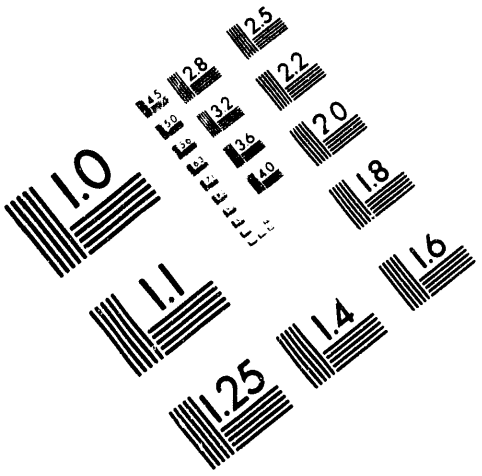

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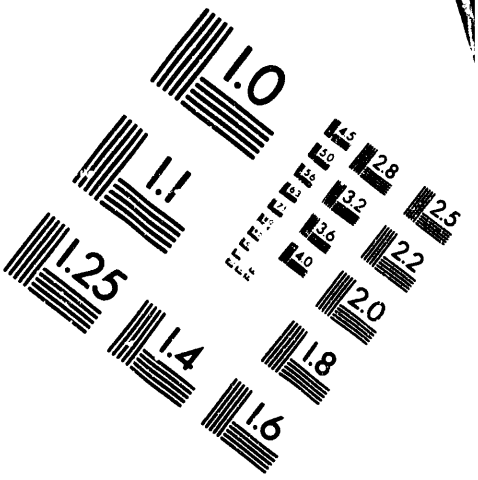

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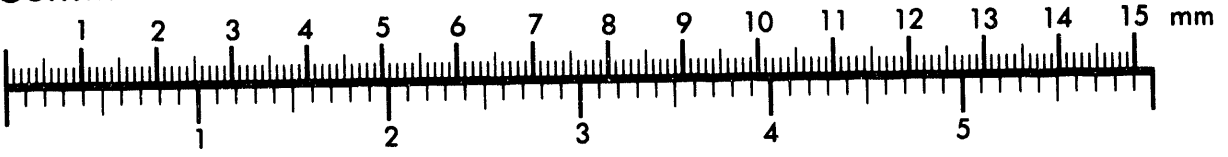

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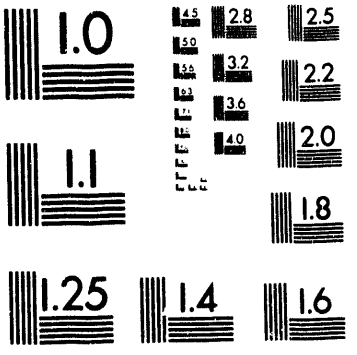

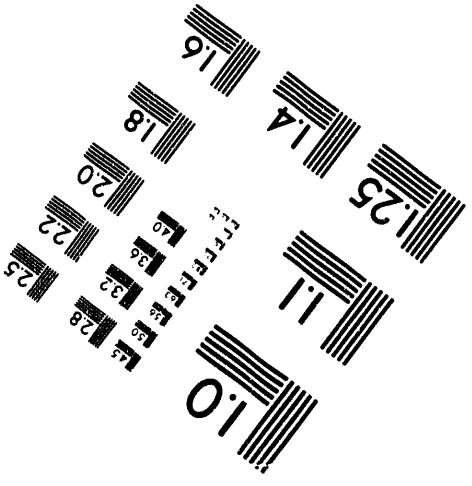

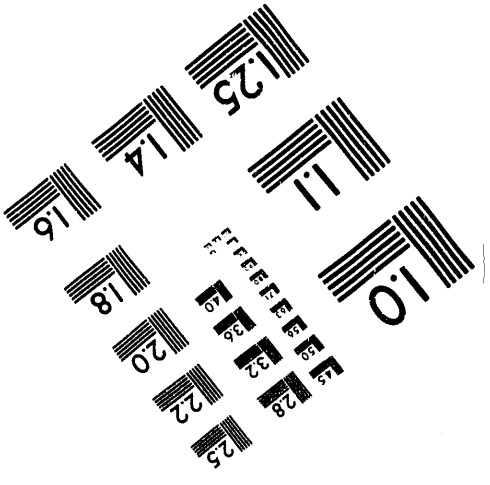

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PNL-SA-22634

CARBON DIOXIDE CONTROL COSTS FOR GASIFICATION COMBINED-CYCLE PLANTS IN THE UNITED STATES

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Prepared for
the U.S. Department of Energy
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SUMMARY

The objective of this study, conducted for the U.S. Department of Energy by the Pacific Northwest Laboratory's (PNL) Global Studies Program, was to initiate the development of a carbon dioxide (CO_2) control "supply curve." The curve would relate the amount of CO_2 controlled as a function of the cost of control in the electric utility sector. This information, along with similar characterizations of other options, could be used in general planning studies evaluating alternative responses to the potential global warming problem.

This study focused on evaluating the cost of recovering CO_2 from coal gasification, combined-cycle (GCC) power plants and transporting the CO_2 in pipelines for disposal in deep ocean water, depleted oil and gas reservoirs, or aquifers. Other fuels and conversion technologies were not evaluated. Technical feasibility, environmental acceptability, and other implementation issues were not addressed in detail.

Ocean disposal of CO_2 offers essentially unlimited capacity, but is distant from most U.S. coal-fired power plants and presents environmental concerns at the disposal point. Depleted oil and gas reservoirs are also distant from most U.S. coal-fired power plants and have a more limited disposal capacity, but were calculated to have a potential capacity more than double that required to dispose of all CO_2 from 830 GCC power plants (380-MWe each) for a period of 40 years. The existence of oil and gas reservoirs provides "proof" of the long-term CO_2 confinement potential in these formations. In contrast, aquifer disposal is believed to be significantly riskier. Key concerns are lack of geologic knowledge at depths adequate for CO_2 disposal; uncertainty about geochemical impacts from decreased water pH; and long-term confinement, which is unproven for non-petroleum formations.

Carbon dioxide recovery at GCC plants increased the levelized energy cost (LEC) by about one third relative to a reference GCC plant without CO_2 recovery. The transmission distance is the key factor affecting total CO_2 control costs. The LEC with CO_2 recovery and disposal increased by one third to more than a factor of two, depending on the transmission distance, which

ranged from about 25 to nearly 2000 mi. While CO_2 recovery and disposal would likely be too expensive to implement on a national basis, regional or site-specific applications may be competitive with other CO_2 control strategies.

The significant impact of transmission on the cost-effectiveness of CO_2 recovery and disposal suggests that the following topics are worthy of further examination:

1. The impact of locational and seasonal variation in ambient temperature on CO_2 properties, hence pipeline design.
2. CO_2 distribution equipment within oil and gas reservoirs.
3. Integrated pipelines from multiple GCC units or power plants.
4. Specific design requirements for CO_2 pipelines.
5. Impact of elevation drop on recompression requirements in overland pipelines.

Carbon dioxide control costs for the GCC power plant should be compared with other control options, such as increased efficiency of energy supply and end-use equipment, reforestation, and carbon taxes. CO_2 control costs for other fossil fuels and combustion technologies should also be evaluated to complete the development of a CO_2 control "supply curve" for U.S. electric utilities.

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1.0 INTRODUCTION

The concentration of CO_2 in the atmosphere has been rising steadily for several decades. Predictions of global warming and related deleterious effects give cause for considering potential responses. Electric utilities account for approximately one third of U.S CO_2 emissions via the combustion of coal, oil, and natural gas. One option for reducing atmospheric CO_2 emissions is to capture CO_2 at power plants and transport it for disposal in an alternative "sink."

Carbon dioxide control (capture and disposal) costs would vary significantly depending on the fuel, conversion technology, and location of the electric power plant. Coal, oil, and gas produce different amounts and concentrations of CO_2 per Btu of energy released during combustion. For a given fuel, such as coal, the best control technology for a pulverized coal plant would differ from that for a gasification type plant. Carbon dioxide transportation costs are extremely site-specific, depending on the proximity to a disposal location.

The objective of this study, conducted for the U.S. Department of Energy (DOE) by the Pacific Northwest Laboratory's (PNL) Global Studies Program,[a] was to initiate the development of a CO_2 control "supply curve" relating the amount of CO_2 controlled as a function of the cost of control in the electric utility sector. This information could be used (along with similar characterizations of other options) in general planning studies evaluating alternative responses to the potential global warming problem.

The scope of this study was limited to coal-fired power plants employing gasification, combined-cycle technology. Other fuels and conversion technologies were not evaluated. Deep ocean water, depleted oil and gas reservoirs, and/or aquifers were considered as potential disposal locations. Emphasis was placed on determining the cost impact of varying the coal-fired power plant

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(a) Pacific Northwest Laboratory is operated for the U.S. Department of Energy by Battelle Memorial Institute under Contract DE-AC06-76RLO 1830.

location and disposal concept. Technical feasibility, environmental acceptability, and other implementation issues were not addressed in detail.

The following three sections on recovery, disposal, and transmission define the analytical procedure and resultant characterization of the major CO_2 control system elements. The final two sections in the main body of the report summarize the system results, conclusions, and recommendations. Supporting detail describing the calculation of CO_2 storage capacity in depleted oil and gas reservoirs is presented in Appendix A. Appendix B describes design details of the CO_2 pipeline.

2.0 RECOVERY

As indicated in the Introduction, CO_2 recovery was based on coal-fired power plants employing gasification, combined-cycle technology. Coal-fired power plants were chosen for evaluation because coal produces more CO_2 per Btu of energy released during combustion and is the predominant fossil fuel consumed by U.S. utilities. Currently, practically all large-scale coal-fired power plants use pulverized coal (PC) combustion technology. However, more advanced coal combustion technologies such as fluidized bed (atmospheric or pressurized) or gasification, combined-cycle (GCC) (integrated or non-integrated) that are less polluting and more efficient are more likely to be employed in the future. In addition, several previous studies (e.g., Smelser and Booras 1990) have indicated that CO_2 capture from PC plants would be more costly, particularly in a retrofit situation, than CO_2 capture from GCC plants.

2.1 REFERENCE PLANT SELECTION

Three reports describing evaluations of CO_2 recovery from GCC plants were reviewed to define the specific design and cost characteristics (Smelser and Booras 1990; Shell Internationale 1990; Hendriks, Blok and Turkenburg 1990). In each of these evaluations, carbon monoxide in the fuel gas is converted to carbon dioxide via the water/gas shift reaction. Carbon dioxide is subsequently scrubbed from the fuel gas prior to combustion of the hydrogen in the gas turbine. Each of the three studies is briefly described below.

Smelser and Booras evaluated a 400-MWe GCC plant that used Texaco's total quench gasification technology. The water/gas shift reaction was accomplished in two stages. Ninety percent of the CO_2 was recovered by washing the syngas at pressure with Selexol after first using the same solvent to preferentially remove hydrogen sulfide. The CO_2 was compressed and dried for transport in a pipeline presumed to be 400 mi long. Current technology was employed.

The analysis by Hendriks, Blok and Turkenburg evaluated a 600-MWe integrated GCC plant that was based on Shell's gasification technology. Fuel

gases were partially cooled by generating steam rather than quenching. The water/gas shift reaction was conducted after sulfur removal to protect the catalyst in the shift reactors from becoming poisoned. Selexol was used to recover 88% of the CO_2, which was compressed and dried for pipeline transport. The hydrogen sulfide solvent was not specified. Design and performance assumptions were based on capabilities expected to be available by the year 2000.

As might be expected, Shell employed its own gasification technology in its evaluation of a 750-MWe IGCC plant. Sulfur removal and CO_2 separation followed the water/gas shift reaction similar to the Smelser and Booras study, but SulFerox and DEMEA (two licensable Shell processes) were used for hydrogen sulfide removal and CO_2 separation, respectively. Higher conversion in the water/gas shift reactions allowed recovery of 94% of the CO_2, which was compressed and dried for pipeline transport. Currently available technology was employed.

The evaluation described by Smelser and Booras was selected as the reference for defining GCC plant cost and performance characteristics. The results presented in Smelser and Booras were consistent with the Shell study while results from Hendriks, Blok, and Turkenburg were considerably more optimistic. Factors favoring selection of the Smelser and Booras data were greater cost and performance detail, U.S. design conditions, and a moderate plant size.

