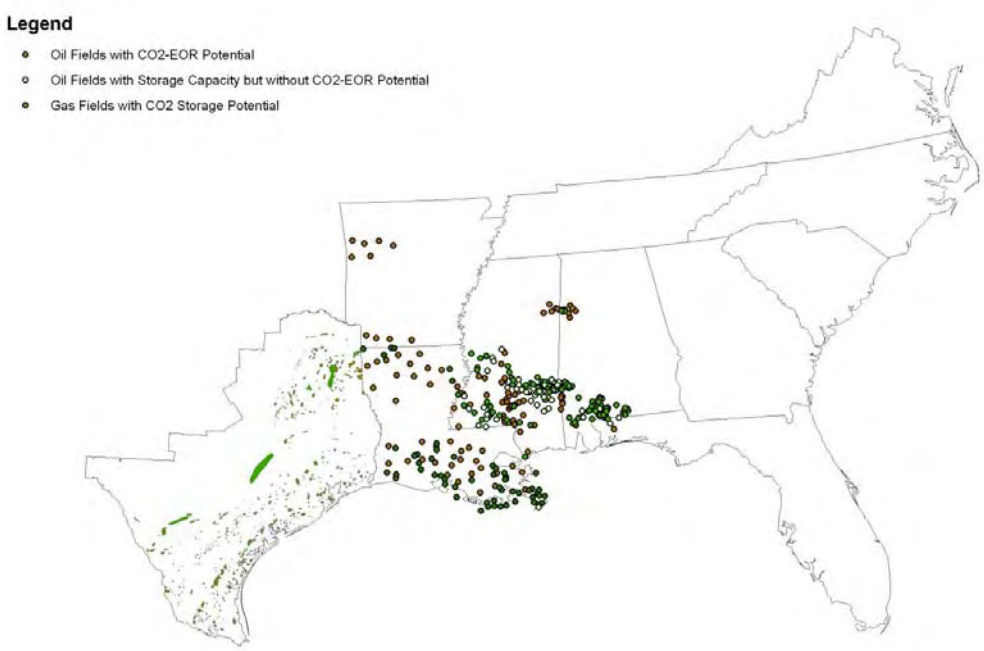
The gas fields are classified into three categories based on the depth information:

(6) Fields with CO_2 storage potential (depth > 3000 feet)
(7) Fields without CO_2 storage potential (depth < 3000 feet)
(8) Undetermined Fields (Unknown depth)

3.1.4 CO_2 Capacity Estimation Results

The methods presented above were then used to estimate the CO_2 storage capacity for oil and gas reservoirs included in the SECARB Phase I database (see Figure 3-1). Panel A of Table 3-2 summarizes the CO_2 storage capacity for oil fields aggregated by the five categories mentioned above. There are 378 oil fields in SECARB region with miscible or immiscible CO_2 EOR potential. These fields with CO_2 EOR potential have a CO_2 storage capacity of 2.3 Gt. The storage capacity of non-EOR oil fields is trivial, amounting to roughly 0.1 Gt.

Figure 3-1: Oil & Gas Fields with CO_2 Storage Capacity in Phase I Database



The CO_2 storage capacity of gas fields, screened by depth, was also estimated using the expression in equation 3.7. Panel B of Table 3-2 shows the storage capacity for gas fields aggregated by the three categories mentioned above. The result yielded 1,662 gas fields with a combined CO_2 storage capacity of 6.2 Gt.

Table 3-2: Estimates of CO_2 Storage Capacity in Oil Fields and Gas Fields

Fields Group	Number of Fields	Estimated Total Storage Capacity (Mt)
A: Oil Fields		
Oil fields with CO_2 storage potential	486	2,389
Oil fields with miscible CO_2-EOR potential	*347*	*2,134*
Oil fields with immiscible CO_2-EOR potential	*31*	*171*
Oil fields with CO_2 storage capacity no EOR potential[1]	*108*	*84*
Oil fields without CO_2 storage potential	44	0
Oil fields without depth information	1,202	0
B: Gas Fields		
Gas fields with CO_2 storage potential	1,662	6,166
Gas fields without CO_2 storage potential	88	0
Gas fields without enough information	740	0

Note:
1. Oil fields that lack API data also included.

Table 3-3 shows the CO_2 storage capacity for oil fields and gas fields, respectively, in each state. Among the 11 states in the SECARB region, 5 states have CO_2 storage capacity in both oil and gas fields and one state (AR) has CO_2 capacity only in gas fields, while the remaining 5 states have no capacity in either category. Among the states with CO_2 storage capacity in oil fields, eastern Texas has the largest share of the storage capacity: with 122 oil fields amounting to a total CO_2 storage capacity of 1.4 Gt. Among the states having gas fields with CO_2 storage potential, Louisiana and eastern Texas dominate the storage capacity. The two states also dominate the total storage capacity in hydrocarbon fields in the region. There are 922 fields with the capacity to store 2.7 Gt of CO_2 in Louisiana, and 556 fields with the capacity to store 2.6 Gt of CO_2 in eastern Texas.

Table 3-3: Estimates of CO_2 Storage Capacity in Oil Fields and Gas Fields by States

States	Oil Fields		Gas Fields	
	Number of Fields	Estimated Total Storage Capacity (Mt)	Number of Fields	Estimated Total Storage Capacity (Mt)
AL	112	66	42	154
AR	-	-	46	347
FL	3	103	2	32
GA	-	-	-	-
LA	79	585	922	2,685
MS	170	229	94	348
NC	-	-	-	-
SC	-	-	-	-
TN	-	-	-	-
TX*	122	1,406	556	2,599
VA	-	-	-	-
Total	**486**	**2,389**	**1,662**	**6,166**

Note:
* eastern Texas

3.2 CO_2 STORAGE IN SALINE AQUIFERS

Deep saline aquifers have the greatest CO_2 sequestration potential since they are the most common and most voluminous type of reservoirs. Two preliminary screening criteria are used to evaluate the CO_2 storage suitability of saline aquifers. The first screening criterion is similar to hydrocarbon reservoirs that the depth of the aquifer needs to be more than 800 m to ensure that the injected CO_2 can be kept at the supercritical phase. Second, the aquifer needs to have good seal properties so that the injected CO_2 can be sufficiently trapped in the aquifer.

If the above two screening criteria are satisfied, the CO_2 storage capacity of a saline aquifer can be calculated using the following formula:

$$Q_{aqui} = V_{aqui} * p * e * \rho_{CO_2} \tag{3.8}$$

where Q_{aqui} = storage capacity of entire aquifer (Mt CO_2)
V_{aqui} = total volume of entire aquifer (km^3)
p = reservoir porosity (%)
e = CO_2 storage efficiency (%)
ρ_{CO_2} = CO_2 density at reservoir conditions (kg/m^3)

If accurate spatial data are available for an aquifer, then the aquifer volume used in equation (3.8) can be calculated as an integral of the surface area and the thickness of the aquifer:

$$V_{aqui} = \sum_i S_i T_i \tag{3.9}$$

where S_i is the area of the raster cell,
T_i is the thickness of the cell,

The term "CO_2 storage efficiency" refers to the fraction of the reservoir pore volume that can be filled with CO_2. For the "closed" aquifer, the storage efficiency is assumed to be 2% (Holloway, 1996).

Figure 3-2 shows the aquifers in the Phase I database that meet the two screening criteria discussed above. Table 3-4 shows the estimates of CO_2 storage capacity in brine aquifers included in the Phase I database. The brine-filled volume of the aquifers in SECARB region is estimated to be 43.5×10^{12} m^3. Most of the areas with brine-filled volume are located in the Gulf Coast Region. If the saline aquifers are assumed to be "closed" then the CO_2 storage efficiency is estimated as 2%, the CO_2 storage capacity in the aquifers would equal to 498 Gt.

Figure 3-2 Aquifers in the Phase I Database Satisfying the CO_2 Storage Screening Criteria

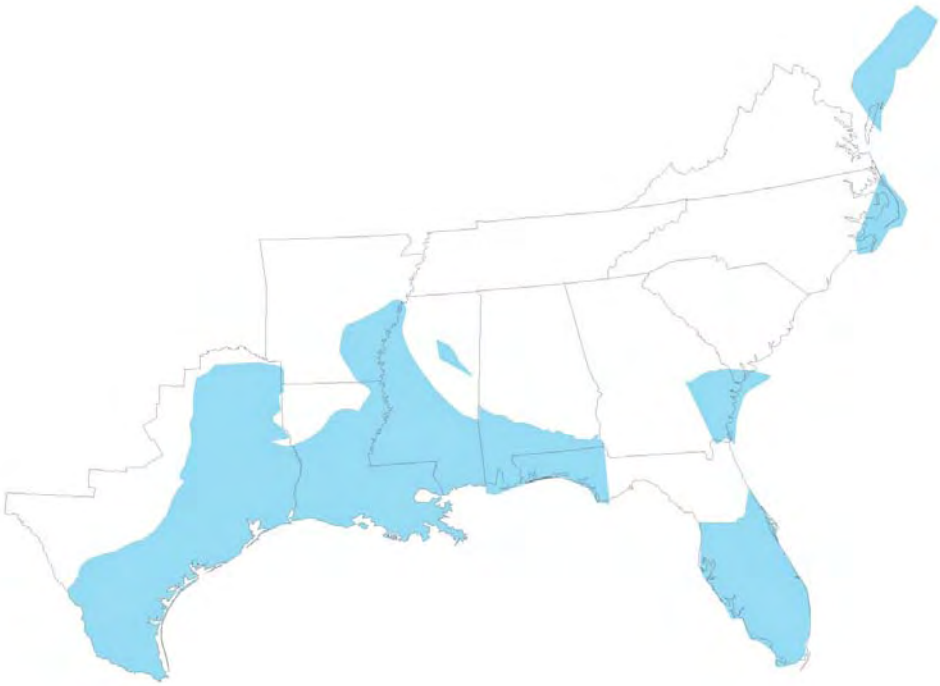


Table 3-4: Estimates of CO_2 Storage Capacity in Brine Aquifers

Basin	Formation	Brine-filled Volume (10^{12} m^3)	Capacity Estimates[1] (Gt)
Gulf Coast Region[2,3]	Upper Cretaceous	17.9	250.9
	Vicksburg & Jackson	5.3	74.2
	Miocene	3.7	51.6
	Subtotal	26.9	376.6
East Texas Basin[4]	Paluxy Sandstone	1.3	10.5
	Woodbine	1.6	14.9
Black Warrior Basin[4]	Pottsville	0.5	5.6
Alabama Gulf Coastal Plain[4]	Tuscaloosa	0.6	4.6
South Carolina Coastal Plain[4]	Cape Fear	1.0	6.5
Central Florida plain[4]	Cedar Keys/Lawson	7.6	55.5
Eastern Costal[4]	Lower Potomac	4.0	23.5
Appalachian Plain[5]		n.a	n.a
Illinois Basin[5]	St. Peter Sandstone	n.a	n.a
Total		**43.5**	**497.8**

Note:
1. CO_2 storage efficiency estimated as 2% and all the aquifer assumed as "colsed".
2. There should be 9 plates in the Gulf Coast Region as to the datasets UTBEG is working for. However, only 3 out of the 9 plates can be provided with the detailed information. The report at this stage only includes these 3 plates.
3. Brine-filled volume data for Gulf Coast Region was obtained from UTBEG's estimates, which assumes an average standstone percentage of 23% an average porosty of 30%.
4. Porosity assumed uniformly distributed as the lower range of well samples.
5. CO_2 storage capacity near zero.

3.3 CO_2 STORAGE IN COALBEDS

The CO_2 storage capacity of coalbeds used for CO_2-Enhanced Coalbed Methane Recovery (ECBMR) operations can be estimated using a methodology based on work by Scott R. Reeves (2003). The original methodology developed by Reeves is useful for estimates of storage capacity at the basin level. In this study Reeves's methodology was adapted for use with data collected at the coalfield level.

The principle idea of the CO_2 disposal in coalbeds is that CO_2 can be adsorbed more readily onto the coal matrix than methane. Therefore, the CO_2-ECBMR operation involves absorbing the injected CO_2 at the expense of methane. The displaced methane can be recovered as a free gas at production wells.

The CO_2 storage potential of a Coalbed results from the two primary mechanisms listed below:

- Storage capacity via methane replacement
  In this process, the primary methane production is assumed to create a voidage in the coal reservoir, which can be replaced by CO_2 up to the original pressure of the coal reservoir.

- Incremental storage capacity via ECBMR
  The secondary methane production through CO_2 injection produces additional methane which enables some additional CO_2 storage capacity.

Coalfields are categorized as either "commercial" or "non-commercial" according to the economic feasibility of producing methane from the field. "Non-commercial" areas are areas where ECBMR and CO_2 storage are technically feasible, yet unprofitable. "Commercial" coalfields are those where ECBMR operations are both technically and financially feasible. "Non-commercial" areas are usually deeper, have thinner coals, and are less permeable than the "commercial" areas. The storage capacity of "commercial" coalfields results from both primary and incremental methane replacement, whereas the capacity of "non-commercial" coalfields is from incremental methane replacement. Accordingly, different parameters are used to calculate the storage capacity of the two types of fields via ECBMR. Section 3.3.1 and Section 3.3.2 discuss details of the methodology for estimating the CO_2 storage capacity for "commercial" methane fields and "non-commercial" methane fields, respectively.

3.3.1 CO_2 Storage in "Commercial" Methane Fields

3.3.1.1 Storage Capacity via Methane Replacement

CO_2 storage capacity available due to methane displacement can be estimated using a coal-rank based ratio that specifies the ratio of the volume of CO_2 that can be injected per volume of CH_4 produced and the primary recovery factor of methane. Due to concerns about reservoir over-pressurization or the ability to gain adequate reservoir access a Voidage Replacement Efficiency Factor (*e*) is used to reflect the percentage of void space occupied by CO_2.

$$Q_{replacement} = r * e * V_{OGIP} * PRF * \rho_{CO_2} \tag{3.10}$$

where $Q_{replacement}$ = CO_2 storage capacity via methane replacement
r = CO_2/CH_4 ratio
e = Voidage replacement efficiency
V_{OGIP} = original gas in place (volume in standard condition)
PRF = primary recovery factor of methane (%)
ρ_{CO_2} = CO_2 density (in standard condition)

According to Reeves (2003), the baseline value of e is 0.75 and the baseline value of PRF is 65%. Column (2) of Table 3-5 gives the CO_2/CH_4 ratio based on the coal rank.

Table 3-5: Coal Rank, CO_2/CH4 Ratio, and ECBM Recovery Factors

(1)	(2)	(3)	(4)
Coal Rank	**CO2/CH4 Ratio**	**ECBM Recovery Factor ("Commercial" Methane Fields)**	**ECBM Recovery Factor ("Non-Commercial" Methane Fields)**
Low-volatile (LV)	1:1	50%	25%
Medium-volatile (MV)	1.5:1	55%	32%
High-volatile A (HVA)	3:1	61%	37%
High-volatile (HV)	6:1	67%	42%
Sub-bituminous (Sub)	10:1	100%	74%

3.3.1.2 Incremental Storage Capacity via ECBMR

Additional CO_2 storage capacity due to the incremental methane production is estimated using a coal-rank based ratio and the ECBMR recovery factor (expressed as a percentage of in-place resource at the start of CO_2 injection).

$$Q_{ECBM} = r * e * V_{OGIP} * (1 - PRF) * ERF * \rho_{CO_2} \tag{3.11}$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery
r = CO_2/CH_4 ratio
e = Voidage replacement and ECBMR efficiency factor
V_{OGIP} = original gas in place (volume in standard condition)
PRF = primary recovery factor
ERF = ECBM recovery factor
ρ_{CO_2} = CO_2 density (in standard condition)

The baseline values for e and PRF are 0.75 and 65%, respectively, while the ERF depends on the coal rank. Column (3) of Table 3-5 gives the ECBM recovery factor for each type of coal ranks.

3.3.1.3 Overall Storage Capacity for "Commercial" Methane Fields

The overall CO_2 storage capacity for "commercial" methane fields is the sum of equation (3.10) and equation (3.11):

$$Q_{CO_2} = Q_{replacement} + Q_{ECBM} \tag{3.12}$$

3.3.2 CO_2 Storage in "Non-Commercial" Methane Fields

"Non-commercial' methane fields, though not economically viable for primary methane production, can generate room for CO_2 storage via CO_2-ECBMR. By substituting a zero for the PRF in equation (3.11), a modified version of the equation (3.13) can be used to estimate the CO_2 storage capacity for "non-commercial" methane fields.

$$Q_{ECBM} = r * e * V_{OGIP} * ERF * \rho_{CO_2} \tag{3.13}$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery

R = CO_2/CH_4 ratio
e = accessible portion of 'non-commercial' area
V_{OGIP} = original gas in place (volume in standard condition)
ERF =ECBM recovery factor (%)
ρ_{CO_2} = CO_2 density (in standard condition)

The default value for *e* for "non-commercial" methane fields is 0.5 (unlike 0.75 for "commercial" fields). Column (4) of Table 3-5 gives the ECBM recovery factor for "non-commercial" methane fields by coal rank, which is less than the corresponding ECBM recovery factor for "commercial" methane fields within each coal rank type.

3.3.3 The "Adopted" Approach to Estimate the CO_2 Storage Capacity for "Commercial" Methane Fields

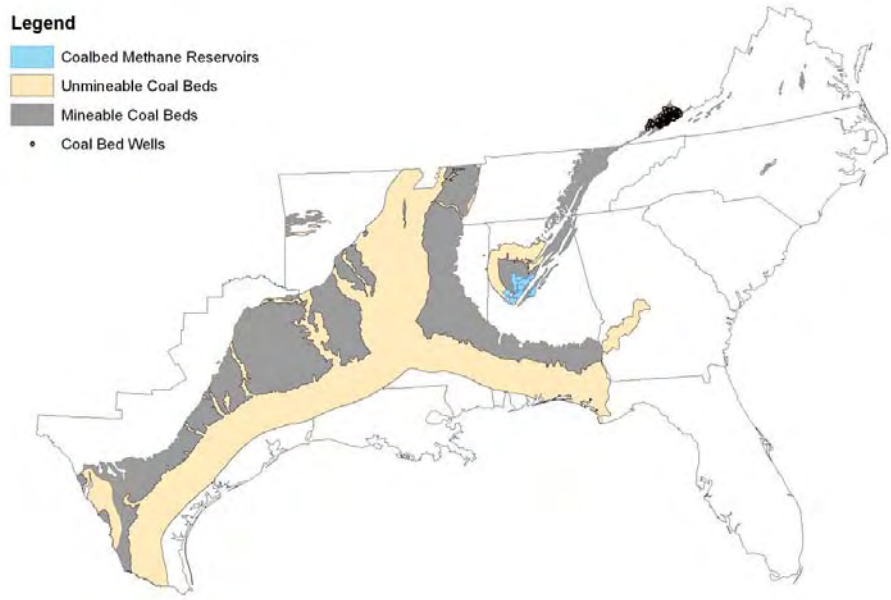
Equations (3.10) and (3.13) use data on the original gas in place in order to estimate the CO_2 storage capacity of methane fields. Just like the case with hydrocarbon fields, however, this data is generally unavailable. For "commercial" methane fields, however, data usually available regard to the cumulative gas production to date. This cumulative gas production data is used as a lower bound of the ultimately recoverable gas—equivalent to the term "V_{OGIP}*PRF" in equation (3.10). By using this lower bound value of the ultimately recoverable gas, equation (3.14) gives a very conservative estimate of the CO_2 storage capacity for "commercial" methane fields. Since little data is available for "noncommercial" methane fields, equation (3.13) is used to estimate the CO_2 storage capacity.

$$Q_{ECBM} = r * e * \tilde{V}_{CGP} * [\frac{PRF + (1 - PRF) * ERF}{PRF}] * \rho_{CO_2} \tag{3.14}$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery
r = CO_2/CH_4 ratio
e = Voidage replacement and ECBMR efficiency factor
$\tilde{V}_{CGP}$ = cumulative gas production (volume in standard condition)
PRF = primary recovery factor
ERF = ECBM recovery factor
ρ_{CO_2} = CO_2 density (in standard condition)

Equation (3.14) was used to estimate the CO_2 storage capacity of "commercial" methane fields using cumulative gas production data. The limitation of this approach was that it underestimated the CO_2 storage capacity for "commercial" methane fields, particularly for those in their early stage of production. Moreover, it could not be applied to "noncommercial" methane fields since these fields have no gas production. In Phase II of the study, effort will be put into collecting original gas in place data for methane fields so that the theoretically more sound formulas (3.12) and (3.13) can be used for both "commercial" and "noncommercial" methane fields.

Figure 3-3: Coalbeds in the Phase I Database



3.3.4 CO_2 Coalbed Storage Capacity Estimate Results

The primary dataset on coalfields used in this study was the USGS coal dataset (see Figure 3-3). This study only considers the unmineable coldbeds as potential CO_2 storage sites. As mentioned in the above discussion, original gas in place information (or cumulative gas production) and coal rank are required to estimate coalbed CO_2 storage potential. Since this information is not in the USGS coal dataset the CO_2 storage capacity of coalbeds throughout SECARB region was not estimated. More detailed data was available from the Alabama Geological Survey (AGS) regarding coalbed methane reservoirs in Black Warrior Basin. This data was used to estimate coalbed CO_2 storage capacity in this limited region.

Table 3-6 summarizes the CO_2 storage capacity for commercial coalbed methane reservoirs in Black Warrior Basin. The total CO_2 storage capacity is estimated to be 346 Mt, of which 257 Mt is via methane replacement and 88 Mt is via ECBMR. Considering that the Black Warrior Basin only represents a small proportion of the coalbeds in SECARB region, the CO_2 storage capacity for the coalbeds in the whole region could be very substantial. However, an accurate estimation of this capacity was not possible at this time given the limited data available.

Table 3-6: Estimates of CO_2 Storage Capacity for Coalbed Methane Reservoirs in Black Warrior Basin, Alabama

Type	Storage Capacity (Mt)
Storage Capacity via Methane Replacement	257
Incremental Storage Capacity via ECBMR	88
Total Storage Capacity	346

Note:
1. The Black River Basin, AL is the only coalbed counted in these totals.
2. Estimates were not done for the entire region due to limited data availability

3.4 REGIONAL CO_2 STORAGE SUMMARY

Table 3-7 summarizes the estimated CO_2 storage capacity for formations in the SECARB Phase I Database. The total CO_2 storage potential in the southeast region is estimated to be 507 Gt. Aquifers makeup the largest portion of this storage capacity, far surpassing the capacity of all other types of geological storage sinks.

Table 3-7: Estimates of CO_2 Storage Capacity for Formations in the Phase I Database

Field Group	Number of Fields	Total Storage Capacity (Gt)
Oil fields with CO_2-EOR potential	378	2.3
Oil fields with CO_2 storage capacity but without EOR potential	108	0.1
Gas fields with CO_2 storage potential	1662	6.2
Coalbeds[1]	n.a	0.3
Aquifers	n.a	497.8
Total		**506.7**

Note:
1. Only the Black Warrior Basin, Alabama was included in this estimate.

4 CO_2 CAPTURE COST ESTIMATION

4.1 METHODOLOGY

The study uses the "*Generic* CO_2 *Capture Retrofit*" spreadsheet prepared by *SFA Pacific, Inc*. as the basis for calculating the CO_2 capture cost for stationary CO_2 sources in the SECARB region (see Figure 4-1). These estimates vary according to three key input variables: (1) the flue gas flow rate (in tonnes per hour); (2) the flue gas composition (volume share or weight share of CO_2 in flue gas); and (3) the annual load factor.

The SFA Pacific spreadsheet provides estimates of capture cost in terms of both CO_2 captured and CO_2 avoided. CO_2 captured is the amount of CO_2 captured by the absorber and kept out of the atmosphere; assumed to be 90% of the CO_2 in the flue gas except for ammonia and gas processing facilities, for which capture factor was assumed to be 100% as their flue gas only consists of pure CO_2. However, since the CO_2 capture process requires energy for purification and compression, the CO_2 avoided term subtracts the CO_2 emitted producing this process energy from the total amount of CO_2 captured. The two terms are used differently in CO_2 sequestration analysis. The CO_2 captured term is used for calculations involving the amount of CO_2 being handled, such as for pipeline transportation costs; while theCO_2 avoided term is used for calculations involving the amount of CO_2 withheld from the atmosphere and therefore eligible for possible CO_2 emissions credits.

According to these two measurements, there are also two definitions on the per unit CO_2 capture cost. To avoid ambiguity, this report uses "CO_2 capture cost" to refer to the capture cost measured in per tonne CO_2 captured while "CO_2 avoidance cost" to refer to the capture cost measured in per tonne CO_2 avoided.

Figure 4-1: SFA Pacific CO_2 Capture Cost Tool

Generic Industrial CO2 Capture for Any Large CO2 Flue Gas Stream

April 2005 working draft by Dale Simbeck at SFA Pacific, Inc

Key assumption is that NG is use as the added energy source to make the steam & power required for CO2 capture
This avoides the loss of capacity or increased off-site CO2 emission of supplying additional electric power
Also the high demand of low pressure stripping steam for the amine CO2 stripper, favors a NG cogen boiler

Color codes: **Primary Inputs** | Secondary Inputs | **Key notes or outupts**

April 13, 2005 Version

Existing Industrial Flue Gas
2,054 metirc ton/h total
48.51 million scf/h

Weight %	Analysis	Volume %
75.00%	N2	75.86%
6.50%	CO2	4.18394545%
5.20%	H2O	8.18%
13.30%	O2	11.77%
0.00%	misc	0.00%
100.00%	Total	100.00%

0.936 million mietic tons per year CO2 (based on below input annual capacity factor)

flue gas normally vented
2,054.0 mt/h
133.5 mt/h CO2

Additional Clean-up & booster Compress

clean flue gas
2,225.6 mt/h
133.5 mt/h CO2

New CO2 Absorber
90%

CO2 depleted Flue Gas Vented
2,105.48 mt/h
13.35 mt/h CO2

NG Energy Required for CO2 Capture steam & power
171.64 mt/h
25.18 mt/h CO2

NG cogen Flue Gas Vented
15% wt% CO2 fuel gas

CO2 rich | amine solvent | CO2 lean

Thus, the CO2 Avoided to the atm
94.98 mt/h CO2

Air → 162.48 mt/h **Natural Gas** →

New NG Boiler 95%

high pressure steam
180.24 mt/h
116.434071 MWt
0.68 MWt/mt

New Backpress Cogen ST/gen

50 psig steam
180.24 mt/h
93.18 MWt if
0.52 MWt/mt

New CO2 Stripper

1.50 tons steam/ton CO2 or
1,200 Btu/lb CO2

122.56 MWt LHV in 100% cogen
418.30 MM Btu/h LHV
464.32 MM Btu/h HHV
9.16 mt/h at
23,000 Btu HHV/lb
0.464 MM scf/h NG at
1,000 Btu/scf HHV

Electric Power via 100% cogen@
17.09 lb steam/kWh cogen

23.25 MWe total
38% 8.83 MWe misc booster fan & amine
62% 14.42 MWe CO2 compressor
MWe flue gas boostet compressor

New CO2 Drying Compress

CO2 Captured
120.16 mt/h or
2,884 mt/d
55 MM scf/d

Indirect offsite CO2 from import power generation **11.63** mt/h CO2 assuming
0.5 mt CO2 per MWh electric

Capital Costs		Unit cost basis at 60	mt/h CO2	cost/size factors	Actual unit cost at 120	mt/h CO2	millions of $ 2003 dollars	Notes
NG boiler	$	15	/lb/hr steam	75%	$13	/lb/hr steam	5.0	
cogen ST gen	$	500	/kWe	75%	$420	/kWe	9.8	
Additional cleanup	$	-	mt/h flue gas	75%	$0	mt/h flue gas	-	if SO2, NOx cleanup
Booster compressor	$	800	/kWe	75%	$672	/kWe	-	needed in many cases
CO2 absorber	$	25,000	mt/h flue gas	75%	$21,015	mt/h flue gas	46.8	
CO2 Stripper	$	200,000	mt/h CO2	75%	$168,124	mt/h CO2	20.2	
CO2 Compressor	$	1,000	/kW	75%	$841	/kW	12.1	
					Total process units		93.9	
General Facilities			**20%**	of process units			18.8	20-40% typical
Eng. Permitting & Startup			**10%**	of process units			9.4	10-20% typical
Contingencies			**10%**	of process units			9.4	10-20% typical
Working Capital, Land & Misc.			**5%**	of process units			4.7	5-10% typical
					U.S. Gulf Coast Capital Costs		136.1	
Site specific factor		**110%**	of US Gulf Coast		**Total Capital Costs**		**149.7**	CA costs are likely higher than Gulf Coast

CO2 Costs				MM $/yr	$/Mscf CO2 Capture	$/mt CO2 Cost Capture	$/mt CO2 Cost Avoided	Notes
		80%	**ann load factor**					**high ann load is critical to cost**
Variable Non-fuel O&M		**1.0%**	/yr of capital	1.5	0.09	1.78	2.25	0.5-1.5% typical
Natural Gas	**$**	**5.00**	/MM Btu HHV	16.3	1.02	19.32	24.44	$4- 7/MM Btu **industrial** rate
Carbon Tax	**$**	**10.00**	/ton Carbon	0.3	0.02	0.30	0.38	all electric power made onsite
Total Variable Operating Cost				**18.0**	1.13	**21.40**	27.08	
Fixed Operating Cost		**5.0%**	/yr of capital	7.5	0.47	8.89	11.25	4-7% typical for refining
Capital Charges		**15%**	/yr of capital	22.5	1.40	26.67	33.74	15-25% typical for private investment
			Total CO2 Costs	**48.0**	**3.00**	**56.97**	**72.07**	including return on investment

Note that the difference between capture and avoided CO2 costs is due to the energy required for CO2 capture steam & power

Source SFA Pacific, Inc. **April 13, 2005**

4.2 CO_2 CAPTURE COST FOR FOSSIL FUEL POWER PLANTS

In order to use the SFA Pacific capture cost tool with fossil fuel power plants, an assumption was made that the CO_2 capture cost for such plants varied only as a function of fuel type, design capacity, and operating factor. A further assumption was made *that power plants would operate at 80% of their designed capacity once the capture facility has been installed.* So for each fuel type the CO_2 capture cost only varies based on the plant's design capacity. The fossil power plants were grouped into three categories by fuel type: coal-fired, gas-fired, and oil-fired.[8] The study only analyzed power plants with a design capacity greater than 100MWe.

Table 4-1 provides summary statistics for the fossil fuel power plants in SECARB region by fuel type. The SECARB region hosts 316 power plants with a design capacity over 100MWe. 109 of these power plants are coal-fired, 186 are gas-fueled, and 21 are oil-fueled. The actual total CO_2 emission for these facilities in year 2000 was 862 Mt, while the adjusted (under the assumption of 80% capacity factor) annual CO_2 emission were 1,402 Mt.

Table 4-1: Fossil Fuel Power Plants by Fuel Type (Design Capacity>100MWe)

Fuel Type	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP
# of Plants	109	186	21
Total Design Capacity (MWe)	115,412	91,822	17,298
2000 Average Operating Factor[a]	0.64	0.30	0.36
Actual 2000 Total CO_2 Emission (Million tonnes)[b]	684	143	35
Ajusted Total Annual CO_2 Emission (Million tonnes)[c]	862	442	99

Note: [a]Weigted (by design capacity) average operating factor
[b]eGRID published 2000 CO_2 emission based on the actual plant operating factor
[c]Estimated plant CO_2 emssion at 80% operating factor

Two key input variables needed to estimate the CO_2 capture cost for the fossil fuel power plants are the flue gas flow rate and the flue gas composition. Since this specific information was unavailable for all of the power facilities, two further assumptions were used to derive reasonable values for these variables. The two flue gas assumptions were that: (*1) the flue gas flow increases linearly with the design capacity of a power plant; (2) within each fuel-type category, the flue gas composition is independent of the design capacity.* Table 4-2 provides the flue gas flow rate and composition used in the data for each type of fossil fuel power plant.

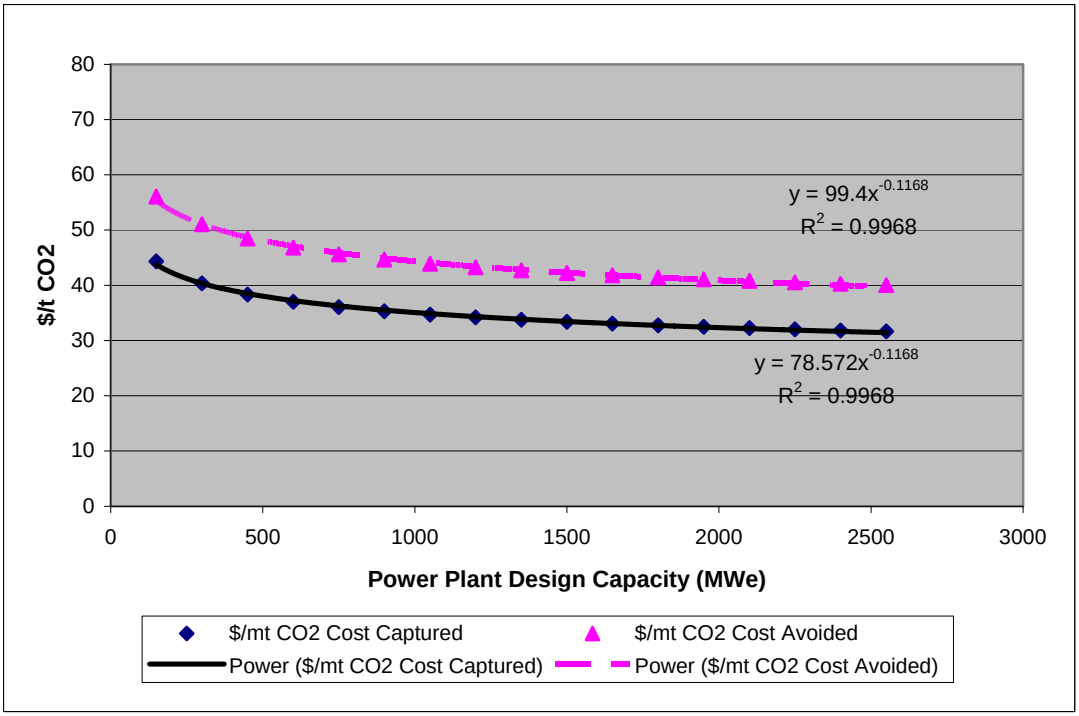
[8] There are few power plants using BL (black liquid) or MWC (municipal waste solid) as primary fuels that have a design capacity slightly above 100 MWe. But the CO_2 emissions from those plants are substantially lower than plants using oil, gas, or coal as primary fuel. Therefore, the analysis is restricted to oil-, gas-, and coal-fueled power plants with design capacity of at least 100MWe.

Table 4-2: Flue Gas Flow Rate and Composition for Coal-, Gas-, and Oil-Fired Power Plants

		Coal-fired PP	Gas-fired PP	Oil-fired PP[1]
Flow Rate (mt/h per 100MW design capacity)		4.06	5.14	4.6
Flue Gas Composition (% in Volume)				
	N_2	73.81%	75.86%	74.84%
	CO_2	15.15%	4.18%	9.67%
	H_2O	8.33%	8.18%	8.26%
	O_2	2.54%	11.77%	7.16%
	misc	0.16%	0.00%	0.08%

Note: [1]Data about oil-fired power plants are MIT Carbon Capture and Sequestration Technologies Program estimates. Others are from SFA, Pacific "*Generic CO_2 Capture Retrofit*" and *"Existing Coal Power Plant CO_2 Migration*" spreadsheets.

Figure 4-2: Estimated CO_2 Capture and Avoidance Costs for Coal-fired Power Plants



Using data derived from the SFA Pacific capture cost estimation tool, Figure 4-2 plots both the CO_2 capture cost and avoidance cost for coal-fired power plants as functions of the plant design capacity. The relationship between CO_2 capture and avoidance costs and the design capacity of the coal-fired power plant can be represented by the following two power functions (with R^2 close to 1):

$$yc = 78.57 * x^{-0.1168} \quad (4.1)$$

$$ya = 99.40 * x^{-0.1168} \quad (4.2)$$

where yc = cost per tonne of CO_2 captured ($/t)
ya = cost per tonne of CO_2 avoided ($/t)
x = design capacity of the coal-fired power plant (MWe)

Taking derivatives on both sides of Equation (4.1), the CO2 capture/avoidance cost elasticity with respect to plant design capacity is $\frac{dy/y}{dx/x} = -0.1168$. In practical terms this means that due to economies of scale the per unit CO_2 capture/avoidance cost decreases by 0.1168 percent for every 1 percent increase in power plant design capacity.

Figure 4-3 and Figure 4-4 plot the relationship between the CO_2 capture and avoidance costs and plant design capacity for gas-fired and oil-fired power plants, respectively. Table 4-3 summarizes the estimated formula for CO_2 capture and avoidance costs as functions of power plant design capacity for each fuel type category.

Table 4-3: Formula and Range of per tonne CO_2 Capture and Avoidance Cost for Power Plants

Category	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP
# of Facilities	109	186	21
Capacity Range	109~3,969 MWe	100~2,315 MWe	112~2951 MWe
$/t CO_2 Captured Formula	$78.57x^{-0.1168}$	$144.87x^{-0.1564}$	$93.34\ x^{-0.1295}$
$/t CO_2 Avoided Formula	$99.40x^{-0.1168}$	$183.27x^{-0.1564}$	$118.08x^{-0.1295}$
Capture Cost Range ($/t CO_2 captured)	$29.8~$45.5	$43.1~$73.5	$33.2~$50.7
Avoidance Cost Range ($/t CO_2 avoided)	$37.8~$57.5	$54.6~$89.2	$42.0~$64.1

Note: x is the power plant design capacity in MWe.

Figure 4-2: Estimated CO_2 Capture and Avoidance Costs Oil-fired Power Plants

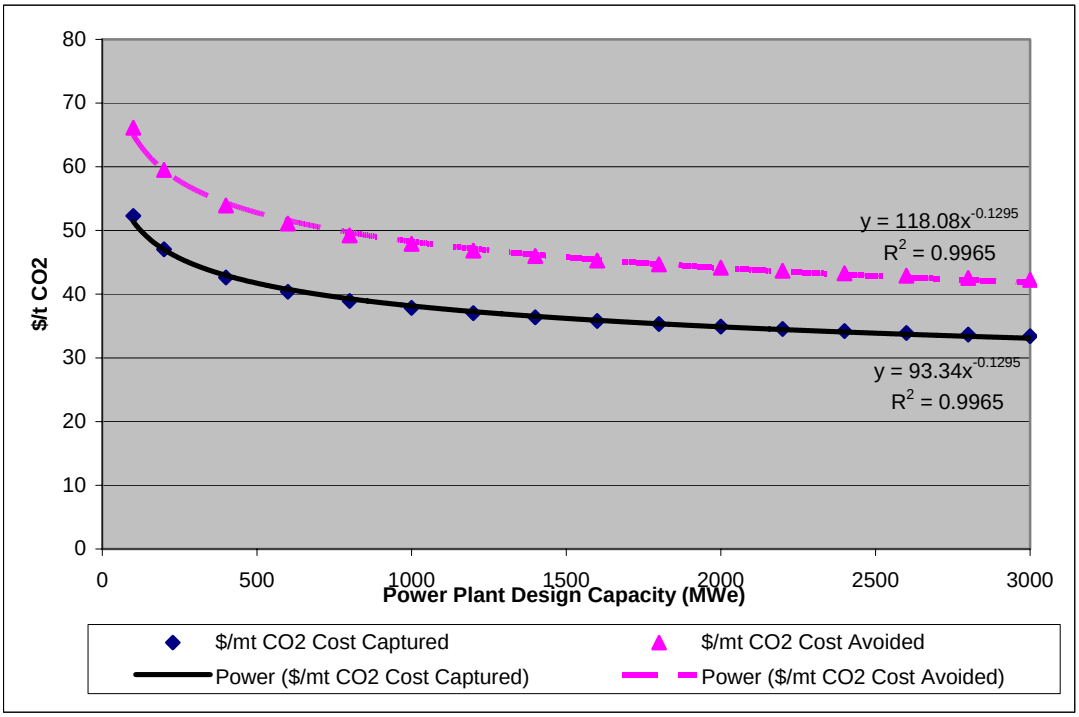
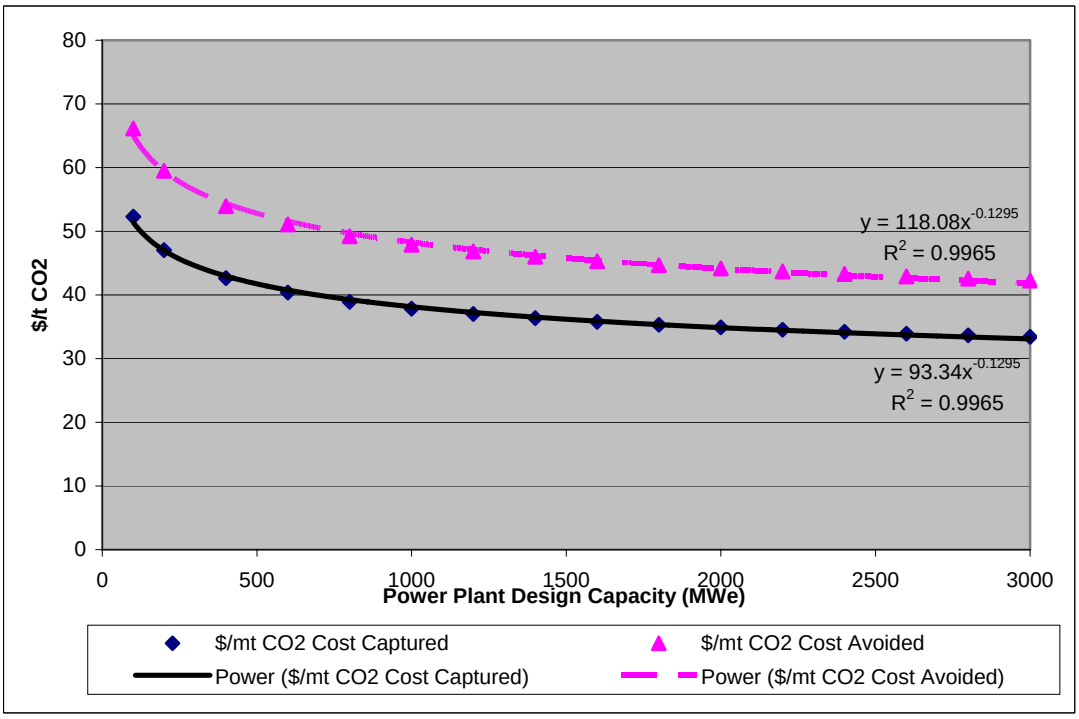


Figure 4-3: Estimated CO_2 Capture and Avoidance Costs for Ammonia Plants



The study applies the above methodology to the fossil fuel power plants with design capacity over 100 MWe in the SECARB region. Column (9) and column (10) in Appendix B present CO_2

capture cost and avoidance cost for these power plants when operated at 80% of design capacity. The capture cost varies from $29.9 per tonne for a 3,970 MWe coal plant to $70.5 per tonne for a 100 MWe gas plant. The avoidance cost varies from $37.8/t to $89.2/t for these same facilities. The capacity-weighted average *capture costs* for all facilities in the SECARB region are $33.8/t, $52.3/t, and $38.4/t for coal, gas, and oil plants respectively. The capacity-weighted average *avoidance costs* for these plants are $42.7/t, $66.2/t, and $48.6/t for coal, oil, and gas plants respectively.