2.2 REFERENCE PLANT DESCRIPTION

Smelser and Booras presented design, cost, and performance data for GCC plants with and without CO_2 recovery. The CO_2 was initially pressurized to 2200 psia for transmission through a 400-mi pipeline. The pipeline was eliminated and the initial pressurization was reduced in order to create a common plant design independent of the actual transmission distance.

A minimum pipeline pressure of 1200 psia was selected based on advice presented in Decker (1986), which described an actual CO_2 pipeline running from Colorado to Texas. The critical pressure for CO_2 is about 1070 psia. Therefore, operation at 1200 psia or above eliminates two-phase flow. The

amount of additional pressurization required beyond 1200 psia depends on the pipeline length and pressure drop per unit of length. Pipeline pressure losses and incremental pressurization requirements are discussed in more detail in Section 4 and Appendix B.

Besides eliminating the costs associated with the pipeline, the reduction of initial CO_2 pressure reduced the size, cost, and power consumption of the compression equipment. The resultant plant characteristics for a GCC plant, with and without CO_2 recovery, are shown in Table 2.1. The "total plant cost" shown in Table 2.1 represents construction costs. Startup and working capital costs were estimated for each plant based on the relationships shown in Table 2.2. All cost data were adjusted to mid-1990 dollars.

Many different technologies have been considered for coupling CO_2 recovery with coal-fired power plants (Blok et al. 1992). While several of these

TABLE 2.1. GCC Power Plant Characteristics

Characteristic	Reference GCC Plant	GCC Plant with 90% CO_2 Recovery[b]
Gross Power Output, kWe	501,656	496,600
Net Power Output, kWe	431,647	381,500
Total Plant Cost, $1000[a]	705,911	832,902
Annual O&M Costs[a]		
Labor, $1000	20,092	23,681
Fixed Materials, $1000	12,707	18,081
Consumables, mills/kWh	0.432	0.826
Heat Rate, Btu/kWh	9,639	11,894
Annual Power Production @ 65% Capacity Factor, MWh	2,457,798	2,172,261

(a) All costs are in mid-1990 dollars.
(b) Does not include CO_2 transmission and disposal.

TABLE 2.2. Startup and Working Capital

Startup = 0.02 * Total Plant Cost +
1/12 * Total Annual O&M Cost +
1/52 * Total Annual Fuel Cost

Working Capital = 0.005 * Total Plant Cost +
1/6 * Total Annual O&M Cost +
1/6 * Total Annual Fuel Cost

technologies may eventually prove to be better, the gasification plant and CO_2 recovery described above is a reasonable option using proven technology that could be constructed today.

3.0 DISPOSAL

Three possible disposal options were considered in this study: deep ocean water, depleted oil and gas reservoirs, and aquifers. The first two options have been given the most attention by researchers considering CO_2 recovery and disposal. By comparison, the possibility of disposing CO_2 in aquifers has been less vigorously investigated. The following three subsections present discussions of each of these options.

3.1 OCEAN DISPOSAL

Deep ocean water has several characteristics that make it a potentially attractive alternative to atmospheric release of CO_2. The deep ocean has a tremendous CO_2 storage capacity compared with global CO_2 emission rates. The ocean is a relatively homogeneous medium, which reduces the site-specific technical uncertainty, particularly when compared with terrestrial disposal options such as depleted oil and gas reservoirs and aquifers. Ultimately, CO_2 released to the atmosphere will dissolve in the ocean. Deep ocean injection of CO_2 serves to speed the long-run (hundreds of years) equilibrating processes. Nevertheless, there are legitimate concerns about the potential negative impact on the local aquatic environment near disposal points. Differences of opinion also exist with regard to the CO_2 retention period.

Several different ocean disposal concepts have been proposed. These include 1) dissolution of liquid CO_2 into moderately deep water; 2) injection of CO_2-rich sea water into moderately deep water; 3) sinking of liquid CO_2 into very deep water; 4) injection of CO_2 into naturally sinking currents; 5) surface injection of solid CO_2; and 6) surface injection of solid CO_2 hydrate. Each of these concepts is described below.

In the first concept, liquid CO_2 is injected into the ocean at a depth of approximately 500 m and dissolves in the surrounding water. The CO_2 is injected via a pipeline extending from the nearest shore or from a platform on the ocean's surface. The required injection depth is subject to some debate. Essentially all sources agree that the upper layer of the ocean in relatively intimate contact with the atmosphere is about 100 m deep. This upper layer is

well-mixed and subsequently maintains a fairly uniform temperature. In the next few hundred meters, water temperature drops very quickly. Below the thermocline, which varies in depth depending on location, the ocean water is uniformly a few degrees above the freezing point. At a depth of 500 m, CO_2 is less dense than the surrounding ocean water and will bubble up towards the surface before it dissolves. At issue is the depth at which the CO_2 would dissolve and the amount of interaction water at this depth actually has with the well-mixed upper 100 m.

In the second concept, CO_2 is first dissolved in a stream of sea water near the ocean shore. The CO_2-rich stream is then injected via pipeline to a depth of approximately 500 m. This approach eliminates CO_2 bubbling concerns at the injection point, but requires a much larger pipe or multiple pipes to handle the significant increase in fluid volume.

The third concept is similar to the first, except the CO_2 is injected at a greater depth. At a depth of 3000 m, liquid CO_2 has a density greater than sea water and will sink to the ocean floor where it will slowly dissolve over time. Presumably, this disposal approach results in a considerably longer retention period than injection at 500 m. Of course, a longer, more costly pipeline would be required.

In the fourth concept, CO_2 is injected directly into a near-surface sinking current that transports the CO_2 into the deep ocean. Several locations in the world have naturally sinking currents that originate relatively close to shore and are relatively shallow. One example of this is the thermohaline current that exits to the Atlantic from the Mediterranean Sea. Surface evaporation of Mediterranean waters exceeds the inflow of water from rivers, causing the Sea to be saltier than the ocean. This creates two different currents crossing the entrance to the Mediterranean at the Straits of Gibraltar. Near the floor of the sea, the denser salt water flows out to the Atlantic and sinks below the lighter ocean water. At the surface, a larger current flows into the Mediterranean, making up for the net water lost via evaporation and the subsurface outflow. This concept, while interesting, has obvious geographic limitations. No similar currents exist close to the shore in the United States.

The fifth and sixth ocean disposal concepts are based on solidified CO_2 that can be transported via refrigerated ocean freighter and dropped directly in the ocean. Both solid CO_2 and solid CO_2 hydrate ($CO_2 \cdot 6H_2O$) are denser than sea water and sink when dropped onto the ocean surface. Initially, some CO_2 is released as the cube sinks, but sublimation ceases at a pressure corresponding to a depth of about 500 m. Below 500 m, the cube continues to melt on its way to the ocean floor. Because it is denser than CO_2 hydrate, solid CO_2 sinks more quickly and should lose less CO_2 to sublimation. The principal drawback of solid CO_2 disposal is the energy required for solidification, which is several times that required for liquefaction.

The ocean disposal concepts selected for evaluation in this study were injection of liquid CO_2 at either 500-m or 3000-m depth. The other concepts are either significantly more expensive (concepts 2, 5, and 6) or have limited geographic applicability (concept 4). Examination of the two depths should help identify the economic importance of resolving the injection depth issue. Bathymetric maps prepared by the National Oceanic and Atmospheric Administration were used to locate 500-m and 3000-m deep water off the U.S. coastlines (see Figure 3.1). Ocean disposal capacity was assumed to be a non-issue, i.e., the deep ocean water was assumed to have adequate capacity to absorb all the CO_2 recovered from the GCC power plants. For further discussion of ocean disposal issues and prospects, the reader is referred to several papers presented in Blok et al. (1992).

3.2 DEPLETED OIL AND GAS RESERVOIR DISPOSAL

In general, petroleum (natural gas and crude oil) is found in sedimentary (e.g., sandstone and limestone) rock formations at depths as shallow as 40 ft and as deep as 21,000 ft. Petroleum is not found in all geographical regions, but rather in localized accumulations under certain geologic conditions (Amyx, Bass and Whiting 1960). The concept of CO_2 disposal in abandoned

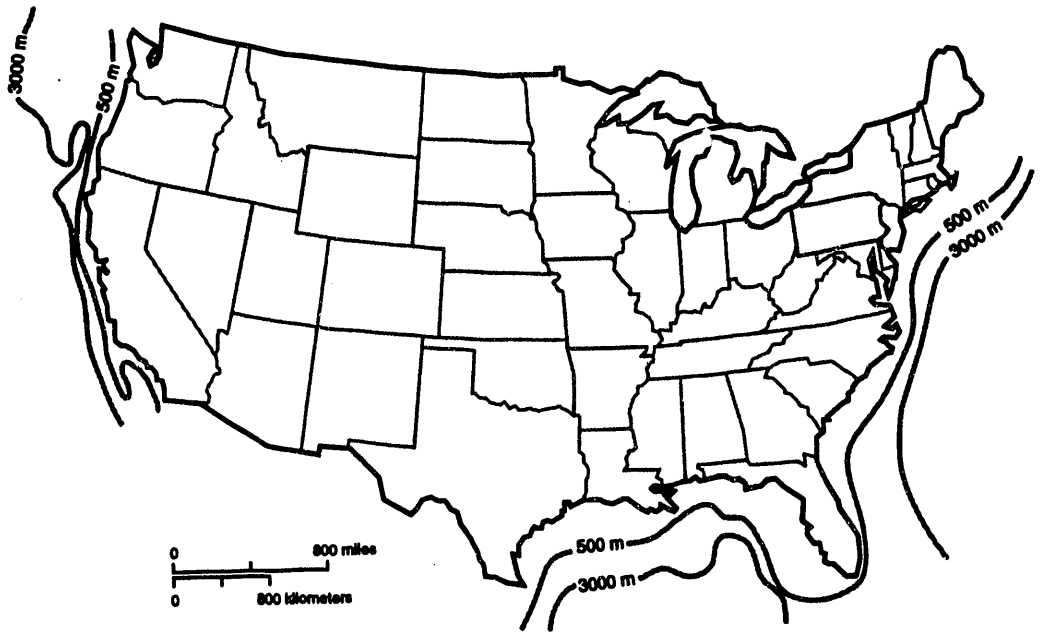

FIGURE 3.1. 500 m and 3000 m Ocean Depth Contours

reservoirs is that once petroleum has been evacuated from the reservoir[a] rock, the void space can be filled with compressed CO_2.

In addition to the basic presence of a reservoir, factors that must be considered in order to determine the technical and economic feasibility of CO_2 disposal in an abandoned reservoir include the following:

- the ability of the reservoir to accommodate an acceptable quantity of CO_2
- the presence of an impermeable cap rock to prevent upward migration of CO_2, leakage, and pressure loss
- sufficient reservoir depth to allow for a safe pressure
- the ability (legally and economically) of the disposal system operator to obtain a lease for the entire reservoir

---

(a) A reservoir is defined as a porous and permeable underground formation containing a natural accumulation of hydrocarbon (oil and/or gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

- the physical tightness of the reservoir (i.e., lateral sealing by formations with a minimal number of unusable abandoned wells [which promote leakage])
- the extent of reconditioning required because of water encroachment, corrosion of tubing, or deposition of mud on the well bore
- the number and size of injection wells required for an acceptable disposal rate
- proximity to major CO_2 transmission lines and the auxiliary equipment required.

This analysis estimates the total volume of abandoned petroleum reservoirs, including offshore reservoirs, available for CO_2 disposal through the year 2030 for the lower 48 states. It is assumed that any reservoir capable of producing petroleum could ultimately be capable of storing compressed CO_2. The result of this analysis is an estimated theoretical CO_2 storage capacity. For the technical and economic considerations listed above, this theoretical capacity represents an upper bound of available capacity and subsequently should be reduced to incorporate the impact of each of the considerations.

3.2.1 Historical Approaches to Estimating CO_2 Disposal Capacity

Several studies have previously estimated the available CO_2 storage capacity (Hamilton 1989; Horn and Steinberg 1982; Steinberg, Lee and Morris 1991) in abandoned petroleum reservoirs. These studies used two basic approaches to approximate storage capacity. The two approaches have the advantage of being relatively quick and straightforward; however, they do not fully incorporate some critical factors that affect storage capacity. Each approach is outlined below.