4.3 CO_2 CAPTURE FOR NON-POWER STATIONARY SOURCES

The capture cost estimation tool from SFA Pacific, Inc. was adapted so that it could be used with the non-power sources in the SECARB region. As discussed in Section 4.1, three key variables were needed for the estimation: (1) the flue gas flow rate; (2) the flue gas composition; and (3) the annual load factor. The SECARB database includes seven types of non-power CO_2 sources, but flue gas composition information was only available for the following four facility types: ammonia plants, cement plants, gas processing facilities, and refineries. As a result the analysis was limited to estimating the capture cost for the four facility types listed.

Table 4-4: Assumed CO_2 Emission Factor, Flue Gas Component and Load Factor for Non-power CO_2 Sources

Facility Type	CO_2 Emission Factor	Flue Gas Component (volume)	Annual Load Factor
Ammonia	1.13t CO_2/t Ammonia	100% CO_2	100%
Cement	0.75t CO_2/t Clinker	25% CO_2, 75%N_2	100%
Gas Processing	608t CO_2/mmcfd	100% CO_2	100%
Refineries	9.9t CO_2/BPD	10% CO_2, 90% N_2	100%

Table 4-4 lists the assumed CO_2 emission rates per unit of primary product production, the flue gas composition, and the annual load factor used for each of the four types of non-power CO_2 sources evaluated. The actual flue gas flow rates were unknown, but they were estimated based on plant capacity, the CO_2 emissions factor, and the flue gas composition.

Using these assumptions with the generic SFA CO_2 capture model, Figure 4-5 through Figure 4-8Figure 4-6 plot the per unit CO_2 capture cost and avoidance cost as power functions of facility capacity for each type.

Figure 4-4: Estimated CO_2 Capture and Avoidance Costs for Cement Plants

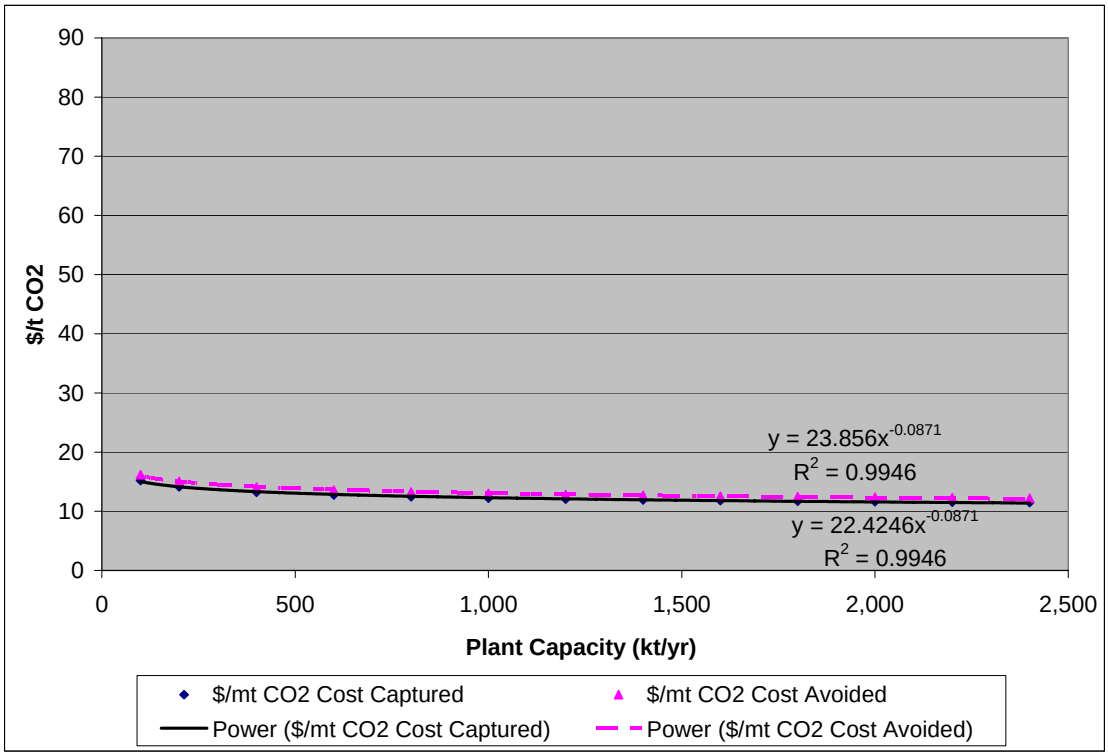


Figure 4-5: Estimated CO_2 Capture and Avoidance Costs for Gas Processing Plants

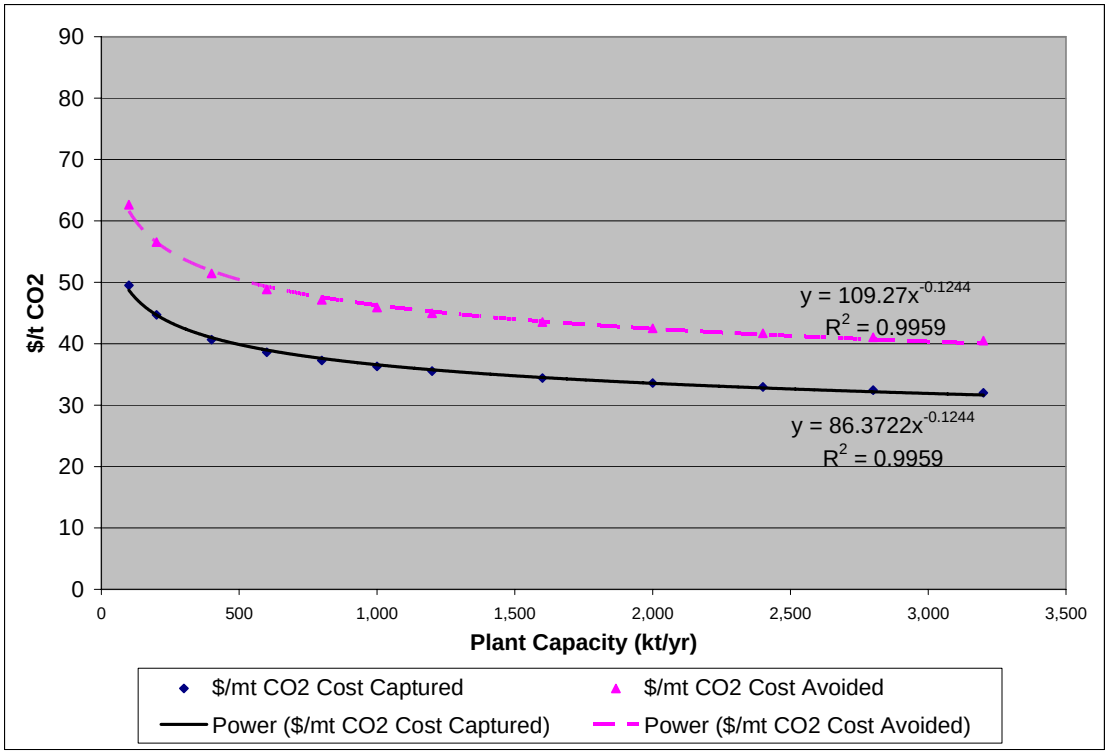


Figure 4-6: Estimated CO_2 Capture and Avoidance Costs for Refineries

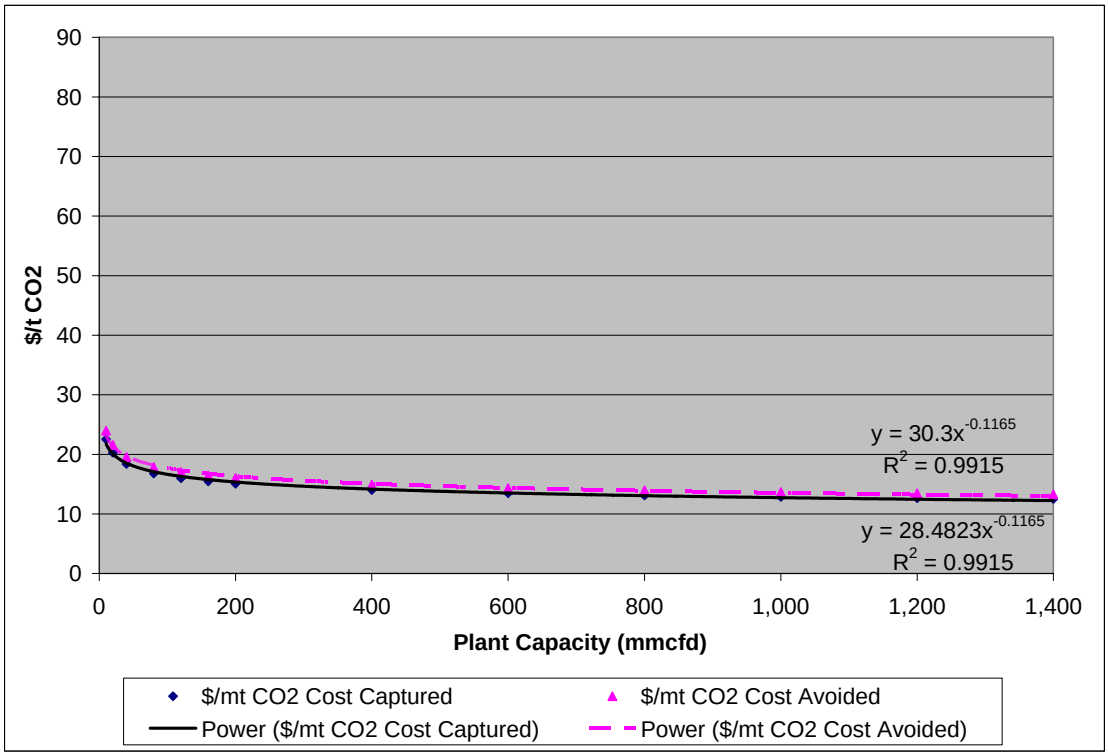
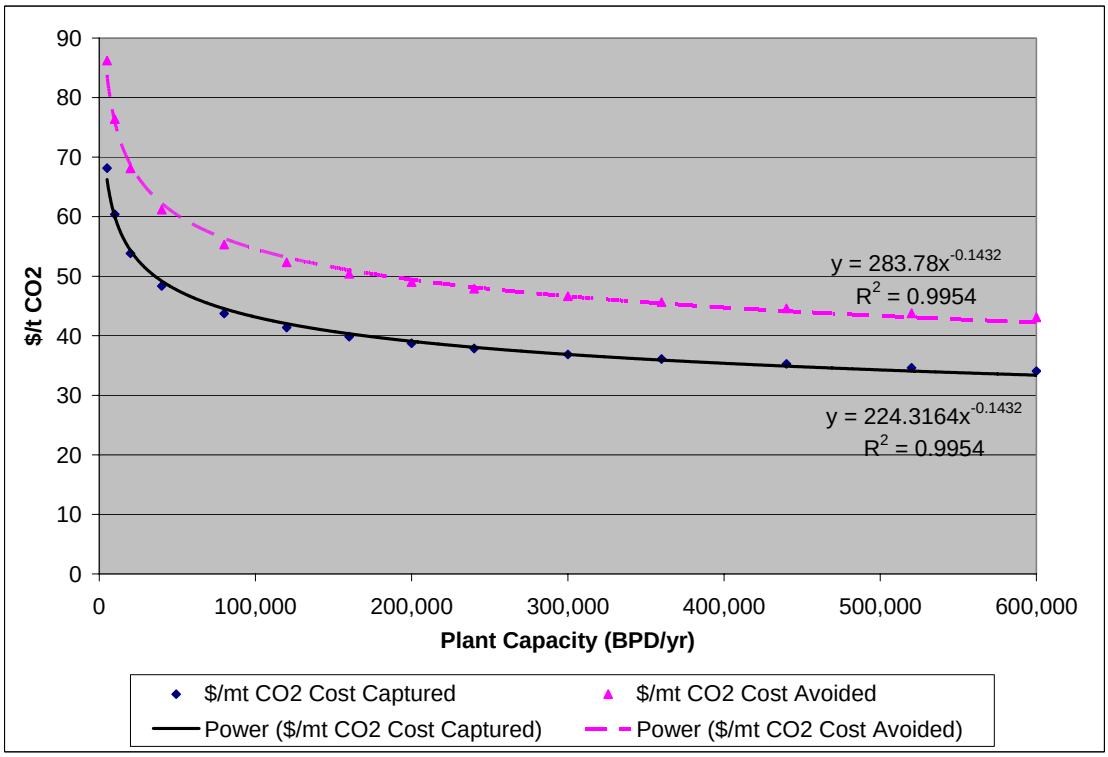


Figure 4-7: Estimated CO_2 Capture and Avoidance Costs for Refineries



Columns (6) and (7) in Appendices B to E show the estimated per tonne CO_2 capture and avoidance costs for the four non-power CO_2 sources in the region[9]. The range of per tonne CO_2 capture and avoidance costs are summarized in Table 4-5 for each category. Since both ammonia and gas processing facilities produce pure CO_2 byproduct streams, CO_2 capture at these facilities only requires gas compression but not gas separation. As a result the CO_2 capture cost at these facilities is less than at either cement or refinery facilities.

Table 4-5: Range of per tonne CO_2 Capture and Avoidance Costs for Four Non-Power Sources[9]

Category	Ammonia	Cement	Gas Processing	Refineries
# of Facilities	13	28	21	41
Capacity Range	90~2,250 kt	100~2,540 kt	300~1,350 MMCFD	5,400~557,000 BPD
Capture Cost Range ($/t CO_2 captured)	$15.2~$11.5	$48.8~$32.6	$14.7~$12.3	$65.5~$33.7
Avoidance Cost Range ($/t CO_2 avoided)	$16.2~$12.2	$61.7~$41.2	$15.6~$13.1	$82.9~$42.7

[9] Gas processing facilities with a design capacity less than 300 mmcfd were excluded.

5 CO_2 PIPELINE TRANSPORTATION COSTS

In cases where the CO_2 source is not co-located with an appropriate sink, large quantities of CO_2 will need to be transported from the source to the sink for sequestration. Underground pipelines are considered the most economical means of transporting such large quantities of CO_2, and a pipeline network would be necessary for carbon sequestration to be feasible. Pipeline construction entails significant capital costs, and this section presents models and methods to estimate the CO_2 pipeline transportation costs based on key pipeline variables.

5.1 TRANSPORT PIPELINE DESIGN CAPACITY

The pipeline design capacity is one of the first design criteria needed for cost estimation. Pipeline capacity is a factor of both pipeline diameter and operating pressure, and pipelines need to be appropriately sized for the CO_2 transportation requirements of their corresponding CO_2 emissions sources. For pipelines originating at refineries, cement plants, the pipeline design capacity is set equal to the 2002 CO_2 emission multiplied by a default capture efficiency (90%). For pure CO_2 streams originating from ammonia and gas processing facilities, the default capture efficiency is set to be 100%. For power plants, the pipeline design capacity is calculated as follows:

$$VC_{CO2} = \frac{VE_{CO2}^{2000}}{OE^{2000}} * CE_0 \tag{5.1}$$

where VC_{CO2} = Maximum CO_2 flow rate (t/yr);
VE_{CO2}^{2000} = 2000 annual CO_2 emission (t);
OE^{2000} = 2000 plant operating factor;
CE_0 = Default CO_2 capture efficiency (90%)

Equation (5.1) gives the maximum CO_2 flow rate (in terms of tonne/yr) for a power plant operating at its full design capacity. The required pipeline capacity is an overestimate since plants usually operate below their maximum design capacity.

Figure 5-1: Maximum Mass CO_2 Flow Rate as a Function of Pipeline Diameter

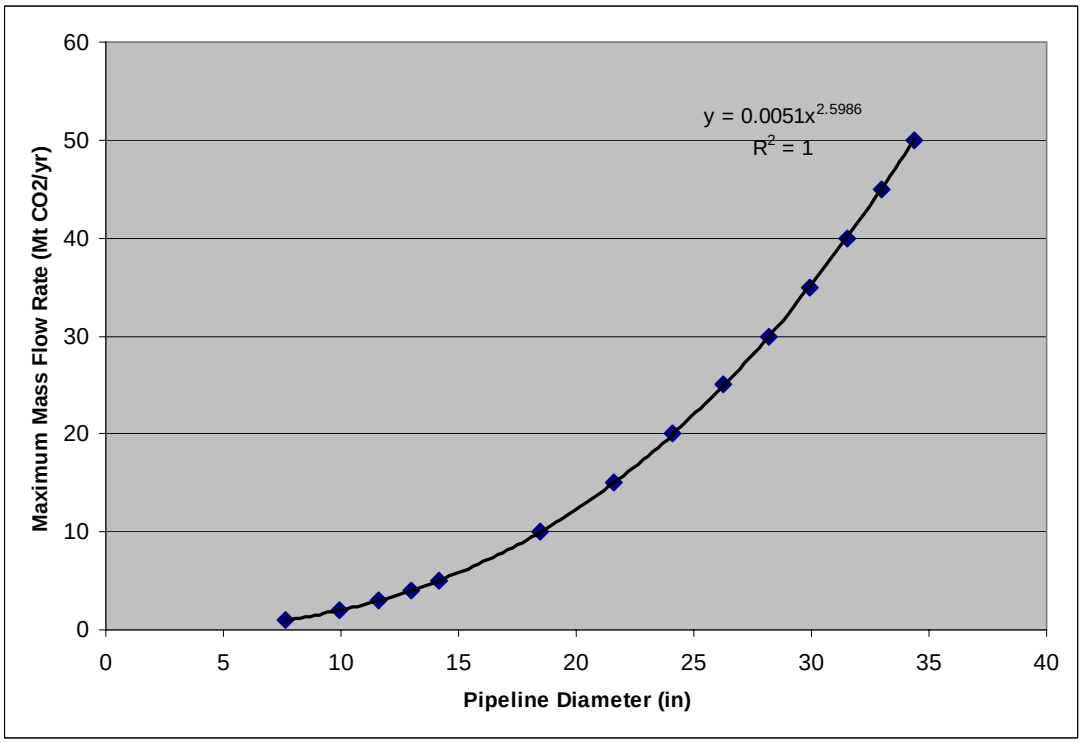


Table 5-1: Pipeline Diameter and the CO_2 Flow Rate Range

Pipeline Diameter (inch)	CO_2 Flow Rate (Mt/yr)	
	lower bound	upper bound
4		0.19
6	0.19	0.54
8	0.54	1.13
12	1.13	3.25
16	3.25	6.86
20	6.86	12.26
24	12.26	19.69
30	19.69	35.16
36	35.16	56.46

5.2 PIPELINE DIAMETER CALCULATION

Figure 5-1 plots the relationship between the maximum mass flow rate and the pipeline diameter. A power function closely models this relationship. In this study it is assumed that standard type gas industry pipelines will be used for CO_2 transportation (True, 1998). Based on the power function in Figure 5-1, Table 5-1 gives the breakdown of the CO_2 flow rate for each pipeline standard diameter within the range from 4 to 36 inches. For any given maximum CO_2 flow rate, Table 5-1 provides a look-up table to determine the appropriate pipeline diameter. Column (5) of the Appendix G provides the corresponding transport pipeline diameter for all sources located in eastern Texas used in the detailed source-sink matching analysis in Section 7.

5.3 OBSTACLE LAYER CONSTRUCTION

In addition to the diameter and capacity, the terrain being traversed by a pipeline is another significant pipeline construction cost variable. These costs vary considerably according to the local terrain and are also affected by the presence of buildings or infrastructure. Pipeline construction is more expensive in hilly areas than on flat plains. In order to reduce complications and costs, a pipeline's route should avoid passing through populated places[10], wetlands, and national or state parks. In order to account for such obstacles in the study, the locations and characteristics of these obstacles were loaded into Geographic Information System (GIS) software. Using the GIS software the costs for traversing such obstacles during pipeline construction were combined into a single obstacle data layer. This obstacle layer reflected three types of general obstacles: land slope, protected areas, and crossings and three line type obstacles: waterways, railroads, and highways.

In order to use this land obstacle data to help calculate optimal pipeline routes, the continuous obstacle data layer was rasterized into 1km by 1km cells. If there were no transportation obstacles contained within a given 1 km^2 cell, then the construction costs of a pipeline traversing the cell was assumed to be "1". From this base case construction cost, relative weights were then assigned to each obstacle in Table 5-2 according to the difficulty of traversing the obstacle. These relative weights were then added to the base case construction cost to form a combined pipeline construction cost factor.

Table 5-2: Estimated Relative Construction Cost Factor

Construction Condition		Cost Factor
Base Case		1
Slope		
	10-20%	0.1
	20-30%	0.4
	>30%	0.8
Protected Area		
	Populated Area	15
	Wetland	15
	National Park	30
	State Park	15
Crossing		
	Wateway Crossing	10
	Railroad Crossing	3
	Highway Crossing	3

Note: The relative weights are calculated as the ratios of the additional construction costs to cross those obstacles and the base case construction cost for an 8 inch pipeline.

The total pipeline construction cost factor for a cell is then the sum of the base case cost factor and the cost factors of all of the obstacles that exist in that cell. For example, the relative cost of

[10] The populated places data is from US Land Use and Land Cover (LULC) data set, which adopts the census definition of "populated place areas" that include census designated places, consolidated cities, and incorporated places within United States identified by the U.S. Bureau of the Census.

a 8 inch pipeline crossing a river in the national park would be 41: 1 (base case) + 30 (national park) + 10 (river crossing). Using the weighted cost layer calculated above, the spatial analysis function in ArcGIS was used to determine the least cost pipeline path for connecting each source and sink.

5.4 PIPELINE TRANSPORT COST ESTIMATION

The model decomposes the pipeline construction cost into two components: the basic pipeline construction cost (diameter-dependent) and the additional obstacle cost (diameter-independent). The basic pipeline construction cost is estimated to be $12,000/in/km[11]. The additional obstacle cost was calculated as the product of the relative weight assigned in Table 5-2 and the basic construction cost of an 8 inch pipeline[12]. The additional obstacle cost does not vary with the pipeline diameter, since the amount of site preparation required for pipeline construction does not vary according to pipeline size. The cumulative pipeline construction cost was then calculated as the sum of the basic construction cost and the additional obstacle cost.

For pipeline operations the pipeline O&M cost were estimated to be $3,100/km per year, regardless of pipeline diameter (Heddle, et.al., 2003). A capital charge of 0.15 was used to annualize the construction cost over the operating life of the pipeline so that the annual pipeline transportation was 0.15 of its construction cost plus the annual O&M cost.

[11] Heddle et al., (2003) estimate that the average pipeline construction cost (including obstacle crossing cost) is $20,989/in/km. For sparsely populated areas average pipeline construction costs are estimated to be $12,400/in/km.

[12] For a 100km 8 inch pipeline with 6 waterway crossings, 1 railroad crossing, 1 highway crossing, and pass 1 km wetland. The estimated construction cost is ($12,000/in/km)*(8 in)*(100km) (base case construction) + $960,000*6 (waterway crossing) + $288,000 (railroad crossing) + $288,000 (highway crossing) + $1,440,000 (wetland crossing) = $17,376,000, which is similar to the average number provided by Heddle: ($20,989/in/km)*(8in)*(100km) = $16,791,200.

6 DISTANCE BASED SOURCE-SINK MATCHING

This section presents the methodology developed to estimate the distance from each CO_2 source to its nearest sink. This methodology was applied to sources and sinks in the SECARB region in order to estimate the transportation requirements for captured CO_2 and to study how these requirements changed as a function of the sink set included in the analysis. The results from this analysis provide estimates of the distance between sources and their closest sinks, but do not consider the transportation costs or optimal pipeline routing when matching, as will be considered in Section 7.

The source-sinking matching in the SECARB region considers 316 power producing CO_2 sources and 103 non-power producing CO_2 sources[13]. Over an assumed 25 year project lifetime, 34 Gt of CO_2 would need to be sequestered[14]. After excluding sinks with less than 5 Mt of storage capacity, the regional CO_2 storage capacity was estimated to be at least 504 Gt. Since the estimated CO_2 storage capacity was significantly larger than the amount of captured CO_2, an assumption was made in this analysis that all sources could be transported and stored in the nearest sinks. The sink storage capacity constraint was considered in the analyses presented in the following section.

Table 6-1 summarizes the CO_2 to be sequestrated for the sources and CO_2 storage capacity for the sinks in the SERCARB region. Figure 6-1 presents a map of all the sources and sinks considered in this section.

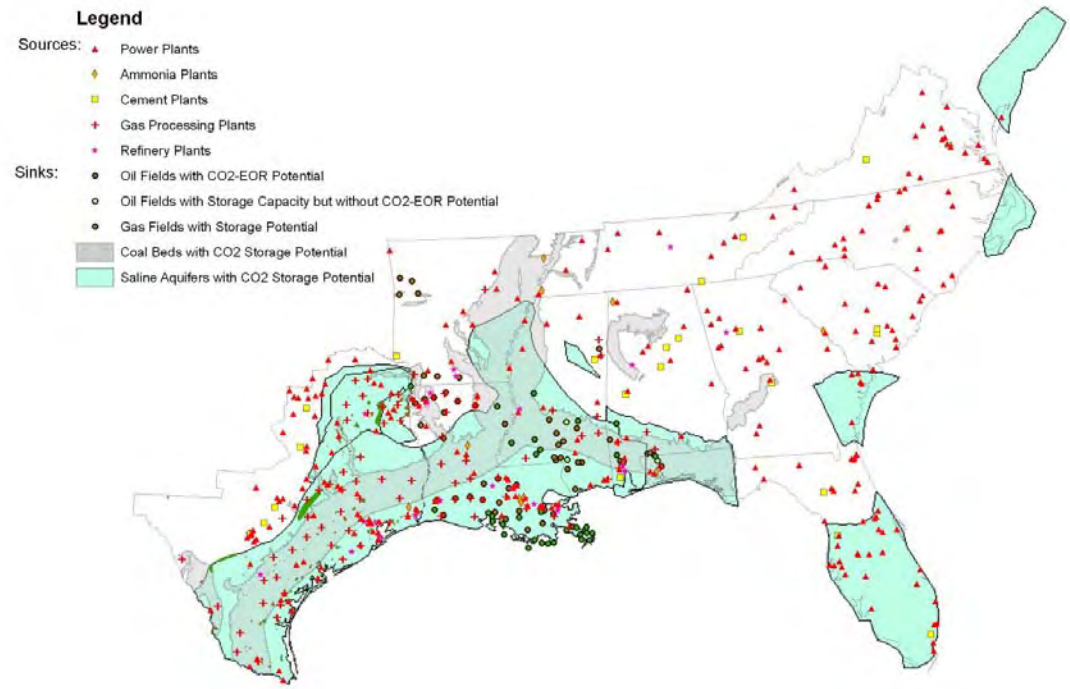
Table 6-1: CO_2 Capture Capacity for Sources and Storage Capacity for Sinks Considered in the Matching Analysis

Field Group		Number of Fields	CO_2 Capture Capacity (Gt)[1]	CO_2 Storage Capacity (Gt)
Sources	Power Plants[2]	316	31.6	-
	Non-power Stationary Sources[3]	103	2.4	-
	Total	419	**33.9**	**-**
Sinks[4]	Oil Fields w/ EOR potential	74	-	1.9
	Oil Fields w/o EOR potential and Gas Fields	246	-	3.6
	Coalbeds[5]	n.a	-	0.3
	Aquifers	n.a	-	497.8
	Total			**503.6**

Note:
1. Project lifetime 25 years.
2. Only design capacity over 100MWe included.
3. Only includes ammonia, cement, gas processing, and refineries. Also, for gas processing facilities, those with design capacity less than 300 mmdcfd were excluded.
4. Only CO_2 storage capacity over 5 Mt included.
5. Only coalbed methane data in Black Warrior Basin, Alabama from AGS included in the estimate.

[13] See note 2 and 3 of Table 6-1 for criteria used in screening CO_2 sources.
[14] The CO_2 emission was estimated under the assumption of 80% capacity factor for power plants and full production capacity factor for non-power stationary CO_2 sources. A capture efficiency of 90% is assumed for all the sources except for the pure CO_2 sources(ammonia and gas processing).

Figure 6-1: CO_2 Sources and Sinks considered in Straight-line Distance Matching



6.1 METHODOLOGY

This analysis was used to calculate the straight-line distance from each CO_2 source to the nearest sink and provides an estimate of the CO_2 storage potential within a given distance from the CO_2 sources. The analysis was performed using GIS software tools. The Straight-Line Distance function in the spatial analyst extension of ArcMap was used to calculate the shortest straight-line distance from each source in the study area to the nearest geological sink. The output from this analysis was a raster layer where the cell values were equal to the straight-line distance from each cell to the nearest sink.

6.2 STRAIGHT-LINE DISTANCE BASED SOURCE-SINK MATCHING IN SECARB REGION

Four hundred and nineteen CO_2 sources, including 316 power plants, 13 ammonia plants, 28 cement plants, 21 gas processing plants and 41 refineries, were included in the source-sink matching analysis. The annual amount of captured CO_2 from these sources was estimated at 1.4 Gt.

The distance matching analysis was performed for each of the five groups of eligible sinks: (1) oil and gas fields with EOR potential; (2) all oil and gas fields; (3) coalbeds; (4) saline aquifers; and (5) all geological sinks.

Table 6-2, Figure 6-2 and Figure 6-3 show the results for the source-sink matching in the SECARB region. Appendix B to Appendix F present the detailed results with the straight-line distance to nearest EOR site, oil & gas field, coalbed and aquifer, respectively, for each CO_2 source. It is interesting to note that the cases with the hydrocarbon reservoirs needed much larger transportation distances than the cases with the saline aquifers and coalbeds. If all of the sinks can be included in the analysis, then all the CO_2 sources can be matched to a sink within 250 km from the source.

Table 6-2: Annual CO_2 Storage Capacity (Mt/y) of Various Sinks by Straight-line Distance from Source to Sink

Sink Type	Straight Line Distance from Source to Sink		
	50 km or less	100 km or less	250 km or less
Oil & Gas Fields with EOR Potential	349	484	675
Oil & Gas Fields	507	598	726
Coalbeds	606	856	1,190
Aquifers	794	867	1,125
All Sinks	**972**	**1,143**	**1,357**

Note:
1. The total annual CO_2 storage rate was 1, 357 Mt.
2. Sinks with less than 5 Mt storage capacity were excluded from the analysis.

Figure 6-2: Marginal Straight-Line Distance to Nearest Sink (4 cases) by Annual Storage Rate for CO_2 Sources

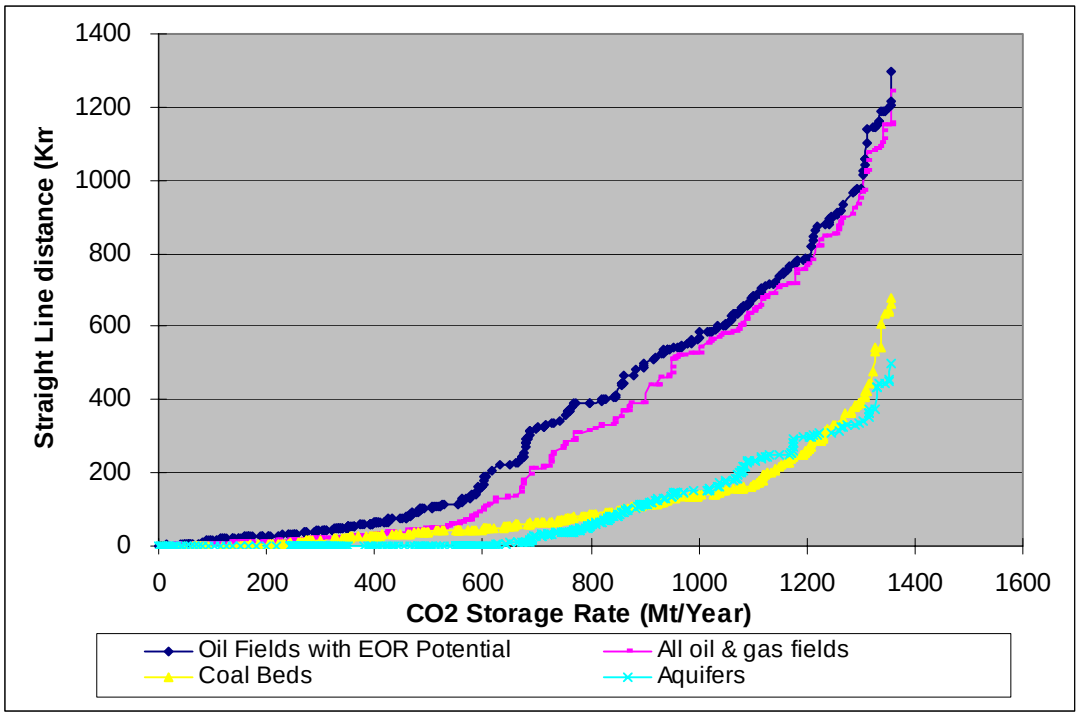
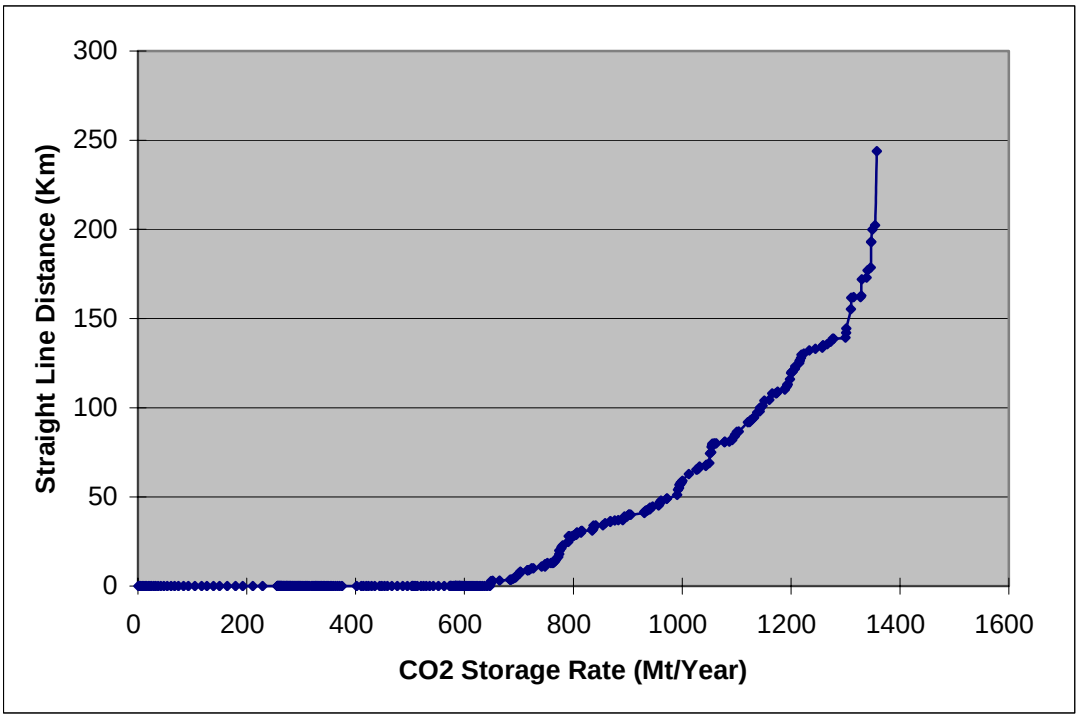


Figure 6-3: Marginal Straight-Line Distance to Nearest Sink by Annual CO_2 Storage Rate for CO_2 Sources



6.3 SOURCE-SINK MATCHING DISCUSSION

This section presented results from analyses of the straight-line distance between sources and sinks in the SECARB region. While these results are not an accurate representation of the total cost for CCS within the SECARB region, the results do provide a sense of the CCS transportation requirements for cases where there is insufficient information for a full cost evaluation. If EOR sites in the SECARB region were the only sinks available for sequestration, only half of the CO_2 sources by volume could be matched with a sink that were less than 250 km from the source. And for some sinks in VA and NC, the closest EOR sinks were over 1000 km far away. If all sink types were considered for sequestration, however then all of the CO_2 sources could be matched with appropriate sinks could be matched to sinks within 250 km from the source. More than 70% of the sources (by volume) would find their nearest sinks within 50 km from the source. Around 40% of the sources were actually co-located with an appropriate sink, which was usually a saline aquifer. The actual transportation distance requirements would be larger if sink capacity constraints and transportation obstacles were considered, and these analyses are presented in the following section.

7 LEAST-COST PATH SOURCE-SINK MATCHING AND FULL COSTING ANALYSIS (EASTERN TEXAS)

In this section estimates of the total cost of carbon capture and sequestration are calculated by combining the methods presented in sections 4 and 5 for calculating capture and transportation costs with a more detailed method of calculating pipeline paths. Whereas in the previous sections pipeline paths were calculated according to the shortest distance, in this section the pipeline paths were calculated using an iterated GIS-based least-cost path algorithm that considers typography, social, and political data for the study region. This more cumulative sequestration cost analysis, which consists of capture, transport, and injection costs, were performed for eastern Texas due to the limited availability of detailed data for the entire SECARB region. As more detailed data is collected for the other SECARB states in Phase II this least-cost path source-sink matching and full capture cost analyses will be extended to the entire SECARB region.