The first historical approach has been to assume that reservoirs are depleted at a rate close to the rate of U.S. consumption and that the depleted reservoir volume is available for CO_2 storage. This approach has two very important limitations which result in an imprecise estimation of storage capacity: 1) U.S. consumption is not a very good proxy for U.S. reservoir depletion because imports and petroleum storage systems supply a large segment of U.S. consumption, and 2) because of compressibility, the relationship between the volume of petroleum extracted from a reservoir and the volume of

CO_2 that can be injected for disposal is complex and cannot be accurately estimated without reservoir temperature and pressure data, which this approach does not fully incorporate.

The second historical approach has been to assume that the available volume for CO_2 disposal is represented by the total volume (at reservoir conditions) of proved U.S. petroleum reserves. As applied by organizations that report reserve volume, the term "proved reserves" means "the volume of petroleum that can with reasonable certainty be recovered in future years from known reservoirs under existing economic and operating conditions." Figure 3.2 illustrates the difference between "proved reserves" and the available petroleum resources that underlie the lower 48 states.

The use of proved reserves to estimate total CO_2 disposal capacity results in a significant limitation. U.S. reserves have historically and will continue to increase significantly as technology improves and the economic climate changes. Given the current rate of lower 48 production, current reserves will be expended in ten years; however, in the meantime, many more reserves will be identified and will allow the lower 48 states to produce well

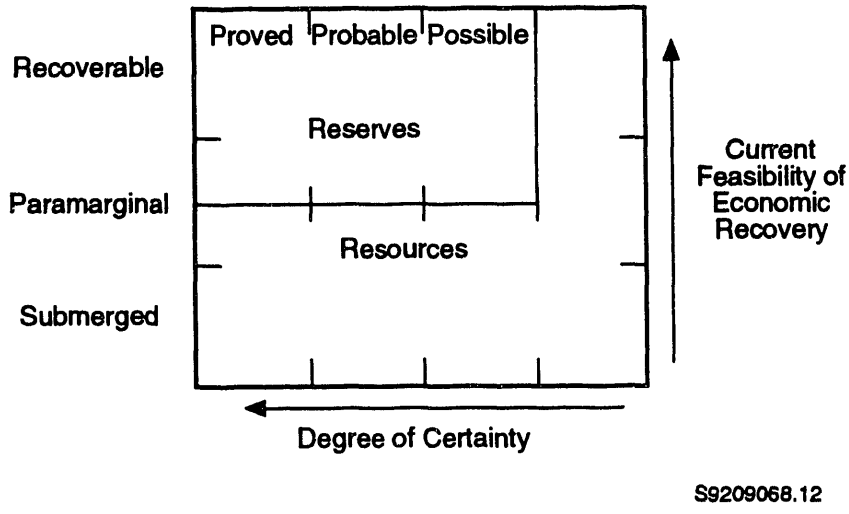

FIGURE 3.2. Comparison of Total Petroleum Resources and Proved Reserves (after Ikoku 1984)

beyond the year 2030 (DOE 1991). Consequently, the approach of assuming future available volume is equivalent to current reserves underestimates the potential volume several times.

Similar to the first historical approach, the second historical approach makes some significant assumptions regarding the relationship of petroleum volume at standard surface temperature and pressure and the resulting reservoir void volume at reservoir temperature and pressure. The non-proportional relationship between petroleum and CO_2 compressibility results in complex relationships between surface volume and reservoir volume. For example, for the pressure and temperature ranges examined in this analysis, if 1 cu ft of gas is produced, the amount of CO_2 that can be stored in the corresponding reservoir void varies from 1 to 3 cu ft.

3.2.2 Current Approach to Estimating CO_2 Disposal Capacity

Some of the limitations of the above two historical approaches are addressed in an approach that incorporates the procedures described below.

- Petroleum reservoir volume that has been or will be produced by the year 2030 was assumed to become available for CO_2 disposal. The production basis was derived from DOE production statistics (Energy Information Administration [EIA] 1990) and the National Energy Strategy's (NES) base case for crude oil and natural gas production through the year 2030 (DOE 1991).

- A reservoir capacity profile for CO_2 disposal by depth and geographical region was developed. Separate profiles were developed for capacity generated by gas production and by oil production. Subsequently, average temperature and pressure gradients were used to add reservoir temperature and pressure attributes to the capacity profiles.

- The differing compressibilities of gas and CO_2 were factored into the ultimate CO_2 storage capacity estimate.

To segment the analysis, CO_2 storage capacity generated by oil and gas production are discussed separately. In reality, the vast majority of oil and

gas fields[a] produce both products. For example, of the 45,120 petroleum fields identified in the United States (EIA 1991b), 33,495 fields (74%) produce significant quantities of oil and 30,161 (67%) produce significant quantities of gas.

The approach used to segment the analysis is based on the concept that a reservoir has a volume (V_R) of hydrocarbon at reservoir temperature (T_R) and reservoir pressure (P_R). As the hydrocarbon is produced,[b] its temperature and pressure decrease. A significant amount of gas is released, resulting in a volume of gas (V_{gsc}) and volume of oil (V_{osc}) at standard surface conditions (i.e., 60°F, 14.73 psia). Figure 3.3 illustrates this concept.

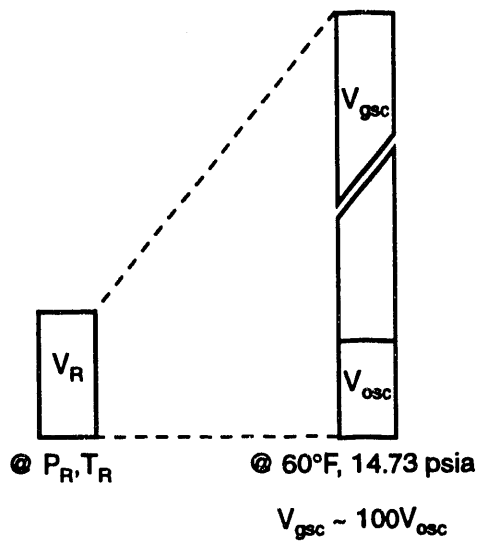

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FIGURE 3.3. Idealized Volume Relations of Petroleum Fluid at Reservoir and Surface Conditions (adapted from Amyx, Bass and Whiting 1960)

(a) An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. A field may have two or more reservoirs which are separated vertically by intervening impervious strata, laterally by local geologic barriers, or both.

(b) Produced refers to the process of allowing a hydrocarbon to escape from its resident formation into a wellbore at which point, through natural or human applied forces, it travels to the surface, passing through the wellhead into surface equipment (i.e., separators, heaters, filters, stock tanks, etc.).

Regional oil and gas production figures reported by organizations such as the DOE are based on the produced volume of oil and gas at standard conditions. As noted above, without knowing the reservoir-by-reservoir production volumes and the reservoir temperature and pressure data, it is not possible to estimate the total volume of a specific reservoir. However, by defining a representative regional capacity profile by depth and assuming that average temperature and pressure gradients apply, the total volume of oil or gas produced at surface conditions can be used to estimate the corresponding reservoir void volume created during the production process,[a] adjusting as appropriate for compressibility. The specific details describing the implementation of this approach are presented in Appendix A. The cumulative CO_2 storage capacity resulting from all petroleum production is shown in Table 3.1 for each petroleum production Region. Substate regions are identified in Figures 3.4 through 3.7.

3.3 AQUIFER DISPOSAL

Because of the prevalence of aquifers in the United States, disposal of CO_2 in aquifers would significantly reduce the transmission-related costs associated with CO_2 recovery and disposal. Roughly two thirds of the country is underlain by aquifers (Reilly, Brown and Huber 1981). The locations of major aquifers are shown in Figure 3.8.

An aquifer suitable for CO_2 disposal would have high porosity and adequate thickness to provide good storage capacity, adequate depth to allow CO_2 disposal as a supercritical fluid, high hydraulic conductivity to allow a high injection rate, homogeneous hydraulic conductivity to obtain a high sweep efficiency or high aquifer utilization, and a very low-permeability confining layer without fractures to ensure long-term isolation. Key issues affecting CO_2 disposal in aquifers are discussed below.

(a) The term "reservoir void volume" would imply that the reservoir contains empty pore space that is available for CO_2 storage. In fact, residual gas, oil and water expand into the voided area. The CO_2 injected is assumed to drive back the gas, oil and water that expanded.

TABLE 3.1. Cumulative CO_2 Storage Capacity Resulting from Petroleum Production (10^6 ft^3 at 14.73 psia, 32°F)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Total	1.75E+09	1.79E+09	1.83E+09	2.03E+09	2.24E+09	2.46E+09	2.66E+09	2.87E+09	3.07E+09	3.26E+09	3.44E+09
Alabama Onshore	2.83E+06	3.04E+06	3.24E+06	4.29E+06	5.42E+06	6.55E+06	7.63E+06	8.69E+06	9.73E+06	1.07E+07	1.16E+07
Arkansas	1.41E+07	1.45E+07	1.49E+07	1.70E+07	1.92E+07	2.15E+07	2.37E+07	2.59E+07	2.80E+07	3.01E+07	3.20E+07
California											
Coastal Region Onshore	1.57E+07	1.58E+07	1.58E+07	1.63E+07	1.68E+07	1.73E+07	1.77E+07	1.82E+07	1.86E+07	1.90E+07	1.94E+07
Los Angeles Basin Onshore	1.67E+07	1.68E+07	1.68E+07	1.72E+07	1.76E+07	1.80E+07	1.83E+07	1.87E+07	1.90E+07	1.93E+07	1.95E+07
San Joaquin Basin	4.91E+07	5.00E+07	5.09E+07	5.56E+07	6.05E+07	6.54E+07	7.00E+07	7.45E+07	7.89E+07	8.29E+07	8.65E+07
Offshore	8.73E+06	8.92E+06	9.12E+06	1.01E+07	1.11E+07	1.22E+07	1.31E+07	1.41E+07	1.50E+07	1.58E+07	1.66E+07
Colorado	1.48E+07	1.53E+07	1.57E+07	1.79E+07	2.03E+07	2.28E+07	2.51E+07	2.73E+07	2.96E+07	3.17E+07	3.37E+07
Florida	1.96E+06	1.99E+06	2.03E+06	2.19E+06	2.37E+06	2.54E+06	2.70E+06	2.86E+06	3.01E+06	3.14E+06	3.26E+06
Illinois	4.09E+06	4.11E+06	4.13E+06	4.24E+06	4.34E+06	4.44E+06	4.54E+06	4.63E+06	4.71E+06	4.78E+06	4.83E+06
Indiana	4.88E+05	4.92E+05	4.95E+05	5.14E+05	5.32E+05	5.49E+05	5.66E+05	5.82E+05	5.95E+05	6.07E+05	6.16E+05
Kansas	8.50E+07	8.67E+07	8.84E+07	9.72E+07	1.07E+08	1.17E+08	1.26E+08	1.35E+08	1.44E+08	1.53E+08	1.61E+08
Kentucky	9.03E+06	9.17E+06	9.31E+06	1.00E+07	1.08E+07	1.16E+07	1.24E+07	1.31E+07	1.38E+07	1.46E+07	1.52E+07
Louisiana Onshore											
North	6.98E+07	7.08E+07	7.17E+07	7.67E+07	8.21E+07	8.77E+07	9.29E+07	9.80E+07	1.03E+08	1.08E+08	1.13E+08
South Onshore	1.73E+08	1.75E+08	1.77E+08	1.88E+08	2.00E+08	2.12E+08	2.24E+08	2.35E+08	2.46E+08	2.57E+08	2.67E+08
Michigan	9.56E+06	1.00E+07	1.04E+07	1.28E+07	1.53E+07	1.78E+07	2.02E+07	2.26E+07	2.50E+07	2.72E+07	2.93E+07
Mississippi	1.82E+07	1.86E+07	1.91E+07	2.13E+07	2.37E+07	2.62E+07	2.85E+07	3.08E+07	3.31E+07	3.53E+07	3.73E+07
Montana	5.62E+06	5.77E+06	5.92E+06	6.70E+06	7.52E+06	8.35E+06	9.13E+06	9.90E+06	1.06E+07	1.13E+07	1.20E+07
Nebraska	5.61E+05	5.68E+05	5.75E+05	6.10E+05	6.44E+05	6.77E+05	7.09E+05	7.38E+05	7.64E+05	7.86E+05	8.03E+05
New Mexico											
East	5.08E+07	5.18E+07	5.28E+07	5.79E+07	6.35E+07	6.92E+07	7.45E+07	7.98E+07	8.50E+07	9.00E+07	9.47E+07
West	3.37E+07	3.45E+07	3.52E+07	3.93E+07	4.38E+07	4.84E+07	5.26E+07	5.69E+07	6.12E+07	6.53E+07	6.92E+07
New York	1.54E+06	1.60E+06	1.67E+06	2.00E+06	2.37E+06	2.74E+06	3.10E+06	3.45E+06	3.80E+06	4.14E+06	4.46E+06
North Dakota	4.69E+06	4.89E+06	5.09E+06	6.11E+06	7.18E+06	8.26E+06	9.27E+06	1.03E+07	1.12E+07	1.21E+07	1.29E+07
Ohio	1.54E+07	1.57E+07	1.60E+07	1.76E+07	1.92E+07	2.09E+07	2.25E+07	2.41E+07	2.57E+07	2.72E+07	2.86E+07
Oklahoma	1.43E+08	1.47E+08	1.51E+08	1.73E+08	1.96E+08	2.20E+08	2.42E+08	2.65E+08	2.87E+08	3.08E+08	3.29E+08
Pennsylvania	2.33E+07	2.36E+07	2.40E+07	2.58E+07	2.78E+07	2.98E+07	3.17E+07	3.36E+07	3.55E+07	3.74E+07	3.91E+07
Texas Onshore											
RRC D1[a]	1.15E+07	1.19E+07	1.23E+07	1.45E+07	1.69E+07	1.93E+07	2.15E+07	2.38E+07	2.60E+07	2.81E+07	3.02E+07
RRC D2 Onshore	5.12E+07	5.19E+07	5.27E+07	5.65E+07	6.08E+07	6.51E+07	6.91E+07	7.31E+07	7.71E+07	8.10E+07	8.46E+07
RRC D3 Onshore	1.12E+08	1.13E+08	1.14E+08	1.20E+08	1.27E+08	1.33E+08	1.39E+08	1.46E+08	1.52E+08	1.58E+08	1.63E+08
RRC D4 Onshore	1.14E+08	1.17E+08	1.19E+08	1.32E+08	1.47E+08	1.62E+08	1.76E+08	1.89E+08	2.03E+08	2.17E+08	2.29E+08
RRC D5	1.51E+07	1.57E+07	1.63E+07	1.91E+07	2.23E+07	2.55E+07	2.85E+07	3.15E+07	3.45E+07	3.73E+07	4.01E+07
RRC D6	6.84E+07	6.96E+07	7.09E+07	7.73E+07	8.42E+07	9.13E+07	9.80E+07	1.05E+08	1.11E+08	1.17E+08	1.23E+08
RRC D7B	1.19E+07	1.22E+07	1.25E+07	1.41E+07	1.58E+07	1.75E+07	1.91E+07	2.07E+07	2.22E+07	2.37E+07	2.51E+07
RRC D7C	2.15E+07	2.21E+07	2.27E+07	2.60E+07	2.95E+07	3.30E+07	3.64E+07	3.97E+07	4.30E+07	4.62E+07	4.92E+07
RRC D8	1.06E+08	1.09E+08	1.11E+08	1.21E+08	1.33E+08	1.44E+08	1.55E+08	1.66E+08	1.76E+08	1.86E+08	1.96E+08
RRC D8A	2.91E+07	2.96E+07	3.02E+07	3.29E+07	3.57E+07	3.85E+07	4.11E+07	4.37E+07	4.60E+07	4.81E+07	4.99E+07

(a) Railroad Commission District.

TABLE 3.1. (contd)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
RRC D9	1.41E+07	1.44E+07	1.47E+07	1.62E+07	1.78E+07	1.94E+07	2.09E+07	2.24E+07	2.39E+07	2.54E+07	2.67E+07
RRC D10	1.32E+08	1.34E+08	1.36E+08	1.44E+08	1.53E+08	1.62E+08	1.71E+08	1.80E+08	1.89E+08	1.97E+08	2.05E+08
Utah	7.16E+06	7.33E+06	7.50E+06	8.35E+06	9.25E+06	1.02E+07	1.10E+07	1.18E+07	1.26E+07	1.34E+07	1.40E+07
West Virginia	3.58E+07	3.62E+07	3.66E+07	3.87E+07	4.09E+07	4.32E+07	4.53E+07	4.75E+07	4.96E+07	5.17E+07	5.36E+07
Wyoming	4.24E+07	4.39E+07	4.53E+07	5.29E+07	6.10E+07	6.92E+07	7.70E+07	8.47E+07	9.23E+07	9.95E+07	1.06E+08
Misc.	5.17E+06	5.25E+06	5.32E+06	5.71E+06	6.13E+06	6.55E+06	6.95E+06	7.35E+06	7.75E+06	8.13E+06	8.48E+06
Gulf of Mexico											
Louisiana Offshore	1.75E+08	1.81E+08	1.87E+08	2.19E+08	2.54E+08	2.89E+08	3.23E+08	3.56E+08	3.89E+08	4.20E+08	4.49E+08
Texas Offshore	2.78E+07	3.04E+07	3.30E+07	4.66E+07	6.14E+07	7.65E+07	9.07E+07	1.05E+08	1.19E+08	1.33E+08	1.45E+08

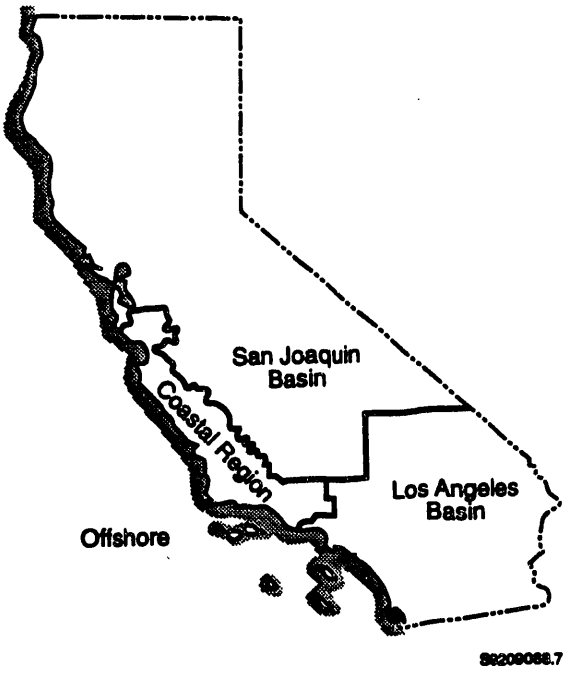

FIGURE 3.4. California Petroleum Production Regions

FIGURE 3.5. Louisiana Petroleum Production Regions

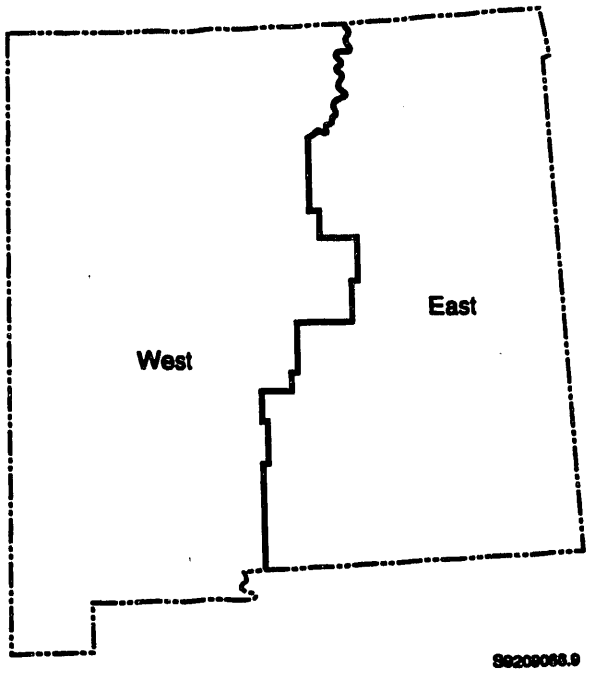

FIGURE 3.6. New Mexico Petroleum Production Regions

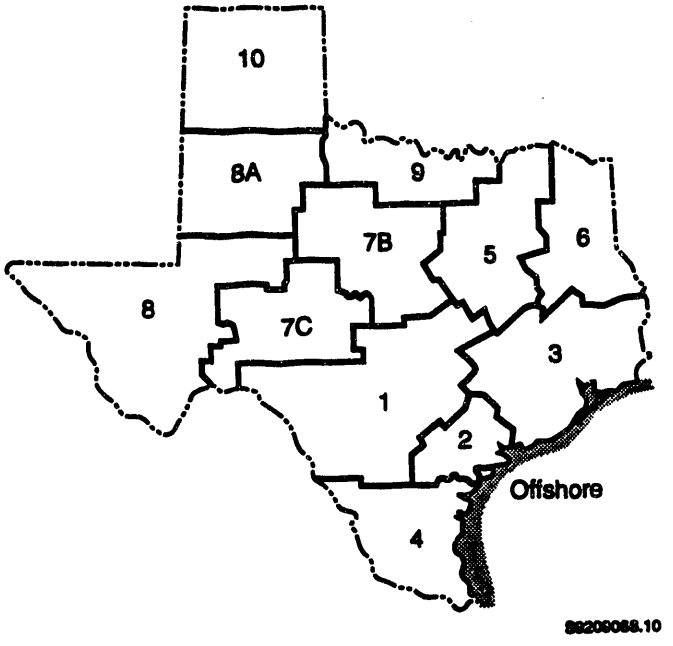

FIGURE 3.7. Texas Petroleum Production Regions

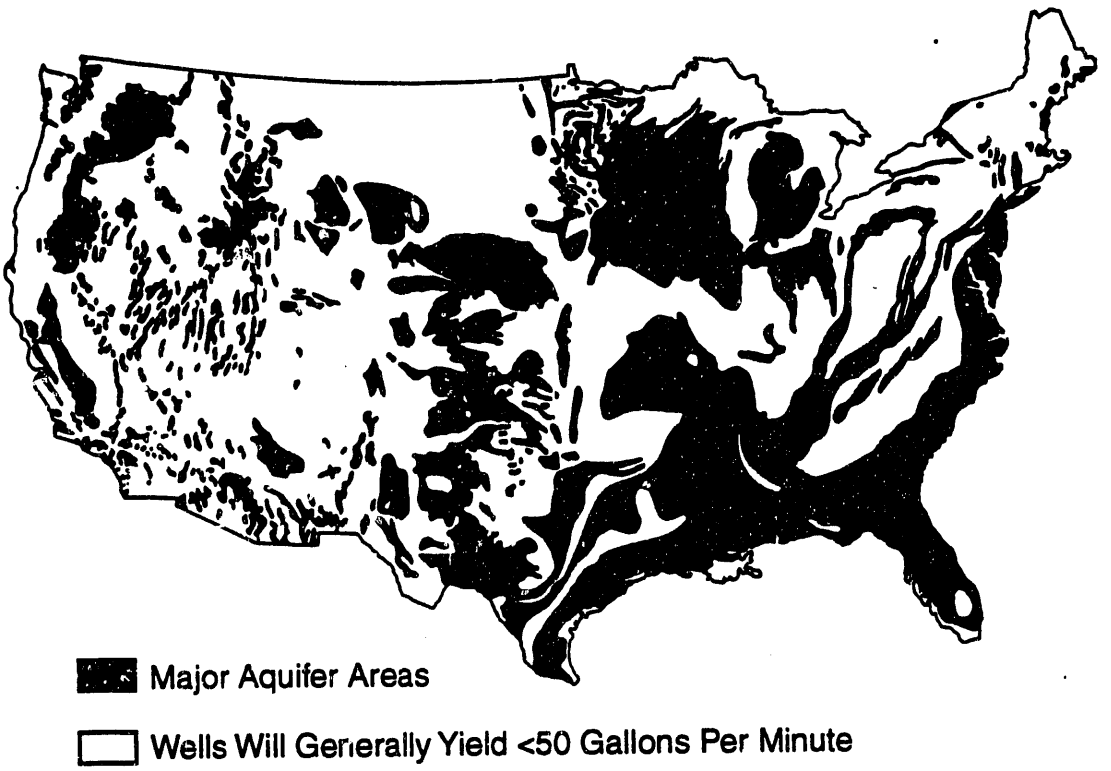

FIGURE 3.8. Major U.S. Aquifers

To reduce the storage volume requirements and buoyant drive, the CO_2 should be stored as a supercritical fluid with a density close to that of water. Both pressure and temperature increase with depth. Unfortunately, higher temperatures will require even higher pressures to minimize the buoyant force. The depths required for CO_2 disposal are generally at least a few thousand feet. Most exploration and characterization at these depths have been performed for oil and gas. Very little is known about non-petroleum reservoirs at these depths, which makes CO_2 disposal in deep aquifers a risky proposition.