7.1 METHODOLOGY

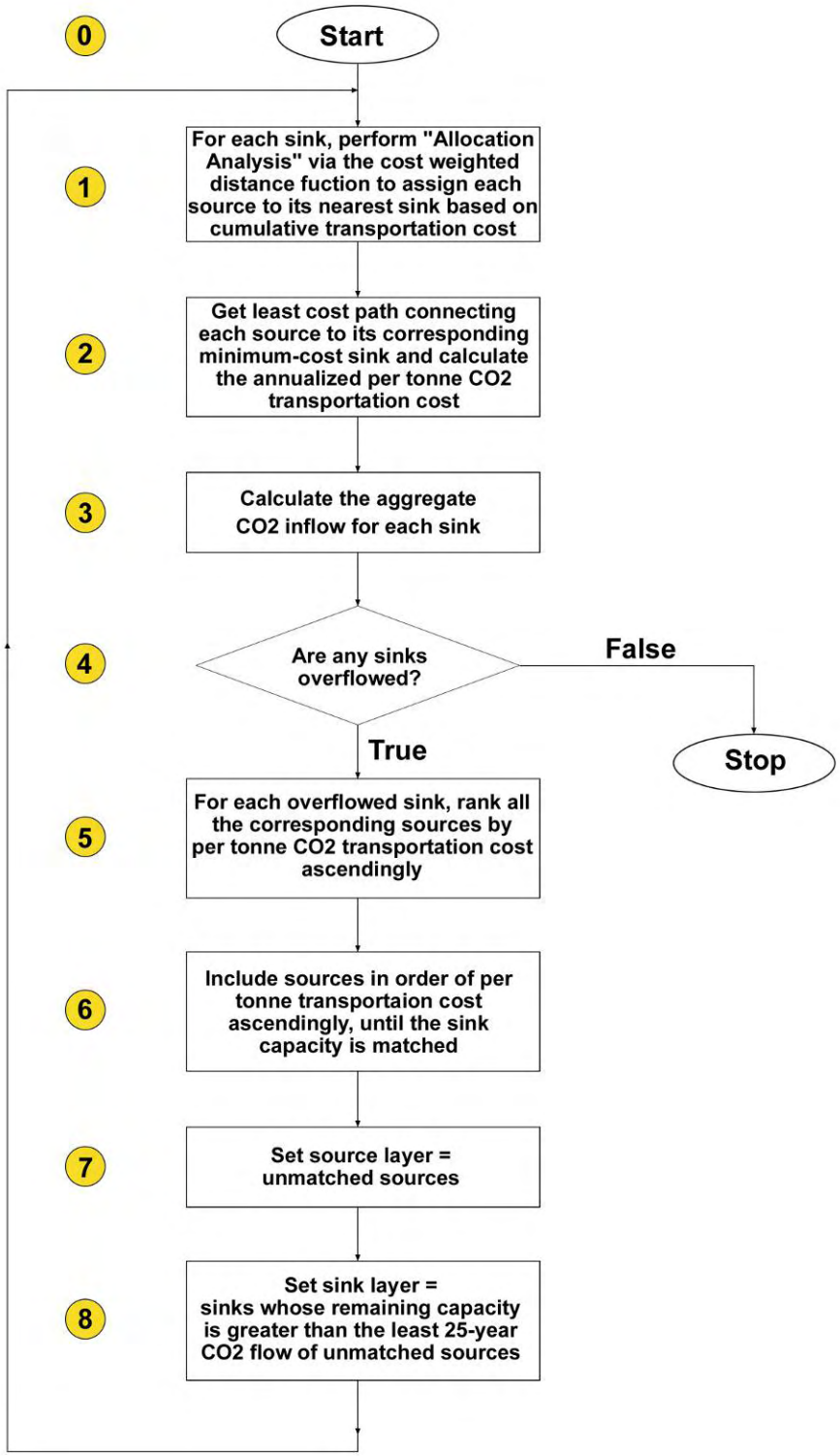
In contrast to the distance-based matching analysis performed in section 6, this section presents a method of matching sources and sinks based on least total cost. For this analysis each CO_2 source in eastern Texas was linked to a least cost geological sink based on a least-cost transportation route and an estimated injection cost. The linking algorithm also considered reservoir storage capacity and ensured that each linked sink had sufficient storage capacity for all sources matched with it.

The list of sinks used in the matching analysis included hydrocarbon fields with EOR potential, hydrocarbon fields without EOR potential and saline aquifers[15]. While all of these sinks are suitable for sequestration, the cost of sequestration varies for each sink type. The sinks can be grouped into two basic categories: (1) oil fields with EOR potential that are eligible for oil production credits, and (2) non-EOR hydrocarbon fields and saline aquifers that will have to bear the full cost for CO_2 transportation, compression, and injection. Projects were assumed to have 25 year lifetimes, and sources were only matched up to a sink if its remaining storage capacity exceeded the source's 25-year CO_2 flow.

The linking analysis was conducted in two stages: first considering cheaper sinks before proceeding to sinks with higher storage costs. In the first iteration only EOR sites were included as potential sinks, since they would purchase CO_2 from a provider. After allocating the EOR storage capacity to the appropriate sources, the matching algorithm was rerun with the regular hydrocarbon fields and saline aquifers included in the list of potential sinks. An algorithm flow chart is shown in Figure 7-1.

[15] There is no coalbed methane fields included in the sink set for eastern Texas.

Figure 7-1: Flow Chart of the Least-cost Path CO_2 Source-Sink Matching Algorithm



An iterative algorithm was developed to "optimize" the source-sink matching using the ArcGIS *"spatial analysis tool."* Figure 7-1 depicts the flow chart for this iterative matching algorithm using an example of stage 1 matching process when only transportation cost needs are considered:

- At the first step, the *"Allocation Analysis*" function was used to assign each source to its nearest sink based on the transportation cost as calculated in section 5. The allocation result provided a picture of how the sources would be optimally linked to the sinks within the region if there were no restriction on the storage capacity of each sink.

- In the second step, the *"Least Cost Path"* function was used to get the least cost path linking each source to its corresponding least-cost sink. Using the transportation cost estimation algorithm discussed in section 5.4, the capital cost and maintenance cost were calculated as the cost per tonne of CO_2 transported.

- In the third step, the 25-year CO_2 flow volumes from all sources assigned to each sink in step 1 were summed up to get the aggregate 25-year CO_2 flow.

- In step 4, the aggregate 25-year CO_2 flow calculated in step 3 was compared to the estimated CO_2 storage capacity for each sink.

    - If none of the sinks were over capacity, then the iteration ended with an approximately "optimal" matching outcome.

    - If some of the sinks were over capacity, the program continued to step 5 to evaluate which sources should be excluded from the "overfilled" sinks.

- In step 5, for each "overfilled" sink, the associated sources were ranked in ascending order by the transportation cost per tonne of CO_2.

- In step 6, the ordered sources for each "overfilled" sink were re-added to the sink's "matched source set" in ascending order of CO_2 transportation cost. Sources were added until the sink's remaining storage capacity was less than the 25-year CO_2 flow of the smallest source assigned to this sink in step 1 that had not been added to the "matched source set."

- In step 7, all of the sources that were not included in "matched source set" for any sinks were set as the new "source layer".

- In step 8, all sinks with remaining CO_2 storage capacity exceeding the 25-year CO_2 flow of the smallest source in the new "source layer" defined in step 7 was set as the new "sink layer". The program then went back to step 1 and reran the source-sink matching algorithm until all sources were matched and no sinks were "overfilled."

While the matching algorithm described above was capable of determining a near optimal solution, the algorithm might not find the absolute least cost solution. Since the algorithm did

not evaluate whether assigning one source to a relatively more costly sink could reduce overall system cost, the optimization was not truly optimal. Even though the matching algorithm used in this analysis was not "truly optimal," this is a typical problem in system optimization and the algorithm produces a reasonable result. The complexity of a "true" system optimization algorithm was beyond the scope of the Phase I analysis, but efforts in Phase II will focus on improving the algorithm functionality.

7.2 LEAST-COST PATH SOURCE-SINK MATCHING

This analysis was conducted using the CO_2 sources located in eastern Texas which included power plants, ammonia, cement, refineries, and gas processing plants. Power plants with less than 100MWe design capacity and non-power plants with less than 5 Mt of CO_2 emissions over the 25 year study period were exclude from the analysis. In total, 130 sources were included in the source-sink matching process. The project lifetime was assumed to be 25 years. Total source CO_2 flow over 25 years was about 8.9 Gt. Table 7-1 shows the CO_2 flow rate by source type.

Table 7-1: CO_2 Flow Rate by Plant Types, eastern Texas

Plant Type	Number of Plants	Annual CO_2 Flow (Mt)	25-year CO_2 Flow (Mt)
Power Plant	98	316	7,904
Ammonia	1	0	6
Cement	8	7	166
Gas Processing	8	3	82
Refinery	15	31	771
All sources	130	357	8,929

The potential sink list included EOR oil reservoirs[16], gas reservoirs, and saline aquifers with a CO_2 storage capacity of at least 5 Mt.

Eastern Texas has 122 oil fields with a total CO_2 storage capacity of 1.4 Gt. 109 of these fields, or 1.2 Gt of the capacity, were favorable for miscible EOR operations. 13 of the fields, or 0.2 Gt of the capacity, were categorized as immiscible EOR reservoirs. After screening out fields with storage capacity less than 5 Mt, 34 fields with an overall storage capacity of 1.2 Gt were included in the analysis. One hundred and one gas fields with totaled CO_2 storage capacity of 1.7 Gt were also included in the analysis after screening out those with storage capacity below 5 Mt.

The total CO_2 storage capacity for oil and gas fields included in the analysis was 2.9 Gt. Since the total 25 yr CO_2 flow rate from all sources was 8.9 Gt, aquifers were also included as potential sinks. Saline aquifers in eastern Texas, including those in eastern Texas Basin and Gulf Coast Region, were estimated to have a CO_2 storage capacity of 196 Gt.[17]

[16] There is no oil reservoir with CO_2 storage potential but no EOR potential in eastern Texas.
[17] The CO_2 storage capacity in east Texas Basin is estimated to be 26 Gt. The Gulf Coast aquifer plates cover portions of Texas, Louisiana, and Mississippi and have an estimated storage capacity of 377 Gt (see Table 3-6). We are unable to divide this storage capacity along state lines, although we can estimate storage capacity in each state

The cost surface used in this study is an aggregate transportation cost layer generated using the method presented in section 5. The cell value in this layer was calculated using the obstacle cost factor plus the construction cost factor calculated for a standard 8-inch pipeline. The raw data sources for the obstacle types are listed in Table 7-2.

Table 7-2: Data Sources of Transportation Barrier Layers

Barrier Layer	Raw Data Source
Slope	ESRI Digital Elevation Model Data
Populated area	ESRI Data & Maps
Wetland	USGS LULC Data
National Park	ESRI Data & Maps
State Park	ESRI Data & Maps
Waterway	ESRI Data & Maps
Railway	ESRI Data & Maps
Highway	ESRI Data & Maps

based on the land area. The Texan aquifers occupy 45% of the regional aquifers by area, and our estimate of 170 Gt of storage capacity assumes uniform distribution of the storage capacity over the aquifer area.

Figure 7-2: CO_2 Sources and Sinks shown over the Transportation Cost Surface, eastern Texas

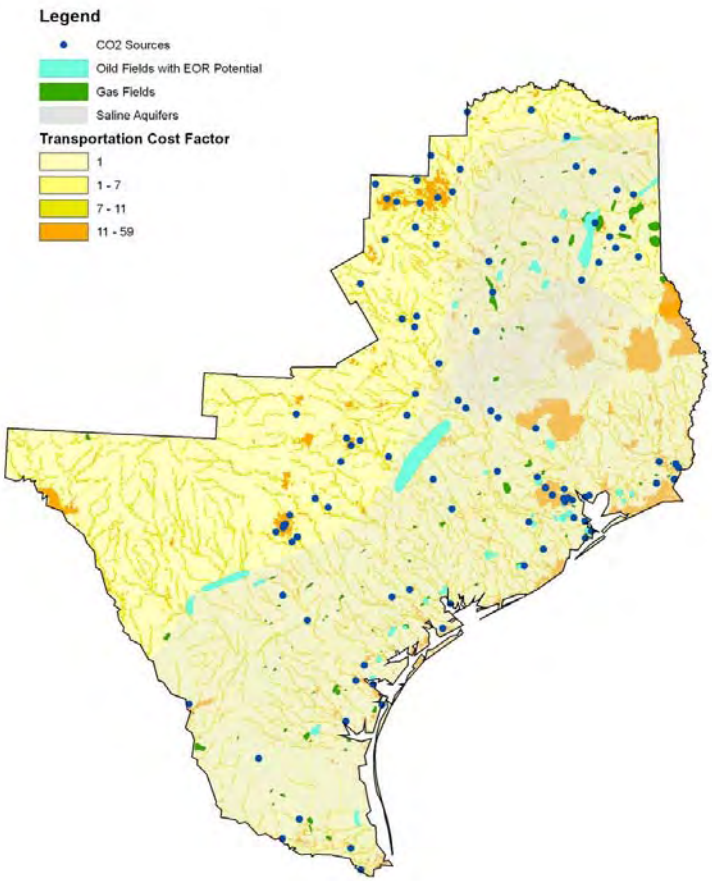


Figure 7-2 shows all the CO_2 sources, geological sinks, and transportation cost factors used in the least-cost path analysis. After the first stage of the source-sink matching analysis, 29 sources were linked to EOR sites, while 101 sources remained unmatched. Figure 7-3 and Table 7-3 present the results of the first stage analysis linking CO_2 sources to oil fields with EOR potential in eastern Texas. Figure 7-4 plots the marginal transportation distance by annual CO_2 storage rate for those sources transported to the oil fields with EOR potential. Figure 7-5 plots the marginal transportation cost by annual CO_2 storage rate for sources transported to EOR oil fields.

Figure 7-3: Source-sink Matching to Oil Fields with EOR Potential, eastern Texas

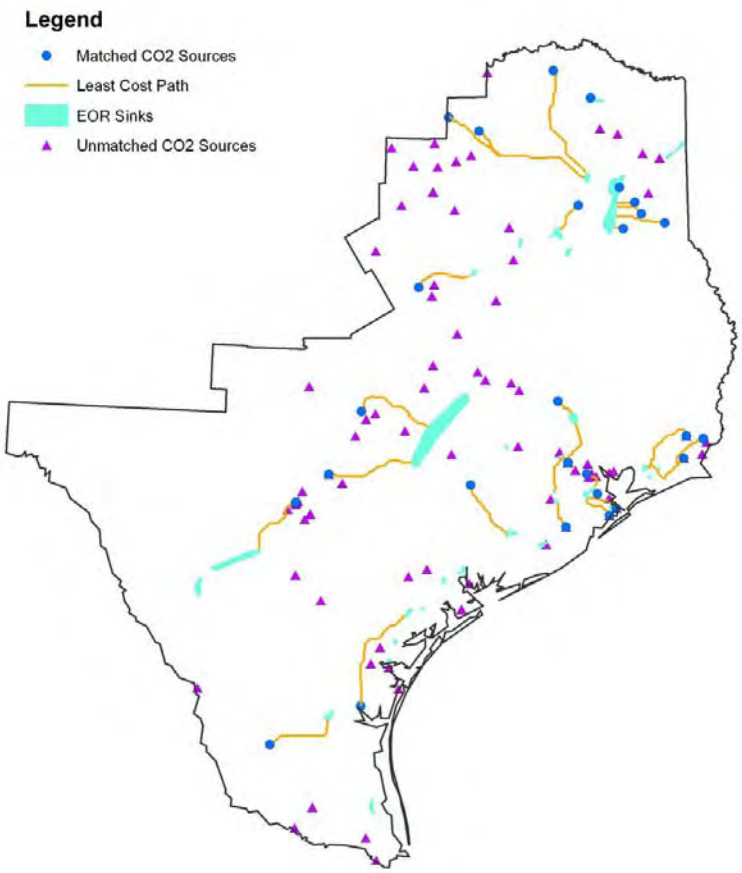


Table 7-3: Least-Cost Path analysis for CO_2 Sources Transported to Oil Fields with EOR Potential, eastern Texas

Company Name	Facility Name	Plant Type	Annual CO2 Flow (Mt)	Destination[1]	Transportation Distance (km)	Pipeline Diameter (Inch)	Construction Cost (M$)	Crossing Cost(M$)	Annual O&M Cost (M$)	Transportation cost ($/t)
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	0	6	0.00	0.00	0.00	0.00
Texas Genco	WEBSTER	Power Plant	1.90	O358	6	12	0.86	0.19	0.02	0.09
AEP NUGs	MARTIN LAKE	Power Plant	18.25	O80	30	30	10.80	0.29	0.09	0.10
Southwestern Electri	KNOX LEE	Power Plant	1.87	O80	19	12	2.74	0.19	0.06	0.27
Entergy Gulf States	LEWIS CREEK	Power Plant	2.18	O59	22	12	3.17	0.58	0.07	0.29
TXU Generation LLC	RIVER CREST	Power Plant	0.50	O319	2	8	0.19	0.86	0.01	0.33
VALERO REFINING	CO T	Refinery	1.83	O135	37	12	5.33	1.25	0.11	0.60
Sweeny Cogeneration	SWEENY COGENE	Power Plant	1.67	O322	32	12	4.61	1.82	0.10	0.64
Texas Genco	DEEPWATER	Power Plant	0.86	O358	26	8	2.50	2.02	0.08	0.88
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	12	6	0.86	2.02	0.04	1.10
Marathon Ashland Pet		Refinery	0.64	O135	37	8	3.55	1.25	0.11	1.30
BP Amoco	POWER STATION	Power Plant	0.48	O135	34	8	3.26	0.29	0.11	1.33
La Gloria Oil & Gas		Refinery	0.49	O92	38	8	3.65	2.69	0.12	2.17
Garland City of	RAY OLINGER	Power Plant	1.57	O136	136	12	19.58	1.54	0.42	2.29
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	56	6	4.03	2.11	0.17	2.57
Motiva Enterprises L	PORT ARTHUR RE	Power Plant	0.36	O8	65	6	4.68	0.86	0.20	2.87
Copano Energy LLC	Houston Central	GAS PROC	0.38	O200	73	6	5.26	1.92	0.23	3.40
Exxon Mobil	BAYTOWN TURBI	Power Plant	0.59	O59	56	8	5.38	7.30	0.17	3.52
Exxon Mobil	EXXON MOBIL CC	Power Plant	0.57	O59	56	8	5.38	7.30	0.17	3.63
Panda Energy	LAMAR POWER PI	Power Plant	1.05	O136	135	12	19.44	3.65	0.42	3.68
CEMEX		Cement	0.61	O115	96	8	9.22	5.47	0.30	4.09
TXU Generation LLC	COLLIN	Power Plant	0.67	O136	170	8	16.32	2.11	0.53	4.92
University of Texas	UNIVERSITY OF T	Power Plant	0.28	O115	99	6	7.13	2.21	0.31	6.00
ExxonMobil Corp.	King Ranch	GAS PROC	0.51	O25	129	8	12.38	6.62	0.40	6.42
E I DuPont De Nemour	SABINE RIVER W(	Power Plant	0.27	O8	99	6	7.13	3.65	0.31	7.05
Air Liquide America	SABINE COGEN LI	Power Plant	0.27	O8	99	6	7.13	3.65	0.31	7.20
Terra Industries, In		Ammonia	0.26	O8	74	6	5.33	6.24	0.23	7.44
Occidental Chemical	DEER PARK PLAN	Power Plant	0.34	O313	54	6	3.89	12.38	0.17	7.65
El Paso Field Servic	Thompsonville	GAS PROC	0.16	O317	80	6	5.76	1.54	0.25	8.18

Note: 1. Destination Code O represents Oil fields; the number represents the ID field in the SECARB sink database.

Figure 7-4: Marginal Transportation Distance by Annual CO_2 Storage Rate in Oil Fields with EOR Potential, eastern Texas

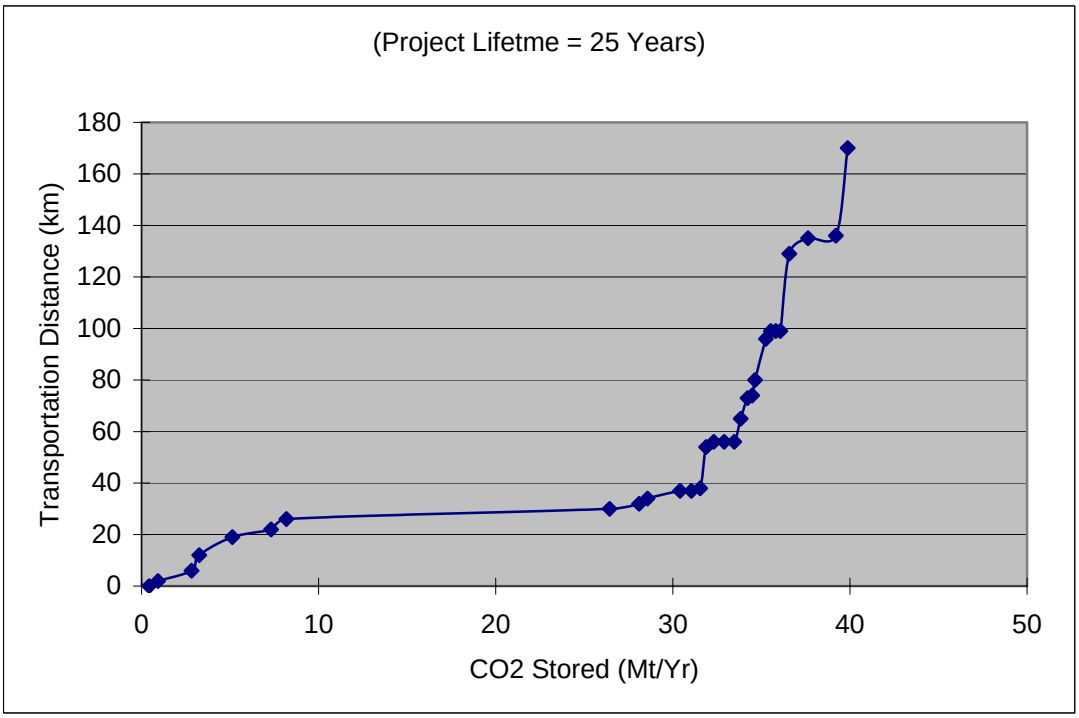
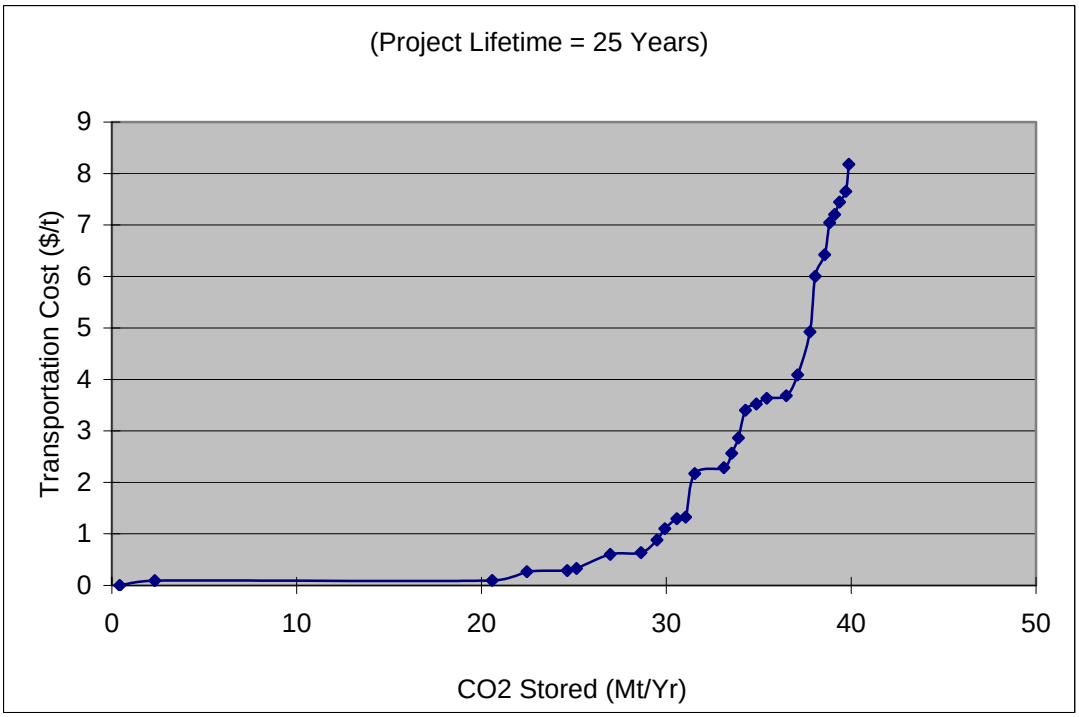


Figure 7-5: Marginal Transportation Cost in eastern Texas Oil Fields with EOR Potential



In this analysis \$16/t of CO_2 was used as an assumed EOR credit value, meaning that a CO_2 source can receive \$16/t of CO_2 used for EOR. If the transportation cost from a CO_2 source to an EOR site was less than \$16/t, then the CO_2 was allocated to that EOR site instead of an alternative non EOR sink. If the transportation costs to the closest EOR site were greater than \$16/t, then the CO_2 was considered unmatched and was allocated to the saline aquifers or gas fields during the second step of the analysis. In actuality, when the algorithm was run it turned out that all of the sources that were initially allocated to the EOR sites had transportation costs that were less than \$16/t.

After the first matching stage, 101 sources remained unmatched with appropriate sinks. The storage capacity of the gas fields is relatively small, while the aquifers have a storage capacity that is greater than the total 25-year CO_2 flow. In addition to transportation and capacity constraints, sources were allocated while considering the differential injection costs for gas fields and saline aquifers at the second stage.[18] Since there is a large saline aquifer that covers much of the study region, sources within this region were allocated directly to the saline aquifer. Next sources outside of the aquifer region were matched via the least cost method to the optimal CO_2 sink. A final check was run to compare final cost calculations for each source to alternative options to ensure that the selected pair represents the true least cost option.

[18] According to Heddle, the injection cost for gas fields is usually higher than for saline aquifers. Accordingly it was assumed that saline aquifers were preferred over gas fields for injection, and all sources located on top of saline aquifers were injected directly into the aquifer. For example, the base case provided by Heddle et al. (2003) estimated the injection cost for an aquifer would be \$0.16 per tonne of CO_2 from a power plant with a daily flow rate 7, 389 tonne, while the injection cost for a gas reservoir would be \$2.58 per tonne of CO_2 using the same flow rate.

Figure 7-6: Source-sink Matching Final Result

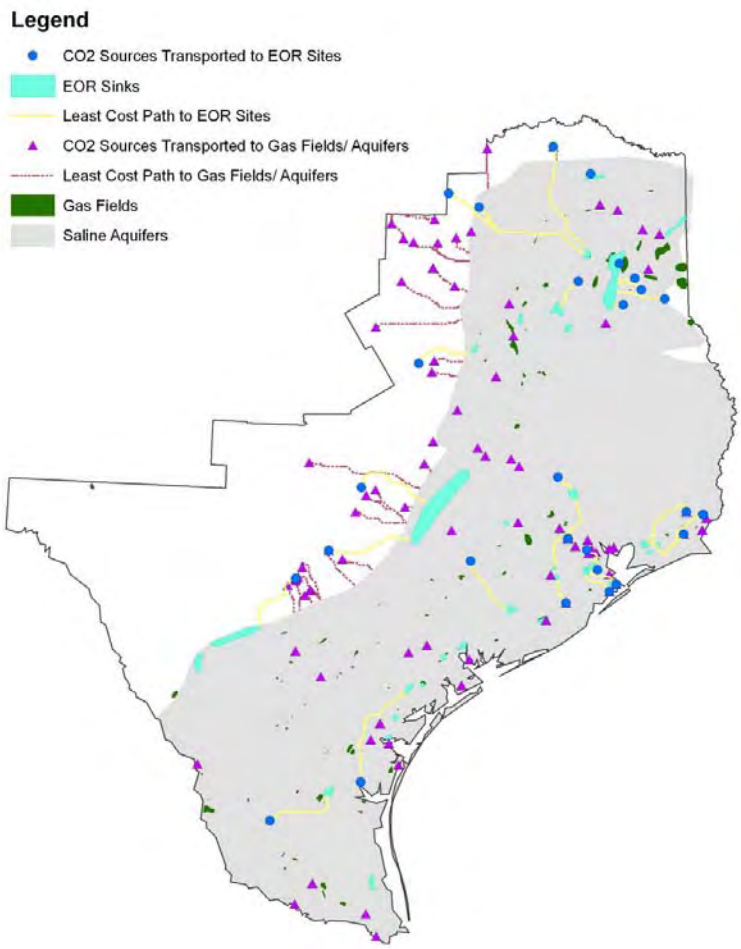


Figure 7-6 shows the final results for all of the sources in eastern Texas. Appendix G presents the corresponding destination sink for each of the CO_2 sources listed in this section. Figure 7-7 plots the marginal transportation distance by annual CO_2 storage rate for all sources including those transported to EOR sites. Figure 7-8 plots the marginal transportation cost by annual CO_2 storage rate.

Figure 7-7: Marginal Transportation Distance by Annual CO_2 Storage Rate for All Sources, eastern Texas

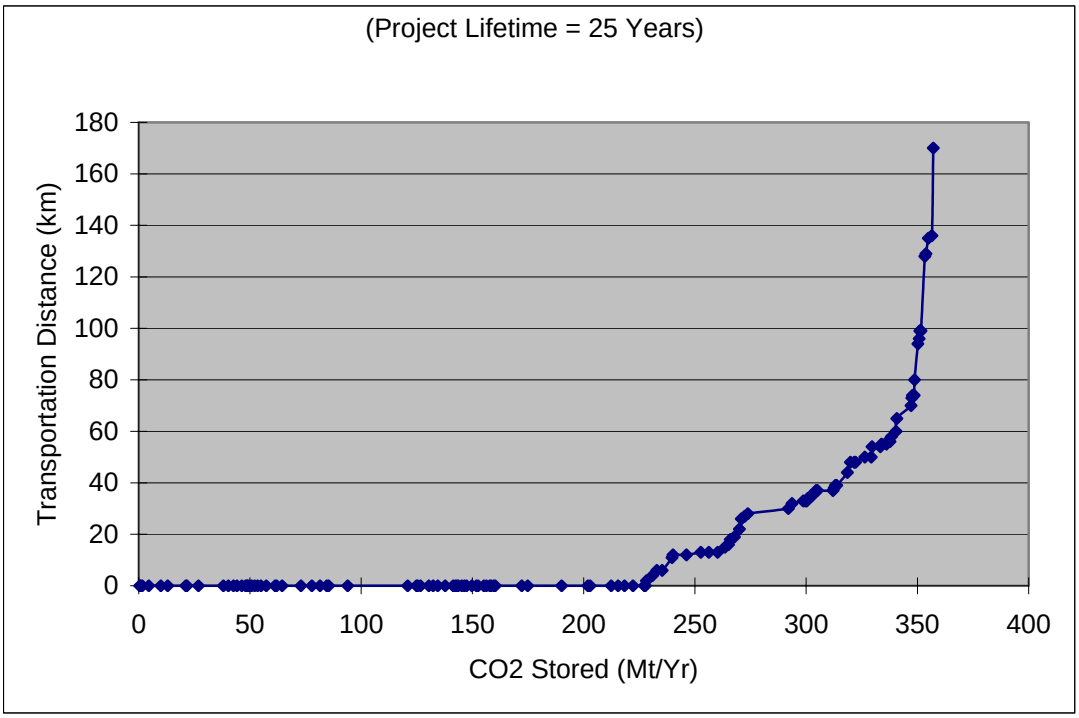
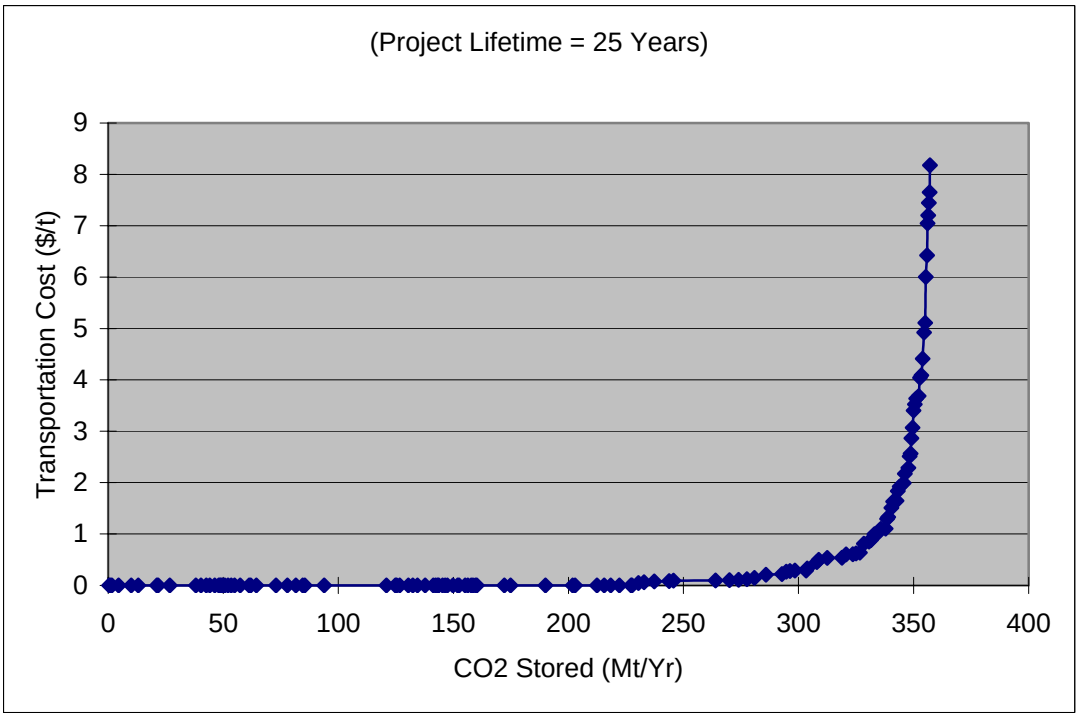


Figure 7-8: Marginal Transportation Cost for all Sources in eastern Texas



In contrast to the results from the previous section, the results from the least-cost path source-sink matching provide an optimized pipeline arrangement based on construction cost criteria. In many cases this transportation distance will be longer than the straight-line distance calculated in the previous section. But since transportation obstacle costs are included, the overall transportation cost will be less. If EOR fields were the only sequestration sinks considered (Stage I), then 12.5% of the sources could be linked to an appropriate sink. Most of these sinks were within 150 km from the CO_2 source. The total transportation costs for all sources calculated in the Stage I analysis were less than \$9/t CO_2. The assumed EOR credit was \$16/t CO_2, which reinforced the need to use the two-stage analysis strategy.

When all sources were included in the analysis all of them could be linked to a least-cost sink within 200 km from the source. While the maximum transportation cost was around \$9/t CO_2, in most cases the transportation cost was less than \$1/t CO_2. In reality the transportation costs might be less since in some cases sources and sinks in the same region could share pipelines or pipeline routes. This would likely decrease transportation costs below the estimates presented here.

7.3 CO_2 SEQUESTRATION FULL-COST ESTIMATION

For sources matched with EOR sites the full cost estimate included costs for capture, transportation, and an EOR credit. For sources matched with gas fields or aquifers, the full cost estimate included capture cost, transportation cost, and injection cost.

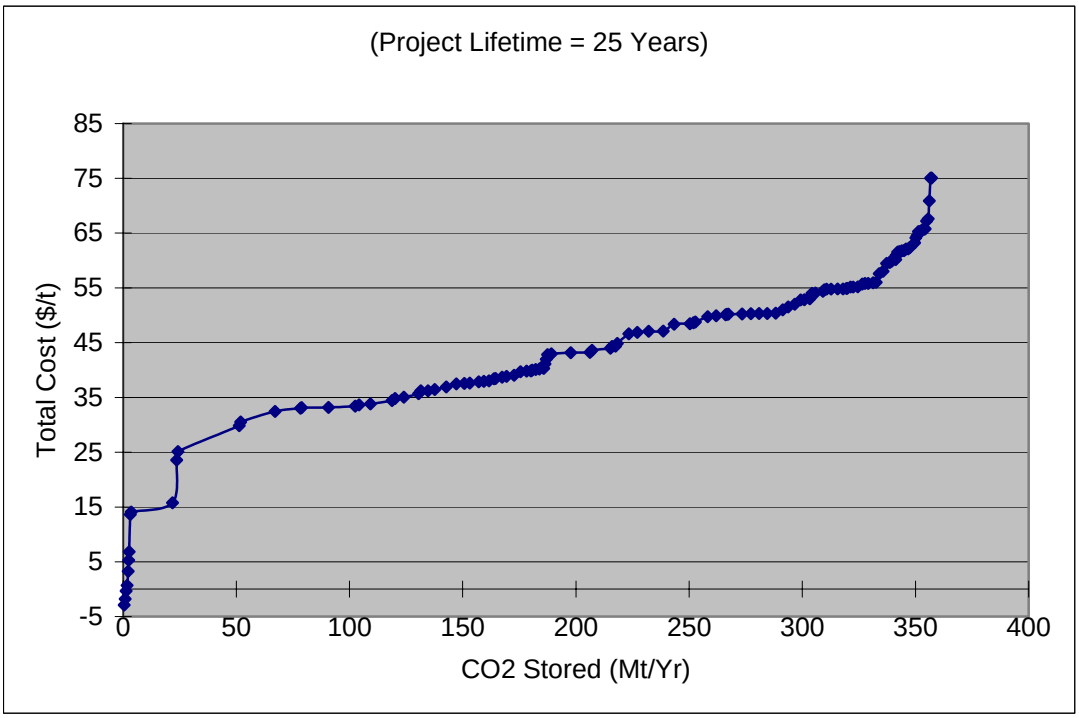
The injection cost analysis was based on methods used by Heddle, et.al. (2003). The Heddle injection cost model requires inputs for surface injection pressure, downhole injection pressure, CO_2 flow rate, and reservoir properties. Heddle, et.al. (2003) defined a base case, a high cost case, and a low cost case derived from an analysis of typical data for aquifers and gas fields. Since the spatially distributed aquifer data was unavailable at this stage, a regional mean value in the Gulf Cost was used in this analysis. For gas fields, the reservoir properties used in the analysis were referenced from the SECARB database. The surface injection pressure was assumed to be 10.30 MPa. Using the spreadsheet shown in Figure 7-9 the injection cost was calculated using the source CO_2 flow rate. A power plant with a 25-year CO_2 emission of 67.4 Mt was used as a reference case in the spreadsheet. In this reference case, the injection cost was estimated to be \$0.16 per tonne of CO_2.

Figure 7-10 and Appendix G show the results of the CO_2 sequestration full cost estimation. The results of the full cost sequestration analysis in eastern Texas indicate that 20, 100, or 200 M tonnes of CO_2 per year could be sequestered in eastern Texas at a cost of \$16/t, \$33/t, or \$43/t, respectively. This total costs could be less and the specific sequestration cost could even be negative for specific ammonia and gas processing plants with low transportation costs since their capture cost was less than the assumed EOR credit.