Aquifers are never homogeneous. A simple alluvial aquifer system will often have hydraulic conductivities ranging through several orders of magnitude within a few meters, particularly in the vertical direction. This variability significantly reduces the sweep efficiency of the injection well. This problem would be made worse by the viscous fingering of the two fluids

(CO_2 and water). For CO_2 disposal, nonhomogeneous hydraulic conductivity could significantly limit the effective aquifer disposal capacity as well as the allowable injection rate.

A CO_2 disposal system would require a large aquifer that would confine the CO_2 for several hundred years. By their existence, gas and oil reservoirs provide evidence of long-term confinement; however, such long-term confinement is much more speculative for aquifers.

Natural aquifer waters generally have a pH of about 8, which CO_2 injection will reduce. A probable moderate drop in the pH to about 5 could cause increased weathering of the aquifer matrix. Geochemical impacts would have to be analyzed on a case-by-case basis.

Aquifers have only recently been given serious attention as a possible disposal location for CO_2. Much of this work has been conducted in The Netherlands (e.g., van Engelenburg and Blok 1992; van der Meer 1992) where preliminary feasibility studies (particularly van Engelenburg and Blok 1992) have yielded cautious optimism. The authors of this study do not share that optimism, particularly for the United States, where the geology is much more complex than that of The Netherlands. The technical issues described above make CO_2 disposal in aquifers significantly riskier than disposal in either the deep ocean or depleted oil and gas reservoirs. Therefore, the potential cost of aquifer disposal for comparison with disposal in the ocean or depleted oil and gas reservoirs was not calculated at this time.

Despite these currently perceived risks, aquifers have the potential to provide low-cost CO_2 disposal for the majority of U.S. fossil-fired power plants and warrant further investigation of their technical, environmental, and economic feasibility.

4.0 TRANSMISSION

Transmitting CO_2 to the disposal point can be a significant part of the overall cost of control, depending on the distance. In this analysis, where the power plant and CO_2 recovery technology are held constant, the range of impact on power generation costs and CO_2 control costs is due entirely to differences in the transmission distance. With the prospective transmission distance ranging from less than 100 mi up to about 2000 mi, differences in transmission costs may have a significant bearing on the regional efficacy of implementing CO_2 capture at fossil-fired power plants.

4.1 TRANSMISSION DISTANCE

Calculating the transmission distance requires identifying the prospective disposal points and source points (the power plants). The locations of prospective disposal points in deep ocean water or depleted oil and gas (DOG) reservoirs were identified in Section 3. This section of the report describes the assumptions used for establishing the locations of the power plants and calculating the transmission distance.

Many factors affect the siting of coal-fired power plants, especially at the local level. However, when examined at the state or regional level, two factors stand out: the demand for power and the availability of coal. Thus, most coal-fired power plants are located in well-populated states with significant coal resources. Coal and electricity transmission costs are obviously important siting factors. Proximity to potential CO_2 disposal points and CO_2 transmission costs may become an important factor in the future. Many other factors, such as shifting demographics, will also contribute to future siting decisions.

In this study, the GCC plants with CO_2 recovery were assumed to be sited at the same location as current PC power plants with generating capacities greater than about 100 MWe. Note that future plants need not be physically located at exactly the same place in order for the results of this analysis to be valid. Rather, a physical distribution of coal-fired plants similar to the

current distribution would be sufficient. The actual locations of current sites merely provide a convenient data base for measuring the prospective CO_2 transmission distances.

The specific procedure was to identify the location and generating capacity of all coal-fired power plants with a generating capacity greater than 100 MWe (McGraw-Hill 1989; EIA 1991a). The sum of the coal-fired generating capacity identified was assumed to be replaced with an equal generating capacity supplied by multiple GCC plants with CO_2 recovery as described in Section 2. As noted above, the new plants were assumed to be located at current plant sites. The number of units per site was set to match (with rounding to the nearest whole unit) the current generating capacity at the site. The resultant number of GCC generating units is identified for each state in Figure 4.1.

With the source points and disposal points identified, the design and cost of the transmission network depends on the degree of integration or independence among the plants. At one extreme, each generating unit could have its own pipeline running directly from the unit to the disposal point. At the other extreme, every unit in the country could be connected to a common piping network, or at least to regional networks. The latter approach would likely be significantly less expensive, as CO_2 from several units could be combined into larger trunk lines, allowing economy-of-scale benefits in pipeline construction. However, the transmission costs estimated on this basis would be valid only if CO_2 capture was implemented at all of the units included in the network. Implementation at fewer plants would likely lead to higher transportation costs because the network would be limited. In addition, pipeline economies-of-scale might not be great. The pipe diameter required for a single unit (18 in.) is already quite large (particularly for operating pressures in excess of 1200 psia), so larger diameter pipes may not offer any significant economies-of-scale. Network construction also generates a significant cost allocation problem, which makes it extremely difficult to calculate the marginal cost of CO_2 control for each unit. For these reasons,

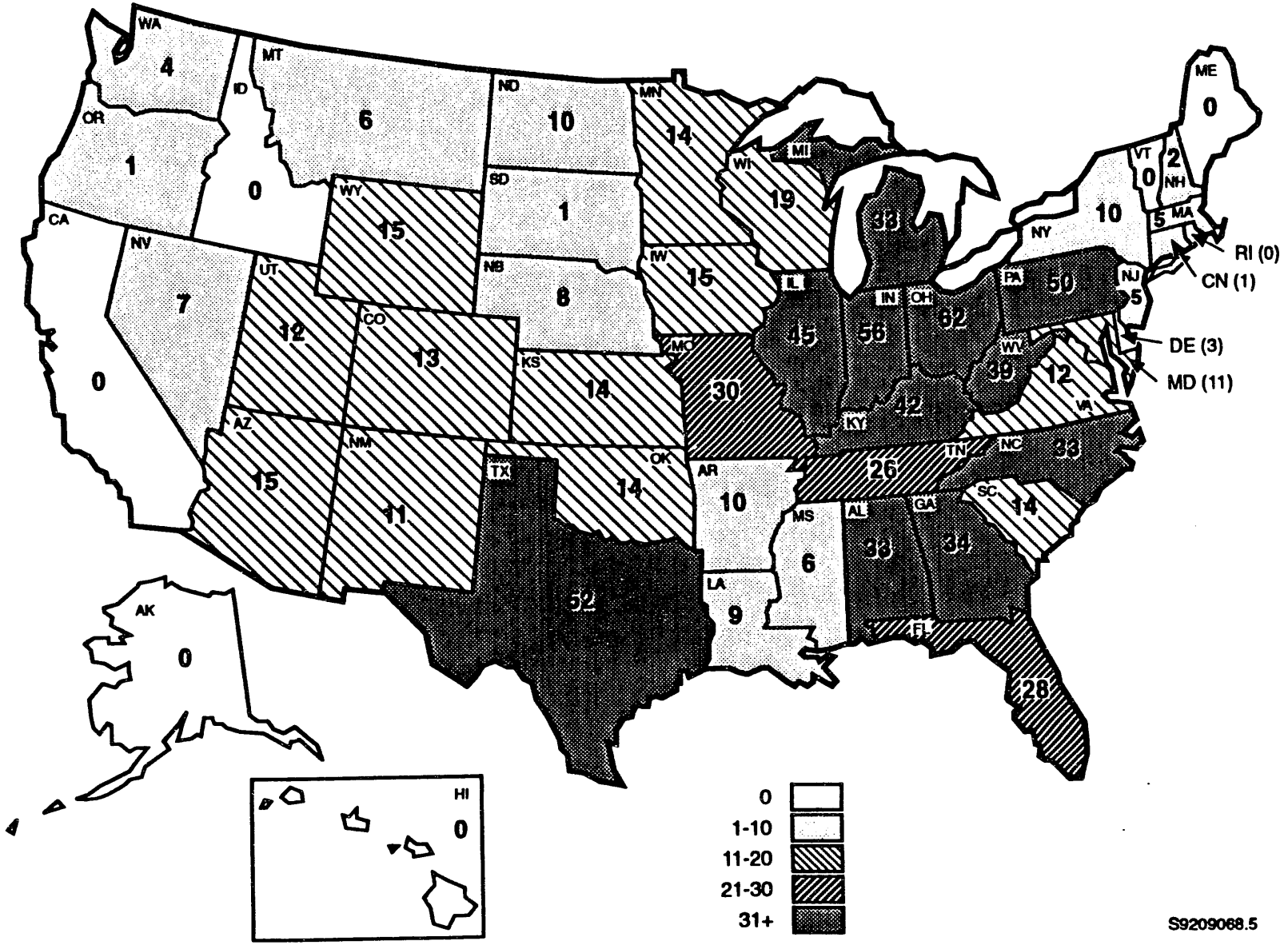

FIGURE 4.1. GCC Units with CO_2 Recovery

each unit was assumed to have its own pipeline connecting to a disposal point. The costs derived from this design assumption should represent an upper bound on the actual costs.

Three transmission lengths were calculated for each power plant, representing disposal in the ocean at a depth of 500 m or 3000 m, or disposal in a depleted oil and gas reservoir. Total mileage was segregated into overland and undersea portions. Overland "airline" distance was multiplied by 1.17 to account for expected deviations from a perfectly straight path. This factor was established by comparing airline miles and highway miles between several major cities, as published in the OAG Desktop Flight Guide (Official Airline Guides 1992) and Rand McNally Road Atlas (Rand McNally and Company 1990), respectively. Undersea mileage was not multiplied by this factor. Separation into overland and undersea portions was also important for distinguishing expected costs per mile of pipe.

The disposal point in the ocean was assumed to be the location with 500-m or 3000-m deep water that was closest to the power plant in question. A relatively small (compared to the entire pipeline) diffuser section is presumed to discharge the CO_2 into the water. In contrast, disposal in depleted oil and gas reservoirs is complicated by their non-uniform and disperse nature. The CO_2 flow from a single GCC unit would require distribution from a trunk line to multiple wells, the number depending on the characteristics of the depleted wellfield. For example, in their evaluation of CO_2 capture and disposal from an IGCC plant, Hendriks, Blok and Turkenburg (1990) estimate that disposal of 487,000 kg/hr of CO_2 would require 15-20 wells. In their evaluation of a larger IGCC plant, Shell Internationale (1990) estimates that only 6 wells would be required to dispose of 625,000 kg/hr of CO_2. By comparison, the reference CO_2 recovery unit defined in Section 2 produces 370,000 kg/hr of CO_2. Both of the above references assume that CO_2 injection will commence immediately after production is terminated. Hence, all existing collection equipment is assumed to be available for use as CO_2 distribution equipment. The implied assumption in both studies is that the equipment is appropriate, without modification, for CO_2 disposal.

Complete availability and applicability of residual oil/gas collection equipment for use as CO_2 distribution equipment represents the best possible situation. A more rigorous analysis of CO_2 distribution requirements and the availability and applicability of residual wellfield equipment is needed, but was beyond the scope of this study. Therefore, the simplifying assumption employed in the above two references was used in this study as well. Thus transmission costs to depleted oil and gas wells may be underestimated, especially compared with transmission to ocean disposal points.

The total potential CO_2 disposal volume by state or substate region was presented in Section 3. In recognition of the CO_2 distribution concerns noted above, one-half of the potential disposal volume in each region was assumed to be infeasible for CO_2 disposal because of the disperse nature of the available volume within a formation. Even so, half of the potential total was adequate for disposing all CO_2 from all 830 GCC units for 40 years. For the purposes of calculating the length of the transmission pipeline, the disposal volume available in each region was presumed to exist at the geographic center of the region. Because of the limited disposal volume available in each region, a filling strategy was necessary to determine the applicable disposal location for each unit. In general, disposal locations were assigned to GCC units so as to minimize the incremental transmission distance, i.e., the unit and disposal location with the shortest possible transmission distance were paired first, followed by the pair with the next shortest possible transmission distance, and so on.