Figure 7-9 Injection Cost Estimation Spreadsheet

		AQUIFER - Base Case			
Inputs					
Surface inj. pressure	(MPa)	10.30			
Downhole inj. pressure	(MPa)	21.30	17.08	18.25	17.92
CO_2 mass flow rate	(t/d)	7,389			
	(kg/s)	86			
Reservoir properties					
Reservoir pressure	(MPa)	8.4			
Thickness	(m)	171			
Depth	(m)	1239			
Permeability	(md)	22			
Temperature	(deg C)	46.0			
Viscosity calculation					
Intermediate pressure	(MPa)	14.85	12.74	13.33	13.16
Viscosity	(mPa.s)	0.050	0.042	0.044	0.044
Well number calculation					
CO_2 mobility	(md/mPa.s)	242.4	286.8	272.6	276.5
CO_2 injectivity	(t/d/m/MPa)	5.042	5.966	5.670	5.751
CO_2 injection rate per well	(t/d)	11123	8856	9555	9363
Number wells required		0.7	0.8	0.8	0.8
Cost calculation					
Site screening & evaluation	($M)	1.69			
Injection equipment	($M)	0.04	0.04	0.04	0.04
Well drilling cost	($M)	0.24	0.24	0.24	0.24
Total capital cost	($M)	1.97	1.97	1.97	1.97
Normal daily expenses	($M/yr)	0.01	0.01	0.01	0.01
Consumables	($M/yr)	0.02	0.02	0.02	0.02
Surface maintenance	($M/yr)	0.01	0.01	0.01	0.01
Subsurface maintenance	($M/yr)	0.01	0.01	0.01	0.01
Total O&M costs	($M/yr)	0.04	0.04	0.04	0.04
Annual total cost	($M)	0.34	0.34	0.34	0.34
$/tonne CO_2		0.16	0.16	0.16	0.16
Pressure change calculation					
CO_2 temperature	(deg C)	25			
CO_2 density	(kg/m^3)	822			
Gravity head					
Elevation change	(m)	-1239			
Pressure change	(MPa)	9.99			
Friction loss					
Well diameter	(m)	0.1200			
Viscosity	($N.s/m^2$)	6.06E-05			
Reynolds number	unitless	2.26E+07	1.80E+07	1.94E+07	1.90E+07
Roughness	(ft)	0.00015			
Friction factor	unitless	0.00395	0.00395	0.00395	0.00395
Well length	(m)	1239			
Velocity	(m/s)	13.85	11.03	11.90	11.66
Pressure change	(MPa)	3.21	2.04	2.37	2.28
Downhole pressure	(MPa)	17.08	18.25	17.92	18.02

Figure 7-10 Marginal Total Cost of Capture and Sequestration in eastern Texas



8 References

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9 Appendices

Appendix A. List of Acronyms

Abbreviation	Meaning
AGS	Alabama Geological Survey
CO_2	Carbon dioxide
DOE	United States Department of Energy
ECBMR	Enhanced Coalbed Methane Recovery
eGRID	Emissions and Generation Resource Integrated Database
EIA	Energy Information Agency
EOR	Enhanced oil recovery
ERF	ECBM recovery factor
GASIS	Gas Information System
GHG	Greenhouse gas
GIS	Geographical information System
GNIS	Geographical Names Information System
Gt	giga metric tones
HV	High-volatile
HVA	High-volatile A
IEA	International Energy Agency
IFDC	International Fertilizer Development Commission
IGEM	Institute of Geology of Ore Deposits, Petrography, Mineralogy & Geochemistry
LFEE	Laboratory for Energy and the Environment (at MIT)
LULC	Land use and land cover
LV	Low-volatile
MIT	Massachusetts Institute of Technology
Mt	million metric tons
MV	Moderate-volatile
MWe	megawatt electrical
OGIP	Original gas in place
O&M	Operation and maintenance
OOIP	Original oil in place
PRF	Primary Recovery Factor
RRC	Railroad Commission
SECARB	Southeast Regional Carbon Sequestration Partnership
Sub	Sub-bituminous

tonne	metric ton
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
UTBEG	University of Texas at Austin, Bureau of Economic Geology

Appendix B. CO_2 Capture Cost Estimation and Straight-line Distance Source-Sink Matching for Fossil-Fuel Power Plants in SECARB Region

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
2739	COGENTRIX SOUTHPOR	NC	108.46	0.26	420,387	COAL	1,293,498	45.45	57.50	142	174	898	898	142
4248	COGENTRIX HOPEWELI	VA	108.46	0.36	342,024	COAL	760,053	45.45	57.50	144	58	1085	1144	58
4250	COGENTRIX PORTSMOU	VA	108.46	0.26	228,979	COAL	704,552	45.45	57.50	81	143	1150	1187	81
2746	DWAYNE COLLIER BAT	NC	114.75	0.86	1,018,239	COAL	947,199	45.15	57.12	111	128	1022	1041	111
1129	CENTRAL POWER&LIM	FL	125.00	0.92	1,029,635	COAL	895,335	44.70	56.55	0	298	510	539	0
161	GADSDEN	AL	138.00	0.42	635,483	COAL	1,210,444	44.19	55.90	263	47	236	317	47
4281	MECKLENBURG COGEN	VA	139.86	0.60	806,519	COAL	1,075,358	44.12	55.82	218	130	974	1028	130
3781	DOLPHUS M GRAINGER	SC	163.20	0.64	956,023	COAL	1,195,029	43.33	54.82	218	172	822	822	172
2815	WESTMORELAND LG&E	NC	182.32	0.83	1,326,460	COAL	1,278,516	42.78	54.12	135	138	1025	1056	135
3910	AES DEEPWATER INC	TX	184.00	0.77	1,838,231	COAL	1,909,850	42.73	54.06	0	1	7	7	0
3897	TENN EASTMAN DIV A	TN	194.30	0.71	1,022,947	COAL	1,152,616	42.46	53.71	454	74	647	750	74
1236	ARKWRIGHT	GA	213.89	0.20	486,156	COAL	1,944,625	41.99	53.12	136	29	391	391	29
1977	NELSON INDUSTRIAL S	LA	227.27	0.71	1,163,969	COAL	1,311,515	41.69	52.74	0	24	3	22	0
4282	MIRANT BIRCHWOOD P	VA	240.00	0.65	1,344,173	COAL	1,654,367	41.42	52.41	130	54	1135	1218	54
3902	WATTS BAR FOSSIL	TN	240.00	0.00	0	COAL	1,654,367	41.42	52.41	432	108	390	515	108
4237	BREMO BLUFF	VA	254.28	0.74	1,795,589	COAL	1,941,177	41.15	52.05	219	65	1021	1103	65
4249	COGENTRIX OF RICHMO	VA	270.00	0.50	1,134,672	COAL	1,815,474	40.86	51.69	155	29	1075	1142	29
3818	URQUHART	SC	277.28	0.55	1,506,944	COAL	2,191,918	40.73	51.53	109	180	563	563	109
1126	CEDAR BAY GENERATI	FL	285.00	0.79	1,911,811	COAL	1,936,011	40.60	51.36	42	284	509	528	42
3800	MCMEEKIN	SC	293.76	0.73	1,908,812	COAL	2,091,849	40.46	51.18	177	210	652	652	177
1158	INDIANTOWN COGENE	FL	330.00	0.83	2,316,185	COAL	2,232,467	39.91	50.49	0	542	753	783	0
2809	W H WEATHERSPOON	NC	342.19	0.28	949,505	COAL	2,712,870	39.74	50.28	186	94	862	862	94
1292	MITCHELL	GA	343.88	0.23	826,518	COAL	2,874,845	39.72	50.25	93	42	286	294	42
4121	TNP ONE	TX	349.20	0.72	2,708,874	COAL	3,009,860	39.65	50.16	0	5	60	65	0
1285	KRAFT	GA	355.90	0.46	1,467,952	COAL	2,552,961	39.56	50.05	0	224	578	585	0
4092	SANDOW	TX	363.00	0.88	3,387,082	COAL	3,079,165	39.47	49.93	3	4	43	43	3
2743	DAN RIVER	NC	387.97	0.27	1,178,919	COAL	3,493,095	39.16	49.55	301	112	853	918	112

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
2672	R D MORROW	MS	400.00	0.69	2,645,042	COAL	3,066,715	39.03	49.37	0	5	26	94	0
2725	CAPE FEAR	NC	405.97	0.52	1,683,226	COAL	2,589,579	38.96	49.28	206	0	885	909	0
4090	SAN MIGUEL	TX	410.00	0.83	3,869,295	COAL	3,729,441	38.91	49.23	0	17	11	46	0
3777	COPE	SC	417.36	0.76	3,043,113	COAL	3,203,277	38.83	49.13	104	250	633	633	104
3977	GIBBONS CREEK	TX	443.97	0.84	3,417,398	COAL	3,254,664	38.55	48.77	0	9	33	48	0
3820	W S LEE	SC	460.30	0.34	1,553,879	COAL	3,656,185	38.39	48.57	245	244	565	596	244
1141	DEERHAVEN	FL	471.09	0.43	1,896,848	COAL	3,529,020	38.29	48.44	92	257	459	482	92
2722	BUCK	NC	474.57	0.41	1,974,179	COAL	3,852,058	38.25	48.39	324	87	772	818	87
3769	CANADYS STEAM	SC	489.60	0.51	2,362,176	COAL	3,705,374	38.12	48.22	80	273	655	657	80
2764	LEE	NC	508.62	0.43	2,497,634	COAL	4,646,762	37.95	48.00	117	84	966	972	84
223	FLINT CREEK	AR	510.83	0.85	4,292,162	COAL	4,039,682	37.93	47.98	303	113	80	325	80
1194	POLK	FL	521.23	0.38	1,678,771	COAL	3,534,255	37.84	47.87	0	393	604	634	0
153	CHARLES R LOWMAN	AL	538.00	0.71	4,028,993	COAL	4,539,710	37.70	47.69	0	0	45	47	0
3994	J K SPRUCE	TX	546.00	0.83	4,536,490	COAL	4,372,521	37.63	47.61	13	41	51	67	13
3942	COLETO CREEK	TX	570.06	0.97	4,791,472	COAL	3,951,730	37.44	47.37	0	0	34	34	0
3795	JEFFERIES	SC	578.20	0.41	2,259,942	COAL	4,409,642	37.38	47.29	116	237	717	719	116
4091	SANDOW	TX	590.64	0.69	4,283,849	COAL	4,966,781	37.29	47.17	10	31	32	32	10
2789	RIVERBEND	NC	601.20	0.45	2,674,171	COAL	4,754,081	37.21	47.08	325	130	711	752	130
1121	C D MCINTOSH JR	FL	625.01	0.58	3,519,130	COAL	4,853,972	37.04	46.86	0	363	574	604	0
4055	PIRKEY	TX	660.40	0.75	5,311,704	COAL	5,665,817	36.81	46.56	0	36	6	30	0
1283	JACK MCDONOUGH	GA	682.10	0.61	3,342,995	COAL	4,384,256	36.67	46.39	254	139	370	402	139
3824	WILLIAMS	SC	686.54	0.72	4,704,565	COAL	5,227,295	36.64	46.35	98	261	714	717	98
4246	CLINCH RIVER	VA	712.50	0.80	4,751,106	COAL	4,751,106	36.48	46.15	501	35	675	786	35
1947	DOLET HILLS	LA	720.75	0.73	5,186,835	COAL	5,684,203	36.43	46.09	40	7	16	107	7
2771	MAYO	NC	735.84	0.74	5,827,689	COAL	6,300,204	36.34	45.98	243	97	925	979	97
2763	L V SUTTON	NC	744.94	0.40	2,916,875	COAL	5,833,751	36.29	45.91	108	170	932	932	108
3823	WATEREE	SC	771.80	0.68	4,206,893	COAL	4,949,286	36.14	45.72	162	196	689	689	162
2734	CLIFFSIDE	NC	780.90	0.59	4,167,193	COAL	5,650,431	36.09	45.66	307	202	638	687	202
3875	JOHN SEVIER	TN	800.00	0.74	5,468,726	COAL	5,912,137	35.99	45.53	450	82	585	695	82

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Dist to Nearst Sink (km)
4242	CHESAPEAKE	VA	812.39	0.63	4,898,924	COAL	6,220,856	35.93	45.45	69	155	1153	1187	69
1288	MCINTOSH	GA	817.66	0.18	1,382,520	COAL	6,144,533	35.90	45.41	0	218	582	587	0
2712	ASHEVILLE	NC	837.17	0.37	3,003,068	COAL	6,493,120	35.80	45.29	343	179	578	657	179
4247	CLOVER	VA	848.06	0.92	7,615,277	COAL	6,621,980	35.75	45.22	251	137	952	1015	137
3997	J T DEELY	TX	892.00	0.71	6,344,394	COAL	7,148,613	35.54	44.96	13	41	51	67	13
1217	STANTON ENERGY CTR	FL	929.16	0.79	6,572,178	COAL	6,655,370	35.37	44.74	0	408	619	646	0
3853	BULL RUN	TN	950.00	0.72	4,963,295	COAL	5,514,772	35.28	44.63	447	45	474	594	45
1270	HAMMOND	GA	953.00	0.60	5,456,479	COAL	7,275,305	35.26	44.61	329	108	309	389	108
3789	H B ROBINSON	SC	991.64	0.84	1,029,395	COAL	980,376	35.10	44.40	234	120	754	754	120
2677	VICTOR J DANIEL JR	MS	1000.00	0.72	7,071,914	COAL	7,857,682	35.06	44.36	0	35	60	142	0
1997	RODEMACHER	LA	1003.50	0.53	4,843,732	COAL	7,311,293	35.05	44.34	0	0	51	162	0
2660	JACK WATSON	MS	1051.36	0.61	5,850,686	COAL	7,673,030	34.86	44.10	0	64	43	129	0
3778	CROSS	SC	1147.12	0.86	8,756,646	COAL	8,145,717	34.51	43.65	125	226	712	714	125
2751	G G ALLEN	NC	1155.00	0.57	5,914,264	COAL	8,300,721	34.48	43.62	305	136	703	737	136
3920	BIG BROWN	TX	1186.80	0.82	10,834,509	COAL	10,570,252	34.37	43.48	0	4	1	16	0
1133	CRIST	FL	1229.00	0.52	6,457,296	COAL	9,934,302	34.23	43.30	0	0	27	50	0
4321	YORKTOWN	VA	1257.00	0.32	3,571,960	COAL	8,929,901	34.14	43.19	81	112	1152	1200	81
3825	WINYAH	SC	1260.00	0.70	8,447,634	COAL	9,654,439	34.13	43.18	173	205	784	786	173
165	GREENE COUNTY	AL	1288.48	0.40	4,647,240	COAL	9,294,480	34.04	43.07	66	37	92	92	37
1213	ST JOHNS RIVER POWEI	FL	1358.00	0.84	10,809,674	COAL	10,294,927	33.83	42.80	36	288	524	542	36
164	GORGAS	AL	1416.70	0.70	9,503,886	COAL	10,861,584	33.67	42.59	133	25	117	204	25
1206	SEMINOLE	FL	1429.20	0.73	10,424,329	COAL	11,423,922	33.63	42.55	49	330	529	551	49
1342	YATES	GA	1487.50	0.48	6,736,641	COAL	11,227,736	33.48	42.35	241	132	327	343	132
4144	WELSH	TX	1536.96	0.80	13,121,748	COAL	13,121,748	33.35	42.19	0	26	30	39	0
1993	R S NELSON	LA	1596.80	0.45	7,706,978	COAL	13,701,294	33.20	42.00	0	21	8	30	0
3848	ALLEN	TN	1610.80	0.38	5,238,480	COAL	11,028,380	33.17	41.96	29	0	218	319	0
4013	LIMESTONE	TX	1626.80	0.79	13,081,433	COAL	13,247,020	33.13	41.91	0	43	21	36	0
3969	FAYETTE POWER PRJ	TX	1690.00	0.80	12,514,443	COAL	12,514,443	32.98	41.72	0	0	22	22	0
229	INDEPENDENCE	AR	1700.00	0.69	12,310,474	COAL	14,273,013	32.96	41.69	104	9	213	360	9
247	WHITE BLUFF	AR	1700.00	0.68	11,920,913	COAL	14,024,603	32.96	41.69	6	3	146	227	3
3877	KINGSTON	TN	1700.00	0.66	10,723,952	COAL	12,998,729	32.96	41.69	447	63	438	563	63

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
1271	HARLLEE BRANCH	GA	1746.24	0.55	8,785,873	COAL	12,779,452	32.85	41.56	129	67	438	438	67
4243	CHESTERFIELD	VA	1799.60	0.60	9,084,140	COAL	12,112,186	32.74	41.42	148	45	1081	1143	45
154	COLBERT	AL	1826.00	0.46	8,347,215	COAL	14,516,896	32.68	41.35	161	34	134	325	34
1934	BIG CAJUN 2	LA	1833.00	0.73	14,124,989	COAL	15,479,440	32.67	41.33	0	41	21	105	0
3868	GALLATIN	TN	1918.72	0.43	7,390,039	COAL	13,748,909	32.49	41.11	377	162	352	525	162
1337	WANSLEY	GA	1956.80	0.57	9,899,030	COAL	13,893,376	32.42	41.01	236	134	321	335	134
205	WIDOWS CREEK	AL	1968.76	0.56	11,905,974	COAL	17,008,534	32.40	40.99	329	81	285	405	81
4026	MONTICELLO	TX	1980.05	0.71	14,960,317	COAL	16,856,696	32.38	40.96	0	18	13	29	0
1116	BIG BEND	FL	1998.00	0.62	11,607,158	COAL	14,976,978	32.34	40.91	0	346	554	586	0
2770	MARSHALL	NC	2000.00	0.86	13,262,502	COAL	12,337,211	32.34	40.91	351	133	717	769	133
158	E C GASTON	AL	2034.05	0.71	13,815,864	COAL	15,567,170	32.27	40.83	178	65	194	223	65
2715	BELEWS CREEK	NC	2160.14	0.65	11,727,317	COAL	14,433,621	32.05	40.54	317	110	818	881	110
4020	MARTIN LAKE	TX	2379.75	0.79	20,026,130	COAL	20,279,625	31.69	40.09	0	58	12	28	0
2795	ROXBORO	NC	2574.57	0.67	15,577,368	COAL	18,599,842	31.40	39.72	252	92	908	964	92
3863	CUMBERLAND	TN	2600.00	0.84	21,370,347	COAL	20,352,711	31.36	39.68	297	51	314	510	51
172	JAMES H MILLER JR	AL	2822.00	0.83	22,337,062	COAL	21,529,698	31.06	39.30	153	4	132	224	4
149	BARRY	AL	2834.80	0.50	12,435,918	COAL	19,897,469	31.05	39.28	0	0	14	78	0
3876	JOHNSONVILLE	TN	2911.52	0.34	8,918,108	COAL	20,983,784	30.95	39.15	251	31	268	468	31
1134	CRYSTAL RIVER	FL	3333.33	0.72	15,433,230	COAL	17,148,034	30.46	38.54	11	250	461	489	11
1249	BOWEN	GA	3540.45	0.70	21,226,831	COAL	24,259,236	30.25	38.27	307	139	333	395	139
1316	SCHERER	GA	3564.00	0.68	23,701,643	COAL	27,884,286	30.23	38.24	153	41	390	390	41
4140	W A PARISH	TX	3969.12	0.52	19,499,213	COAL	29,998,789	29.85	37.76	0	19	4	4	0
1929	ARSENAL HILL	LA	100.00	0.24	157,083	GAS	523,611	70.50	89.19	30	0	13	53	0
4083	SABINE COGEN LP	TX	101.46	0.76	281,876	GAS	296,711	70.34	88.98	0	22	5	49	0
196	SO EASTERN ELECTRIC	AL	103.14	0.04	28,718	GAS	574,363	70.16	88.76	143	80	245	245	80
4128	UNIVERSITY OF TEXAS	TX	103.43	0.35	138,293	GAS	316,098	70.13	88.72	59	31	70	70	31
1937	BORDEN CHEMICALS PI	LA	104.09	0.74	289,212	GAS	312,662	70.06	88.63	0	115	37	52	0
3948	DANSBY	TX	105.00	0.38	238,945	GAS	503,041	69.96	88.51	0	4	26	26	0
4084	SABINE RIVER WORKS	TX	105.53	0.80	303,329	GAS	303,329	69.91	88.44	0	22	5	49	0
1306	RIVERSIDE	GA	108.03	0.05	41,707	GAS	667,306	69.65	88.12	0	228	580	587	0

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
201	WASHINGTON COUNTY	AL	109.00	0.68	313,566	GAS	368,901	69.56	87.99	0	0	21	49	0
1963	KAISER ALUMINUM	LA	110.20	0.46	252,057	GAS	438,359	69.44	87.84	0	135	27	38	0
3952	DEER PARK PLANT	TX	111.06	0.79	374,057	GAS	378,792	69.35	87.74	0	1	7	7	0
4077	RIVER CREST	TX	112.50	0.19	131,822	GAS	555,038	69.21	87.56	0	8	2	2	0
1955	GEISMAR PLANT	LA	113.00	0.84	417,377	GAS	397,502	69.16	87.50	0	115	37	52	0
4025	MISSION ROAD	TX	114.00	0.06	40,043	GAS	533,907	69.07	87.38	30	60	56	62	30
1191	PENSACOLA FLORIDA P	FL	116.00	0.61	284,857	GAS	373,582	68.88	87.14	0	0	33	44	0
4039	NORTH MAIN	TX	116.25	0.14	110,426	GAS	631,003	68.86	87.11	71	127	28	140	28
3773	CHEROKEE COUNTY CC	SC	117.73	0.55	276,429	GAS	402,079	68.72	86.94	283	193	645	682	193
4061	POWER STATION 3	TX	118.13	0.36	240,223	GAS	533,829	68.69	86.89	0	73	5	6	0
2674	SWEATT	MS	119.40	0.19	161,602	GAS	680,431	68.57	86.75	25	49	77	77	25
210	BAILEY	AR	120.00	0.26	203,618	GAS	626,516	68.52	86.68	64	0	210	313	0
1322	SOWEGA POWER LLC	GA	120.00	0.09	39,497	GAS	351,080	68.52	86.68	74	42	269	280	42
188	MOBILE ENERGY SERVI	AL	121.80	0.51	396,059	GAS	621,270	68.36	86.48	0	3	21	101	0
3790	HAGOOD	SC	122.00	0.05	38,907	GAS	622,518	68.34	86.46	78	283	704	708	78
1184	ORLANDO COGEN LP	FL	122.40	0.80	405,518	GAS	405,518	68.31	86.41	0	395	606	633	0
1992	PPG RIVERSIDE	LA	124.00	0.46	220,318	GAS	383,161	68.17	86.24	0	24	3	22	0
4058	PORT ARTHUR REFINER	TX	125.35	0.64	320,516	GAS	400,645	68.05	86.09	0	37	9	28	0
1187	PASCO COGEN LTD	FL	126.60	0.62	322,473	GAS	416,094	67.95	85.96	0	307	518	548	0
235	MCCLELLAN	AR	136.00	0.33	289,635	GAS	702,144	67.19	85.00	48	0	47	128	0
1183	ORANGE COGENERATIC	FL	136.67	0.40	192,122	GAS	384,244	67.14	84.93	0	393	604	634	0
1974	MONROE	LA	137.50	0.05	51,518	GAS	824,292	67.07	84.85	13	0	2	60	0
226	HAMILTON MOSES	AR	138.00	0.07	72,516	GAS	828,757	67.04	84.81	11	0	256	293	0
3929	BRYAN	TX	138.00	0.08	81,763	GAS	817,631	67.04	84.81	0	6	25	25	0
1150	HENRY D KING	FL	142.01	0.07	73,511	GAS	840,129	66.74	84.43	0	534	746	775	0
1165	JOHN R KELLY	FL	142.71	0.05	62,138	GAS	994,212	66.68	84.36	85	264	467	490	85
1950	FORMOSA PLASTICS CC	LA	143.80	0.80	460,875	GAS	460,875	66.61	84.26	0	75	3	84	0
4097	SI RAY	TX	145.00	0.09	79,892	GAS	710,148	66.52	84.15	0	39	49	51	0
1225	TOM G SMITH	FL	146.29	0.11	125,813	GAS	915,000	66.43	84.04	0	608	819	849	0

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
183	MCWILLIAMS	AL	147.00	0.28	384995.76	GAS	1,099,988	66.24	83.79	0	4	88	88	0
2650	CHEVRON OIL	MS	147.29	0.82	432011.80	GAS	421,475	65.96	83.45	0	40	66	149	0
1926	A B PATERSON	LA	149.00	0.14	288194.88	GAS	1,646,828	65.83	83.28	0	148	27	33	0
1178	MULBERRY COGENERA	FL	153.00	0.31	165891.02	GAS	428,106	65.75	83.17	0	393	604	634	0
1940	CALCASIEU POWER LL(	LA	155.00	0.08	70410.00	GAS	704,100	65.64	83.04	0	24	3	22	0
3943	COLLIN	TX	156.25	0.22	204364.90	GAS	743,145	65.38	82.71	30	122	63	149	30
1166	LAKE COGEN LTD	FL	157.82	0.51	321531.86	GAS	504,364	65.13	82.39	0	350	560	587	0
1122	CANE ISLAND	FL	162.00	0.53	385498.10	GAS	581,884	65.00	82.24	0	424	635	664	0
3995	J L BATES	TX	166.00	0.36	375449.80	GAS	834,333	64.99	82.21	0	0	17	84	0
4094	SEADRIFT PLANT UNIO	TX	168.00	0.58	451496.27	GAS	622,753	64.59	81.71	0	28	33	33	0
4008	LAREDO	TX	168.29	0.50	521733.30	GAS	834,773	64.59	81.71	0	0	10	102	0
1946	DG HUNTER	LA	175.00	0.12	139432.10	GAS	929,547	64.51	81.61	0	0	74	153	0
1969	LOUISIANA 2	LA	175.00	0.00	50135.00	GAS	929,547	64.31	81.35	0	75	3	84	0
4089	SAN JACINTO SES	TX	176.40	0.88	690700.00	GAS	627,909	64.15	81.16	0	1	7	7	0
2783	PANDA ROSEMARY LP	NC	180.00	0.07	59874.50	GAS	684,280	64.09	81.08	135	138	1025	1056	135
227	HARVEY COUCH	AR	182.80	0.11	171519.10	GAS	1,247,412	64.01	80.98	42	13	17	62	13
1311	ROBINS	GA	183.87	0.08	104706.90	GAS	1,047,069	63.88	80.81	115	0	368	368	0
1294	MPC GENERATING	GA	185.40	0.06	98997.60	GAS	1,319,968	63.82	80.74	205	120	438	444	120
3951	DEEPWATER	TX	187.85	0.12	143445.50	GAS	956,303	63.71	80.59	0	22	10	15	0
4009	LEON CREEK	TX	189.00	0.05	68495.60	GAS	1,095,930	63.62	80.49	29	64	50	53	29
4062	POWER STATION 4	TX	191.12	0.86	612906.43	GAS	570,146	63.26	80.02	0	73	5	6	0
1111	AUBURNDALE POWER I	FL	192.78	0.63	456277.92	GAS	579,401	63.02	79.73	0	393	604	634	0
3990	HOUSTON CHEMICAL C	TX	200.00	0.86	574688.34	GAS	534,594	62.68	79.30	0	1	7	7	0
3918	BEAUMONT REFINERY	TX	204.84	0.56	1662006.44	GAS	2,374,295	62.54	79.12	0	37	9	28	0
3917	BAYTOWN TURBINE GE	TX	212.00	0.80	654346.09	GAS	654,346	62.44	78.99	0	1	7	7	0
3967	EXXON MOBIL CO USA	TX	215.00	0.87	689698.23	GAS	634,205	62.41	78.95	0	1	7	7	0
1320	SMARR ENERGY CENTE	GA	217.40	0.00	142098.80	GAS	1,123,580	62.10	78.56	159	38	379	379	38
1169	LARSEN MEMORIAL	FL	218.02	0.24	338627.23	GAS	1,128,757	61.89	78.29	0	367	578	608	0
2652	DELTA	MS	225.00	0.14	266814.60	GAS	1,524,655	61.84	78.24	0	0	167	167	0

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
1933	BIG CAJUN 1	LA	230.00	0.12	150,421	GAS	1,002,809	61.89	78.29	0	49	23	103	0
216	CECIL LYNCH	AR	231.10	0.04	108,901	GAS	2,178,026	61.84	78.24	50	7	130	245	7
3957	E S JOSLIN	TX	234.87	0.29	383,809	GAS	1,058,783	61.69	78.04	0	13	14	14	0
1137	CUTLER	FL	236.50	0.19	266,715	GAS	1,123,012	61.62	77.95	2	663	869	901	2
1964	LIEBERMAN	LA	240.00	0.21	264,491	GAS	1,007,585	61.48	77.77	14	0	15	25	0
1243	BACONTON POWER	GA	240.00	0.03	4,431	GAS	118,149	61.48	77.77	74	42	269	280	42
4003	LA PALMA	TX	242.33	0.29	423,539	GAS	1,168,384	61.39	77.66	0	23	25	28	0
4126	TRINIDAD	TX	243.36	0.19	262,494	GAS	1,105,240	61.34	77.61	0	0	15	16	0
4096	SHELL DEER PARK	TX	250.00	0.84	935,882	GAS	891,317	61.09	77.28	0	1	7	7	0
4111	TENASKA III TEXAS PAI	TX	250.00	0.68	788,323	GAS	927,439	61.09	77.28	15	57	49	49	15
2665	MOSELLE	MS	260.00	0.24	477,000	GAS	1,590,000	60.71	76.81	0	0	31	103	0
2000	ST CHARLES OPERATIO	LA	264.00	0.80	1,048,847	GAS	1,048,847	60.57	76.62	0	156	4	4	0
1223	TIGER BAY	FL	278.22	0.55	608,203	GAS	884,659	60.07	76.00	0	393	604	634	0
1239	ATKINSON	GA	281.70	0.04	98,363	GAS	1,967,259	59.96	75.85	254	139	370	402	139
4112	TENASKA IV TEXAS PAI	TX	282.60	0.63	706,816	GAS	897,545	59.93	75.81	68	114	73	106	68
3916	BAYOU COGENERATIOI	TX	300.00	0.98	1,128,743	GAS	921,423	59.37	75.11	0	1	7	7	0
4265	GORDONSVILLE ENERG	VA	300.40	0.09	135,503	GAS	1,204,474	59.36	75.09	194	43	1054	1139	43
2723	BUTLER WARNER GEN	NC	303.40	0.06	122,514	GAS	1,633,521	59.26	74.97	171	59	898	898	59
1956	GEORGIA GULF CORPOI	LA	306.00	0.75	1,101,673	GAS	1,175,118	59.19	74.87	0	87	23	63	0
1290	MID GEORGIA COGEN	GA	315.24	0.25	313,705	GAS	1,003,857	58.91	74.53	115	0	368	368	0
4004	LAKE CREEK	TX	321.63	0.32	629,962	GAS	1,574,905	58.73	74.29	28	41	49	49	28
1936	BONIN	LA	328.50	0.22	413,861	GAS	1,504,949	58.53	74.05	0	63	2	39	0
182	MCINTOSH	AL	336.00	0.07	148,787	GAS	1,700,422	58.33	73.79	0	0	21	49	0
4024	MIRANT TEXAS LP BOS	TX	340.00	0.16	326,702	GAS	1,633,511	58.22	73.65	93	118	107	107	93
4049	PARKDALE	TX	340.63	0.21	447,117	GAS	1,703,304	58.20	73.63	14	81	71	109	14
1157	INDIAN RIVER PLANT	FL	342.80	0.05	100,309	GAS	1,604,949	58.14	73.56	0	442	653	679	0
4070	RAY OLINGER	TX	345.00	0.36	784,981	GAS	1,744,402	58.09	73.48	0	94	70	119	0
2673	REX BROWN	MS	350.20	0.12	381,064	GAS	2,540,423	57.95	73.31	0	11	37	113	0
1991	PPG POWERHOUSE C	LA	357.81	0.80	1,443,285	GAS	1,443,285	57.76	73.06	0	24	3	22	0
1272	HARTWELL ENERGY LP	GA	360.00	0.13	321,760	GAS	1,980,058	#REF!	#REF!	234	200	515	543	200

Appendix B: (Continued)

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4256	DARBYTOWN	VA	368.52	0.02	56,948	GAS	2,277,937	57.49	72.73	147	28	1084	1151	28
1153	HINES ENERGY COMPL	FL	373.15	0.83	1,164,775	GAS	1,122,675	57.38	72.59	0	393	604	634	0
3939	CLEAR LAKE COGENER	TX	377.00	0.90	1,688,152	GAS	1,500,580	57.29	72.47	0	1	7	7	0
1110	ARVAH B HOPKINS	FL	377.57	0.41	924,149	GAS	1,803,217	57.27	72.45	59	57	252	273	57
1203	S O PURDOM	FL	378.80	0.17	232,716	GAS	1,095,133	57.24	72.42	79	82	277	301	79
4251	COMMONWEALTH ATL	VA	388.88	0.03	70,067	GAS	1,868,450	57.01	72.12	67	157	1154	1188	67
4270	HOPEWELL COGENERA	VA	399.00	0.14	261,244	GAS	1,492,822	56.78	71.83	144	58	1085	1144	58
4266	GRAVEL NECK	VA	407.92	0.01	34,000	GAS	2,719,967	56.58	71.58	120	93	1112	1160	93
1261	DOYLE GENERATING F	GA	409.18	0.06	90,322	GAS	1,204,287	56.56	71.55	205	120	438	444	120
1930	BATON ROUGE COGEN	LA	422.10	0.79	1,055,404	GAS	1,068,763	56.28	71.20	0	75	3	84	0
4143	WEBSTER	TX	426.36	0.13	343,439	GAS	2,113,469	56.19	71.09	0	47	3	3	0
2669	NEW ALBANY POWER F	MS	427.20	0.02	70,099	GAS	2,803,960	56.18	71.07	75	75	101	304	75
2004	TECHE	LA	427.90	0.38	952,391	GAS	2,005,033	56.16	71.05	0	123	15	22	0
1968	LOUISIANA 1	LA	437.50	0.01	51,173	GAS	4,093,830	55.97	70.80	0	73	11	82	0
4120	THOMAS C FERGUSON	TX	446.00	0.37	886,780	GAS	1,917,363	55.80	70.59	121	94	133	133	94
4114	TEXAS CITY COGENER	TX	450.00	0.90	1,640,527	GAS	1,458,246	55.72	70.49	0	73	5	6	0
4001	KNOX LEE	TX	458.69	0.32	833,323	GAS	2,083,308	55.55	70.28	0	53	10	19	0
4108	SWEENY COGENERATI(	TX	460.00	0.68	1,579,420	GAS	1,858,141	55.53	70.25	0	54	25	26	0
4137	VICTORIA	TX	460.87	0.22	618,149	GAS	2,247,816	55.51	70.23	0	0	19	19	0
3981	GREGORY POWER FACI	TX	464.00	0.39	625,517	GAS	1,283,112	55.45	70.15	0	0	14	14	0
4234	BELLMEADE	VA	467.50	0.07	154,292	GAS	1,763,337	55.39	70.07	147	28	1084	1151	28
1149	HARDEE POWER STATI(	FL	470.05	0.28	29,370	GAS	83,913	55.34	70.01	0	412	621	652	0
2002	STERLINGTON	LA	480.78	0.33	809,093	GAS	1,961,437	55.15	69.77	37	0	25	59	0
4141	W B TUTTLE	TX	495.00	0.08	244,670	GAS	2,446,695	54.90	69.45	39	64	72	78	39
4046	OYSTER CREEK UNIT V	TX	498.05	0.66	1,269,951	GAS	1,539,335	54.84	69.38	0	1	7	7	0
3987	HIDALGO ENERGY CEN	TX	500.00	0.25	409,021	GAS	1,308,867	54.81	69.34	0	0	10	63	0
4014	LON C HILL	TX	510.87	0.35	1,172,816	GAS	2,680,722	54.63	69.11	0	4	14	16	0
3975	FRONTERA GENERATIC	TX	511.00	0.34	706,478	GAS	1,662,300	54.62	69.10	0	0	10	63	0
4042	NUECES BAY	TX	513.69	0.51	1,411,893	GAS	2,214,734	54.58	69.05	0	21	6	6	0
2649	CALEDONIA POWER FA	MS	519.18	0.03	76,963	GAS	2,052,339	54.49	68.93	40	21	18	188	18

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
3991	INGLESIDE COGENERA	TX	528.00	0.63	846,313	GAS	1,074,683	54.35	68.75	0	0	14	14	0
3852	BROWNSVILLE PEAKIN	TN	529.20	0.04	135,178	GAS	2,703,564	54.33	68.73	127	9	229	408	9
4011	LEWIS CREEK	TX	542.80	0.60	1,818,204	GAS	2,424,271	54.11	68.45	0	0	19	19	0
3907	A VON ROSENBERG	TX	549.63	0.45	887,520	GAS	1,577,813	54.01	68.32	31	59	60	67	31
3989	HOLLY STREET	TX	558.00	0.25	711,016	GAS	2,275,250	53.88	68.16	51	23	62	62	23
3940	COGEN LYONDELL INC	TX	564.00	0.81	1,686,257	GAS	1,665,439	53.79	68.05	0	1	7	7	0
3869	GLEASON POWER FACIL	TN	567.90	0.01	5,333	GAS	426,624	53.73	67.97	215	12	293	498	12
1317	SEWELL CREEK ENERG	GA	570.00	0.00	37,986	GAS	2,227,142	53.70	67.93	295	120	307	367	120
1197	PUTNAM	FL	580.00	0.48	1,359,729	GAS	2,266,215	53.55	67.75	55	320	522	545	55
1989	POWER AND UTILITIES	LA	587.00	0.69	1,480,457	GAS	1,716,472	53.45	67.62	0	87	23	63	0
3766	BROAD RIVER ENERGY	SC	591.00	0.03	22,965	GAS	612,405	53.40	67.55	283	193	645	682	193
4098	SIM GIDEON	TX	639.00	0.40	1,323,358	GAS	2,646,715	52.75	66.73	7	5	19	19	5
3914	BARNEY M DAVIS	TX	647.14	0.61	2,193,268	GAS	2,876,417	52.64	66.60	0	44	7	31	0
3970	FORMOSA UTILITY VEN	TX	652.20	0.67	1,547,062	GAS	1,847,238	52.58	66.52	0	28	33	33	0
4297	REMINGTON	VA	697.00	0.01	61,636	GAS	4,930,863	52.04	65.83	203	101	1104	1206	101
1339	WEST GEORGIA GENER	GA	701.40	0.10	395,583	GAS	3,164,664	51.98	65.76	185	43	337	337	43
3958	EAGLE MOUNTAIN	TX	706.15	0.15	687,020	GAS	3,664,108	51.93	65.70	86	147	10	161	10
4038	NORTH LAKE	TX	708.61	0.31	1,236,395	GAS	3,190,697	51.90	65.66	40	111	43	139	40
4106	STRYKER CREEK	TX	713.48	0.38	1,530,830	GAS	3,222,799	51.85	65.59	0	74	15	15	0
1160	J D KENNEDY	FL	727.20	0.03	44,126	GAS	1,176,693	51.69	65.39	43	289	518	536	43
1258	DAHLBERG	GA	735.49	0.09	337,169	GAS	2,997,058	51.60	65.28	115	0	368	368	0
4258	DOSWELL COMBINED C	VA	742.40	0.23	772,758	GAS	2,687,853	51.52	65.18	148	4	1090	1163	4
231	LAKE CATHERINE	AR	752.00	0.24	1,061,320	GAS	3,537,734	51.42	65.05	69	21	113	190	21
4051	PASADENA COGENERA	TX	760.90	0.28	934,618	GAS	2,670,338	51.33	64.93	0	1	7	7	0
4150	WILKES	TX	807.39	0.34	1,475,791	GAS	3,472,449	50.85	64.33	0	27	12	25	0
2793	ROCKINGHAM POWER I	NC	809.08	0.03	398,185	GAS	10,618,277	50.84	64.31	299	104	846	908	104
2812	WAYNE COUNTY	NC	847.06	0.05	223,782	GAS	3,580,516	50.47	63.85	114	87	969	975	87
1140	DEBARY	FL	861.22	0.07	371,547	GAS	4,246,250	50.34	63.69	0	385	592	617	0
4085	SAM BERTRON	TX	875.26	0.24	1,218,280	GAS	4,060,933	50.21	63.53	0	25	6	14	0
3980	GREENS BAYOU	TX	878.40	0.12	648,993	GAS	4,326,621	50.19	63.49	0	14	17	25	0

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
2006	WATERFORD 1 & 2	LA	891.00	0.19	1,117,647	GAS	4,705,882	50.08	63.35	0	156	9	9	0
2646	BATESVILLE GENERATI	MS	891.00	0.15	295,123	GAS	1,573,987	50.08	63.35	41	8	155	257	8
4043	O W SOMMERS	TX	892.00	0.33	1,657,749	GAS	4,018,784	50.07	63.34	13	41	51	67	13
4131	V H BRAUNIG	TX	894.00	0.23	1,937,823	GAS	6,740,254	50.05	63.32	11	43	43	59	11
1949	EVANGELINE POWER S	LA	922.84	0.13	4,883,137	GAS	30,050,072	49.80	63.00	0	0	40	113	0
244	ROBERT E RITCHIE	AR	923.15	0.12	1,421,037	GAS	9,473,579	49.80	63.00	0	0	212	241	0
4005	LAKE HUBBARD	TX	927.52	0.33	1,732,061	GAS	4,198,937	49.76	62.95	0	75	69	104	0
3949	DECKER CREEK	TX	932.58	0.27	1,402,241	GAS	4,154,789	49.72	62.90	43	16	55	55	16
4110	TENASKA FRONTIER GE	TX	939.70	0.10	753,244	GAS	6,025,951	49.66	62.82	0	0	42	55	0
4031	MOUNTAIN CREEK	TX	958.49	0.27	1,558,564	GAS	4,617,967	49.51	62.63	34	93	56	118	34
1972	MICHOUD	LA	959.25	0.41	2,410,194	GAS	4,702,817	49.50	62.62	0	148	31	42	0
3779	DARLINGTON COUNTY	SC	1045.99	0.02	111,864	GAS	4,474,576	48.83	61.78	229	122	766	766	122
4007	LAMAR POWER PROJEC	TX	1090.84	0.23	336,553	GAS	1,170,620	48.52	61.38	15	57	49	49	15
3982	GUADALUPE GENERATI	TX	1142.20	0.01	96,872	GAS	7,749,735	48.17	60.94	30	51	63	78	30
4023	MIDLOTHIAN ENERGY I	TX	1156.00	0.10	216,771	GAS	1,734,164	48.08	60.82	14	56	57	67	14
4135	VALLEY	TX	1175.49	0.31	2,082,438	GAS	5,374,033	47.95	60.66	39	116	100	112	39
1965	LITTLE GYPSY	LA	1250.78	0.27	2,039,012	GAS	6,041,517	47.49	60.08	0	153	8	8	0
1159	INTERCESSION CITY	FL	1310.20	0.06	487,923	GAS	6,505,636	47.14	59.64	0	424	635	664	0
2647	BAXTER WILSON	MS	1327.60	0.32	4,081,548	GAS	10,203,870	47.05	59.52	0	0	48	59	0
4117	THE DOW CHEMICAL C	TX	1378.84	0.56	2,914,646	GAS	4,163,780	46.77	59.17	0	54	25	26	0
4125	TRADINGHOUSE	TX	1379.70	0.45	3,141,153	GAS	5,584,272	46.77	59.16	28	51	42	42	28
4109	T H WHARTON	TX	1421.52	0.32	2,268,818	GAS	5,672,046	46.55	58.89	0	0	4	4	0
3985	HANDLEY	TX	1433.35	0.24	2,123,689	GAS	7,078,964	46.49	58.81	60	115	37	131	37
2765	LINCOLN COMBUSTION	NC	1548.80	0.03	366,070	GAS	9,761,861	45.93	58.10	337	155	691	742	155
1170	LAUDERDALE	FL	1863.97	0.40	2,935,000	GAS	5,870,000	44.62	56.44	0	636	844	876	0
4082	SABINE	TX	2051.20	0.47	5,303,958	GAS	9,028,014	43.95	55.60	0	26	9	46	0
1980	NINEMILE POINT	LA	2141.62	0.32	4,372,680	GAS	10,931,701	43.66	55.23	0	155	18	22	0
2008	WILLOW GLEN	LA	2178.00	0.24	3,335,416	GAS	11,118,054	43.54	55.08	0	96	28	57	0
3934	CEDAR BAYOU	TX	2295.00	0.41	4,836,827	GAS	9,437,711	43.19	54.64	0	32	19	28	0
4047	P H ROBINSON	TX	2314.50	0.46	5,441,940	GAS	9,464,243	43.13	54.56	0	57	7	7	0

Appendix B: (Continued)

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (Mwe)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emmision (t)	(7) Fuel Type	(8) Adjusted Annual CO2 Emmision (t)	(9) CO2 Capture Cost ($/t)	(10) Avoid Cost ($/t)	(11) Nearest Aquifer (km)	(12) Nearest Coalbed (km)	(13) Nearest Oil & Gas Fields(km	(14) Nearest EOR Oil (km)	(15) Nearst Sink (km)
3801	MYRTLE BEACH	SC	111.50	0.01	21,071	OIL	1,685,714	50.69	64.13	203	163	836	836	163
3792	HILTON HEAD	SC	117.90	0.02	25,768	OIL	1,030,713	50.33	63.67	5	260	623	629	5
1314	SAVANNAH RIVER MILI	GA	140.40	0.55	563,486	OIL	819,616	49.20	62.24	0	202	566	571	0
4252	COMMONWEALTH CHE	VA	172.50	0.02	8,071	OIL	322,832	47.91	60.61	0	165	1243	1296	0
1146	G E TURNER	FL	180.98	0.03	61,583	OIL	1,642,210	47.61	60.23	0	383	592	618	0
1115	BAYBORO	FL	226.80	0.06	135,773	OIL	1,810,303	46.24	58.50	0	315	522	554	0
1154	HOOKERS POINT	FL	232.60	0.07	245,110	OIL	2,801,262	46.09	58.31	0	332	554	586	0
1211	SOUTHSIDE GENERATIN	FL	265.60	0.24	487,133	OIL	1,623,778	45.30	57.31	46	290	515	534	46
1341	WILSON	GA	321.35	0.02	64,477	OIL	2,579,066	44.20	55.92	66	160	543	543	66
1220	SUWANNEE RIVER	FL	330.60	0.15	462,772	OIL	2,468,115	44.04	55.71	128	172	369	389	128
1199	RELIANT ENERGY INDI	FL	608.54	0.23	1,010,301	OIL	3,514,089	40.69	51.48	0	442	653	679	0
1289	MCMANUS	GA	644.35	0.05	479,476	OIL	7,671,622	40.39	51.10	0	228	523	536	0
1185	P L BARTOW	FL	717.16	0.29	1,778,037	OIL	4,904,931	39.83	50.39	0	315	522	554	0
2656	GERALD ANDRUS	MS	781.47	0.35	2,478,529	OIL	5,665,209	39.39	49.84	0	0	107	107	0
1204	SANFORD	FL	1028.45	0.35	2,958,916	OIL	6,763,236	38.02	48.10	0	379	588	614	0
1145	FORT MYERS	FL	1302.30	0.25	2,433,894	OIL	7,788,462	36.87	46.65	0	475	679	712	0
1181	NORTHSIDE GENERATII	FL	1435.10	0.19	2,174,236	OIL	9,154,677	36.41	46.06	37	289	524	542	37
1195	PORT EVERGLADES	FL	1665.34	0.34	4,331,017	OIL	10,190,627	35.72	45.19	0	641	850	881	0
1172	MANATEE	FL	1726.60	0.33	4,837,988	OIL	11,728,455	35.55	44.97	0	364	571	603	0
1227	TURKEY POINT	FL	2337.85	0.71	2,712,755	OIL	3,056,625	34.18	43.24	4	676	881	913	4
1174	MARTIN	FL	2950.60	0.51	7,617,557	OIL	11,949,108	33.17	41.96	0	542	753	783	0

Appendix C. CO_2 Capture Cost Estimation and Straight-line Distance Source-Sink Matching for Ammonia Plants, SECARB Region

(1) ID	(2) Company Name	(3) State	(4) Design Capacity (Kg)	(5) Estimated Annual CO2 Emmsion(t)	(6) CO2 Capture Cost ($/t)	(7) CO2 Avoid Cost ($/t)	(8) Dist to Nearest Aquifer (km)	(9) Dist to Nearest Coalbed (km)	(10) Dist to Nearest Oil & Gas Fields(km)	(11) Dist to Nearest EOR Oil (km)	(12) Dist to Nearst Sink (km)
3	Air Products & Chemicals, I	FL	86	98,900	15.21	16.18	0	0	21	46	0
1	El Dorado Chemical Company	AL	193	221,950	14.18	15.08	153	36	131	325	36
13	Terra Industries, Inc.	TX	255	293,250	13.84	14.72	0	15	12	45	0
12	PCS Nitrogen Fertilizer, LL	TN	409	470,350	13.28	14.13	42	4	216	330	4
6	Triad Nitrogen L.L.C.	LA	465	534,750	13.13	13.97	0	120	22	38	0
2	Terra Industries, Inc.	AR	467	537,050	13.13	13.97	122	0	283	414	0
8	PCS Nitrogen Fertilizer, LL	LA	532	611,800	12.98	13.81	0	108	32	49	0
15	IMC Phosphates Company	LA	560	644,000	12.92	13.75	0	113	36	53	0
5	Triad Nitrogen L.L.C.	LA	576	662,400	12.89	13.71	0	120	22	38	0
14	Honeywell Nylon Inc.	VA	584	671,600	12.88	13.70	142	57	1087	1146	57
4	PCS Nitrogen Fertilizer, LL	GA	758	871,700	12.59	13.39	113	178	560	560	113
11	Koch Nitrogen Company	LA	1222	1,405,300	12.07	12.84	35	0	24	58	0
7	CF Industries, Inc.	LA	2250	2,587,500	11.45	12.18	0	120	22	38	0

Appendix D. CO_2 Capture Cost Estimation and Straight-line Distance Source-Sink Matching for Cement Plants in SECARB Region

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
ID	Plant Name	State	Annual Cement Production (Kt)	Estimated Annual CO2 Emission (t)	CO2 Capture Cost ($/t)	CO2 Avoid Cost ($/t)	Dist to Nearest Aquifer (km)	Dist to Nearest Coalbed (km)	Dist to Nearest Oil & Gas Fields(km)	Dist to Nearest EOR Oil (km)	Dist to Nearst Sink (km)
28	Lehigh Cement C	TX	99	74,250	48.77	61.69	44	57	59	59	44
1	Holcim (US) Inc	MS	419	314,250	40.75	51.56	20	41	32	180	20
2	Lafarge North A	GA	605	453,750	38.93	49.25	242	127	379	401	127
4	Rinker Material	FL	605	453,750	38.93	49.25	0	298	510	539	0
16	Lehigh Cement C	AL	636	477,000	38.69	48.95	195	32	181	242	32
12	Giant Cement Ho	SC	639	479,250	38.67	48.92	100	252	677	679	100
23	Florida Rock In	FL	647	485,250	38.61	48.84	84	237	441	465	84
15	CEMEX	TN	701	525,750	38.23	48.36	433	58	487	602	58
17	Tarmac America	FL	716	537,000	38.13	48.23	0	645	851	883	0
7	RC Cement Co.In	TN	735	551,250	38.00	48.08	372	123	329	443	123
8	CEMEX	GA	750	562,500	37.91	47.95	110	1	369	369	1
22	Texas Industrie	TX	771	578,250	37.78	47.79	47	65	79	91	47
25	Alamo Cement Co	TX	795	596,250	37.63	47.61	32	61	59	64	32
11	Ash Grove Cemen	AR	803	602,250	37.59	47.55	22	42	55	68	22
19	North Texas Cem	TX	840	630,000	37.38	47.28	40	85	72	96	40
10	CEMEX	AL	853	639,750	37.30	47.19	54	48	81	81	48
26	Capitol Aggrega	TX	868	651,000	37.22	47.09	32	61	59	64	32
24	National Cement	AL	886	664,500	37.13	46.97	236	42	216	283	42
21	CEMEX	TX	906	679,500	37.03	46.84	47	65	79	91	47
14	Holcim (US) Inc	SC	1002	751,500	36.57	46.26	113	239	684	685	113
5	Texas-Lehigh Ce	TX	1078	808,500	36.23	45.84	55	34	66	66	34
13	Lafarge North A	SC	1084	813,000	36.21	45.81	100	252	677	679	100
9	Roanoke Cement	VA	1120	840,000	36.06	45.62	365	126	876	972	126
3	CEMEX	FL	1190	892,500	35.79	45.28	0	298	510	539	0
27	Holcim (US) Inc	AL	1439	1,079,250	34.96	44.22	0	25	41	109	0
6	Lafarge North A	AL	1494	1,120,500	34.79	44.02	153	49	173	192	49
18	Holcim (US) Inc	TX	2024	1,518,000	33.50	42.38	40	85	72	96	40
20	Texas Industrie	TX	2536	1,902,000	32.58	41.21	40	85	72	96	40

Appendix E. CO_2 Capture Cost Estimation and Straight-line Distance Source-Sink Matching for Gas Processing Plants, SECARB Region

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
ID	State	Plant Name	Design Capacity (MMCFD) [	Estimated Annual Emmision ($)	CO2 Capture Cost ($/t)	CO2 Avoid Cost ($/t)	Dist to Nearest Aquifer (km)	Dist to Nearest Coalbed (km)	Dist to Nearest Oil & Gas Fields(km)	Dist to Nearest EOR Oil (km)	Dist to Nearst Sink (km)
31	LA	Lowry	300	182,400	14.66	15.59	0	66	6	23	0
37	LA	Sabine Pass	300	182,400	14.66	15.59	0	66	6	23	0
119	TX	Thompsonville	300	182,400	14.66	15.59	0	0	32	66	0
32	LA	Stingray	305	185,440	14.63	15.56	0	66	6	23	0
34	LA	Cow Island	500	304,000	13.81	14.69	0	98	38	38	0
58	LA	Iowa	500	304,000	13.81	14.69	0	40	4	59	0
78	TX	Houston Central	700	425,600	13.28	14.13	0	0	17	55	0
72	MS	Muldon	750	456,000	13.17	14.01	57	20	24	229	20
88	TX	East Texas	780	474,240	13.11	13.95	0	9	7	7	0
89	TX	East Texas	780	474,240	13.11	13.95	0	56	0	0	0
90	TX	East Texas	780	474,240	13.11	13.95	0	38	21	54	0
91	TX	East Texas	780	474,240	13.11	13.95	0	82	10	10	0
11	AR	Searcy	850	516,800	12.98	13.81	76	3	178	313	3
16	LA	Sea Robin	900	547,200	12.89	13.72	0	98	38	38	0
135	TX	King Ranch	925	562,400	12.85	13.67	0	24	20	30	0
134	TX	Katy	950	577,600	12.81	13.63	0	0	11	11	0
64	MS	Pascagoula	1000	608,000	12.74	13.55	0	34	59	140	0
40	LA	Bluewater	1050	638,400	12.67	13.47	0	48	4	62	0
38	LA	North Terrebonne	1250	760,000	12.41	13.20	0	141	20	29	0
59	LA	Venice	1300	790,400	12.35	13.14	0	191	9	35	0
35	LA	Eunice	1350	820,800	12.30	13.08	0	48	4	62	0

Appendix F. CO_2 Capture Cost Estimation and Straight-line Distance Source-Sink Matching for Refineries, SECARB Region

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(8)	(10)	(11)	(12)
ID	Plant Name	State	Design Capacity (BPD)	Estimated Annual Emission (t)	CO2 Capture Cost ($/t)	CO2 Avoid Cost ($/t)	Dist to Nearest Aquifer (km)	Dist to Nearest Coalbed (km)	Dist to Nearest Oil & Gas Fields(km)	Dist to Nearest EOR Oil (km)	Dist to Nearst Sink (km)
3850	Young Refining Corp.	GA	5400	53665	65.52	82.89	269	144	345	380	144
1236	Cross Oil Refining and Mktg, Inc.	AR	6800	67578	63.39	80.20	52	8	24	123	8
345	Calumet Lubricants Co. LP	LA	8300	82485	61.61	77.94	52	1	13	63	1
3	Age Refining, Inc.	TX	9112	90555	60.79	76.91	32	61	59	64	32
330	Calumet Lubricants Co. LP	LA	13020	129393	57.76	73.08	52	0	14	56	0
3353	TRIGEANT EP LTD	AL	16700	165965	55.74	70.52	0	4	23	89	0
1329	Ergon Refining Inc.	MS	23000	228574	53.24	67.36	0	0	57	61	0
319	Calcasieu Refining Co.	LA	30000	298140	51.26	64.84	0	29	13	28	0
1937	Hunt Refining Co.	AL	33500	332923	50.45	63.83	94	1	100	162	1
381	Calumet Lubricants Co. LP	LA	46200	459136	48.18	60.95	31	0	14	53	0
2646	Placid Refining Co.	LA	48500	481993	47.85	60.53	0	75	10	78	0
1995	La Gloria Oil & Gas Co.	TX	55000	546590	46.99	59.45	0	72	16	27	0
1828	Giant Yorktown Refg	VA	58600	582367	46.57	58.91	366	162	333	493	162
2023	Lion Oil Co.	AR	63000	626094	46.09	58.31	56	16	9	124	9
2275	Marathon Ashland Petro LLC	TX	72000	715536	45.22	57.20	0	71	2	2	0
3618	Valero Refining Co. Louisiana	LA	78000	775164	44.70	56.55	0	42	24	72	0
2788	Shell Chem LP	AL	80000	795040	44.54	56.35	0	0	8	87	0
3728	Valero Refining Co. Texas	TX	83000	824854	44.31	56.05	0	13	19	19	0
3510	VALERO ENERGY CORPORATI	TX	90000	894420	43.79	55.40	0	0	18	85	0
1263	Crown Central Petro Corp	TX	100000	993800	43.14	54.57	0	26	8	11	0
2474	Murphy Oil U.S.A. Inc.	LA	120000	1192560	42.03	53.17	0	157	23	41	0
3761	VALERO SAINT CHARLES REF	LA	155000	1540390	40.51	51.25	0	153	2	2	0
88	Atofina Petrochemicals Inc.	TX	175068	1739826	39.81	50.37	0	38	7	48	0
2739	PREMCOR REFINING GROUP II	TN	180000	1788840	39.66	50.17	42	4	216	330	4
469	Chalmette Refining LLC	LA	182500	1813685	39.58	50.07	0	156	23	40	0
3547	VALERO REFINING CO TEXAS	TX	204250	2029837	38.95	49.27	0	71	2	2	0
1055	CONOCOPHILLIPS	TX	217000	2156546	38.61	48.84	0	51	1	1	0
2409	Motiva Enterprises LLC	LA	226500	2250957	38.37	48.54	0	153	2	2	0
2201	Marathon Ashland Petro LLC	LA	232000	2305616	38.24	48.38	0	142	24	24	0

Appendix F: (Continued)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(8)	(10)	(11)	(12)
ID	Plant Name	State	Design Capacity (BPD)	Estimated Annual Emission (t)	CO2 Capture Cost ($/t)	CO2 Avoid Cost ($/t)	Dist to Nearest Aquifer (km)	Dist to Nearest Coalbed (km)	Dist to Nearest Oil & Gas Fields(km)	Dist to Nearest EOR Oil (km)	Dist to Nearst Sink (km)
2334	Motiva Enterprises LLC	LA	235000	2335430	38.17	48.29	0	135	25	37	0
2445	Motiva Enterprises LLC	TX	250000	2484500	37.83	47.86	0	38	7	48	0
1122	CONOCOPHILLIPS	LA	252000	2504376	37.79	47.81	0	26	10	28	0
831	CONOCOPHILLIPS	LA	253500	2519283	37.76	47.77	0	166	14	40	0
2718	Premcor Refg Group Inc	TX	255000	2534190	37.73	47.73	0	38	7	48	0
2085	Lyondell Citgo Refining Co. Ltd.	TX	270200	2685248	37.42	47.33	0	13	19	19	0
709	Citgo Petroleum Corp.	LA	324300	3222893	36.45	46.11	0	29	13	28	0
1305	Deer Park Refg Ltd Ptnrshp	TX	333700	3316311	36.30	45.92	0	29	1	11	0
1475	ExxonMobil Refg & Supply Co.	TX	348500	3463393	36.08	45.64	0	15	12	45	0
168	BP Products North America, Inc.	TX	437000	4342906	34.93	44.18	0	71	2	2	0
1386	ExxonMobil Refg & Supply Co.	LA	493500	4904403	34.32	43.42	0	78	13	77	0
1433	ExxonMobil Refg & Supply Co.	TX	557000	5535466	33.73	42.68	0	32	14	23	0

Appendix G. CO_2 Sequestration Full Cost Estimation, eastern Texas

(1) Company Name	(2) Facility Name	(3) Plant Type	(4) Annual CO2 Flow (Mt)	(5) Destination[1]	(6) Pipeline Diameter (Inch)	(7) Capture Cost ($/t)	(8) Transportation Cost ($/t)	(9) EOR Credit ($/t)	(10) Injection Cost ($/t)	(11) Total Cost ($/t)
TXU Generation LLC	RIVER CREST	Power Plant	0.50	O319	8	69.21	0.33	16.00		53.54
Garland City of	RAY OLINGER	Power Plant	1.57	O136	12	58.09	2.29	16.00		44.38
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	6	13.11	0.00	16.00		-2.89
Southwestern Electri	KNOX LEE	Power Plant	1.87	O80	12	55.55	0.27	16.00		39.82
La Gloria Oil & Gas		Refinery	0.49	O92	8	46.99	2.17	16.00		33.16
AEP NUGs	MARTIN LAKE	Power Plant	18.25	O80	30	31.69	0.10	16.00		15.79
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	6	13.11	2.57	16.00		-0.32
Duke Energy Field Se	East Texas	GAS PROC	0.43	O80	6	13.11	1.10	16.00		-1.79
Entergy Gulf States	LEWIS CREEK	Power Plant	2.18	O59	12	54.11	0.29	16.00		38.40
University of Texas	UNIVERSITY OF TEX	Power Plant	0.28	O115	6	70.13	6.00	16.00		60.13
Texas Genco	DEEPWATER	Power Plant	0.86	O358	8	63.88	0.88	16.00		48.76
CEMEX		Cement	0.61	O115	8	37.03	4.09	16.00		25.12
Texas Genco	WEBSTER	Power Plant	1.90	O358	12	56.19	0.09	16.00		40.28
El Paso Field Servic	Thompsonville	GAS PROC	0.16	O317	6	14.66	8.18	16.00		6.84
Panda Energy	LAMAR POWER PRO	Power Plant	1.05	O136	12	48.52	3.68	16.00		36.20
Terra Industries, In		Ammonia	0.26	O8	6	13.84	7.44	16.00		5.28
Air Liquide America	SABINE COGEN LP	Power Plant	0.27	O8	6	70.34	7.20	16.00		61.54
E I DuPont De Nemour	SABINE RIVER WORK	Power Plant	0.27	O8	6	69.91	7.05	16.00		60.96
Motiva Enterprises L	PORT ARTHUR REFI	Power Plant	0.36	O8	6	68.05	2.87	16.00		54.92
Exxon Mobil	BAYTOWN TURBINE	Power Plant	0.59	O59	8	62.68	3.52	16.00		50.20
Exxon Mobil	EXXON MOBIL CO U	Power Plant	0.57	O59	8	62.54	3.63	16.00		50.17
Copano Energy LLC	Houston Central	GAS PROC	0.38	O200	6	13.28	3.40	16.00		0.68
VALERO REFINING CO T		Refinery	1.83	O135	12	38.95	0.60	16.00		23.55
Marathon Ashland Pet		Refinery	0.64	O135	8	45.22	1.30	16.00		30.52
BP Amoco	POWER STATION 3	Power Plant	0.48	O135	8	68.69	1.33	16.00		54.02
Sweeny Cogeneration	SWEENY COGENERA	Power Plant	1.67	O322	12	55.53	0.64	16.00		40.17
TXU Generation LLC	COLLIN	Power Plant	0.67	O136	8	65.75	4.92	16.00		54.67

Note: 1.Destination Code O represents oil fileds, G represents gas fields. The number is taken from the ID field in the SECARB sink database.

Appendix G: (Continued)

(1) Company Name	(2) Facility Name	(3) Plant Type	(4) Annual CO2 Flow (Mt)	(5) Destination	(6) Pipeline Diameter (Inch)	(7) Capture Cost ($/t)	(8) Transportation Cost ($/t)	(9) EOR Credit ($/t)	(10) Injection Cost ($/t)	(11) Total Cost ($/t)
Occidental Chemical	DEER PARK PLANT	Power Plant	0.34	O313	6	69.35	7.65	16.00		61.00
ExxonMobil Corp.	King Ranch	GAS PROC	0.51	O25	8	12.85	6.42	16.00		3.27
Bryan City of	DANSBY	Power Plant	0.45	Aquifer	8	69.96	0.00		0.93	70.89
Bryan City of	BRYAN	Power Plant	0.74	Aquifer	8	67.04	0.00		0.57	67.61
Texas Municipal Powe	GIBBONS CREEK	Power Plant	2.93	Aquifer	16	38.55	0.00		0.14	38.69
Tenaska	TENASKA FRONTIER	Power Plant	5.42	Aquifer	16	49.66	0		0.08	49.74
ExxonMobil Refg & Su		Refinery	3.12	Aquifer	16	36.08	0		0.14	36.22
Entergy Gulf States	SABINE	Power Plant	8.13	Aquifer	20	43.95	0		0.05	44.00
ExxonMobil Corp.	Katy	GAS PROC	0.52	Aquifer	8	12.81	0		0.81	13.62
Texas Genco	T H WHARTON	Power Plant	5.10	Aquifer	16	46.55	0		0.08	46.63
Lower Colorado River	FAYETTE POWER PR	Power Plant	11.26	Aquifer	24	32.98	0		0.04	33.02
Motiva Enterprises L		Refinery	2.24	Aquifer	12	37.83	0		0.19	38.02
Premcor Refg Group I		Refinery	2.28	Aquifer	12	37.73	0		0.19	37.92
Atofina Petrochemica		Refinery	1.57	Aquifer	12	39.81	0		0.27	40.08
Exxon Mobil	BEAUMONT REFINE	Power Plant	2.14	Aquifer	12	63.02	0		0.20	63.22
AES NUGs	AES DEEPWATER IN	Power Plant	1.72	Aquifer	12	42.73	0		0.25	42.98
Texas Genco	SAN JACINTO SES	Power Plant	0.57	Aquifer	8	64.51	0		0.75	65.26
Occidental Chemical	HOUSTON CHEMICA	Power Plant	0.48	Aquifer	8	63.26	0		0.88	64.14
Shell	SHELL DEER PARK	Power Plant	0.80	Aquifer	8	61.09	0		0.53	61.62
Air Liquide America	BAYOU COGENERAT	Power Plant	0.83	Aquifer	8	59.37	0		0.51	59.88
Calpine	CLEAR LAKE COGEN	Power Plant	1.35	Aquifer	12	57.29	0		0.31	57.60
Dow Chemical	OYSTER CREEK UNIT	Power Plant	1.39	Aquifer	12	54.84	0		0.31	55.15
Dynegy Generation	COGEN LYONDELL I	Power Plant	1.50	Aquifer	12	53.79	0		0.28	54.07
Calpine	PASADENA COGENE	Power Plant	2.40	Aquifer	12	51.33	0		0.18	51.51
Texas Genco	GREENS BAYOU	Power Plant	3.89	Aquifer	16	50.19	0		0.11	50.30
Valero Refining Co.		Refinery	0.74	Aquifer	8	44.31	0		0.57	44.88
Lyondell Citgo Refin		Refinery	2.42	Aquifer	12	37.42	0		0.18	37.60
Texas Genco	CEDAR BAYOU	Power Plant	8.49	Aquifer	20	43.19	0		0.05	43.24

Appendix G: (Continued)

(1) Company Name	(2) Facility Name	(3) Plant Type	(4) Annual CO2 Flow (Mt)	(5) Destination	(6) Pipeline Diameter (Inch)	(7) Capture Cost ($/t)	(8) Transportation Cost ($/t)	(9) EOR Credit ($/t)	(10) Injection Cost ($/t)	(11) Total Cost ($/t)
ExxonMobil Refg & Su		Refinery	4.98	Aquifer	16	33.73	0		0.08	33.81
Texas Genco	SAM BERTRON	Power Plant	3.65	Aquifer	16	50.21	0		0.12	50.33
Deer Park Refg Ltd P		Refinery	2.98	Aquifer	16	36.30	0		0.14	36.44
Crown Central Petro		Refinery	0.89	Aquifer	8	43.14	0		0.47	43.61
Texas Genco	P H ROBINSON	Power Plant	8.52	Aquifer	20	43.13	0		0.05	43.18
Texas Genco	W A PARISH	Power Plant	27.00	Aquifer	30	29.85	0		0.02	29.87
BP Products North Am		Refinery	3.91	Aquifer	16	34.93	0		0.11	35.04
BP Amoco	POWER STATION 4	Power Plant	0.51	Aquifer	8	63.71	0		0.82	64.53
Texas City Cogenerat	TEXAS CITY COGENI	Power Plant	1.31	Aquifer	12	55.72	0		0.32	56.04
Dow Chemical	THE DOW CHEMICAI	Power Plant	3.75	Aquifer	16	46.77	0		0.11	46.88
CONOCOPHILLIPS		Refinery	1.94	Aquifer	12	38.61	0		0.22	38.83
AEP NUGs	VICTORIA	Power Plant	2.02	Aquifer	12	55.51	0		0.21	55.72
San Miguel Electric	SAN MIGUEL	Power Plant	3.36	Aquifer	16	38.91	0		0.13	39.04
AEP NUGs	COLETO CREEK	Power Plant	3.56	Aquifer	16	37.44	0		0.12	37.56
AEP NUGs	E S JOSLIN	Power Plant	0.95	Aquifer	12	61.69	0		0.44	62.13
VALERO ENERGY CORPOR		Refinery	0.80	Aquifer	8	43.79	0		0.53	44.32
Union Carbide	SEADRIFT PLANT UN	Power Plant	0.56	Aquifer	8	65.00	0		0.75	65.75
Formosa Plastics Cor	FORMOSA UTILITY V	Power Plant	1.66	Aquifer	12	52.58	0		0.25	52.83
LG&E Power Services	GREGORY POWER FA	Power Plant	1.15	Aquifer	12	55.45	0		0.37	55.82
Occidental Chemical	INGLESIDE COGENEI	Power Plant	0.97	Aquifer	12	54.35	0		0.44	54.79
AEP NUGs	LON C HILL	Power Plant	2.41	Aquifer	12	54.63	0		0.18	54.81
AEP NUGs	NUECES BAY	Power Plant	1.99	Aquifer	12	54.58	0		0.21	54.79
AEP NUGs	LAREDO	Power Plant	0.75	Aquifer	8	64.99	0		0.56	65.55
AEP NUGs	BARNEY M DAVIS	Power Plant	2.59	Aquifer	12	52.64	0		0.16	52.80
Hidalgo Energy Cente	HIDALGO ENERGY C	Power Plant	1.18	Aquifer	12	54.81	0		0.36	55.17
CSW Energy Inc	FRONTERA GENERA'	Power Plant	1.50	Aquifer	12	54.62	0		0.28	54.90
AEP NUGs	J L BATES	Power Plant	0.75	Aquifer	8	65.13	0		0.56	65.69
AEP NUGs	LA PALMA	Power Plant	1.05	Aquifer	12	61.39	0		0.40	61.79

Appendix G: (Continued)

(1) Company Name	(2) Facility Name	(3) Plant Type	(4) Annual CO2 Flow (Mt)	(5) Destination	(6) Pipeline Diameter (Inch)	(7) Capture Cost ($/t)	(8) Transportation Cost ($/t)	(9) EOR Credit ($/t)	(10) Injection Cost ($/t)	(11) Total Cost ($/t)
Brownsville Public U	SI RAY	Power Plant	0.64	Aquifer	8	66.52	0		0.66	67.18
Texas Genco	LIMESTONE	Power Plant	11.92	Aquifer	24	33.13	0		0.06	33.19
Sempra Energy Resour	TNP ONE	Power Plant	2.71	Aquifer	16	39.65	0		0.16	39.81
AEP NUGs	MONTICELLO	Power Plant	15.17	Aquifer	24	32.38	0		0.06	32.44
Southwestern Electri	WELSH	Power Plant	11.81	Aquifer	24	33.35	0.00		0.06	33.41
TXU Generation LLC	TRINIDAD	Power Plant	0.99	Aquifer	12	61.34	0.00		0.43	61.77
TXU Generation LLC	BIG BROWN	Power Plant	9.51	Aquifer	20	34.37	0.00		0.07	34.44
Southwestern Electri	WILKES	Power Plant	3.13	Aquifer	16	50.85	0.00		0.14	50.99
TXU Generation LLC	STRYKER CREEK	Power Plant	2.90	Aquifer	16	51.85	0.00		0.15	52.00
TXU Generation LLC	LAKE HUBBARD	Power Plant	3.78	Aquifer	16	49.76	0.00		0.14	49.90
Southwestern Electri	PIRKEY	Power Plant	5.10	Aquifer	16	36.81	0.00		0.10	36.91
Duke Energy Field Se	East Texas	GAS PROC	0.43	Aquifer	6	13.11	0.00		0.98	14.09
Alcoa NUGS	SANDOW	Power Plant	2.77	Aquifer	16	39.47	0.05		0.15	39.67
TXU Generation LLC	TRADINGHOUSE	Power Plant	5.03	Aquifer	16	46.77	0.21		0.11	47.09
TXU Generation LLC	LAKE CREEK	Power Plant	1.42	Aquifer	12	58.73	0.62		0.30	59.65
AEP NUGs	SANDOW	Power Plant	4.47	Aquifer	16	37.29	0.08		0.09	37.46
Austin City of	DECKER CREEK	Power Plant	3.74	Aquifer	16	49.72	0.53		0.11	50.36
Austin City of	HOLLY STREET	Power Plant	2.05	Aquifer	12	53.88	1.10		0.21	55.19
Lower Colorado River	SIM GIDEON	Power Plant	2.38	Aquifer	12	52.75	0.06		0.18	52.99
Texas-Lehigh Ce		Cement	0.73	Aquifer	8	36.23	1.63		0.58	38.44
Texas Industrie		Cement	0.52	Aquifer	8	37.78	2.51		0.81	41.10
Guadalupe Power Part	GUADALUPE GENER	Power Plant	6.97	Aquifer	20	48.17	0.22		0.06	48.45
San Antonio Public S	W B TUTTLE	Power Plant	2.20	Aquifer	12	54.90	0.85		0.19	55.94
San Antonio Public S	A VON ROSENBERG	Power Plant	1.42	Aquifer	12	54.01	1.51		0.30	55.82
Alamo Cement Co		Cement	0.54	Aquifer	8	37.63	4.41		0.79	42.83
Capitol Aggrega		Cement	0.59	Aquifer	8	37.22	4.04		0.72	41.98
San Antonio Public S	MISSION ROAD	Power Plant	0.48	Aquifer	8	69.07	5.11		0.88	75.06
San Antonio Public S	LEON CREEK	Power Plant	0.99	Aquifer	12	63.82	1.07		0.43	65.32

Appendix G: (Continued)

(1) Company Name	(2) Facility Name	(3) Plant Type	(4) Annual CO2 Flow (Mt)	(5) Destination	(6) Pipeline Diameter (Inch)	(7) Capture Cost ($/t)	(8) Transportation Cost ($/t)	(9) EOR Credit ($/t)	(10) Injection Cost ($/t)	(11) Total Cost ($/t)
San Antonio Public S	J T DEELY	Power Plant	6.43	Aquifer	20	35.54	0.08		0.07	35.69
San Antonio Public S	O W SOMMERS	Power Plant	3.62	Aquifer	16	50.07	0.12		0.12	50.31
San Antonio Public S	J K SPRUCE	Power Plant	3.94	Aquifer	16	37.63	0.11		0.11	37.85
San Antonio Public S	V H BRAUNIG	Power Plant	6.07	Aquifer	20	50.05	0.10		0.07	50.22
Lower Colorado River	THOMAS C FERGUSC	Power Plant	1.73	Aquifer	12	55.80	1.99		0.25	58.04
TXU Generation LLC	PARKDALE	Power Plant	1.53	Aquifer	12	58.20	1.00		0.28	59.48
Exelon Generation	HANDLEY	Power Plant	6.37	Aquifer	20	46.49	0.54		0.08	47.11
Exelon Generation	MOUNTAIN CREEK	Power Plant	4.16	Aquifer	16	49.51	0.45		0.13	50.09
Holcim (US) Inc		Cement	1.37	Aquifer	12	33.50	1.02		0.31	34.83
Texas Industrie		Cement	1.71	Aquifer	12	32.58	0.81		0.25	33.64
Mirant Corp	MIRANT TEXAS LP E	Power Plant	1.47	Aquifer	12	58.22	1.65		0.29	60.16
North Texas Cem		Cement	0.57	Aquifer	8	37.38	1.84		0.74	39.96
ANP	MIDLOTHIAN ENERC	Power Plant	1.56	Aquifer	12	48.08	0.28		0.27	48.63
TXU Generation LLC	VALLEY	Power Plant	4.84	Aquifer	16	47.95	0.29		0.11	48.35
North American Energ	TENASKA IV TEXAS	Power Plant	0.81	Aquifer	8	59.93	1.92		0.52	62.37
North American Energ	TENASKA III TEXAS	Power Plant	0.83	Aquifer	8	61.09	0.50		0.51	62.10
TXU Generation LLC	NORTH MAIN	Power Plant	0.57	G287	8	68.86	3.07		3.09	75.02
TXU Generation LLC	NORTH LAKE	Power Plant	2.87	G287	16	51.90	0.61		2.30	54.81
TXU Generation LLC	EAGLE MOUNTAIN	Power Plant	3.30	G287	16	51.93	0.15		2.29	54.37

Southeast Regional Carbon Sequestration Partnership

Technical Team and Technology Council Membership

Protocol	First Name	Last Name	Role in SERCSP	Title	Organization	Address1	City	State	Zip	Phone	Fax	Email
Technical Team												
Southern States Energy Board												
Mr.	Kenneth	Nemeth	Project Director	Executive Director	Southern States Energy Board	6325 Amherst Court	Norcross	GA	30092	(770) 242-7712	(770) 242-9956	nemeth@sseb.org
Ms.	Kathryn	Baskin	Project Manager	Managing Director	Southern States Energy Board	6325 Amherst Court	Norcross	GA	30092	(770) 242-7712	(770) 242-9956	baskin@sseb.org
Dr.	Gerald	Hill	Tech Manager	Senior Technical Adviso	Southern States Energy Board	6325 Amherst Court	Norcross	GA	30092	(770) 894-4709	(770) 894-4709	hill@sseb.org
Ms.	Kathy	Sammons	Financial	Business Operations Manage	Southern States Energy Board	6325 Amherst Court	Norcross	GA	30092	(770) 242-7712	(770) 242-9956	sammons@sseb.org
Ms.	Kimberly	Sams	Tech Team Asst	Assistant Manager, Project Operations	Southern States Energy Board	6325 Amherst Court	Norcross	GA	30092	(770) 242-7712	(770) 242-0421	sams@sseb.org
Ms.	Leigh	Parson	Financial	Accounting Assistant	Southern States Energy Board	6325 Amherst Court	Norcross	GA	30092	(770) 242-7712	(770) 242-9956	parson@sseb.org
Mr.	Gary	Garrett	Tech Team	ITRC Program Advisor	Southern States Energy Board	6325 Amherst Court	Norcross	GA	30092	(770) 242-7712	(770) 242-0421	garrett@sseb.org
Mr.	Cloyce	Brackett	Administrative	Projects & Training Coordinator	Southern States Energy Board	6325 Amherst Court	Norcross	GA	30092	(770) 242-7712	(770) 242-0421	brackett@sseb.org
Ms.	Monica	Childs	Administrative	Staff Assistant	Southern States Energy Board	6325 Amherst Court	Norcross	GA	30092	(770) 242-7712	(770) 242-0421	childs@sseb.org
Electric Power Research Institute (EPRI)												
Subcontractor to SSEB												
Mr.	Richard	Rhudy	Senior Tech Advisor	Project Manager	EPRI	3412 Hillview Avenue	Palo Alto	CA	94304	(650) 855-2421	(650) 855-8759	rrhudy@epri.com
Dr.	Kristie	Ebi	Tech Team	Technical Manager, Global Climate Change	EPRI	3412 Hillview Avenue	Palo Alto	CA	94304	(650) 855-2735		krisebi@epri.com
Mr.	Roger	Bedard	Financial		EPRI	3412 Hillview Avenue	Palo Alto	CA	94304	(650) 855-2131		rbedard@epri.com
	Stu	Dalton				3412 Hillview Avenue	Palo Alto	CA	94304	(650) 855-2467		sdalton@epri.com
	Stanley	Sussman		Vice President Environmen	EPRI	3412 Hillview Avenue	Palo Alto	CA	94304	(650) 855-2000		
	Adam	Davis			EPRIsolutions					(415) 454-8800		adavis@eprisolutions.com
	Adam	Diamant			EPRIsolutions					(415) 454-8800		adiamant@eprisolutions.com
Mississippi State University Diagnostic Instrumentation Analysis Laboratory (MSU-DIAL)												
Subcontractor to SSEB												
Dr.	M. John	Plodinec	Senior Tech Advisor	Director	Diagnostic Instrumentation Analysis Laboratory at MSU	205 Research Boulevard	Starkville	MS	39759	(662) 325-8701	(662) 325-8465	plodinec@dial.msstate.edu
Dr.	Jeffrey	Lindner	Tech Team	Research Professor	Diagnostic Instrumentation Analysis Laboratory at MSU	205 Research Boulevard	Starkville	MS	39759	(662) 325-7641	(662) 325-8465	lindner@dial.msstate.edu
Dr.	Fengxiang	Han	Tech Team	Assistant Research Professor	Diagnostic Instrumentation Analysis Laboratory at MSU	205 Research Boulevard	Starkville	MS	39759	(662) 325-2897	(662) 325-8465	han@dial.msstate.edu
Dr.	Chuji	Wang	Tech Team	Assistant Research Professor	Diagnostic Instrumentation Analysis Laboratory at MSU	205 Research Boulevard	Starkville	MS	39759	(662) 325-7388	(662) 325-8465	wang@dial.msstate.edu
Dr.	Donald	Grebner	Tech Team	Associat Professor	Forestry Department, MSU	PO Box 9681	Starkville	MS	39762	(662) 325-0928	(662) 325-8465	dgrebner@cfr.msstate.edu
Dr.	Sandra	Harpole	Tech Team	Associate VP for Research	Office of Research, MSU	PO Box 6343	Starkville	MS	39762	(662) 325-3570	(662) 325-8465	sharpole@research.msstate.edu
Dr.	Darrel	Schmitz	Tech Team	Professor	Department of Geosciences, MSU	PO Box 5448	Starkville	MS	39762	(662) 325-3915	(662) 325-8465	schmitz@ra.msstate.edu
Ms.	Yu (Rita)	Zhong	Tech Team	Research Engineer	Diagnostic Instrumentation Analysis Laboratory at MSU	205 Research Boulevard	Starkville	MS	39759	(662) 325-2891	(662) 325-8465	zhong@dial.msstate.edu
Ms.	Michelle	Eaves	Financial	Finance Manager	Diagnostic Instrumentation Analysis Laboratory at MSU	205 Research Boulevard	Starkville	MS	39759	(662) 325-7197	(662) 325-8465	eaves@dial.msstate.edu
Ms.	Tina	Hood	Financial	Asc Administrator	MSU-DIAL Sponsored Programs	PO BOX 6156	Starkville	MS	39762	(662) 325-3273	6623253803??	thood@spa.msstate.edu
Massachusetts Institute of Technology (MIT)												
Subcontractor to EPRI, Managed by EPRI												
Mr.	Howard	Herzog	Technical Advisor - Carbon Source Data, Archiving Data and Evaluation	Principal Research Engineer	Massachusetts Institute of Technology	1 Amherst Street, Room E40-471	Cambridge	MA	02139	(617) 253-0688	(617) 253-8013	hjherzog@mit.edu
Mr.	Henry	Zhang										hlzhang@MIT.EDU
Tennessee Valley Authority Public Power Institute (TVA-PPI)												
Subcontractor to EPRI, Managed by EPRI												
	Frances	Weatherford	Technical Advisor - CO2 Source and Economics	Senior Manager, Research & Technology Applications, Environmental Technologies	Tennessee Valley Authority	Reservation Road, CTR 2T	Muscle Shoals	AL	35661	(256) 386-2556	(256) 386-2126	fpweartherford@tva.gov
Mr.	Ed	Stephens		Project Manager	Tennessee Valley Authority Research & Technology Applications, Environmental Technologies	1101 Market Street, SP 5D	Chattanooga	TN	37402-2801	(423) 751-7474	(423) 751-6087	eastephens@tva.gov