Summary statistics describing the resultant pipeline lengths are presented in Table 4.1 and Figure 4.2. The prospective transmission distance varies from practically zero (for a GCC unit sitting on top of a depleted oil and gas reservoir) to nearly 2000 mi. The average transmission distance is about 700 mi for disposal in DOG reservoirs or ocean water at a 3000-m depth; disposal at a 500-m depth reduces the average transmission distance by about 100 mi. If both ocean and DOG reservoir disposal are available, the average transmission distance drops to about 400 mi. The dispersion of transmission

TABLE 4.1. Transmission Distance Summary

Disposal Location	Transmission Distance, Miles Minimum	Average	Maximum
500-m-deep ocean	76	583	1425
3000-m-deep ocean	155	670	1538
DOG reservoirs	24	694	1960
500-m-deep ocean or DOG reservoirs, whichever is closer	24	373	970
3000-m-deep ocean or DOG reservoirs, whichever is closer	24	408	1042

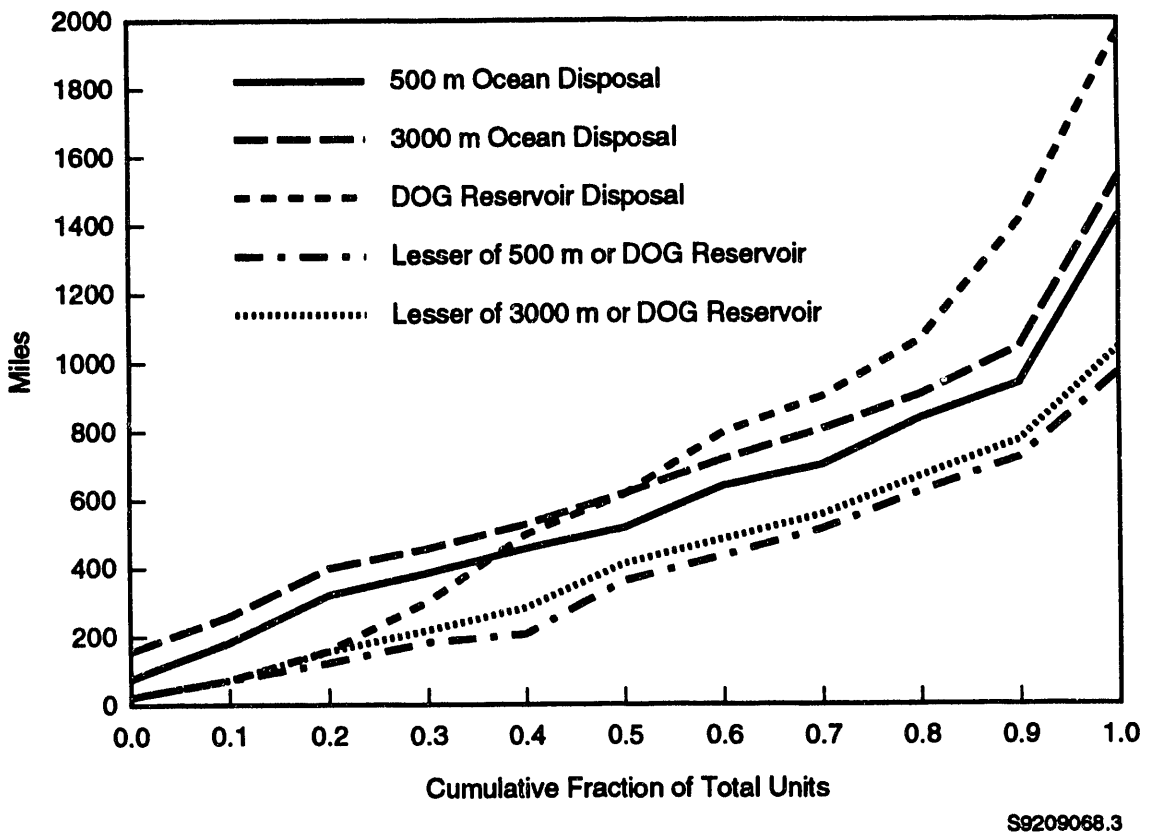

FIGURE 4.2. Transmission Distance Summary

distances is greatest for disposal in DOG reservoirs: about 20% of the units have transmission distances less than 150 mi, but another 20% have transmission distances greater than 1050 mi.

4.2 PIPELINE DESIGN AND COST

Selection of the pipe diameter involves a tradeoff between the size and cost of the pipe and the size and cost of the compression equipment required to overcome frictional losses plus the cost of power to run the compressors. Smaller diameters reduce the cost of the pipe, but increase compression costs and vice-versa. An appropriate pipe diameter was determined from CO_2 pipeline design data developed in two previous studies (Decker 1986; Anada et al. 1982). In Decker, an actual CO_2 pipeline running from Southeastern Colorado to West Texas had a flow density of 1.05 MMSCFD/in.^{2} of pipe cross sectional area. Pipe designs developed in Anada et al. had flow densities averaging 0.65 MMSCFD/in.^{2}. Pressure loss was not an issue in the system described by Decker, which had a significant elevation drop, so the design rule-of-thumb derived from Anada et al. was used. The resulting pipe diameter required for each GCC plant with CO_2 recovery was 18 in.

Calculation of the pressure drop through the pipe is complicated because of the compressible, non-ideal nature of CO_2 and its quickly changing fluid properties near the critical point design conditions. Overall pressure and temperature changes were calculated by integrating over simultaneous evaluations of temperature and pressure changes for sequential pipeline segments. The minimum pipeline pressure was set at 1200 psia as described in Section 2. Recompression would occur whenever pipeline pressure falls to this level. The maximum pressure was set at 1800 psia based on design assumptions used in Anada et al. (1982) and Smelser and Booras (1990). In general, a higher exit pressure would be expected to increase the required pipe wall thickness, but the required pipe diameter would decrease as the density of CO_2 increases. A higher pressure ratio would also increase the compressor power required per unit of pressure added if non-intercooled compression was used. The size and frequency of compression stations are additional factors that would need to be

considered in a more detailed piping analysis. A maximum pressure of 1800 psia was felt to be a reasonable assumption based on the two studies cited.

At each station CO_2 was assumed to be compressed from 1200 psia to 1800 psia. Initial compression at the GCC unit also requires aftercooling to reduce the temperature of CO_2 entering the pipeline to 100°F. The exit temperature after recompression is already below 100°F (due to a lower inlet temperature), so aftercooling is not needed. During transport in buried pipelines, the CO_2 will gradually cool as heat is transferred to the surrounding soil. Soil temperatures will obviously vary with location and time of year. An average soil temperature of 60°F was assumed based on data from U.S. Geological Survey maps. The pressure drop per unit length of pipe at 100°F and 1200 psia is nearly double that at 60°F and 1800 psia, so an accurate determination of the expected temperature and pressure conditions is important.

Heat transfer and pressure drop equations governing the design of the pipeline are presented in Appendix B. The results of the overland pipeline analysis are summarized in Table 4.2. Pressure drop per mile declines as temperature and pressure drop over the length of the pipe, averaging 3.07 psia/mi for the first segment and 2.70 psia/mi for the last segment. The entrance conditions shown are applicable for initial compression at the power plant, where cooling water allows intercooling between compression stages and final aftercooling to 100°F. Subsequent recompression from 1200 psia to 1800 psia, with a compressor inlet temperature near 60°F, would yield a compressor exit

TABLE 4.2 Overland Pipeline Temperature and Pressure Profile

Pipe Segment	Temperature, °F		Pressure, psia	
	Entrance	Exit	Entrance	Exit
0-60 mi	100.0	83.6	1800	1616
60-120 mi	83.6	72.0	1616	1447
120-180 mi	72.0	65.9	1447	1284
180-210 mi	65.9	64.1	1284	1203

temperature of about 70°F. Therefore, the average pressure loss per mile after the first 210 miles was assumed to be 2.70 psia. Additional discussion of the compressor sizing is presented later in this section.

The pressure drop relationships described above were applied to overland pipelines and did not take into account any elevation loss between the power plant and the ocean shore. Thus, the estimated overland pipeline pressure drop may be conservatively high. The impact of elevation drop was specifically considered for the undersea pipelines, however.

Two fundamental requirements govern the undersea pipeline sizing: 1) the exit pressure must be greater than the static head of the ocean at the injection point and 2) pressure throughout the pipeline must be greater than the local liquid-vapor equilibrium pressure (to avoid two-phase flow problems), which varies as the CO_2 temperature adjusts to the local ocean temperature. At the temperatures prevalent in deep ocean water, the pressure in the pipeline can be significantly lower than 1200 psia and still avoid two-phase flow.

An initial analysis showed that the CO_2 would cool to the ocean water temperature within the first several hundred meters of the pipeline. Ocean temperatures off the U.S. coasts vary considerably depending on the location, time of year, and depth. Data from Thurman (1986) were used to develop the following temperature profile that is roughly representative of average summer conditions for U.S. coastal waters: 23°C at the surface, 11°C at 500 m and 2°C at 3000 m. The average offshore pipeline distances were 93 mi to 500 m and 172 mi to 3000 m. The minimum CO_2 exit pressure (ocean static pressure) is 5.13 MPa at 500 m and 30.3 MPa at 3000 m.

The undersea pipeline analysis indicated that the required exit pressures for 500-m and 3000-m discharge would be exceeded with an entrance pressure of 1200 psia (the minimum pressure allowed in the overland pipeline) without any additional compression stations. In fact, the diameter of an undersea pipeline discharging at 500 m could be reduced to 14 in., while the diameter of an undersea pipeline discharging at 3000 m could be reduced to 16 in.

Well pressures for DOG reservoirs were also evaluated to determine if the minimum overland pipeline pressure of 1200 psia would be adequate or if additional compression would be required at the well head. As described in Section 2, DOG reservoir pressure was assumed to increased linearly with depth at rate of about 30 bars per 1000 ft. Temperature rise and frictional loss would be negligible as the CO_2 flowed down the injection well, while pressure increases dramatically with the drop in elevation. At all depths up to at least 9000 ft, the CO_2 pressure was calculated to be greater than the prevailing reservoir pressure. Therefore, additional compression at the well head would not be required.

Pipeline costs were estimated based on recent actual construction costs reported in the Oil and Gas Journal (True 1989a; True 1990) for onshore and offshore oil and gas pipelines. Regression analysis was applied to pipeline cost data for pipelines with 12- to 24-in. diameters and lengths greater than 10 mi to predict construction costs for onshore and offshore applications. No pipelines have currently been laid at depths greater than about 600 m. Therefore, the offshore data were assumed to apply to disposal at 500 m only. Pipelines from 500 m to 3000 m were assumed to cost an additional 50%. For additional information on deep water pipe-laying techniques that could potentially be applied to 3000-m depths, the reader is referred to Timmermans (1984a, 1984b, 1989), True (1989b), and Stoll (1986). Pipeline unit capital costs and sizing assumptions are summarized in Table 4.3. Annual pipeline O&M was set at 2.25% of initial capital, based on data in Matchak et al. (1984).

Compression power requirements and costs were calculated based on conditions presumed to exist at the power plant and subsequent recompression stations. In both cases, the inlet pressure was assumed to be 1200 psia, the minimum pipeline operating pressure. At the power plant, supplementary compression from 1200 to 1800 psia was based on prior intercooling of the CO_2 to 100°F in a water-cooled heat exchanger. As previously discussed, CO_2 in the pipeline was calculated to cool to a temperature of about 64°F for a presumed soil temperature of 60°F. Hence, recompression occurs at a lower entering temperature.