Protocol	First Name	Last Name	Role in SERCSP	Title	Organization	Address1	City	State	Zip	Phone	Fax	Email
Winrock International												
Subcontractor to EPRI, Managed by EPRI												
Mr.	John	Kadyszewski	Technical Advisor - Terrestrial Storage Data and Archiving Data and Evaluation	Coordinator, Ecosystem Services	Winrock International	1621 N. Kent Street, Suite 1200	Arlington	VA	22209-2134	(703) 525-9430	(703) 525-1744	jkadyszewski@winrock.org
Ms.	Sandra	Brown			Winrock Internationa							
Mr.	Aaron	Dushku			Winrock Internationa							
Mr.	Nathan	Moore			Winrock Internationa							
Mr.	Jonathan	Brooks			Winrock Internationa							
Mr.	Jonathan	Winsten			Winrock Internationa							
	Ye	Qi			Winrock Internationa							
Mr.	David	Shoch			Winrock Internationa							
Ms.	Inna	Vancurova	Administrative		Winrock Internationa							
Augusta Systems, Incorporated												
Subcontractor to SSEB												
Dr.	Patrick	Esposito, Sr.	Technical Advisor - Geologic Sequestration Research, Industry and Public Outreach	Founder and Chief Executive Officer	Augusta Systems, Incorporated	3606 Collins Ferry Road, Suite 202	Morgantown	WV	26505	(304) 599-3200	(304) 599-3480	pesposito@augustasystems.com
Mr.	Patrick	Esposito, II	Technical Advisor - Regulatory and Permitting Requirements, Outreach Activities	Chief Operating Officer	Augusta Systems, Incorporated	3606 Collins Ferry Road, Suite 202	Morgantown	WV	26505	(304) 599-3200	(304) 599-3480	patesposito@augustasystems.com
Mr.	C. David	Locke	Tech Team	Director of Engineering	Augusta Systems, Incorporated	3606 Collins Ferry Road, Suite 202	Morgantown	WV	26505	(304) 599-3200	(304) 599-3480	clocke@augustasystems.com
Mr.	William	Overbey	Tech Team	Senior Geologist	Augusta Systems, Incorporated	3606 Collins Ferry Road, Suite 202	Morgantown	WV	26505	(304) 599-3200	(304) 599-3480	woverbey@augustasystems.com
Ms.	Janet	Wood	Tech Team	Project Engineer	Augusta Systems, Incorporated	3606 Collins Ferry Road, Suite 202	Morgantown	WV	26505	(304) 599-3200	(304) 599-3480	jwood@augustasystems.com
Mr.	James	Dobbs	Tech Team	Director of Corporate Relations	Augusta Systems, Incorporated	3606 Collins Ferry Road, Suite 202	Morgantown	WV	26505	(304) 599-3200	(304) 599-3480	jdobbs@augustasystems.com
Ms.	Michelle	Varga	Financial	Director of Operations	Augusta Systems, Incorporated	3606 Collins Ferry Road, Suite 202	Morgantown	WV	26505	(304) 599-3200	(304) 599-3480	mvarga@augustasystems.com
Applied Geo Technologies (AGT)												
Subcontractor to DIAL												
Mr.	David	Dermody	Technical Advisor - Archiving Data and Evaluation	Senior Geodetic Engineer	Applied Geo Technologies	390 Industrial Road	Choctaw	MS	39350			
Mr.	Michael	Frank	Tech Team	Software & Systems Support Engineer	Applied Geo Technologies	390 Industrial Road	Choctaw	MS	39350			
Mr.	Daniel	Kruempel	Tech Team	Production Manager	Applied Geo Technologies	390 Industrial Road	Choctaw	MS	39350			
Mr.	Jason	Bourisaw	Tech Team	Productions Specialist	Applied Geo Technologies	390 Industrial Road	Choctaw	MS	39350			
Mr.	Kyle	Ritzheimer	Tech Team	Productions Specialist	Applied Geo Technologies	390 Industrial Road	Choctaw	MS	39350			
Mr.	Eric	Wilson	Tech Team	Productions Specialist	Applied Geo Technologies	390 Industrial Road	Choctaw	MS	39350			
Mr.	James	Kelley	Tech Team	Senior GIS Analyst	Applied Geo Technologies	390 Industrial Road	Choctaw	MS	39350			
Ms.	Michelle	White	Tech Team	GIS Analyst	Applied Geo Technologies	390 Industrial Road	Choctaw	MS	39350			
Mr.	Jim	Markel	Financial		Applied Geo Technologies	390 Industrial Road	Choctaw	MS	39350	(601) 389-3159		jmarkel@choctawgeo.com
Mr.	Allen	Hines		President	Applied Geo Technologies	390 Industrial Road	Choctaw	MS	39350	(601) 389-3084	(601) 389-3015	
Geological Survey of Alabama (GSA)												
Subcontractor to SSEB												
Dr.	Robert	Mink		Deputy Director	Geological Survey of Alabama	420 Hackberry Lane	Tuscaloosa	AL	35486	(205) 247-3589	(205) 349-2861	bmink@gsa.state.al.us
Dr.	Jack	Pashin	Technical Advisor - Assessment of Safety Requirements for Technology Deployment and Ecosystems Impacts	Manager, Energy and Minerals Group	Geological Survey of Alabama	420 Hackberry Lane	Tuscaloosa	AL	35486	(205) 247-3558	(205) 349-2861	jpashin@gsa.state.al.us
Dr.	Richard	Carroll	Tech Team	Coal Geologist	Geological Survey of Alabama	420 Hackberry Lane	Tuscaloosa	AL	35486		(205) 349-2861	rcarroll@gsa.state.al.us
Dr.	Guohai	Jin	Tech Team	Geologist	Geological Survey of Alabama	420 Hackberry Lane	Tuscaloosa	AL	35486	(205) 247-3560	(205) 349-2861	gjin@gsa.state.al.us
Mr.	Wayne	Payton	Tech Team	Geologist	Geological Survey of Alabama	420 Hackberry Lane	Tuscaloosa	AL	35486		(205) 349-2861	wpayton@gsa.state.al.us
Mr.	Stephen	Jones	Tech Team	Geologist II	Geological Survey of Alabama	420 Hackberry Lane	Tuscaloosa	AL	35486		(205) 349-2861	sjones@gsa.state.al.us
Mr.	Berry "Nick"	Tew, Jr.		State Geologist and Oil & Gas Supervisor	Geological Survey of Alabama	420 Hackberry Lane	Tuscaloosa	AL	35486	(205) 349-2852	(205) 349-2861	

Protocol	First Name	Last Name	Role in SERCSP	Title	Organization	Address1	City	State	Zip	Phone	Fax	Email
Susan Rice and Associates, Incorporated												
Subcontractor to EPRI, Managed by EPRI												
Dr.	Susan	Rice	Technical Advisor - Assessment of Safety Requirements for Technology Deployment and Ecosystem Impacts	President	Susan Rice and Associates, Incorporated	19816 Buck Ridge Road	Grass Valley	CA	95949-7025	(530) 346-9612	(530) 346-9512	
Advanced Resources International (ARI)												
Subcontractor to EPRI, Managed by EPRI												
Mr.	Vello	Kuuskraa	Technical Advisor - Identifying Transport Options and Geologic Storage and Sequrestration Options	President	Advanced Resources International	4501 Fairfax Drive, Suite 910	Arlington	VA	22203	(703) 528-8420	(703) 528-0439	vkuuskraa@adv-res.com
Mr.	Michael	Godec	Tech Team	Vice President	Advanced Resources International	4501 Fairfax Drive, Suite 910	Arlington	VA	22203	(703) 528-8420	(703) 528-0439	mgodec@adv-res.com
Mr.	Greg	Bank	Tech Team		Advanced Resources International	4501 Fairfax Drive, Suite 910	Arlington	VA	22203	(703) 528-8420	(703) 528-0439	
Ms.	Joyce	Frank	Administrative		Advanced Resources International	4501 Fairfax Drive, Suite 910	Arlington	VA	22203	(703) 528-8420	(703) 528-0439	
The Phillips Group												
Subcontractor to SSEB												
Mr.	Bill	Phillips, Jr.	Technical Advisor - Public/Industry Involvement, Education and Outreach	President & CEO	The Phillips Group	98 Findley Street	Elkins	WV	26241	(304) 636-5568	(304) 636-1707	phillipsb@meer.net
Ms.	Tracy	Fath	Tech Team	Director of Marketing	The Phillips Group	98 Findley Street	Elkins	WV	26241	(304) 636-5568	(304) 636-1707	fatht@meer.net
	Jeffrey	Loudin	Financial w/Bil		The Phillips Group	98 Findley Street	Elkins	WV	26241	(304) 636-5568	(304) 636-1707	loudinj@meer.net
RMS Strategies												
Subcontractor to SSEB												
Mr.	Robert	Samples	Technical Advisor - Public/Industry Involvement, Education and Outreach	CEO & Managing Partner	RMS Research	One Bridge Place, 10 Hale Street	Charleston	WV	25301	(304) 343-7655	(304) 343-9644	rsamples@rmsstrategies.com
Ms.	Sheri	Skidmore	Tech Team	Vice President, Operations	RMS Research	One Bridge Place, 10 Hale Street	Charleston	WV	25301	(304) 343-7655	(304) 343-9644	sskidmore@rmsstrategies.com
Mr.	Mark	Blankenship	Tech Team	Senior Account Executive	RMS Research	One Bridge Place, 10 Hale Street	Charleston	WV	25301	(304) 343-7655	(304) 343-9644	mblankenship@rmsstrategies.com
University of Texas at Austin, Beureau of Economic Geology												
Subcontractor to SSEB												
Dr.	Susan	Hovorka		Stratigrapher	University of Texas at Austin, Bureau of Economic Geology	Pickle Research Campus, 10100 Burnet Road, Building 130	Austin	TX	78758	(512) 471-4863	(512) 471-0140	susan.hovorka@beg.utexas.edu
Dr.	Scott	Tinker		Director	University of Texas at Austin, Bureau of Economic Geology	Pickle Research Campus, 10100 Burnet Road, Building 130	Austin	TX	78758	(512) 471-0209	(512) 471-0140	scott.tinker@beg.utexas.edu
			Co-PI		University of Texas at Austin, Bureau of Economic Geology	Pickle Research Campus, 10100 Burnet Road, Building 130	Austin	TX	78758	(512) 471-5739	(512) 471-0140	
	J.	Raney		Associate Director	University of Texas at Austin, Bureau of Economic Geology	Pickle Research Campus, 10100 Burnet Road, Building 130	Austin	TX	78758			
	M.	Holtz		Research Associate	University of Texas at Austin, Bureau of Economic Geology	Pickle Research Campus, 10100 Burnet Road, Building 130	Austin	TX	78758			
	R.	Reedy		Research Scientist Associate	University of Texas at Austin, Bureau of Economic Geology	Pickle Research Campus, 10100 Burnet Road, Building 130	Austin	TX	78758			
	C.	Breton		Research Scientist Associate	University of Texas at Austin, Bureau of Economic Geology	Pickle Research Campus, 10100 Burnet Road, Building 130	Austin	TX	78758			
	Deborah	Thomas	Financial		University of Texas at Austin, Bureau of Economic Geology	University Station, Box A	Austin	TX	78713	(512) 471-0305	(512) 471-0140	deborah.thomsas@beg.utexas.edu
Mr.	Bobby	McQuiston	Authorized Official for Signage	Director, Sponsored Projects	University of Texas at Austin	P.O. Box 7726	Austin	TX	78713-7726			
Virginia Polytechnic Institute and State University												
Subcontractor to SSEB												
Dr.	Michael	Karmis		Stonie Barker Professor	Virginia Tech, Mining and Minerals Engineering Department	103 Holden Hall, Mail Code 0239	Blacksburg	VA	24061	(540) 231-5273	(540) 231-4078	mkarmis@vt.edu
Dr.	Steven	Schafrik		Faculty	Virginia Tech	Virginia Tech	Blacksburg	VA	24060	(540) 231-5458	(540) 231-4078	
Mr.	Nino	Ripepi		Research Engineer	Virginia Tech, Virginia Center for Coal and Energy Research	Virginia Tech (0411)	Blacksburg	VA	24060	(540) 231-5458	(540) 231-4078	nripepi@vt.edu
Dr.	Carl	Zipper		Associate Professor	Virginia Tech, Department of Crop & Soil Environmental Sciences	Virginia Tech	Blacksburg	VA	24060			czip@vt.edu

Protocol	First Name	Last Name	Role in SERCSP	Title	Organization	Address1	City	State	Zip	Phone	Fax	Email
United States Department of Energy/National Energy Technology Laboratory (NETL)												
Ms.	Karen	Cohen		Project Manager	U.S. DOE/NETL	626 Cochrans Mill Road	Pittsburgh	PA	15260	(412) 386-6667	(412) 386-4775	karen.cohen@netl.doe.gov
Technology Coalition												
The Hon.	Brian	Griffin		Federal Representative	Southern States Energy Board	6701 Northwest 120th Street	Oklahoma City	OK	73162	(405) 722-8142	(405) 722-8142	bcgriffin@cox.net
SSEB Board Member Governors and Legislators												
SSEB Associate Members and Utility Advisory Committee Members												
Com.	Charles	Sharpe		Commissioner	South Carolina Dept. of Agriculture	PO BOX 11280	Columbia	SC	29211	(803) 734-2210	(803) 734-2192	crsharpe@scda.state.sc.us
Mr.	Grant	Black		Director	Arkansas Oil and Gas Commission	PO BOX 1472	El Dorado	AR	71731-1472	(870) 862-4965	(870) 862-8823	aogc@aogc.state.ar.us
Mr.	Hall	Bohlinger		Secretary	Louisiana Department of Environmental Quality	PO BOX 82263	Baton Rouge	LA	70884-2263	(225) 765-0741	(225) 765-0746	
Mr.	Paul	Burks		Executive Director	Georgia Environmental Facilities Authority	2090 Equitable Bldg; 100 Peachtree ST	Atlanta	GA	30303-1911	(404) 656-0938	(404) 656-6416	
					Georgia Forestry Commission	PO BOX 819	Macon	GA	31202-0819	(478) 751-3500	(478) 751-3465	
Mr.	Larry	Shirley		Director	North Carolina State Energy Officer	1340 Mail Service Center	Raleigh	NC	27699-1340	(919) 733-2230	(919) 733-2953	
Mr.	Phil	Bisesi		Program Manager	North Carolina State Energy Officer	1830 A Tillery Place	Raleigh	NC	27699-1340	(919) 735-1158	(919) 733-2953	phillip.bisesi@ncmail.net
Mr.	Steve	Wilson		Manager, Power Technologies Departmetn	Southern Company	PO BOX 2641	Birmingham	AL	35291-8195	(205) 257-5678		smwilson@southernco.com
Mr.	Larry	Monroe			Southern Company	PO BOX 2641	Birmingham	AL	35291-8195	(205) 257-7772		lsmonroe@southernco.com
Mr.	John Mark	Goodman			Southern Company	PO BOX 2641	Birmingham	AL	35291-8195	(205) 257-6805		jmgoodman@southernco.com
Mr.	Keith	Harrison			Southern Company Services	PO BOX 2641, Bin 14N-8195	Birmingham	AL	35291-8195	(205) 257-6805	(205) 257-5367	keharris@southernco.com
Ms.	Cindy	Angelelli			Duke Power	Mail Code: EC12ZA PO BOX 1006	Charlotte	NC	28201-1006	(704) 382-7990	(704) 373-6410	clangele@duke-energy.com
Mr.	Gregory	Nelson, P.E.		Director, Environmental Affairs	Tampa Electric Company	PO BOX 111	Tampa	FL	33601-0111	(813) 228-4111		
Ms.	Jeanelle	McCain		Director, Public Affairs	Progress Energy	1201 Main Street, Suite 1850	Columbia	SC	29201			
Mr.	James	Landreth		Vice President, Fossil-Hydro	South Carolina Electric & Gas Company	111 Research Park Drive	Columiba	SC	29203	(803) 217-7224	(803) 217-9568	
Mr.	Jim	Burwell			SCANA							
Ms.	Christine	Hansen		Executive Director	Interstate Oil and Gas Compact Commission	PO BOX 53127	Oklahoma City	OK	73152-3127	(405) 525-3556	(405) 525-3592	iogcc@iogcc.state.ok.us
Mr.	Kevin	Bliss		Washington Representative	Interstate Oil and Gas Compact Commission	1235 4th Street, SW	Washington	DC	20024	(202) 484-1026	(202) 484-1027	iogccdc@verizon.net
Mr.	Clifford	Miercort		President and CEO	The North American Coal Corporation	14785 Preston RD, Suite 1100-II	Dallas	TX	75254-7891	(972) 239-2625	(972) 387-1328	clifford.miercort@nacoal.com
Mr.	Mark	Worthey			The North American Coal Corporation	14785 Preston RD, Suite 1100-II	Dallas	TX	75254-7891	(972) 673-2020		
Mr.	Michael	Gregory			The North American Coal Corporation	14785 Preston RD, Suite 1100-II	Dallas	TX	75254-7891	(972) 239-2625		
Mr.	Peter	Dryburgh		Technology Development Manager	The North American Coal Corporation	14785 Preston RD, Suite 1100-II	Dallas	TX	75254-7891	(972) 448-5473	(972) 661-9072	peter.dryburgh@nacoal.com
Mr.	Butch	Wright		Business Development Manager	The North American Coal Corporation	14785 Preston RD, Suite 1100-II	Dallas	TX	75254-7891	(972) 448-5472	(972) 661-9072	butch.wright@nacoal.com
Mr.	Stephen	Miller		President and CEO	Center for Energy and Economic Development	333 John Carlyle Street, Suite 530	Alexandria	VA	22314	(703) 684-6292	(703) 684-6297	
Mr.	Randy	Eminger		Vice President, South Region	Center for Energy and Economic Development	5600 South Bell Street, Suite 105-306	Amarillo	TX	79109	(806) 359-5520	(806) 359-9155	reminger@ceednet.org
Mr.	Ned	Leonard		Associate Vice President, Policy	Center for Energy and Economic Development	333 John Carlyle Street, Suite 530	Alexandria	VA	22314	(703) 684-4748	(703) 684-6297	ned@ceednet.org
Mr.	George	Bullock		Consultant	Gerogia Power Company / Center for Energy and Economic Development	213 South Candler Street	Decatur	GA	30030-3743	(404) 371-9722	(404) 471-5157	gbullock@agnesscott.edu
Mr.	R. G.	Gilliland		Associate Laboratory Director	Oak Ridge National Laboratory	P.O. Box 2008	Oak Ridge	TN	37831-6248	(865) 574-9920	(865) 576-6118	gilliandrg@ornl.gov
Mr.	Gary	Jacobs			Oak Ridge National Laboratory					(865) 576-0567		jacobsgk@ornl.gov
Mr.	Keith	Pronske		CEO	Clean Energy Systems, Inc.	11330 Sunco Drive, Suite A	Rancho Cordova	CA	95742	(916) 378-9143	(916) 379-9146	klpronske@cleanenergysystems.com

Field Test Plan for Verification of Source/Sink Relationships-D45

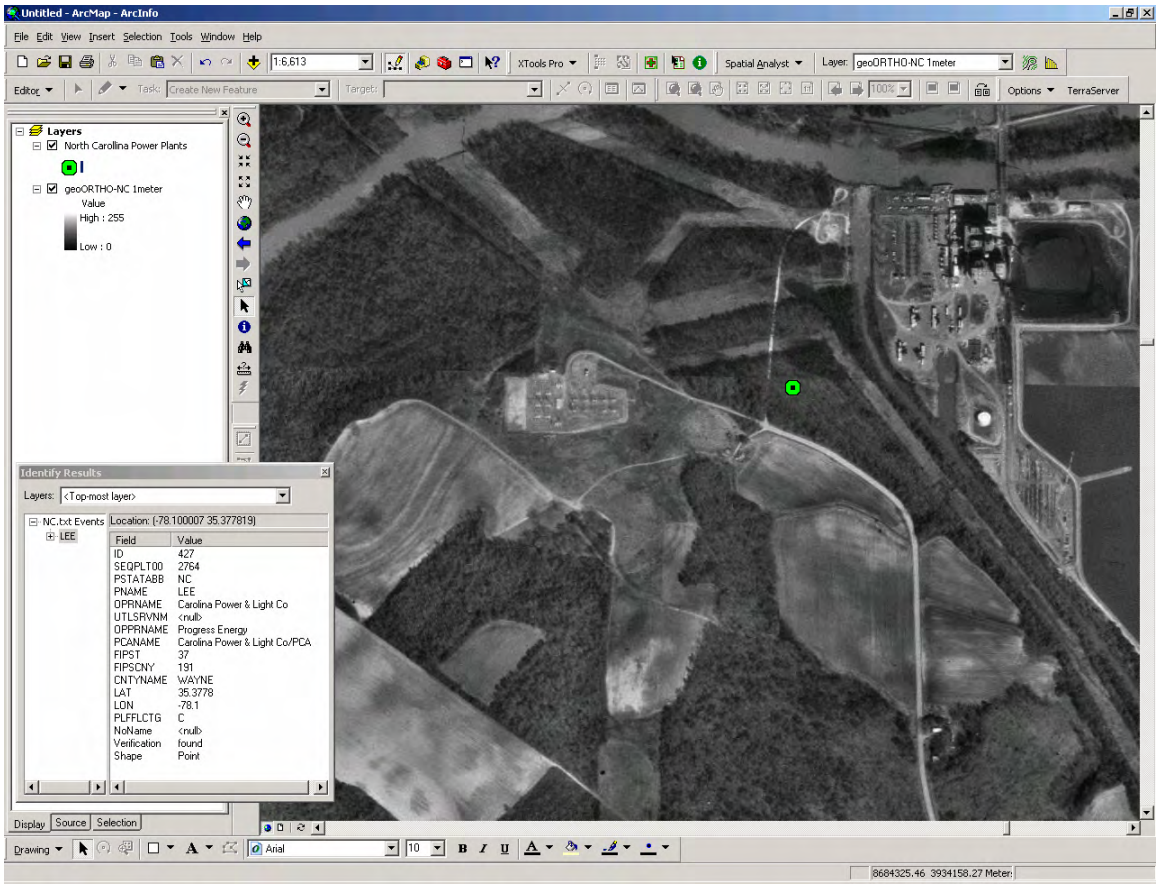
Atmospheric levels of CO_2 have cyclically risen 25% over the past decades. Scientific study suggests that the rise in atmospheric CO_2 levels is due to the extensive use of hydrocarbons for many forms of energy. With global energy use from countries like China and India increasing, carbon emissions will continue to impact our atmosphere and environment. Unless we change the way we produce and use energy, we should consider how to manage carbon. One way is to increase energy efficiency in everything we use in our daily lives, from the miles per gallon our car uses to your home's electrical and heating and cooling needs. Another way is to find alternate energy sources, such as nuclear power and renewable sources such as solar energy, wind power, and biomass fuels. Yet one of the newest and most promising technological approaches to limiting CO_2 in our atmosphere is carbon sequestration. Carbon sequestration refers to the provision of long-term storage of carbon in the terrestrial biosphere, underground, or the oceans so that the buildup of carbon dioxide (the principal greenhouse gas) concentration in the atmosphere will reduce or slow.

In developing a new and better technology to store or ingest CO_2 from our atmosphere, first we must spatially understand where the CO_2 is being produced. One of the major producers of atmospheric CO_2 (other than the automobile) is hydrocarbon power plants. These high producing CO_2 areas can be identified and modeled with geographic information systems (GIS) and analyzed to influence future decision making. Base layers such as topography, hydrology, geology, soil, vegetation, population centers and weather patterns can help

determine where new carbon sequestration technologies could be implemented and produce the largest overall benefit. For example, planting different plant species with enhanced levels of CO_2 use or storage around power plant wind corridors could result in favorable storage of atmospheric CO_2. Geographically, the accurate location of the power plants could influence where certain programs should be initiated and what quantitative measures should be used. In researching the availability of such information, the Environmental Protection Agency has already made a significant effort to quantify the amount of atmospheric CO_2 (among other greenhouse gases) in its EGRID (Emissions & Generation Resource Integrated Database) program. Yet due to EGRID's coarse spatial information (many of the locations where only found within the county), Applied Geo Technologies was assigned to identify and validate existing coordinate information from the EGRID database for 9 states in the southeastern United States.

To identify such a large amount of spatial information, Applied Geo Technologies used its' GeoORTHO aerial photography database for the southeastern United State to validate each of the coordinates supplied by the EPA's EGRID database. GeoORTHO is a Black-and-White, seamless, blended mosaic of USGS Digital Ortho Quarter Quad (DOQQ) aerial photography in one and four meter resolutions. The mosaic covers most of the continental United States. The GeoORTHO imagery meets National Map Accuracy Standards of 1:24,000. With such a high level of accuracy from the base aerial data, standard aerial photography techniques such as identifying high transmission right-of-way

power lines and corridors, cooling towers, and large water sources made the project feasible. Below shows an example of the process for each power plant's coordinate received and identifies that coal is being used at this facility.



In general, most of the major power plants were identified by latitude and longitude for the region, but a large amount only had the center of the counties' geographic area for the latitude and longitude value of the plant location. Only 190 of the 370 power plants were identified as "found", which means they were found within a ½ mile distance of the plant. The EPA/EGRID database was used due to the ease of availability, but due to post 9/11 concerns, no other

governmental agency would share precise GPS location data in reference to the power plants.

ID	SEQ	STATE	NAME	OPERATOR NAME	OWNER NAME	PCA NAME	COUNTY	LAT	LON	TYPE	VERIFY
408	2712	NC	ASHEVILLE	Carolina Power & Light Co	Progress Energy	Carolina Power & Light Co/PCA	BUNCOMBE	35.4714	-82.5431	C	found
409	2715	NC	BELEWS CREEK	Duke Power Co	Duke Energy Corporation	Duke Power Co/PCA	STOKES	36.2811	-80.0603	C	found
410	2722	NC	BUCK	Duke Power Co	Duke Energy Corporation	Duke Power Co/PCA	ROWAN	35.7133	-80.3767	C	found
411	2724	NC	CANTON NORTH CAROLINA	Champion International Corp		Carolina Power & Light Co/PCA	HAYWOOD	35.5413	-83.0005	C	
412	2725	NC	CAPE FEAR	Carolina Power & Light Co	Progress Energy	Carolina Power & Light Co/PCA	CHATHAM	35.5989	-79.0492	C	found
413	2734	NC	CLIFFSIDE	Duke Power Co	Duke Energy Corporation	Duke Power Co/PCA	CLEVELAND	35.22	-81.7594	C	found
414	2735	NC	COGENTRIX ELIZABETHTOWN	Cogentrix		Carolina Power & Light Co/PCA	BLADEN	34.6151	-78.5772	C	found
415	2736	NC	COGENTRIX KENANSVILLE	Cogentrix		Carolina Power & Light Co/PCA	DUPLIN	34.9525	-77.9236	C	
416	2737	NC	COGENTRIX LUMBERTON	Cogentrix		Carolina Power & Light Co/PCA	ROBESON	34.6264	-79.1432	C	found
417	2738	NC	COGENTRIX ROXBORO	Cogentrix		Carolina Power & Light Co/PCA	PERSON	36.3894	-78.9748	C	found
418	2739	NC	COGENTRIX SOUTHPORT	Cogentrix		Carolina Power & Light Co/PCA	BRUNSWICK	34.1051	-78.2935	C	
419	2743	NC	DAN RIVER	Duke Power Co	Duke Energy Corporation	Duke Power Co/PCA	ROCKINGHAM	36.4861	-79.7244	C	found
420	2746	NC	DWAYNE COLLIER BATTLE COGENERATION FACILITY	Cogentrix		Dominion Virginia Power/PCA	EDGECOMBE	35.9145	-77.5843	C	found
421	2747	NC	ENKA	BASF		Carolina Power & Light Co/PCA	BUNCOMBE	35.6211	-82.5299	C	found
422	2751	NC	G G ALLEN	Duke Power Co	Duke Energy Corporation	Duke Power Co/PCA	GASTON	35.1897	-81.0122	C	found
423	2759	NC	KANNAPOLIS ENERGY PARTNERS	Kannapolis Energy Partners LLC		Duke Power Co/PCA	CABARRUS	35.3459	-80.5416	C	
424	2760	NC	KANNAPOLIS ENERGY PARTNERS SPENCER	Fieldcrest Cannon Inc		Duke Power Co/PCA	ROWAN	35.6773	-80.4773	C	found

425	2761	NC	KINSTON NORTH CAROLINA PLANT	E I DuPont De Nemours & Co		Carolina Power & Light Co/PCA	LENOIR	35.2172	-77.6116	C	
426	2763	NC	L V SUTTON	Carolina Power & Light Co	Progress Energy	Carolina Power & Light Co/PCA	NEW HANOVER	34.2831	-77.9867	C	found
427	2764	NC	LEE	Carolina Power & Light Co	Progress Energy	Carolina Power & Light Co/PCA	WAYNE	35.3778	-78.1	C	found
428	2770	NC	MARSHALL	Duke Power Co	Duke Energy Corporation	Duke Power Co/PCA	CATAWBA	35.5975	-80.9658	C	found
429	2771	NC	MAYO	Carolina Power & Light Co	Progress Energy	Carolina Power & Light Co/PCA	PERSON	36.5278	-78.8919	C	found
430	2789	NC	RIVERBEND	Duke Power Co	Duke Energy Corporation	Duke Power Co/PCA	GASTON	35.36	-80.9742	C	found
431	2795	NC	ROXBORO	Carolina Power & Light Co	Progress Energy	Carolina Power & Light Co/PCA	PERSON	36.4831	-79.0711	C	found
432	2803	NC	TOBACCOVILLE UTILITY PLANT	R J Reynolds Tobacco Co		Duke Power Co/PCA	FORSYTH	36.1165	-80.2718	C	
433	2808	NC	UNC CHAPEL HILL COGENERATION FACILITY	University of N C Chapel Hill		Duke Power Co/PCA	ORANGE	36.0523	-79.1076	C	
434	2809	NC	W H WEATHERSPOON	Carolina Power & Light Co	Progress Energy	Carolina Power & Light Co/PCA	ROBESON	34.5889	-78.975	C	found
435	2814	NC	WESTMORELAND LG&E PARTNERS ROANOKE VALLEY II	LG&E Power Services	E.ON (Germany)	Dominion Virginia Power/PCA	HALIFAX	36.2571	-77.6284	C	
436	2815	NC	WESTMORELAND LG&E PARTNERS ROANOKE VALLEY 1	LG&E Power Services	E.ON (Germany)	Duke Power Co/PCA	HALIFAX	36.2571	-77.6284	C	
437	2723	NC	BUTLER WARNER GEN	Fayetteville Public Works Comm		Carolina Power & Light Co/PCA	CUMBERLAND	35.0489	-78.8066	G	
438	2765	NC	LINCOLN COMBUSTION	Duke Power Co	Duke Energy Corporation	Duke Power Co/PCA	LINCOLN	35.485	-81.2393	G	found
439	2783	NC	PANDA ROSEMARY LP	Panda Energy		Dominion Virginia Power/PCA	HALIFAX	36.2571	-77.6284	G	
440	2792	NC	ROCK TENN DALLAS MILL	Rock-Tenn Co		Duke Power Co/PCA	GASTON	32.7669	-96.7773	G	found
441	2793	NC	ROCKINGHAM POWER LLC	Dynegy Generation	Dynegy Inc	Duke Power Co/PCA	ROCKINGHAM	36.3919	-79.7732	G	
442	2798	NC	SOUTHPORT	Archer Daniels Midland Co		Carolina Power & Light Co/PCA	BRUNSWICK	34.1051	-78.2935	G	

443	2812	NC	WAYNE COUNTY	Carolina Power & Light Co	Progress Energy	Carolina Power & Light Co/PCA	WAYNE	35.3858	-78.0555	G	
444	2726	NC	CAROLINA FOOD PROCESS INC GENERATION FACILITY 1	Smithfield Packing Co		Carolina Power & Light Co/PCA	BLADEN	34.6151	-78.5772	O	
445	2727	NC	CAROLINA FOOD PROCESS INC GENERATION FACILITY 2	Smithfield Packing Co		Carolina Power & Light Co/PCA	BLADEN	34.6151	-78.5772	O	
446	2728	NC	CARROLLS FOOD INC	Carrolls Food Inc		Carolina Power & Light Co/PCA	DUPLIN	34.9525	-77.9236	O	
447	2729	NC	CATALYTICA PHARMACEUTICALS INC	Catalytica Pharmaceuticals Inc		Carolina Power & Light Co/PCA	PITT	35.5867	-77.4355	O	
448	2744	NC	DAVIDSON WATER INC	Davidson Water Inc		Duke Power Co/PCA	DAVIDSON	35.7651	-80.2626	O	found
449	2762	NC	KITTY HAWK	Dominion Virginia Power	Dominion	Dominion Virginia Power/PCA	DARE	35.7123	-75.7476	O	
450	2775	NC	MOLL INDUSTRIES - SEAGROVE DIVISION	Moll Industries Inc		Carolina Power & Light Co/PCA	RANDOLPH	35.7131	-79.8043	O	
451	2776	NC	MOREHEAD	Carolina Power & Light Co	Progress Energy	Carolina Power & Light Co/PCA	CARTERET	34.9238	-76.5901	O	
452	2786	NC	PPG INDUSTRIES INC SHELBY NC WORKS 52	PPG Industries Inc		Duke Power Co/PCA	CLEVELAND	35.3716	-81.546	O	
453	2799	NC	SPRINT MID ATLANTIC TELECOM ADMIN BLDG	Sprint Mid Atlantic Telecom		Carolina Power & Light Co/PCA	WAKE	35.7975	-78.6253	O	
454	2811	NC	WATER FILTER PLANT #2	Morganton City of NUGs	Morganton City of	Duke Power Co/PCA	BURKE	35.782	-81.6537	O	
455	2813	NC	WEST PHARMACEUTICAL SERVICES	West Co		Carolina Power & Light Co/PCA	LENOIR	35.2172	-77.6116	O	
488	3769	SC	CANADYS STEAM	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	COLLETON	33.0647	-80.6228	C	found
489	3777	SC	COPE	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	ORANGEBURG	33.3639	-81.0303	C	
490	3778	SC	CROSS	South Carolina Pub Serv Auth		South Carolina Pub Serv Auth/PCA	BERKELEY	33.3694	-80.1119	C	found
491	3781	SC	DOLPHUS M GRAINGER	South Carolina Pub Serv Auth		South Carolina Pub Serv	HORRY	33.8253	-79.0528	C	found

						Auth/PCA					
492	3789	SC	H B ROBINSON	Carolina Power & Light Co	Progress Energy	Carolina Power & Light Co/PCA	DARLINGTON	34.4	-80.1667	C	found
493	3795	SC	JEFFERIES	South Carolina Pub Serv Auth		South Carolina Pub Serv Auth/PCA	BERKELEY	33.2422	-79.9875	C	found
494	3799	SC	MAY PLANT	E I DuPont De Nemours & Co		Carolina Power & Light Co/PCA	KERSHAW	34.3418	-80.582	C	
495	3800	SC	MCMEEKIN	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	LEXINGTON	34.0556	-81.2172	C	found
496	3818	SC	URQUHART	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	AIKEN	33.4339	-81.9114	C	found
497	3819	SC	USDOE SRS (D-AREA)	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	AIKEN	33.5383	-81.6056	C	
498	3820	SC	W S LEE	Duke Power Co	Duke Energy Corporation	Duke Power Co/PCA	ANDERSON	34.6022	-82.435	C	found
499	3823	SC	WATEREE	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	RICHLAND	33.8264	-80.6228	C	found
500	3824	SC	WILLIAMS	South Carolina Genertg Co Inc	SCANA Corporation	South Carolina Electric&Gas Co/PCA	BERKELEY	33.0158	-79.9297	C	found
501	3825	SC	WINYAH	South Carolina Pub Serv Auth		South Carolina Pub Serv Auth/PCA	GEORGETOWN	33.4953	-79.3347	C	found
502	3764	SC	BJU COGENERATION PLANT	Bob Jones University		Duke Power Co/PCA	GREENVILLE	34.841	-82.4548	G	
503	3766	SC	BROAD RIVER ENERGY CENTER	Broad River Energy		Duke Power Co/PCA	CHEROKEE	35.0113	-81.6207	G	
504	3767	SC	BURTON	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	BEAUFORT	32.3926	-80.7183	G	
505	3773	SC	CHEROKEE COUNTY COGENERATION PARTNERS LP	FPL Energy	FPL Group, Inc	Duke Power Co/PCA	CHEROKEE	35.0113	-81.6207	G	
506	3775	SC	COIT GT	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	RICHLAND	34.0057	-80.9808	G	
507	3779	SC	DARLINGTON COUNTY	Carolina Power &	Progress	Carolina Power &	DARLINGTON	34.3089	-79.9736	G	

				Light Co	Energy	Light Co/PCA					
508	3783	SC	FABER PLACE	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	CHARLESTON	32.8542	-79.8597	G	
509	3790	SC	HAGOOD	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	CHARLESTON	32.8269	-79.9639	G	found
510	3805	SC	PARR GT	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	FAIRFIELD	34.3878	-81.0975	G	
511	3791	SC	HARDEEVILLE	South Carolina Electric&Gas Co	SCANA Corporation	South Carolina Electric&Gas Co/PCA	JASPER	32.3995	-81.0537	O	
512	3792	SC	HILTON HEAD	South Carolina Pub Serv Auth		South Carolina Pub Serv Auth/PCA	BEAUFORT	32.3926	-80.7183	O	
513	3801	SC	MYRTLE BEACH	South Carolina Pub Serv Auth		South Carolina Pub Serv Auth/PCA	HORRY	33.9356	-78.9411	O	found
514	3848	TN	ALLEN	Tennessee Valley Authority		Tennessee Valley Authority/PCA	SHELBY	35.0742	-90.1492	C	found
515	3853	TN	BULL RUN	Tennessee Valley Authority		Tennessee Valley Authority/PCA	ANDERSON	36.0211	-84.1567	C	found
516	3862	TN	CORN WET MILLING PLANT	Cargill Inc		Tennessee Valley Authority/PCA	SHELBY	35.1996	-89.9711	C	found
517	3863	TN	CUMBERLAND	Tennessee Valley Authority		Tennessee Valley Authority/PCA	STEWART	36.3942	-87.6539	C	found
518	3868	TN	GALLATIN	Tennessee Valley Authority		Tennessee Valley Authority/PCA	SUMNER	36.3156	-86.4006	C	found
519	3875	TN	JOHN SEVIER	Tennessee Valley Authority		Tennessee Valley Authority/PCA	HAWKINS	36.3767	-82.9639	C	found
520	3876	TN	JOHNSONVILLE	Tennessee Valley Authority		Tennessee Valley Authority/PCA	HUMPHREYS	36.0278	-87.9861	C	found
521	3877	TN	KINGSTON	Tennessee Valley Authority		Tennessee Valley Authority/PCA	ROANE	35.8992	-84.5194	C	found
522	3878	TN	LOWLAND	Lenzig Fibers Corp		Tennessee Valley Authority/PCA	HAMBLEN	36.1875	-83.2746	C	found
523	3889	TN	OLD HICKORY PLANT	E I DuPont De Nemours & Co		Tennessee Valley Authority/PCA	DAVIDSON	36.1869	-86.7855	C	found
524	3897	TN	TENN EASTMAN DIV A DIV OF EASTMAN CHEMICAL CO	Tennessee Eastman Division		American Electric Power East/PCA	SULLIVAN	36.5063	-82.2538	C	found
525	3900	TN	VANDERBILT	Plant Operations Dept		Tennessee Valley	DAVIDSON	36.1869	-86.7855	C	found

			UNIVERSITY POWER PLANT			Authority/PCA					
526	3902	TN	WATTS BAR FOSSIL	Tennessee Valley Authority		Tennessee Valley Authority/PCA	RHEA	35.6171	-84.9348	C	
527	3852	TN	BROWNSVILLE PEAKING POWER PLANT	Brownsville Power I LLC		Tennessee Valley Authority/PCA	HAYWOOD	35.6099	-89.2856	G	found
528	3869	TN	GLEASON POWER FACILITY	Gleason Power LLC		Tennessee Valley Authority/PCA	WEAKLEY	36.2828	-88.7379	G	
529	3890	TN	OPRYLAND USA	Gaylord Entertainment Co		Tennessee Valley Authority/PCA	DAVIDSON	36.1869	-86.7855	G	found
530	3892	TN	PCS NITROGEN FERTILIZER LP	PCS Fertilizer		Tennessee Valley Authority/PCA	SHELBY	35.1996	-89.9711	G	
531	3899	TN	UT STEAM PLANT	University of Tennessee		Tennessee Valley Authority/PCA	KNOX	35.9957	-83.9684	G	found
26	223	AR	FLINT CREEK	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	BENTON	36.2625	-94.5208	C	found
27	229	AR	INDEPENDENCE	Entergy Arkansas Inc	Entergy Corporation	Entergy Electric System/PCA	INDEPENDENCE	35.6733	-91.4083	C	found
28	247	AR	WHITE BLUFF	Entergy Arkansas Inc	Entergy Corporation	Entergy Electric System/PCA	JEFFERSON	34.4236	-92.1392	C	foond
29	210	AR	BAILEY	Arkansas Electric Coop Corp		Entergy Electric System/PCA	WOODRUFF	35.2572	-91.3708	G	found
30	216	AR	CECIL LYNCH	Entergy Arkansas Inc	Entergy Corporation	Entergy Electric System/PCA	PULASKI	34.752	-92.3924	G	found
31	222	AR	FITZHUGH	Arkansas Electric Coop Corp		Entergy Electric System/PCA	FRANKLIN	35.4869	-93.8887	G	found
32	226	AR	HAMILTON MOSES	Entergy Arkansas Inc	Entergy Corporation	Entergy Electric System/PCA	ST FRANCIS	35.0082	-90.7757	G	
33	227	AR	HARVEY COUCH	Entergy Arkansas Inc	Entergy Corporation	Entergy Electric System/PCA	LAFAYETTE	33.3667	-93.4833	G	
34	228	AR	HELENA	Archer Daniels Midland Co		Entergy Electric System/PCA	PHILLIPS	34.382	-90.8424	G	
35	231	AR	LAKE CATHERINE	Entergy Arkansas Inc	Entergy Corporation	Entergy Electric System/PCA	HOT SPRING	34.4417	-92.9125	G	
36	233	AR	LITTLE ROCK	Archer Daniels Midland Co		Entergy Electric System/PCA	PULASKI	34.752	-92.3924	G	
37	234	AR	MABELVALE	Entergy Arkansas Inc	Entergy Corporation	Entergy Electric System/PCA	PULASKI	34.752	-92.3924	G	
38	235	AR	MCCLELLAN	Arkansas Electric Coop Corp		Entergy Electric System/PCA	OUACHITA	33.5642	-92.7875	G	found

39	244	AR	ROBERT E RITCHIE	Entergy Arkansas Inc	Entergy Corporation	Entergy Electric System/PCA	PHILLIPS	34.4667	-90.6	G	found
40	245	AR	SPARKS REGIONAL MEDICAL CENTER	Sparks Regional Medical Center		Oklahoma Gas & Electric Co/PCA	SEBASTIAN	35.1921	-94.238	G	
41	236	AR	MUNICIPAL LIGHT	Piggott City of		Entergy Electric System/PCA	CLAY	36.3498	-90.4363	O	
42	1116	FL	BIG BEND	Tampa Electric Co	TECO Energy, Inc	Tampa Electric Co/PCA	HILLSBOROUGH	27.7944	-82.4036	C	found
43	1121	FL	C D MCINTOSH JR	Lakeland City of		Florida Power Corporation/PCA	POLK	28.075	-81.9292	C	found
44	1126	FL	CEDAR BAY GENERATING CO LP	PG&E National Energy Group	PG&E Corporation	JEA (City of Jacksonville)/PCA	DUVAL	30.3448	-81.7153	C	found
45	1129	FL	CENTRAL POWER&LIME INC	Central Power and Lime Inc		Florida Power & Light Co/PCA	HERNANDO	28.5639	-82.3681	C	
46	1133	FL	CRIST	Gulf Power Co	Southern Company Inc	Southern Co Services Inc/PCA	ESCAMBIA	30.5658	-87.2239	C	found
47	1134	FL	CRYSTAL RIVER	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	CITRUS	28.9575	-82.6997	C	found
48	1141	FL	DEERHAVEN	Gainesville Regional Utilities		Gainesville Regional Utilities/PCA	ALACHUA	29.7167	-82.3833	C	found
49	1142	FL	F J GANNON	Tampa Electric Co	TECO Energy, Inc	Tampa Electric Co/PCA	HILLSBOROUGH	27.9069	-82.4233	C	found
50	1158	FL	INDIANTOWN COGENERATION FACILITY	PG&E National Energy Group	PG&E Corporation	Florida Power & Light Co/PCA	MARTIN	27.1098	-80.4832	C	found
51	1168	FL	LANSING SMITH	Gulf Power Co	Southern Company Inc	Southern Co Services Inc/PCA	BAY	30.2661	-85.6989	C	found
52	1194	FL	POLK	Tampa Electric Co	TECO Energy, Inc	Tampa Electric Co/PCA	POLK	28.0023	-81.6244	C	
53	1205	FL	SCHOLZ	Gulf Power Co	Southern Company Inc	Southern Co Services Inc/PCA	JACKSON	30.6794	-84.8872	C	
54	1206	FL	SEMINOLE	Seminole Electric Coop Inc		Seminole Electric Coop Inc/PCA	PUTNAM	29.7336	-81.6339	C	
55	1213	FL	ST JOHNS RIVER POWER	Jacksonville Electric Auth		JEA (City of Jacksonville)/PCA	DUVAL	30.4308	-81.5508	C	found
56	1217	FL	STANTON ENERGY CTR	Orlando Utilities Comm		Florida Municipal Power Pool/PCA	ORANGE	28.4822	-81.1678	C	found
57	1108	FL	ANCLOTE	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	PASCO	28.1842	-82.7872	G	found

58	1109	FL	ANHEUSER BUSCH INC JACKSONVILLE BREWERY	Anheuser Busch Inc		JEA (City of Jacksonville)/PCA	DUVAL	30.3448	-81.7153	G	
59	1110	FL	ARVAH B HOPKINS	Tallahassee City of		Tallahassee City Of/PCA	LEON	30.4522	-84.4	G	found
60	1111	FL	AUBURNDALE POWER PARTNERS LP	Calpine		Tampa Electric Co/PCA	POLK	28.0023	-81.6244	G	
61	1112	FL	AVON PARK	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	HIGHLANDS	27.3391	-81.2525	G	
62	1113	FL	BAPTIST MEDICAL CENTER	Baptist Memorial Hospital		JEA (City of Jacksonville)/PCA	DUVAL	30.3448	-81.7153	G	found
63	1118	FL	BLACKJACK CREEK TREATING	De Soto Oil & Gas Inc		Southern Co Services Inc/PCA	SANTA ROSA	30.6749	-87.0482	G	
64	1122	FL	CANE ISLAND	Kissimmee Utility Authority		Florida Municipal Power Pool/PCA	OSCEOLA	27.9948	-81.2595	G	
65	1128	FL	CENTRAL ENERGY PLANT	Reedy Creek Improvement Dist		Reedy Creek Improvement District/PCA	ORANGE	28.5662	-81.2613	G	
66	1137	FL	CUTLER	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	MIAMI-DADE	25.6311	-80.2983	G	found
67	1138	FL	CUTRALE CITRUS JUICES USA INC	Cutrale Citrus Juices USA Inc		Tampa Electric Co/PCA	POLK	28.0023	-81.6244	G	
68	1139	FL	CUTRALE CITRUS JUICES USA INC LEESBURG	Cutrale Citrus Juices USA Inc		Florida Power Corporation/PCA	LAKE	28.8112	-81.655	G	
69	1140	FL	DEBARY	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	VOLUSIA	29.0199	-81.2071	G	
70	1144	FL	FLORIDA'S NATURAL GROWERS	Florida's Natural Growers Div		Florida Power Corporation/PCA	POLK	28.0023	-81.6244	G	
71	1147	FL	G W IVEY	Homestead City of		Homestead City Of/PCA	DADE	25.5582	-80.4962	G	
72	1148	FL	HANSEL	Kissimmee Utility Authority		Florida Municipal Power Pool/PCA	OSCEOLA	27.9948	-81.2595	G	
73	1149	FL	HARDEE POWER STATION	TPS Operations Company		Seminole Electric Coop Inc/PCA	HARDEE	27.4914	-81.8097	G	
74	1150	FL	HENRY D KING	Fort Pierce Utilities Auth		Florida Municipal Power Pool/PCA	ST LUCIE	27.45	-80.3239	G	found
75	1151	FL	HIGGINS	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	PINELLAS	28.0022	-82.6631	G	found
76	1153	FL	HINES ENERGY COMPLEX	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	POLK	28.0023	-81.6244	G	
77	1157	FL	INDIAN RIVER PLANT	Orlando Utilities Comm		Florida Municipal Power Pool/PCA	BREVARD	28.4933	-80.78	G	found

78	1159	FL	INTERCESSION CITY	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	OSCEOLA	27.9948	-81.2595	G	
79	1160	FL	J D KENNEDY	Jacksonville Electric Auth		JEA (City of Jacksonville)/PCA	DUVAL	30.3639	-81.6233	G	found
80	1165	FL	JOHN R KELLY	Gainesville Regional Utilities		Gainesville Regional Utilities/PCA	ALACHUA	29.6458	-82.3214	G	found
81	1166	FL	LAKE COGEN LTD	General Electric Co	General Electric Company	Florida Power Corporation/PCA	LAKE	28.8112	-81.655	G	
82	1169	FL	LARSEN MEMORIAL	Lakeland City of		Florida Power Corporation/PCA	POLK	28.0333	-81.9167	G	
83	1170	FL	LAUDERDALE	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	BROWARD	26.0683	-80.2	G	found
84	1176	FL	MERRITT SQUARE MALL	JonesLang LaSalle Americas Inc		Florida Power & Light Co/PCA	BREVARD	28.3065	-80.7175	G	
85	1178	FL	MULBERRY COGENERATION FACILITY	CSW Energy Inc		Florida Power Corporation/PCA	POLK	28.0023	-81.6244	G	found
86	1179	FL	NITRAM INC	Nitram Inc		Tampa Electric Co/PCA	HILLSBOROUGH	27.9091	-82.353	G	
87	1183	FL	ORANGE COGENERATION FACILITY	CSW Energy Inc		Florida Power Corporation/PCA	POLK	28.0023	-81.6244	G	
88	1184	FL	ORLANDO COGEN LP	Air Products		Florida Power Corporation/PCA	ORANGE	28.5662	-81.2613	G	
89	1187	FL	PASCO COGEN LTD	Aquila Generation Services	Aquila Inc	Tampa Electric Co/PCA	PASCO	28.3248	-82.4307	G	
90	1189	FL	PENSACOLA COGENERATION PLANT	Vennie Welch		Southern Co Services Inc/PCA	ESCAMBIA	30.637	-87.3329	G	
91	1191	FL	PENSACOLA FLORIDA PLANT	Solutia Inc		Southern Co Services Inc/PCA	ESCAMBIA	30.637	-87.3329	G	
92	1197	FL	PUTNAM	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	PUTNAM	29.5818	-81.7453	G	
93	1203	FL	S O PURDOM	Tallahassee City of		Tallahassee City Of/PCA	WAKULLA	30.1583	-84.2	G	found
94	1212	FL	ST CLOUD	Orlando Utilities Comm		Florida Municipal Power Pool/PCA	OSCEOLA	27.9948	-81.2595	G	
95	1214	FL	ST JOSEPHS HOSPITAL	St Josephs Hospital		Tampa Electric Co/PCA	HILLSBOROUGH	27.9091	-82.353	G	
96	1216	FL	ST VINCENTS MEDICAL CENTER	St Vincents Medical Center		JEA (City of Jacksonville)/PCA	DUVAL	30.3448	-81.7153	G	
97	1223	FL	TIGER BAY	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	POLK	28.0023	-81.6244	G	

98	1225	FL	TOM G SMITH	Lake Worth City of		Florida Municipal Power Pool/PCA	PALM BEACH	26.6125	-80.0678	G	found
99	1226	FL	TROPICANA PRODUCTS INC BRADENTON COGEN	Tropicana Products Inc		Florida Power & Light Co/PCA	MANATEE	27.4268	-82.4004	G	
100	1229	FL	UNIVERSITY OF FL	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	ALACHUA	29.6828	-82.3558	G	
101	1230	FL	VERO BEACH MUNICIPAL	Vero Beach City of		Florida Municipal Power Pool/PCA	INDIAN RIVER	27.6311	-80.3758	G	found
102	1115	FL	BAYBORO	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	PINELLAS	27.8961	-82.7229	O	
103	1117	FL	BIG PINE	Key West City of	Key West City of	Florida Municipal Power Pool/PCA	MONROE	25.4604	-81.1635	O	
104	1123	FL	CAPE CANAVERAL	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	BREVARD	28.4694	-80.7642	O	found
105	1136	FL	CUDJOE	Key West City of	Key West City of	Florida Municipal Power Pool/PCA	MONROE	25.4604	-81.1635	O	
106	1145	FL	FORT MYERS	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	LEE	26.6969	-81.7819	O	found
107	1146	FL	G E TURNER	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	VOLUSIA	28.8686	-81.2728	O	found
108	1154	FL	HOOKERS POINT	Tampa Electric Co	TECO Energy, Inc	Tampa Electric Co/PCA	HILLSBOROUGH	27.9381	-82.4436	O	found
109	1172	FL	MANATEE	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	MANATEE	27.6058	-82.3456	O	found
110	1173	FL	MARATHON	Florida Keys El Coop Assn Inc		Florida Power & Light Co/PCA	MONROE	25.4604	-81.1635	O	
111	1174	FL	MARTIN	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	MARTIN	27.1098	-80.4832	O	
112	1181	FL	NORTHSIDE GENERATING	Jacksonville Electric Auth		JEA (City of Jacksonville)/PCA	DUVAL	30.4178	-81.5525	O	found
113	1185	FL	P L BARTOW	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	PINELLAS	27.8597	-82.6025	O	found
114	1192	FL	PHILLIPS	Tampa Electric Co	TECO Energy, Inc	Tampa Electric Co/PCA	HIGHLANDS	27.3391	-81.2525	O	
115	1195	FL	PORT EVERGLADES	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	BROWARD	26.0856	-80.1253	O	found
116	1196	FL	PORTLAND	Alabama Electric Coop Inc		Alabama Electric Coop Inc/PCA	WALTON	30.6317	-86.1212	O	
117	1199	FL	RELIANT ENERGY INDIAN RIVER PLANT	Reliant Resources		Florida Municipal Power Pool/PCA	BREVARD	28.4933	-80.78	O	found
118	1201	FL	RIO PINAR	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	ORANGE	28.5662	-81.2613	O	

119	1202	FL	RIVIERA	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	PALM BEACH	26.7653	-80.0525	O	found
120	1204	FL	SANFORD	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	VOLUSIA	28.8419	-81.3256	O	found
121	1208	FL	SMITH STREET	New Smyrna Beach Utils Comm		New Smyrna Beach Utils Comm/PCA	VOLUSIA	29.0199	-81.2071	O	
122	1211	FL	SOUTHSIDE GENERATING	Jacksonville Electric Auth		JEA (City of Jacksonville)/PCA	DUVAL	30.3167	-81.6486	O	found
123	1218	FL	STOCK ISLAND	Key West City of	Key West City of	Florida Municipal Power Pool/PCA	MONROE	25.53	-81.07	O	
124	1220	FL	SUWANNEE RIVER	Florida Power Corp	Progress Energy	Florida Power Corporation/PCA	SUWANNEE	30.3764	-83.1803	O	found
125	1227	FL	TURKEY POINT	Florida Power & Light Co	FPL Group, Inc	Florida Power & Light Co/PCA	MIAMI-DADE	25.4356	-80.3308	O	found
126	1232	FL	W E SWOOPE	New Smyrna Beach Utils Comm		New Smyrna Beach Utils Comm/PCA	VOLUSIA	29.0199	-81.2071	O	
127	1236	GA	ARKWRIGHT	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	BIBB	32.9269	-83.6997	C	found
128	1249	GA	BOWEN	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	BARTOW	34.1256	-84.9192	C	found
129	1250	GA	BROWN WILLIAMSON TOBACCO CO	Brown & Williamson Tobacco Co		Southern Co Services Inc/PCA	BIBB	32.8084	-83.6912	C	found
131	1270	GA	HAMMOND	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	FLOYD	34.3333	-85.2336	C	found
132	1271	GA	HARLLEE BRANCH	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	PUTNAM	33.1942	-83.2994	C	found
133	1283	GA	JACK MCDONOUGH	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	COBB	33.8244	-84.475	C	found
134	1285	GA	KRAFT	Savannah Electric & Power Co	Southern Company Inc	Southern Co Services Inc/PCA	CHATHAM	32.1333	-81.1333	C	found
135	1288	GA	MCINTOSH	Savannah Electric & Power Co	Southern Company Inc	Southern Co Services Inc/PCA	EFFINGHAM	32.3533	-81.1628	C	found
136	1292	GA	MITCHELL	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	DOUGHERTY	31.4444	-84.1322	C	found

139	1316	GA	SCHERER	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	MONROE	33.0583	-83.8072	C	found
141	1337	GA	WANSLEY	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	HEARD	33.4167	-85.0333	C	found
143	1239	GA	ATKINSON	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	COBB	33.8244	-84.475	G	found
144	1243	GA	BACONTON POWER	The PIC Energy Group Inc		Southern Co Services Inc/PCA	MITCHELL	31.2603	-84.2531	G	found
149	1272	GA	HARTWELL ENERGY LP	Dynegy Generation	Dynegy Inc	Southern Co Services Inc/PCA	HART	34.3518	-82.9451	G	found
154	1297	GA	NEXPAK	Atlanta Precision Molding Co		Southern Co Services Inc/PCA	GWINNETT	33.9603	-84.0378	G	found
155	1306	GA	RIVERSIDE	Savannah Electric & Power Co	Southern Company Inc	Southern Co Services Inc/PCA	CHATHAM	32.0833	-81.0958	G	found
156	1307	GA	RIVERSIDE MANUFACTURING CO	Riverside Manufacturing Co		Southern Co Services Inc/PCA	COLQUITT	31.1802	-83.7617	G	found
158	1317	GA	SEWELL CREEK ENERGY	Oglethorpe Power Corp		Southern Co Services Inc/PCA	POLK	33.9986	-85.1721	G	found
159	1320	GA	SMARR ENERGY CENTER	Oglethorpe Power Corp		Southern Co Services Inc/PCA	MONROE	33.0253	-83.9178	G	found
160	1322	GA	SOWEGA POWER LLC	The PIC Energy Group Inc		Southern Co Services Inc/PCA	MITCHELL	31.2603	-84.2531	G	found
161	1339	GA	WEST GEORGIA GENERATING CO	General Electric Co	General Electric Company	Southern Co Services Inc/PCA	UPSON	32.8416	-84.3282	G	found
163	1238	GA	ATHENS REGIONAL MEDICAL CENTER	Athens Regional Medical Center		Southern Co Services Inc/PCA	CLARKE	33.9455	-83.3909	O	found
172	1289	GA	MCMANUS	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	GLYNN	31.2125	-81.5458	O	found
177	1321	GA	SOUTH GEORGIA MEDICAL CENTER	South Georgia Medical Center		Southern Co Services Inc/PCA	LOWNDES	30.8281	-83.2531	O	found
181	1331	GA	THIELE KAOLIN COMPANY SANDERSVILLE PLANT	Thiele Kaolin Co		Southern Co Services Inc/PCA	WASHINGTON	32.9989	-82.7924	O	found
182	1333	GA	VALDOSTA WATER TREATMENT PLANT	Valdosta City of		Southern Co Services Inc/PCA	LOWNDES	30.8281	-83.2531	O	found
184	1343	GA	YKK USA INCORPORATED CHESTNEY FACILITY	YKK USA Inc		Southern Co Services Inc/PCA	BIBB	32.8084	-83.6912	O	found

130	1262	GA	DURANGO-GEORGIA PAPER CO	Durango-Georgia Paper Co		Southern Co Services Inc/PCA	CAMDEN	30.94	-81.6665	C
137	1301	GA	PLANT CRISP	Crisp County Power Comm		Southern Co Services Inc/PCA	WORTH	31.5833	-83.8339	C
138	1315	GA	SAVANNAH SUGAR REFINERY	Savannah Foods&Industries Inc		Southern Co Services Inc/PCA	CHATHAM	31.9812	-81.1175	C
140	1323	GA	SP NEWSPRINT CO	Southeast Paper Mfg Co Inc		Southern Co Services Inc/PCA	LAURENS	32.4314	-82.9372	C
142	1342	GA	YATES	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	COWETA	33.4631	-84.955	C
145	1248	GA	BOULEVARD	Savannah Electric & Power Co	Southern Company Inc	Southern Co Services Inc/PCA	CHATHAM	31.9812	-81.1175	G
146	1258	GA	DAHLBERG	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	HOUSTON	32.4874	-83.6775	G
147	1260	GA	DERST BAKING CO	Derst Baking Co		Southern Co Services Inc/PCA	CHATHAM	31.9812	-81.1175	G
148	1261	GA	DOYLE GENERATING FACILITY	Operational Energy Corporation		Southern Co Services Inc/PCA	WALTON	33.7634	-83.7443	G
150	1282	GA	J M HUBER CORP ENGINEERED MINERALS DIV WRENS	J M Huber		Southern Co Services Inc/PCA	JEFFERSON	33.0372	-82.4554	G
151	1284	GA	JOHN HARMON GEN	Fort Valley Utility Comm		Southern Co Services Inc/PCA	PEACH	32.5801	-83.8593	G
152	1290	GA	MID GEORGIA COGEN	Mid-Georgia Cogen LP		Southern Co Services Inc/PCA	HOUSTON	32.4874	-83.6775	G
153	1294	GA	MPC GENERATING	Progress Ventures	Progress Energy	Southern Co Services Inc/PCA	WALTON	33.7634	-83.7442	G
157	1311	GA	ROBINS	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	HOUSTON	32.4874	-83.6775	G
162	1237	GA	AT&T ALPHARETTA CENTER	Dave P Hulse		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O
164	1240	GA	ATLANTA GIFT MART LP	Walter Speir		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O
165	1244	GA	BANK OF AMERICA PLAZA	Cousins Properties Inc		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O
166	1256	GA	CNN CENTER	TBS Properties		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O
167	1257	GA	COMPAQ COMPUTER CORP	Compaq Computer Corp		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O

168	1259	GA	DEKALB MEDICAL CENTER	Dekalb County Hospital Auth		Southern Co Services Inc/PCA	DE KALB	33.7861	-84.187	O	
169	1268	GA	GEORGIA PACIFIC CENTER	Taylor & Mathis		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O	
170	1276	GA	IMERYS KAOLIN CO JEFFERSONVILLE PLANT	Nord Kaolin Co		Southern Co Services Inc/PCA	TWIGGS	32.6751	-83.4145	O	
171	1277	GA	INFORUM	Cousins Properties Inc		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O	
173	1296	GA	NAVAL SUBMARINE BASE KINGS BAY GA	JA Jones Management Services		Southern Co Services Inc/PCA	CAMDEN	30.94	-81.6665	O	
174	1310	GA	RIVERWOOD 100 BUILDING	Clarien Realty Services		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O	
175	1314	GA	SAVANNAH RIVER MILL	Georgia Pacific		Southern Co Services Inc/PCA	EFFINGHAM	32.3486	-81.3364	O	
176	1318	GA	SHEPHERD CENTER	Shepherd Center		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O	
178	1324	GA	STATE FARM INSURANCE CO ISC EAST	State Farm Mutual Auto Insur Co		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O	
179	1326	GA	SUN TRUST PLAZA	Portman Mngment Co		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O	
180	1330	GA	THIELE KAOLIN CO REEDY CREEK PLANT	Thiele Kaolin Co		Southern Co Services Inc/PCA	JEFFERSON	33.0372	-82.4554	O	
183	1341	GA	WILSON	Georgia Power Co	Southern Company Inc	Southern Co Services Inc/PCA	BURKE	33.0491	-81.9292	O	
185	1345	GA	191 PEACHTREE TOWER	C H Management		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O	
186	1346	GA	3200 WILDWOOD PLAZA	Wildwood Associates		Southern Co Services Inc/PCA	FULTON	33.8443	-84.4094	O	
380	2660	MS	JACK WATSON	Mississippi Power Co	Southern Company Inc	Southern Co Services Inc/PCA	HARRISON	30.4392	-89.0264	C	found
381	2672	MS	R D MORROW	South Mississippi El Pwr Assn		South Mississippi El Pwr Assn/PCA	LAMAR	31.2175	-89.3939	C	found
382	2677	MS	VICTOR J DANIEL JR	Mississippi Power Co	Southern Company Inc	Southern Co Services Inc/PCA	JACKSON	30.5322	-88.5569	C	found
384	2647	MS	BAXTER WILSON	Entergy Mississippi Inc	Entergy Corporation	Entergy Electric System/PCA	WARREN	32.2831	-90.9306	G	found
388	2652	MS	DELTA	Entergy Mississippi Inc	Entergy Corporation	Entergy Electric System/PCA	BOLIVAR	33.7947	-90.7139	G	found

392	2662	MS	MISSCHEM NITROGEN LLC	MissChem Nitrogen LLC		Entergy Electric System/PCA	YAZOO	32.7588	-90.363	G	found
394	2665	MS	MOSELLE	South Mississippi El Pwr Assn		South Mississippi El Pwr Assn/PCA	JONES	31.5292	-89.3	G	found
397	2669	MS	NEW ALBANY POWER FACILITY	New Albany Power I LLC		Tennessee Valley Authority/PCA	UNION	34.4817	-88.9909	G	found
399	2673	MS	REX BROWN	Entergy Mississippi Inc	Entergy Corporation	Entergy Electric System/PCA	HINDS	32.3564	-90.2125	G	found
405	2656	MS	GERALD ANDRUS	Entergy Mississippi Inc	Entergy Corporation	Entergy Electric System/PCA	WASHINGTON	33.3503	-91.1181	O	found
379	2658	MS	HENDERSON	Greenwood Utilities Comm		Entergy Electric System/PCA	LEFLORE	33.5305	-90.2775	C	
383	2646	MS	BATESVILLE GENERATION FACILITY	Cogentrix		Tennessee Valley Authority/PCA	PANOLA	34.3567	-89.9618	G	
385	2648	MS	BENNDALE	South Mississippi El Pwr Assn		South Mississippi El Pwr Assn/PCA	GEORGE	30.8665	-88.6488	G	
386	2649	MS	CALEDONIA POWER FACILITY	Caledonia Power I LLC		Tennessee Valley Authority/PCA	LOWNDES	33.5162	-88.4603	G	
387	2650	MS	CHEVRON OIL	Mississippi Power Co	Southern Company Inc	Southern Co Services Inc/PCA	JACKSON	30.5274	-88.6393	G	
389	2653	MS	DISTRICT 70 TRANS GAS PIPE LINE CORP	Transcontinental Gas Pipe Line		South Mississippi El Pwr Assn/PCA	WALTHALL	31.1754	-90.0482	G	
390	2654	MS	EATON	Mississippi Power Co	Southern Company Inc	Southern Co Services Inc/PCA	FORREST	31.1718	-89.295	G	
391	2655	MS	ERGON REFINING VICKSBURG	Ergon Refining Incorporated		Entergy Electric System/PCA	WARREN	32.3598	-90.8394	G	
N	2663	MS	MISSISSIPPI BAPTIST MEDICAL CENTER	Mississippi Baptist Medical		Entergy Electric System/PCA	HINDS	32.3111	-90.3968	G	
395	2666	MS	MOSS POINT MILL	International Paper Co		Southern Co Services Inc/PCA	JACKSON	30.5274	-88.6393	G	
396	2667	MS	NATCHEZ	Entergy Mississippi Inc	Entergy Corporation	Entergy Electric System/PCA	ADAMS	31.4705	-91.4046	G	
398	2670	MS	PASCAGOULA FACILITY TG 4225	ChevronTexaco Corporation		Southern Co Services Inc/PCA	JACKSON	30.5274	-88.6393	G	
400	2674	MS	SWEATT	Mississippi Power Co	Southern Company Inc	Southern Co Services Inc/PCA	LAUDERDALE	32.4011	-88.6519	G	
401	2675	MS	THIRD STREET	Clarksdale City of		Entergy Electric System/PCA	COAHOMA	34.2545	-90.6745	G	
402	2678	MS	WILKINS	Clarksdale City of		Entergy Electric System/PCA	COAHOMA	34.2545	-90.6745	G	

403	2679	MS	WRIGHT	Greenwood Utilities Comm		Entergy Electric System/PCA	LEFLORE	33.5305	-90.2775	G	
404	2680	MS	YAZOO	Public Serv Comm of Yazoo City		Entergy Electric System/PCA	YAZOO	32.7588	-90.363	G	
406	2659	MS	HIGH PRESSURE INDUSTRIAL WATER FACILITY	Lockheed Martin Space Oper		Southern Co Services Inc/PCA	HANCOCK	30.414	-89.5063	O	
407	2671	MS	PAULDING	South Mississippi El Pwr Assn		South Mississippi El Pwr Assn/PCA	JASPER	32.0131	-89.1167	O	
1	149	AL	BARRY	Alabama Power Co	Southern Company Inc	Southern Co Services Inc/PCA	MOBILE	31.0069	-88.0103	C	found
2	153	AL	CHARLES R LOWMAN	Alabama Electric Coop Inc		Alabama Electric Coop Inc/PCA	WASHINGTON	31.4875	-87.9125	C	found
3	154	AL	COLBERT	Tennessee Valley Authority		Tennessee Valley Authority/PCA	COLBERT	34.7439	-87.8486	C	
4	158	AL	E C GASTON	Alabama Power Co	Southern Company Inc	Southern Co Services Inc/PCA	SHELBY	33.2442	-86.4567	C	found
5	161	AL	GADSDEN	Alabama Power Co	Southern Company Inc	Southern Co Services Inc/PCA	ETOWAH	34.0136	-85.9703	C	found
6	164	AL	GORGAS	Alabama Power Co	Southern Company Inc	Southern Co Services Inc/PCA	WALKER	33.5111	-87.235	C	
7	165	AL	GREENE COUNTY	Alabama Power Co	Southern Company Inc	Southern Co Services Inc/PCA	GREENE	32.6	-87.7667	C	found
8	172	AL	JAMES H MILLER JR	Alabama Power Co	Southern Company Inc	Southern Co Services Inc/PCA	JEFFERSON	33.6319	-87.0597	C	
9	198	AL	U S ALLIANCE COOSA PINES	U S Alliance Corp		Southern Co Services Inc/PCA	TALLADEGA	33.3912	-86.1476	C	
10	205	AL	WIDOWS CREEK	Tennessee Valley Authority		Tennessee Valley Authority/PCA	JACKSON	34.8825	-85.7547	C	found
11	150	AL	BIG ESCAMBIA CREEK TREATING FACILITY	Exxon Mobil		Alabama Electric Coop Inc/PCA	ESCAMBIA	31.1279	-87.1521	G	
12	151	AL	BOISE CASADE PULP&PAPER MILL	Boise Cascade Corporation		Southern Co Services Inc/PCA	CLARKE	31.5915	-87.8198	G	
13	156	AL	JACKSON ALABAMA CRESTWOOD CORP DOTHAN	Ronnie Broadway		Southern Co Services Inc/PCA	HOUSTON	31.1558	-85.355	G	
14	157	AL	DISTRICT 100 TRANS GAS PIPE LINE CORP	Transcontinental Gas Pipe Line		Southern Co Services Inc/PCA	AUTAUGA	32.5245	-86.6642	G	found

15	159	AL	FAIRFIELD WORKS	P M Allbritton		Southern Co Services Inc/PCA	JEFFERSON	33.5443	-86.9025	G	found
16	163	AL	GENERAL ELEC PLASTIC	Alabama Power Co	Southern Company Inc	Southern Co Services Inc/PCA	LOWNDES	32.1784	-86.6559	G	
17	181	AL	MARY ANN GAS PLANT	Exxon Mobil		Southern Co Services Inc/PCA	MOBILE	30.7449	-88.1865	G	found
18	182	AL	MCINTOSH	Alabama Electric Coop Inc		Alabama Electric Coop Inc/PCA	WASHINGTON	31.4067	-88.1903	G	
19	183	AL	MCWILLIAMS	Alabama Electric Coop Inc		Alabama Electric Coop Inc/PCA	COVINGTON	31.4097	-86.3731	G	
20	187	AL	MOBILE BAY ONSHORE TREATING FACILITY	Exxon Mobil		Southern Co Services Inc/PCA	MOBILE	30.7449	-88.1865	G	found
21	188	AL	MOBILE ENERGY SERVICES CO LLC	Exxon Mobil		Southern Co Services Inc/PCA	MOBILE	30.7449	-88.1865	G	found
22	193	AL	SHELL OFFSHORE INC YELLOWHAMMER PLANT	Shell		Southern Co Services Inc/PCA	MOBILE	30.7449	-88.1865	G	
23	196	AL	SO EASTERN ELECTRIC DEVELOPMENT CORP LEE COUNTY AL FACILITY	Energy Services Inc		Southern Co Services Inc/PCA	LEE	32.5781	-85.349	G	found
24	199	AL	UNOCALS CHUNCHULA PLANT 1	Union Oil Co of California		Southern Co Services Inc/PCA	MOBILE	30.7449	-88.1865	G	
25	201	AL	WASHINGTON COUNTY	Alabama Power Co	Southern Company Inc	Southern Co Services Inc/PCA	WASHINGTON	31.4067	-88.1903	G	
215	1934	LA	BIG CAJUN 2	NRG Energy	Xcel Energy Inc	Entergy Electric System/PCA	POINTE COUPEE	30.7283	-91.3686	C	found
216	1947	LA	DOLET HILLS	CLECO Power LLC	CLECO Corporation	CLECO Corporation/PCA	DE SOTO	32.0308	-93.5644	C	found
217	1993	LA	R S NELSON	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	CALCASIEU	30.2861	-93.2917	C	found
218	1996	LA	RODEMACHER	Lafayette City of		Lafayette (LA) Utilities System/PCA	LAFAYETTE	30.21	-92.06	C	found
219	1997	LA	RODEMACHER	CLECO Power LLC	CLECO Corporation	CLECO Corporation/PCA	RAPIDES	31.395	-92.7167	C	found
220	1926	LA	A B PATERSON	Entergy New Orleans Inc	Entergy Corporation	Entergy Electric System/PCA	ORLEANS	30.0158	-90.0258	G	found
221	1929	LA	ARSENAL HILL	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	CADDO	32.5181	-93.7611	G	found

222	1930	LA	BATON ROUGE COGEN	Exxon Mobil		Entergy Electric System/PCA	EAST BATON ROUGE	30.5162	-91.075	G	found
223	1931	LA	BATON ROUGE PLANT	DSM Copolymer		Entergy Electric System/PCA	EAST BATON ROUGE	30.5162	-91.075	G	found
224	1932	LA	BATON ROUGE TURBINE GENERATOR	Exxon Mobil		Entergy Electric System/PCA	EAST BATON ROUGE	30.5162	-91.075	G	found
225	1933	LA	BIG CAJUN 1	NRG Energy	Xcel Energy Inc	Entergy Electric System/PCA	POINTE COUPEE	30.6758	-91.3136	G	found
226	1935	LA	BLUE WATER GAS PLANT	Exxon Mobil		Entergy Electric System/PCA	IBERIA	29.9283	-91.8127	G	
227	1936	LA	BONIN	Lafayette City of		Lafayette (LA) Utilities System/PCA	LAFAYETTE	30.2375	-92.0461	G	found
228	1937	LA	BORDEN CHEMICALS PLASTICS	Borden Chemical Co		Entergy Electric System/PCA	ASCENSION	30.2038	-90.8693	G	found
229	1938	LA	BURAS	Entergy Louisiana Inc	Entergy Corporation	Entergy Electric System/PCA	PLAQUEMINES	29.432	-89.5439	G	found
230	1939	LA	CA II (CHLOR ALKALI II)	Dow Chemical		Entergy Electric System/PCA	IBERVILLE	30.2614	-91.361	G	found
231	1940	LA	CALCASIEU POWER LLC	Dynegy Generation	Dynegy Inc	Entergy Electric System/PCA	CALCASIEU	30.2205	-93.3731	G	found
232	1942	LA	CII CARBON LLC	CII Carbon LLC		Entergy Electric System/PCA	ST BERNARD	29.8954	-89.5968	G	
233	1944	LA	COLONIAL SUGAR REFINERY	Imperial Co		Entergy Electric System/PCA	ST JAMES	30.0276	-90.8027	G	found
234	1946	LA	DG HUNTER	Alexandria City of		CLECO Corporation/PCA	RAPIDES	31.3208	-92.4619	G	found
235	1948	LA	DOMINO SUGAR ARABI PLANT	Tate & Lyle North Am Sugar Inc		Entergy Electric System/PCA	ST BERNARD	29.8954	-89.5968	G	
236	1949	LA	EVANGELINE POWER STATION	CLECO NUGs	CLECO Corporation	CLECO Corporation/PCA	EVANGELINE	30.8756	-92.2608	G	found
237	1950	LA	FORMOSA PLASTICS CORP	Formosa Plastics Corp		Entergy Electric System/PCA	EAST BATON ROUGE	30.5162	-91.075	G	
238	1951	LA	FRANKLIN	CLECO Power LLC	CLECO Corporation	CLECO Corporation/PCA	ST MARY	29.7151	-91.479	G	found
239	1952	LA	GARDEN CITY GAS PLANT	Exxon Mobil		CLECO Corporation/PCA	ST MARY	29.7151	-91.479	G	
240	1954	LA	GEISMAR	BASF		Entergy Electric System/PCA	ASCENSION	30.2038	-90.8693	G	found
241	1955	LA	GEISMAR PLANT	Vulcan Materials Co		Entergy Electric System/PCA	ASCENSION	30.2038	-90.8693	G	
242	1956	LA	GEORGIA GULF CORPORATION PLAQUEMINE DIVISION	Georgia Gulf Corp		Entergy Electric System/PCA	IBERVILLE	30.2614	-91.361	G	found

243	1957	LA	GRAND CHENIER GAS PROCESSING PLANT	Elkhorn Operating Company		Entergy Electric System/PCA	CAMERON	29.8155	-93.254	G	found
244	1958	LA	GRAND ISLE GAS PLANT	Exxon Mobil		Entergy Electric System/PCA	JEFFERSON	29.696	-90.0923	G	found
245	1960	LA	HOUMA	Terrebonne Parish Consol Gov't		Louisiana Energy & Power Auth/PCA	TERREBONNE	29.43	-90.84	G	
246	1963	LA	KAISER ALUMINUM	Kaiser Aluminum&Chemical Corp		Entergy Electric System/PCA	ST JAMES	30.0276	-90.8027	G	found
247	1964	LA	LIEBERMAN	Southwestern Electric Power Co	American Electric Power Co Inc	American Electric Power - West (SPP)/PCA	CADDO	32.7047	-93.9594	G	found
248	1965	LA	LITTLE GYPSY	Entergy Louisiana Inc	Entergy Corporation	Entergy Electric System/PCA	ST CHARLES	30.0033	-90.4611	G	found
249	1967	LA	LOUISIANA TECH UNIVERSITY POWER PLANT	Louisiana Tech University		Entergy Electric System/PCA	LINCOLN	32.6063	-92.6478	G	found
250	1968	LA	LOUISIANA 1	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	EAST BATON ROUGE	30.4903	-91.1875	G	found
251	1969	LA	LOUISIANA 2	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	EAST BATON ROUGE	30.5162	-91.075	G	found
252	1972	LA	MICHOUD	Entergy New Orleans Inc	Entergy Corporation	Entergy Electric System/PCA	ORLEANS	30.0081	-89.9372	G	found
253	1973	LA	MINDEN	Minden City of		Louisiana Energy & Power Auth/PCA	WEBSTER	32.72	-93.34	G	
254	1974	LA	MONROE	Entergy Louisiana Inc	Entergy Corporation	Entergy Electric System/PCA	OUACHITA	32.4996	-92.1641	G	found
255	1975	LA	MORGAN CITY	Morgan City City of		Louisiana Energy & Power Auth/PCA	ST MARY	29.72	-91.44	G	
256	1976	LA	NATCHITOCHES	Natchitoches City of		Lafayette (LA) Utilities System/PCA	NATCHITOCHES	31.73	-93.09	G	found
257	1978	LA	NEW ORLEANS	Air Products		Entergy Electric System/PCA	ORLEANS	30.0324	-89.8748	G	found
258	1979	LA	NEW ROADS	New Roads City of		Louisiana Energy & Power Auth/PCA	POINTE COUPEE	30.7509	-91.392	G	found
259	1980	LA	NINEMILE POINT	Entergy Louisiana Inc	Entergy Corporation	Entergy Electric System/PCA	JEFFERSON	29.9472	-90.1458	G	found

260	1981	LA	NRG STERLINGTON POWER LLC	NRG Energy	Xcel Energy Inc	Entergy Electric System/PCA	OUACHITA	32.4996	-92.1641	G	
261	1982	LA	PCS NITROGEN FERTILIZER LP	PCS Fertilizer		Entergy Electric System/PCA	ASCENSION	30.2038	-90.8693	G	found
262	1986	LA	PLAQUEMINE	Plaquemine City of		Louisiana Energy & Power Auth/PCA	IBERVILLE	30.26	-91.36	G	
263	1987	LA	PORT ALLEN FACILITY	Placid Refining Co LLC		Entergy Electric System/PCA	WEST BATON ROUGE	30.4901	-91.3135	G	found
264	1989	LA	POWER AND UTILITIES	Dow Chemical		Entergy Electric System/PCA	IBERVILLE	30.2614	-91.361	G	
265	1990	LA	POWERHOUSE A	PPG Industries Inc		Entergy Electric System/PCA	CALCASIEU	30.2205	-93.3731	G	
266	1991	LA	PPG POWERHOUSE C	PPG Industries Inc		Entergy Electric System/PCA	CALCASIEU	30.2205	-93.3731	G	
267	1992	LA	PPG RIVERSIDE	PPG Industries Inc		Entergy Electric System/PCA	CALCASIEU	30.2205	-93.3731	G	
268	1994	LA	RELIANT ENERGY FIELD SERVICES	Reliant Resources		American Electric Power - West (SPP)/PCA	BOSSIER	32.6279	-93.5978	G	
269	1998	LA	RUSTON	Ruston City of		Entergy Electric System/PCA	LINCOLN	32.61	-92.66	G	
270	2000	LA	ST CHARLES OPERATIONS	Browns Propane		Entergy Electric System/PCA	ST CHARLES	29.961	-90.3756	G	found
271	2002	LA	STERLINGTON	Entergy Louisiana Inc	Entergy Corporation	Entergy Electric System/PCA	OUACHITA	32.7047	-92.0792	G	found
272	2003	LA	STINGRAY FACILITY	Dynegy Generation	Dynegy Inc	Louisiana Generating LLC/PCA	CAMERON	29.8155	-93.254	G	
273	2004	LA	TECHE	CLECO Power LLC	CLECO Corporation	CLECO Corporation/PCA	ST MARY	29.8222	-91.5417	G	found
274	2005	LA	TOCA PLANT	Western Gas Resources		Entergy Electric System/PCA	ST BERNARD	29.8954	-89.5968	G	
275	2006	LA	WATERFORD 1 & 2	Entergy Louisiana Inc	Entergy Corporation	Entergy Electric System/PCA	ST CHARLES	29.9778	-90.475	G	found
276	2008	LA	WILLOW GLEN	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	IBERVILLE	30.2742	-91.1333	G	found
277	1977	LA	NELSON INDUSTRIAL STEAM CO	Entergy Gulf States Inc	Entergy Corporation	Entergy Electric System/PCA	CALCASIEU	30.2205	-93.3731	O	found

Southeast Regional Carbon Sequestration Partnership (SECARB)

Plan for Identifying Most Promising Terrestrial Options for CO_2 Storage

(Deliverable 5.F)

Principle Author(s):	Winrock International Virginia Tech's Department of Crop and Soil Environmental Sciences Jackson School of Geosciences of the University of Texas at Austin
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1.0. Background

The EPRI Project "Quantifying Carbon Market Opportunities in the United States" began in 2001. The first major task was to design a methodology for estimating the quantity and cost of carbon storage opportunities in the United States and to test this methodology in a pilot region. The pilot region was comprised of Louisiana, Arkansas, and Mississippi. The primary outputs from this task were carbon supply curves for the most important classes of carbon sequestration activities in land-use change and forestry projects. The results were submitted to the Electric Power Research Institute (EPRI) and associated organizations (Winrock International 2003). Subsequently, a similar study and report was developed to include the state of Georgia in this pilot work (Winrock International 2004).