TABLE 4.3. Pipeline Size and Cost Assumptions

Pipe Diameter, in.	Pipeline Costs, 1000s of Mid-1990 $/Mile		
	Onshore	Offshore to 500 m	Offshore 500-3000 m
12	310	520	780
14	370	580	870
16	440	650	975
18	500	710	1065
20	560	770	1155
22	620	830	1245
24	690	890	1335

Note: Onshore pipeline: 18-in. diameter
Offshore pipeline to 500 m: 14-in. diameter
Offshore pipeline to 3000 m : 16-in. diameter

The theoretical compressor power was calculated using Equation 4.1 (Perry and Green 1984). For the temperature and pressure conditions described above, the theoretical compressor power is 1.21 MWe for supplemental compression at the power plant, but only 0.54 MWe for subsequent recompression. The key difference is the compressibility factor, which drops from 0.45 to 0.22 as the temperature drops from 100°F to 64°F at 1200 psia. This example demonstrates the extreme variability of CO_2 fluid properties near ambient temperatures. These properties must be considered very carefully in any design analysis.

$$kW = (M/1000) * k/(k-1) * z * R * T_1 * [(P_2/P_1)^{(k-1)/k} - 1] \qquad (4.1)$$

where kW = kilowatts

M = mass flow rate, kg/s

k = C_p/C_v = 1.3 for CO_2

z = non-ideal gas compressibility factor

R = ideal gas constant = 8314/MW J/kg*K

MW = gas molecular weight = 44 for CO_2

T_1 = inlet temperature, K

P_1 = inlet pressure

P_2 = outlet pressure

Actual compressor power was calculated by applying an 80% efficiency factor for the combined compressor and motor to the theoretical power figures noted above. Based on the pipeline pressure drop data presented earlier, the power consumed in transporting CO_2 is 7.2 kW/mi for the first 210 mi and 3.1 kW/mi thereafter.

Unique compressor unit cost estimates were developed for initial and supplemental compression and subsequent recompression, reflecting the different size and economies-of-scale associated with the two applications. Initial supplemental compression to 1800 psia (or less for pipelines less than 210 mi long) would be accomplished in an integrated, multi-stage compressor. The expected unit cost for this application was set equal to that presented in Smelser and Booras (1990), updated to mid-1990 dollars. The unit cost for recompression was estimated based on the relative size of the two applications and on compressor cost-scaling data presented in Garrett (1989). The resultant capital cost assumptions were $1,541,000/MWe and $3,019,000/MWe (of compressor power) for initial compression and recompression, respectively, which includes a 2% allowance for ancillary cooling system equipment. Annual O&M was set at 3% of capital per data in Matchak et al. (1984).

5.0 SYSTEM RESULTS

Complete system cost and performance characteristics were developed for each of the 329 unique power plant locations. These data were used to calculate the levelized energy cost (LEC) in $/kWh and levelized CO_2 control cost (LCCC) in $/Mg. Levelized cost analysis combines initial cost, annually recurring cost, and system performance characteristics with financial parameters to produce a single figure of merit (the LEC or LCCC) that is economically correct and can be used to compare the projected energy and CO_2 control costs of alternative plants. The specific methodology employed was that defined in Brown et al. (1987), which is consistent with the "required revenue" approach recommended by the Electric Power Research Institute in their Technical Assessment Guide (EPRI 1989). The specific financial assumptions employed are listed in Table 5.1. The majority of these were taken from the Technical Assessment Guide. Exceptions are the price year, first year of operation, and net salvage value, which were assumed by PNL for this study, and the fuel price escalation rate, which was taken from the Annual Energy Outlook (EIA 1992).

TABLE 5.1. Financial Assumptions

Item	Assumption
After-tax nominal discount rate	9.82%
General inflation rate	5.00%
Capital inflation rate	5.00%
Operation and maintenance inflation rate	5.00%
Fuel (coal) inflation rate	6.70%
Investment tax credit	0.00%
Property tax and insurance rate	2.00%
Combined state and federal tax rate	38.0%
Plant economic life	30 years
Plant depreciable life	20 years
Plant construction period	3 years
Price year	1990
First year of operation	2000
Annual power production capacity factor	65.0%
Net salvage value at end of life	0

5.1 LEC AND LCCC CALCULATION

Although LEC calculations are a standard part of utility economic analysis additional discussion of the two economic "figures of merit" is warranted, particularly in regard to the LCCC figure. As noted above, LEC calculations combine the cost and performance characteristics of a power plant into a single, equitably comparable figure. While this is important for the comparison of any two power plants, the LEC approach is crucial to evaluating most CO_2 recovery and disposal concepts where cost has typically increased significantly, while performance has decreased significantly (because of increased parasitic power consumption). These effects are correctly captured in the LEC calculation, where both increased annualized costs and decreased annual net power output cause the LEC for a plant with CO_2 recovery to increase relative to the LEC for a reference plant without CO_2 recovery and disposal.

The LCCC figure expresses the annualized cost of CO_2 control per unit of CO_2. The correct calculation of this figure must focus on the incremental increase in cost and the incremental decrease in CO_2 emission relative to a reference plant. The product of interest from a power plant is electricity. Hence, incremental cost and emission are best measured per kWh, in order to ensure a fair comparison of power plants producing different amounts of electrical energy. Thus, the incremental cost is the difference in LEC ($/kWh) between the plant with CO_2 recovery and disposal and the reference plant. Similarly, the incremental emission is the difference in CO_2 emission per kWh (Mg/kWh) between the reference plant and the plant with CO_2 recovery and disposal. The LCCC ($/Mg) equals the incremental cost ($/kWh) divided by the incremental decrease in CO_2 emission (Mg/kWh).

If the expression defined above seems obvious, consider two calculations that may appear logical at first, but are seen to be inferior upon inspection. One alternative would be to annualize the incremental capital and operation and maintenance costs and use this figure for the incremental cost. Unfortunately, this approach ignores any decrease in plant performance that would provide an additional increase in the incremental cost of electricity. Another alternative would be to use the amount of CO_2 captured and disposed as

the incremental emission reduction. This too would be incorrect because the amount of CO_2 captured and disposed is generally greater than the reduction in emission per kWh, which is the relevant figure. The difference arises from the change in plant performance or heat rate. Additional parasitic power consumption (i.e., power consumed within the boundaries of the power plant) associated with the typical CO_2 recovery plant causes an increase in the heat rate (Btu/kWh) and the amount of fuel burned and CO_2 generated. Thus, it is possible, even with less than 100% CO_2 recovery, to capture and dispose of more CO_2 than is generated in the reference plant. Obviously, the figure of interest is the reduction in emission and not the amount captured and disposed. If either or both of the alternative approaches are used, the cost of CO_2 capture and disposal will be understated.

5.2 LEC AND LCCC RESULTS

The LEC for the reference GCC power plant described in Section 2 (without CO_2 recovery and disposal) was calculated to be \$0.0631/kWh. The LEC rises to \$0.0839/kWh when CO_2 recovery is included. The corresponding LCCC is \$27.15/Mg. This 33% increase in LEC would apply for a power plant located at the disposal point, a situation that might occur for CO_2 disposed of in DOG reservoirs. Although ocean platform power plants have been proposed and would also eliminate transportation costs, increases in other plant construction costs would likely offset the transportation advantage.

Summary statistics describing the range and distribution of LECs and LCCCs when CO_2 transmission is included with recovery are presented in Tables 5.2 and 5.3 and Figures 5.1 through 5.4. Figures 5.1 and 5.2 show how LEC and LCCC vary with the cumulative fraction of the total number of power plants (830). Figures 5.3 and 5.4 have expressed cumulative power plants in terms of cumulative CO_2 emission reductions. Not surprisingly, the trends for both are similar to that described earlier for transmission distance. LECs vary from about 8.5 to 14.5 ¢/kWh, while LCCCs range from about 30 to 105 \$/Mg. The average LEC is about 10.5 ¢/kWh for disposal in DOG reservoirs or 3000-m-deep ocean water; disposal in 500-m-deep ocean water reduces the average LEC by about 0.5 ¢/kWh. The average LCCC for disposal in DOG

TABLE 5.2. LEC Summary

Disposal Location	LEC, $/kWh Minimum	Average	Maximum
500-m-deep ocean	0.0863	0.1015	0.1265
3000-m-deep ocean	0.0902	0.1064	0.1332
DOG reservoirs	0.0846	0.1047	0.1433
500-m-deep ocean or DOG reservoir, whichever is closer	0.0846	0.0951	0.1134
3000-m-deep ocean or DOG reservoir, whichever is closer	0.0846	0.0970	0.1183

TABLE 5.3. LCCC Summary

Disposal Location	LCCC, $/kWh Minimum	Average	Maximum
500-m-deep ocean	30.27	50.15	82.94
3000-m-deep ocean	35.38	56.57	91.73
DOG reservoirs	28.10	54.38	104.98
500-m-deep ocean or DOG reservoir, whichever is closer	28.10	41.83	65.70
3000-m-deep ocean or DOG reservoir, whichever is closer	28.10	44.24	72.13

reservoirs or 3000-m-deep ocean is about $55/Mg; disposal in 500-m-deep ocean water reduces the average LCCC by about $5/Mg. If both ocean and DOG reservoir disposal are available, the average LEC drops to about 9.6 ¢/kWh, while the average LCCC drops to about $43/Mg. The dispersion of LECs and LCCCs is greatest for disposal in DOG reservoirs. For example, about 20% of the units have LECs less than 9 ¢/kWh, but another 20% have LECs greater than 11.6 ¢/kWh.

The LEC and LCCC figures presented for disposal in DOG reservoirs do not include any potential credit for enhanced recovery of oil or natural gas. Shell Internationale (1990) projected little net economic benefit from

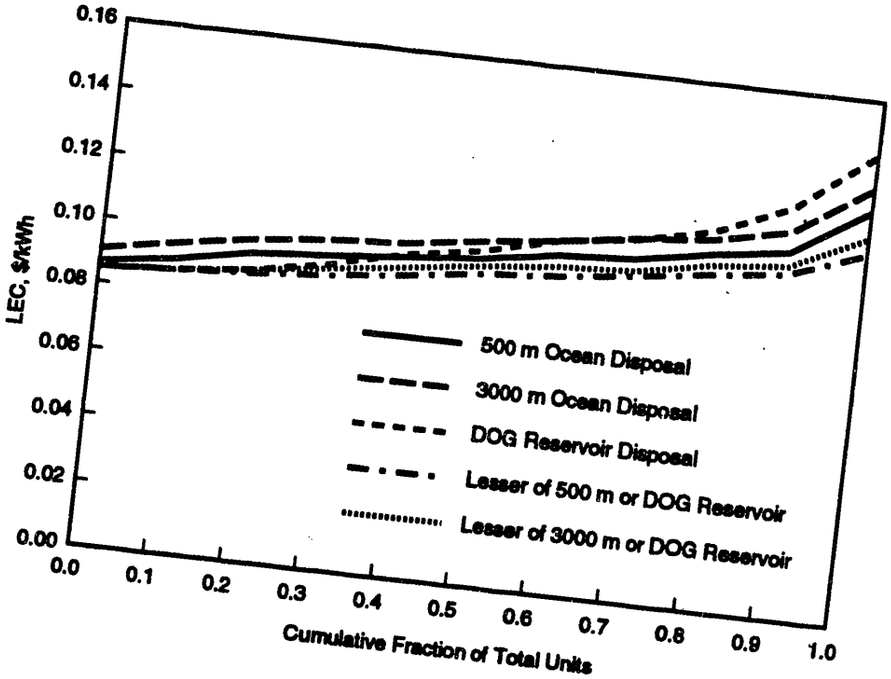

FIGURE 5.1. LEC Summary, Cumulative Units

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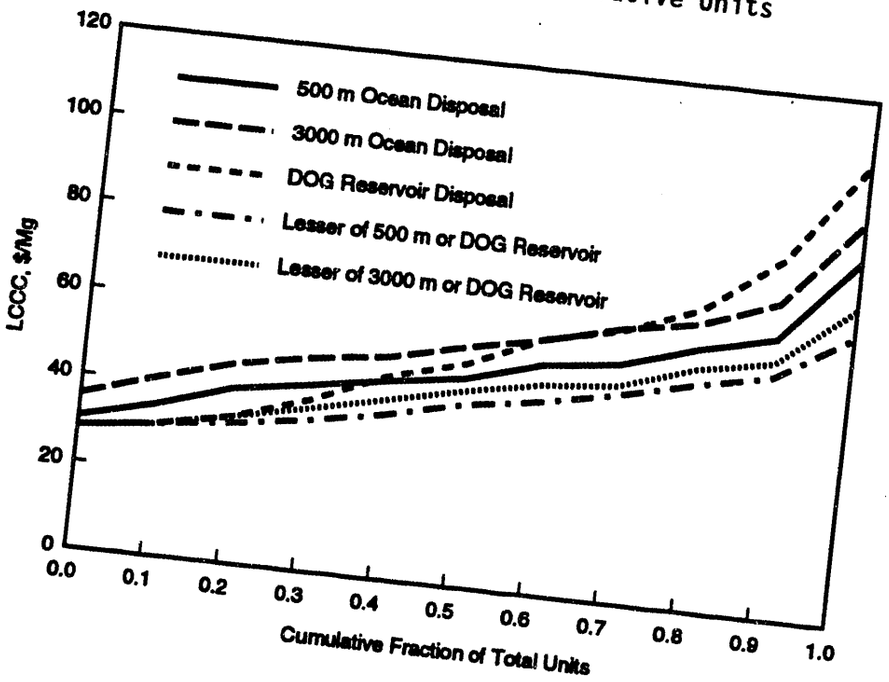