The US Department of Energy's Southeast Regional Carbon Sequestration Partnership (SECARB) is comprised of the eleven states of Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and part of Texas. Winrock International was tasked by SECARB to extend the methods and lessons learned from the EPRI pilot region and Georgia to the remaining five states of Alabama, Florida, North Carolina, South Carolina and Tennessee (Figure 1) in order to conduct an assessment of the terrestrial carbon sequestration opportunities across the region. Using the Winrock methodology, terrestrial carbon sequestration options are being analyzed in two 'late-comer' states: Virginia by Virginia Tech's Department of Crop and Soil Environmental Sciences and Texas by the Jackson School of Geosciences of the University of Texas at Austin. This document reports the progress thus far on the completion of the overall regional assessment.

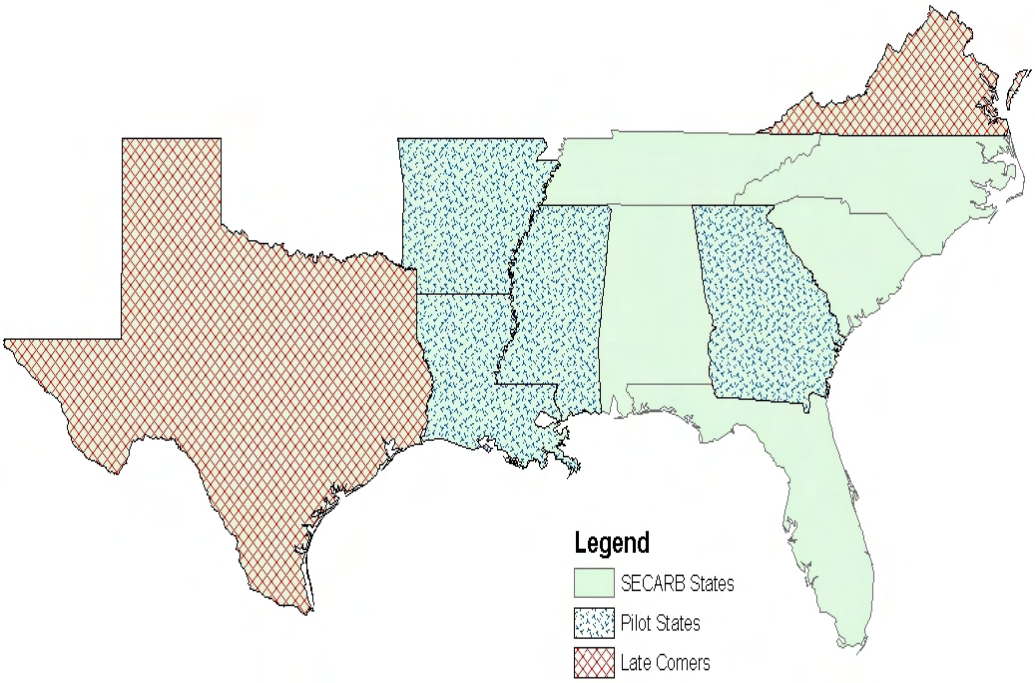

Figure 1. The SECARB states.

2.0. Overall Approach and Methods – Pilot Region

The overall approach used in this report follows those developed for the pilot region estimates. Due to differences in data availability for entire SECARB states, some methodology was altered from the pilot study. In order to create consistent, comparable results, analysis of the pilot states was repeated using the new methodology. An overall attempt was made in each stage of the project to create a methodology that was reproducible at the national scale incorporating data sets that are available in every state. Because of this uniformity of analysis, this section of the report results from all states analyzed by Winrock International (Arkansas, Louisiana, Mississippi, Georgia, Alabama, Florida, North Carolina, South Carolina, and Tennessee). The additional states of Texas and Virginia were completed by other institutions using a Winrock suggested methodology and are not considered in the following analysis; therefore all references to SECARB states in this section of the report will exclude Texas and Virginia.

The main goal of this study was to estimate the carbon supply for the most important classes of land-use change activities in the agriculture and forestry sector. Specifically:

- Estimate how much carbon would be offered at various prices for the main classes of land-use change activities
- Determine the geographic distribution of available carbon at the various prices

Following the pilot region approach, the analyses for the remaining states incorporates both spatial (e.g., STATSGO soils maps and 30 m resolution remote sensing classified maps) and tabular data (e.g. Forest Inventory and Analysis data base on forest volume, agricultural statistics). The analysis incorporates information about current land use, potential changes in land use and the incremental carbon resulting from the change, opportunity costs, conversion costs, annual maintenance costs, measurement and verification costs, and new sources of income that will result from the change. The analysis is performed in a geographic information system (GIS) to include the diversity of land uses, rates of carbon sequestration, and costs in the analyses.

The general approach was to identify and locate classes of land where there is potential to change the use to a higher carbon content, estimate rates of carbon accumulation for each major potential land-use change activity for each land class, assign values to each contributing cost factor, identify datasets and methods to estimate project risks, and identify datasets and methods to estimate co-benefits.

2.1. Classification of lands

Using the United States Geological Survey's National Land Cover Dataset (NLCD), it can be seen that the SECARB area is made up primarily of forestlands (Figure 2). Forested areas are mostly in the interior and coastal regions while agriculture is focused along the Mississippi River and the coastal flats of the Carolinas and Georgia. Florida

shows the highest concentration of urban development, grazing lands and emergent herbaceous wetlands.

This land-cover map that serves as the basis for this analysis is based on status of land cover in the USA as of 1992. Thus all the land areas and total quantities of carbon available reflect the conditions as of 1992. An updated version of the US map is being prepared but is not available for distribution at this time. When that map becomes available, the analysis presented in this report could be updated to reflect a more recent status of land availability and carbon supply.

For this analysis, lands are reclassified into four main groups: crop lands, grazing lands (including improved and unimproved pastures), forests, and other. Cropland is designated as row crops, small grain crops, and fallow areas; grazing lands are designated pasture/hay; and forests include deciduous, evergreen, mixed, wooded wetlands, and transitional forest. 'Other' land-cover classes include all urban and rural development, barren lands, shrublands, herbaceous and emergent herbaceous wetlands land cover-types. For this analysis of afforestation of agricultural lands, tree orchards were excluded from the agricultural land.

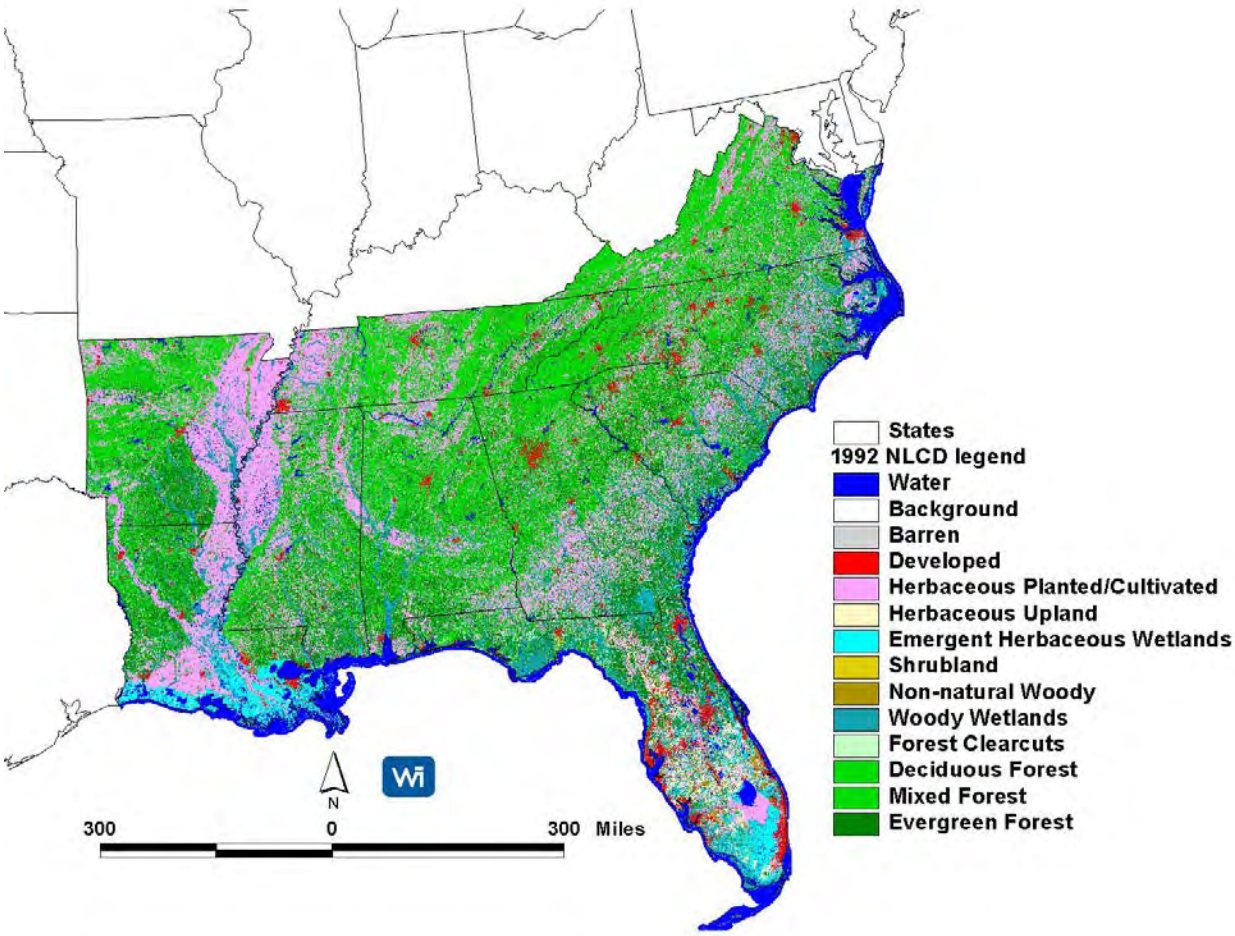

Figure 2. Map of SSEB region showing the land-use/land-cover classes for 1992.

2.2. Overall method for estimating the carbon supply

The steps needed for estimating the carbon supply for a given change in land use are (Figure 3):

1. Estimate the area for each potential change in land use.
2. Estimate the quantities of carbon per unit area that could be sequestered for the change in land use over a given time period.
3. Estimate the total costs (opportunity, conversion, maintenance, and measuring and monitoring).
4. Combine the estimated quantities of carbon per unit area with the corresponding area and cost to produce estimates of the total quantity of carbon that can be sequestered for given range of costs, in \$/ton C or \$/ton CO_2.

The carbon supply for each opportunity of land conversion is estimated for three time periods: 20 years, 40 years and 80 years to reflect the impact of project duration on the likely supply and to provide an assessment for the near–term and longer-term planning horizons.

3.0. Overall Approach and Methods - Texas

Section 3.0 of this report outlines the overall approach and methods used to assess the potential for carbon sequestration in Texas. First, a baseline analysis of past land-use practices needs to be assembled. Changes in land use will need to be documented, and the baseline is set as land use prior to year 1990 for the Kyoto Protocol. Once past land-use practices have been established, future changes in land use can be documented and presented in the context of past practices, and the impact on carbon storage can be assessed.

The 1992 National Land Cover Data (NLCD) can serve as the baseline land use for Texas. Approximately 50% of the state is rangeland, most of which occurs in Railroad Commission of Texas Districts 7c and 8A. Although forests comprise only 15% of the state's land use, most occur in the east half of the state, with percentages of up to 54 percent in District 6. Agricultural areas are widespread throughout the state, with the exception of west Texas (Districts 7c and 8).

Data sources used to provide baseline information include NLCD, and National Agricultural Statistics Service (NASS) county-level tabular databases. National Resources Inventory data are collected by the National Resources Conservation Service (NRCS). Information on land classifications is available on NRI online at http://www.statlab.iastate.edu/survey/nri/est971nr.pdf . Information from the Farmland Mapping and Monitoring Program (FMMP) will also be collated. Full metadata, data collection details, and class descriptions are available online at ftp://ftp.consrv.ca.gov/pub/dlrp/FMMP/fmmp_meta.txt. A consistent land-use classification scheme will be used to document baseline land use and to assess changes in land use.

Estimates of above-ground biomass will be obtained from satellite imagery (Leaf Area Index, Normalized Difference Vegetation Index). Changes in above-ground biomass are evaluated and will be related to natural or anthropogenic processes where possible.

Ground referencing will be used to validate satellite and air photo information. Below-ground biomass values will be estimated from species-specific rooting information and information on soil texture. Such estimates of below-ground biomass may be uncertain. Litter may also be a mechanism of carbon storage that will be examined.

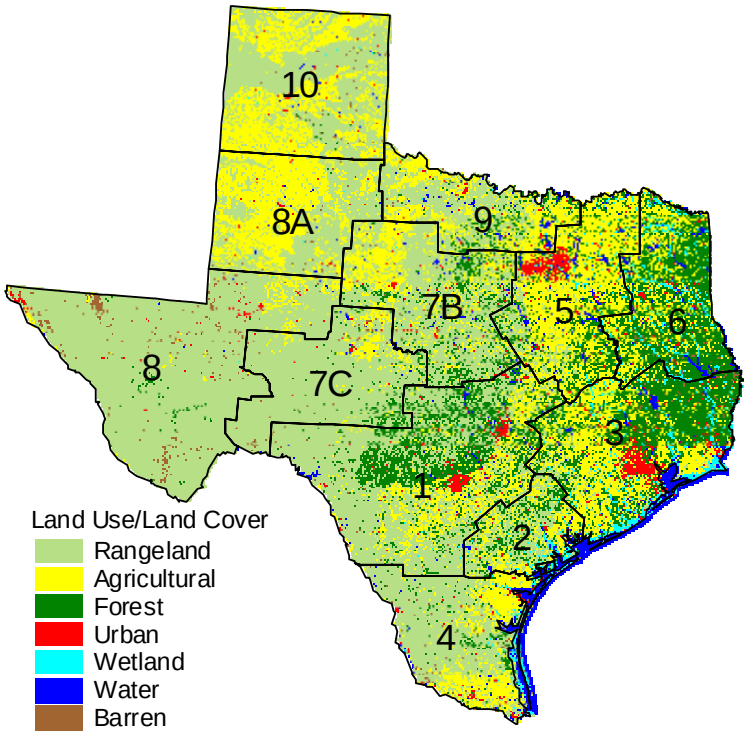

Figure 17. Railroad Commission of Texas district boundaries and National Land Cover Database (NLCD, 1992) land use/land cover.

Table 2. Calculated land use for regions of Texas divided by RRC districts. Districts 1–6 lie in the SECARB region and have much higher forest usage than the rest of the state.

	Land-Use Category Areas (%)						
District	*Rangeland*	*Agricultural*	*Forest*	*Urban*	*Wetland*	*Water*	*Barren*
1	55.9	15.6	24.6	2.2	0.1	1.0	0.6
2	42.4	28.0	20.6	1.1	4.7	2.8	0.4
3	5.4	35.6	40.1	5.7	8.3	3.1	1.7
4	63.0	24.2	5.4	1.7	2.0	2.1	1.7
5	10.0	56.1	21.3	5.8	2.5	3.8	0.4
6	0.1	30.7	54.1	1.8	8.0	3.5	1.8
7B	61.1	24.1	11.7	1.1	0.1	1.3	0.6
7C	85.9	8.0	4.3	0.5	0.0	0.4	0.9
8	92.7	3.0	0.7	0.7	0.0	0.1	2.8

8A	46.9	51.4	0.1	0.6	0.0	0.3	0.7
9	47.4	38.2	9.2	1.5	0.3	3.0	0.4
10	56.6	41.7	0.2	0.5	0.1	0.3	0.6
Texas	51.3	27.0	15.2	2.0	1.8	1.5	1.2

Rangeland: shrublands and grasslands
Agricultural: row crops, small grains, fallow, pasture/hay, orchards
Forest: perennial, evergreen, mixed
Urban: low- and high-density residential, transportation/industrial, urban grasses
Wetland: herbaceous and woody emergent wetlands
Water: open water
Barren: bare rock, quarries/open pit mines, transitional

4.0. Overall Approach and Methods - Virginia

Section 4.0 of this report describes carbon-sequestration modeling methods that can be applied over broad geographic areas, and application of those methods to estimate the carbon sequestration potential of alternative agricultural and forested land management options in Virginia. Options considered include afforestation of marginal agricultural lands, conversion of row crops from conventional tillage (CT) to no till (NT), and afforestation of riparian areas currently in agricultural production. The options were evaluated using two models: the first (and more general) modeling method (Winrock International 2004) was applied with the intent of generating estimates using methods comparable to those applied in other southeastern states through the Southeast Regional Carbon Sequestration Partnership (SECARB), while the second modeling method, developed here at Virginia Tech, was developed and applied with the intent of reflecting more localized factors than those considered by the general model.

The goals of this research are to evaluate and compare the potentials of three terrestrial systems' management options to sequester atmospheric carbon; to evaluate the potential for those options to offset Virginia's energy-related CO_2 emissions; and to identify the most promising terrestrial carbon sequestration option for Virginia. Three primary carbon sequestration options were considered: afforestation of marginal agricultural lands; row-crop tillage conversion; and afforestation of riparian agricultural areas. Marginal agricultural lands are defined as those lands with properties that are poorly suited to agriculture.

4.1. Research Methods

Data for this study consisted mainly of spatial data drawn from a variety of public databases and were compiled into a statewide GIS project file. The data layers provided a database of relevant spatial and tabular information. All of the spatial data layers to be used were projected to the Albers Conical Equal-Area projection using the North American Datum of 1983 (NAD83) and processed using ArcGIS® (Environmental Systems Research Institute, Redlands, CA) software tools.

National Elevation Dataset (NED) tiles were downloaded from the U.S. Geological Survey (USGS) Seamless Server which allows access to 1:24,000 scale raster grids in a seamless format (USGS, 2004). Individual 1-degree x 1-degree data tiles for the state of Virginia (extending beyond the border) were mosaicked together with a 30-m resolution to form a single continuous layer. The Seamless Server also contained the National Land Cover Datasets (NLCD) (USGS, 2005a) for both 1992 and 2001 (partial). These datasets also had a 30-m resolution but were created at a scale of 1:100,000. The partial data for NLCD 2001 included the eastern side of Virginia. This dataset was used to estimate forest growth rates for the Coastal Plain and Piedmont areas.

Hydrographic features from the USGS National Hydrography Dataset (NHD) were created at a scale of 1:100,000 (USGS, 2005b). Data for each Virginia hydrographic feature were merged to form a statewide dataset that included both stream features and water bodies such as lakes and wetlands. Other hydrographic data such as flow accumulation were derived from the NED mosaic within Virginia's 14 major river basins (Virginia Department of Conservation and Recreation, 2004). Sinks (depressions with no outlet) were filled on each group and flow direction/flow accumulation rasters were created. The flow accumulation layer was used in subsequent analyses involving erosion potential.

A tillage database containing acreages planted to various crop types for each county across the state was also created. This dataset was developed by linking county boundary files with agricultural data from both the U.S. Department of Agriculture (USDA) National Agricultural Statistics Service (NASS) and the Conservation Technology Information Center (CTIC) (CTIC, 2000; USDA, 2000). Both NASS and CTIC provided the acreage planted with row crops while CTIC provided additional information on the acreage in no-till (NT) and conventional tillage (CT). Data for the crops of corn, soybean and wheat are identified for each county for the year 2000. The county boundary files were obtained from the U.S. Census Bureau's Topologically Integrated Geographic Encoding and Referencing system (TIGER) for the year 2000 (U.S. Census Bureau, 2000).

Soils data were obtained from the USDA-Natural Resources Conservation Service (NRCS) State Soil Geographic Database (STATSGO) for Virginia (NRCS, 1994b). The data files included a polygon layer created at a scale of 1:250,000 and several attribute tables. STATSGO data is hierarchical in nature with each polygon representing a particular mapunit. Each mapunit was composed of multiple soil components while each soil component was composed of multiple soil layers. The MAPUNIT table in STATSGO included general information for each mapunit such as the name and the mapunit ID (MUID), the unique identification code. The COMPONENT table included aggregated information for each of the soil components of the STATSGO polygon mapunits and was linked to the mapunit table by the MUID. Each record in the LAYER table was then linked to the COMPONENT table by a unique mapunit sequence number (MUIDSEQ).

Level III ecoregion boundaries were obtained as GIS shapefiles were obtained from the U.S. Environmental Protection Agency (USEPA) Western Ecology Division (USEPA, 2003; Figure 1). The ecoregion maps were originally developed at a scale of 1:250,000 and were used to characterize the differences in carbon sequestration potential among regions of the state (US EPA, 2003)

Model 1 (Winrock Method)

Model 1, developed by Winrock International (2004), estimated the potential for carbon sequestration through implementation of two land management options that differ from the baseline or current management. The first option was the conversion of marginal agricultural lands to long-term forest cover using native tree species. The second option was the reduction in tillage intensity through the conversion of CT row crops to NT row crops. For this option, NT refers to practices that do not till the soil (West and Post, 2002).

Model 1, Option A (1A): Afforestation of Marginal Agricultural Lands

Identifying Marginal Agricultural Lands: The first step was to identify "marginal" agricultural lands. This was done using three of the data sources: elevation, land cover and soils. Agricultural lands were identified as pasture/hay, row crops, small grains, and grassland, land cover types that correspond with NLCD grid cells with values of 81, 82, 83, and 71, respectively. Marginal agricultural lands were defined as those areas that have one or more of the following limiting factors: frequent and long-term flooding, steep slopes (>10%), and soils that have shallow or rocky surfaces (Winrock International, 2004). An overview of Model 1A is given in Figure 2.

The process began with the creation of a new binary field "marginal" in the STATSGO COMPONENT table for the existence of limiting factors thought to restrict agricultural production. The STATSGO database was used to locate wet, shallow, or rocky soils. The COMPONENT table fields "annflod" and "anflodur" were queried for mapunit components that were prone to flooding, based on the following condition combinations: 1) "annflod" = "frequent" and "anflodur" = "very long" and 2) "annflod" = "occasional" and "anflodur" = "very long". Shallow soils were defined as components with the "panhard" field = "yes" and the "pandeph" field less than "12". High rock content soils were identified where the "rockhard" field = "hard" and the "rockdeph" was less than "12". All of the mapunit components with any one of the above combinations were assigned a code of "0" in the "marginal" field that was added to the COMPONENT table, while all other components received a "1". The dominant component within each mapunit was then identified as the component with the highest percentage in the "comppct" field. When the representative component had a value of "0" in the "marginal" field, the entire mapunit area was identified as marginal land. With each mapunit being either marginal or non-marginal, the STATSGO mapunits are converted from a vector file to a binary raster file.

Slope percent was calculated from the NED layer for Virginia using the Spatial Analyst extension within ArcGIS®. Slopes with greater than a 10% (model-defined value) gradient were assigned a value of "0" and all other slopes assigned a value of "1". This new raster layer was multiplied by the "STATSGO marginal" raster to produce a STATSGO/NED raster layer. Raster cells with a value of "1" were identified as "non-marginal" land and those with a value of "0" were "marginal" land. Values in this new raster were then switched to identify "marginal" land with a value of "1" and "non-marginal" land with a value of "0". In Virginia, NLCD identified agricultural land as either "pasture/hay" or "row crops." Raster cells of non-agricultural and agricultural lands are assigned a code of "0" or "1", respectively. This raster was then multiplied by the values in the STATSGO/NED layer to produce a final raster layer called "MARGAGLAND" showing marginal agricultural land with values of "1" and non-marginal agricultural land with value of "0".

Estimating Carbon Sequestration Potentials: Once the spatial location of marginal land was obtained, the STATSGO WOODLAND table was used to estimate the carbon sequestration potentials (carbon potentials) for time periods of 20, 40 and 80 years after planting. This table contains the fields "plantsym" and "suitcode" which identified the various tree species existing (code = "E") or with the potential to be planted as a tree crop (code = "EP"). Indications of site quality were obtained from the site index "sitind" and productivity "woodprod" fields for each tree species.

Tree species that already exist or had the potential for planting (EP) were identified for each STATSGO mapunit component. The tree species with the highest planting potential was used for those components with multiple EP codes. Empirical yield tables (Beck and Della-Bianca, 1981; McClure and Knight, 1984), biomass expansion factors (BEFs) (Brown and Schroeder, 1999), and regression equations for predicting root biomass density (RBD) (Cairns et al., 1997) were used to calculate Mg C $cell^{-1}$ for each time period assuming that 50% all biomass was carbon (Table 1). Growing Stock Volume (GSV) was obtained from the yield tables based upon the various tree species and site qualities of a component and used to calculate aboveground biomass density (AGBD) and RBD. The reason for expressing the densities on a grid cell basis was the need for spatially explicit values that correspond to grid cell locations of marginal agricultural lands. Therefore, units of carbon potential were converted from Mg C ha^{-1} to Mg C $cell^{-1}$. These units allow for the summation of the cell values for the total amounts of carbon by ecoregion.

Once a carbon potential was estimated for each soil component, a weighted summation of the carbon potential for each STATSGO mapunit was calculated using the percentage of each mapunit component. Units of carbon potential (Mg C $cell^{-1}$) were added to the STATSGO MAPUNIT table and joined to the STATSGO polygon layer. The resulting carbon potential STATSGO vector layer was converted to 30-m raster layers for each mapunit for each of the three time periods and multiplied by the "MARGAGLAND" raster layer to produce three carbon potential layers for marginal agricultural lands. The total amount of carbon (Tg) sequestered for the three time periods was then calculated within each level III ecoregion in Virginia by overlay of each of the final carbon potential

raster layers with the level III ecoregion vector polygon map. Finally, the total carbon potential (Tg) within each ecoregion was divided by the hectares of marginal agricultural land for that ecoregion to develop sequestration rates.

Model 1, Option B (1B): Tillage Conversion

Identifying Lands Eligible for Conversion: The county level statistics (NASS) data for the year 2000 were used to assess the effects of converting from CT to NT on the number of acres planted in various row crops, based on cropping patterns in the year 2000. To associate the county level data with the more spatially explicit soil and land cover types, the county statistics were used to obtain a raster layer showing the NASS cropland area (m^2) represented by each NLCD "row crop" grid cell within each county. The total NASS land area in m^2 that each county planted with corn for grain (including silage), soybeans, and wheat was then divided by the number of NLCD "row crop" grid cells within that county to identify the area (m^2) of NASS-defined row-crop land that each NLCD "row crop" grid-cell represented. These new values were then rasterized to a resolution of 30 m For this model, all row-cropped area was assumed to be in CT operation. Ten counties , primarily the state's mountainous and urbanized areas, and 37 of 40 independent cities did not have any data reported in the NASS database and were not included in the analyses.

Estimating Carbon Sequestration Potentials: STATSGO mapunits were assigned values from West and Post (2002) for the potential carbon that could be sequestered when converting from CT to NT for the "All crop systems (no wheat-fallow)" crop system. The West and Post values ranged from 43 to 71 with a mean of 57 g C m^{-2} yr^{-1} for approximately 14 years (West and Post, 2002; Table 2, "All treatments, no wheat-fallow"). Following the findings of West and Post (2002), STATSGO mapunits were assigned a carbon potential value based upon the texture of the surface layers (from STATSGO LAYER table) of each component. To define a textural class, a field for a numerical texture value was created in the STATSGO COMPONENT table to represent three broad textural categories: (1) coarse, (2) medium, and (3) fine. The 'surftex' field in the COMPONENT table was used to assign one of the three integer values to each component (all loams were considered as medium-textured, sands as course-textured, and clays as fine-textured). These values were then multiplied by the component percent and a weighted sum was calculated for each mapunit. If the total mapunit value within a mapunit was ≤ 1.5 the mapunit was considered coarse-textured and assigned a value of 43 g C m^{-2} yr^{-1}. If the value was between 1.5 and 2.5, the mapunit was considered medium-textured and assigned a value of 57 g C m^{-2} yr^{-1} while a value ≥ 2.5 was considered fine-textured and assigned a value of 71 g C m^{-2} yr^{-1}. After joining these values to the STATSGO polygon layer, a new raster layer was created based upon those values. Finally, the raster layer of planted land area was multiplied by the potential carbon sequestration raster and an NLCD raster showing the location of "row crops", then multiplied by 14 yrs. This overlay process is illustrated in Figure 3. The final raster displayed the total carbon potential (g C) for each grid cell after the system comes to equilibrium (14 yrs). The total carbon potential raster was then combined with the level III ecoregion polygon map to calculate the sum (g C) within each ecoregion.

Model 2 (Virginia Tech Method)

Model 2, Option A (2A): Afforestation of Marginal Agricultural Lands

Model 2 included a more advanced approach to defining marginal agricultural lands, incorporating information on local and regional parameters (Figure 4). We define marginal lands as those not suited for intensive farming because of inherent site, soil, and management limitations such as poor drainage, frequency of flooding, high slope, high erodibility, poor physical and chemical conditions, proximity to water or wetlands, or degradation due to improper use and management.
Three criteria were used to identify marginal agricultural lands: Steepness of slope, high erodibility, and other STATSGO soil properties.

STATSGO Soil Properties: One method for defining marginal agricultural lands considered soil properties. Under the Farmland Protection and Policy Act, US Department of Agriculture is required to identify "Prime Farmlands" and Farmlands of Statewide Importance." Natural Resources Conservation Service (NRCS) personnel in each state develop criteria for classifying farmlands of these types. We identified all farmlands that were not classified as "prime" and did not fit Virginia criteria for "farmlands of statewide importance," as one mechanism for identifying "marginal" agricultural lands. The following STATSGO soil properties were used in this procedure: hydrologic conditions such as the hydrologic group, drainage class, and if the soil was hydric; factors indicating high erosion potential; and other limiting properties (Table 2). Prime farmland status was also checked as part of this procedure, to assure that prime farmlands were not designated as marginal.

Properties in different soil layers were summarized by component and component properties were summarized by mapunit as described by the NRCS to calculate the percent of STATSGO mapunit that was considered marginal (NRCS, 1994a) Each soil property was grouped as in Table 2 and assessed for the average percent of the mapunit considered to be marginal. Mapunits with marginality of over > 50 % for any soil property were considered marginal. A raster dataset was created with the raster calculator tool where marginal mapunits were indicated by value = "0".

Steepness of Slope: Because pastures are commonly located on steeper slopes than row crops, separate slope thresholds were determined for cropland and pastureland. To obtain these thresholds, the slope percent at each row crop or pasture grid cell was calculated. Then, a frequency distribution showing the number of grid cells occurring at various slope percents was used to identify the slope percent at which 95% of each land-use occurred to reflect the majority of area associated with these land-uses. Lacking a standard for excessive steepness, the 95% criterion was selected as a means of identifying the steepest lands. Figure 5 shows that 95% of all pasture grid cells in Virginia occur on slopes less than 20% while 95% of all row crop grid cells occur on slopes less than 13%. Pasture cells ≥ 20 % and row crop cells ≥ 13 % are then identified as marginal due to excessive steepness, and assigned a marginal value of "0".

Highly Erodible Lands (HELs): The Food Security Act of 1985, as amended, requires that all persons that produce agriculture commodities must protect all cropland classified as being highly erodible from excessive erosion. As a result, the Natural Resource Conservation Service has defined procedures for identifying highly erodible land (HEL) (NRCS, 2004). Those procedures were applied in this analysis, as described below. The basis for the procedure is the Revised Universal Soil Loss Equation (RUSLE) (Renard et al., 1997):

$$A = R\ K\ LS\ C\ P, \tag{1}$$

where A = potential erosion expressed as soil loss, t ha^{-1} yr^{-1}; R = rainfall erosivity factor; K = soil erodibility factor; LS = slope length x steepness factor; C = crop factor; and P = management factor.

The R factor was digitized and interpolated from the original map in Wischmeier and Smith (1978), the K factor was summarized (using a weighted average by component) to the mapunit level from the surface layer from the STATSGO LAYER table and converted to raster format, The C factor was assigned based upon the vegetation type in NLCD (Table 3), and the P factor was assumed to equal 1. The LS factor was then calculated from the NED using the following equation:

$$LS = (0.4 + 1)\left[\frac{A_s}{22.13}\right]^{0.4}\left[\frac{sin\beta}{0.0896}\right]^{1.3} \tag{2}$$

where LS = slope length factor, A_s = flow accumulation * cell size, (m); and β = slope angle (degrees) (Moore et al., 1993). The R, K, C, P, and LS values at each raster cell were then multiplied to estimate the potential erosion A for each grid cell.

The T factor (soil loss tolerance) for each component's surface layer was obtained from the STATSGO LAYER table and a weighted average of T was computed by component percent for each STATSGO mapunit. The calculated erosion potential (A) was then divided by T to obtain the erodibility index (EI) for each STATSGO mapping unit.. An erodibility index, EI, was calculated as

$$EI = [\ R \times K \times LS\ ] / T$$

the potential erosion (A), t ha^{-1} yr^{-1}, divided by the soil loss tolerance (T), ha^{-1} yr^{-1}, and HELs were defined as grid cells with EI ≥ 8 (NRCS, 2004).

As a final reclassification, HELs raster cells were assigned a new value of "0" to indicate marginality. The marginal soils, marginal slopes, agricultural lands, and HEL maps were then combined and assigned carbon potentials (Figure 4).

Estimating Carbon Sequestration Potentials: This procedure was performed as described for Model 1, Option A.

Model 2, Option B (2B): Tillage Conversion

The only difference in the methodology between Model 2 and Model 1 to assess the effects of tillage conversion was in the assumption of the proportion of land area already in conventional tillage (CT). While Model 1 assumed that all row-cropped land area was in CT, the Model 2 used CTIC (2000) estimates of the proportion of row-crop land in each county that is currently cropped using CT methods to determine row-crop area of each county eligible for tillage conversion. The CTIC includes information for all counties (and the 3 cities from NASS); however, no further information was provided for the remaining independent cities although NLCD and TIGER boundaries indicate that there are row crops within those city limits. Those areas are treated as no data and excluded from the analysis.

The areas of row crops within each county/city from NASS were multiplied by proportion of row-crop defined by CTIC (2000) being in CT to re-calculate the m^2 represented by each "row crop" grid cell that is eligible for tillage conversion. These new values were then divided by the number of "row crop" cells to give a new representation of planted area. The remaining part of the procedure followed that in Model 1, Option B.

Option C: Afforestation of Riparian Areas and Farmed Wetlands

All stream, lake and wetland features from the NHD were buffered by a distance of 16.7 m (55 ft), the minimum distance for Zones 1, 2, and 3 as described in the National Handbook of Conservation Practices (NHCP) for the Riparian Buffer Strip standard (practice code 391) and Filter Strip standard (practice code 393) (NRCS, 2003). Once buffered, the buffer polygons were assigned a value of "1" and converted to a 30-m raster. This raster of stream, lake, and wetland buffers was then combined with the 30-m NLCD raster to identify agricultural lands within the buffer. Using the same carbon potentials used for the afforestation of marginal agricultural lands, these areas within the buffer were assigned carbon sequestration potentials. The annual, per ha, and total carbon sequestration potentials within each ecoregion were then summarized as in the previous analyses.

Southeast Regional Carbon Sequestration Partnership (SECARB)

Meetings and Presentations: SECARB Phase I Program (6.E2)

DOE Award Number: DE-FC26-03NT41980

Submitting Organization:
Southern States Energy Board
6325 Amherst Court
Norcross, Georgia 30092 USA

December 31, 2005

Meetings and Presentations

SECARB project team members participated in numerous events over the two-year program period. The purpose was to present the SECARB activities and gain support for, and recognition to, the DOE/NETL Regional Carbon Sequestration Partnership program. Such presentations/events include, but are not limited to, those listed below.

- NETL Regional Carbon Sequestration Partnership kick-off meeting in Pittsburgh, Pennsylvania, November 3-4, 2003
- SECARB's first meeting of the Technical Team and Technology Coalition in Atlanta, Georgia, January 14-15, 2004
- SSEB Associate Members Meeting in Washington, DC, February 23, 2004
  - SECARB recognition by former Governor Bob Wise of West Virginia, who served as SSEB's Chairman at that time
- American Chemical Society Annual Meeting in Anaheim, California, March 31, 2004
- North Carolina State Mercury/ CO_2 workshop April 19-21, 2004
- Third Carbon Sequestration Partnership meeting, May 2-5, 2004
- NETL Workshop, May 6, 2004
- Second Technical Team/Technology Coalition quarterly meeting in conjunction with the SSEB Chairman's Forum on Carbon Management, May 19-21, 2004
- Regional Environmental Impact Statement public meeting sponsored by NETL in Norcross, Georgia, June 2, 2004
- CO_2 conference at the University of Georgia, June 10-11, 2004
- COOP Meeting, Charleston, West Virginia, on July 13, 2004
- Southern States Energy Board Briefing to Legislative Members, Little Rock, Arkansas, on August 14, 2004
- Southern States Energy Board Associate Members and Utility Advisory Committee Meeting, Richmond, Virginia, on September 11, 2004
- Southern States Energy Board 44th Annual Meeting, Richmond, Virginia, on September 13, 2004
- SECARB Focus Group Meeting, Richmond, Virginia, on September 13, 2004
- "Geological Working Group Meeting" in Houston, Texas, on October 20, 2004
- "MIT Carbon Sequestration Forum V: Overcoming Barriers to CCS Implementation" in Cambridge, Massachusetts, on November 2-3, 2004
- NETL "Regional Carbon Sequestration Partnerships Annual Program Review Meeting" in Pittsburgh, Pennsylvania, on November 16-17, 2004
- SECARB Technical Team/Technology Coalition Meeting on Geologic Characterization, December 17, 2004
- SECARB Technical Team/Technology Coalition Meeting, January, 20, 2005

- SECARB Partnership Status Briefing to Southern Company Senior Management, January 2005
- "Southern States Energy Board Associate Members Meeting", February 28, 2005
- SECARB Presentation to Duke Energy in Charlotte, North Carolina, April 14, 2005
- SECARB Presentation to SCANA Energy in Columbia, South Carolina, April 15, 2005
- 3rd Annual West Virginia Leadership Conference in Charleston, West Virginia, April 27, 2005
- Carbon Sequestration Leadership Forum in Alexandria, Virginia, May 2, 2005
- 4th Annual Carbon Sequestration Workshop in Alexandria, Virginia, May 5, 2005
- Eastern Coal Council Meeting in Kingsport, Tennessee, May 24, 2005
- The Energy Council's "2005 State and Provincial Trends in Energy and the Environment Conference" in St. John's, New Foundland, June 25, 2005
- Briefing to South Carolina state officials and to SCANA in Columbia, South Carolina, July 20-21, 2005
- Southern States Energy Board Briefing to Legislative Members in Mobile, Alabama, July 30, 2005
- Southern States Energy Board Associate Members Meeting in Mobile, Alabama, July 30, 2005
- Southern States Energy Board 45th Annual Meeting in Greensboro, Georgia, August 27-29, 2005

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