FIGURE 5.2. LCCC Summary, Cumulative Units

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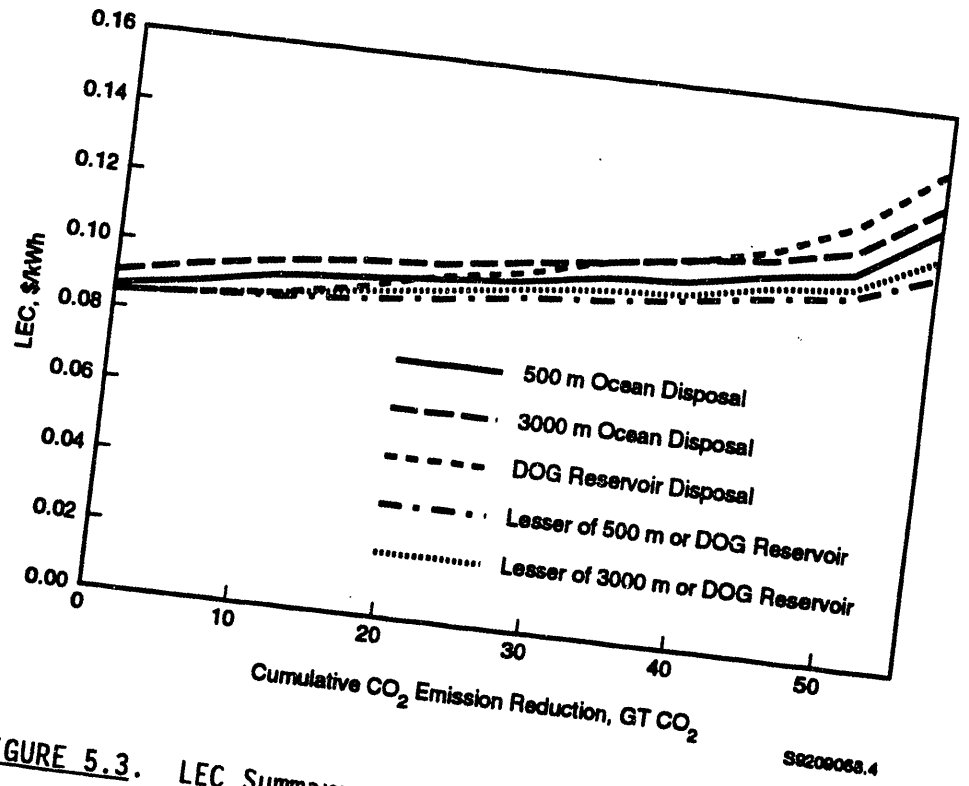

FIGURE 5.3. LEC Summary, Cumulative Emission Reductions

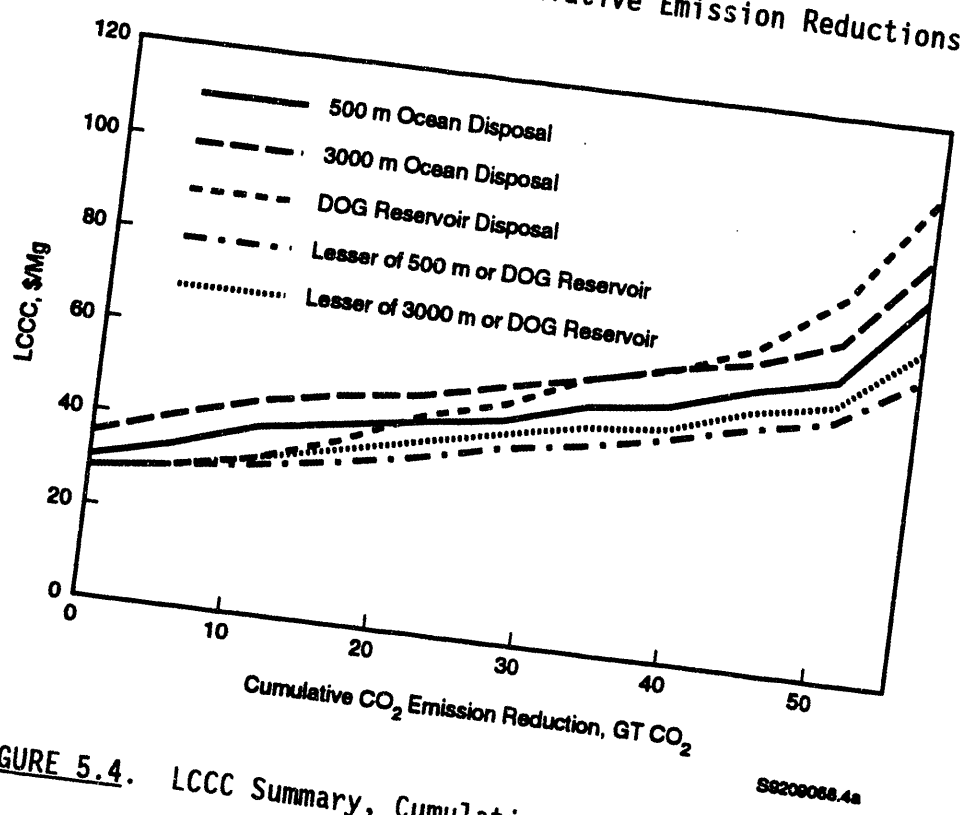

FIGURE 5.4. LCCC Summary, Cumulative Emission Reductions

injecting CO_2 into Dutch gas fields prior to normal closure of the field. Injection of CO_2 into partially depleted oil fields would probably have a significant positive economic benefit that would reduce the net cost of recovery and disposal in some cases.

6.0 CONCLUSIONS AND RECOMMENDATIONS

Ocean disposal of CO_2 offers essentially unlimited capacity, but such disposal is distant from most U.S. coal-fired power plant locations and presents environmental concerns in the vicinity of the disposal point. Depleted oil and gas reservoirs are also distant from most U.S. coal-fired power plants. Although they have a more limited disposal capacity than the ocean, DOG reservoirs were calculated to have a potential capacity more than double that required to dispose of all CO_2 from 830 GCC power plants (380-MWe each) for a period of 40 years. The existence of oil and gas reservoirs provides "proof" that CO_2 can be confined for the long term in these formations.

In contrast, aquifer disposal has great potential in terms of large capacity and low cost, but is believed to be significantly riskier. Key concerns are lack of geologic knowledge about aquifers at depths adequate for CO_2 disposal; geochemical impacts from decreased water pH; and long-term confinement; which is unproven for nonpetroleum formations. The technical, environmental, and economic feasibility of aquifer disposal for the United States should be investigated more thoroughly.

Carbon dioxide recovery at GCC plants increased the LEC by about one third relative to a reference GCC plant without CO_2 recovery. The transmission distance is the key factor affecting CO_2 control costs. The LEC with CO_2 recovery and transmission increased by one third to more than a factor of two, depending on the transmission distance, which ranged from about 25 to nearly 2000 mi. While CO_2 recovery and disposal would likely be too expensive to implement on a national basis, regional or site-specific applications may be competitive with other CO_2 control strategies. Credit for potential enhanced oil recovery benefits in depleted oil reservoir applications (not included in this study) would further improve economic attractiveness.

The significant impact of transmission on the cost-effectiveness of CO_2 recovery and disposal suggests that several key assumptions made in this study are worthy of further examination:

1. CO_2 properties vary dramatically within the range of ambient temperatures that might be encountered by a CO_2 pipeline. For example,

when CO_2 is recompressed from 1200 to 1800 psia, the power required at a 100°F inlet temperature is approximately double that required at a 60°F inlet temperature. The impact of locational and seasonal variation in ambient temperature on pipeline design and performance should be considered.

2. Investment in CO_2 distribution equipment within an oil and gas reservoir was not included in this study, but should be rigorously evaluated before this disposal option is seriously considered.

3. Each GCC unit was presumed to have its own pipeline from the power plant to the disposal point. Combining the CO_2 flow from several units or power plants into an integrated network may have significant economic benefit.

4. Specific material requirements for CO_2 pipelines should be investigated to determine if typical oil and gas pipeline costs are a good proxy for CO_2 pipeline costs.

5. The elevation drop in overland pipelines should be included in the evaluation of recompression requirements.

The costs of CO_2 control for the GCC power plant should be compared with other control options, such as increased efficiency of energy supply and end use equipment, reforestation, and carbon taxes. The cost of CO_2 control for other fossil fuels and combustion technologies should also be evaluated to complete the development of a CO_2 control "supply curve" for U.S. electric utilities. Finally, as advances in CO_2 recovery technology occur, the results of this study should be updated.

APPENDIX A

CALCULATIONS OF CO_2 STORAGE CAPACITY

APPENDIX A

CALCULATIONS OF CO_2 STORAGE CAPACITY

The general approach for calculating the potential cumulative CO_2 storage capacity was presented in Section 3.2. Calculational details are presented in this appendix.

A.1 CO_2 STORAGE CAPACITY RESULTING FROM OIL PRODUCTION

DOE production statistics from 1988 (EIA 1990) for the lower 48 states serve as the base production data for all capacity calculations, as well as the base from which future production is projected (see Table A.1). The crude oil production values include direct oil production and lease condensate production. Lease condensate is oil that condenses from gas streams at wells largely producing natural gas. The DOE crude oil production statistics do not include volumes of liquids recovered at natural gas processing plants. These liquids are included in volumes of natural gas production that are reported by DOE. The cumulative production values presented in Table A.1 include all recorded historical U.S. production. Both 1988 and cumulative production volumes are measured at standard petroleum industry conditions (60°F, 14.73 psia) and given in stock tank barrels (42 U.S. gal).

The DOE data shown in Table A.1 provide the foundation for estimating CO_2 storage capacity resulting from oil production through 1988. Storage capacity resulting from oil production occurring in the years 1989 through 2030 must come from forecast data. However, DOE data publications do not make production forecasts beyond the year 2010. To incorporate a longer time frame into the analysis, production forecasts developed for use in the National Energy Strategy (NES) (DOE 1991) were used (see Table A.2).

The NES production data for 1988 do not directly match the 1988 DOE production data. This discrepancy is probably due to differences in production data accounting. To compensate for this difference, the production trend for

TABLE A.1. 1988 DOE Crude Oil Production Data
(millions of stock tank barrels)

	1988 Production	Cumulative Production
Lower 48 Total	2,236	148,198
Alabama Onshore	21	436
Arkansas	13	1,731
California		
Coastal Region Onshore	30	3,549
Los Angeles Basin Onshore	34	5,496
San Joaquin Basin	264	10,143
Offshore	58	3,049
Colorado	32	1,552
Florida	9	523
Illinois	23	3,967
Indiana	4	473
Kansas	55	5,168
Kentucky	5	705
Louisiana Onshore		
North	27	3,155
South Onshore	115	11,412
Michigan	23	1,096
Mississippi	29	2,353
Montana	23	1,312
Nebraska	6	433
New Mexico		
East	67	4,512
West	7	300
New York	0	0
North Dakota	39	991
Ohio	10	960
Oklahoma	136	11,874
Pennsylvania	2	1,322
Texas Onshore		
RRC D1	20	1,058
RRC D2 Onshore	25	2,733
RRC D3 Onshore	78	8,316
RRC D4 Onshore	23	3,361
RRC D5	8	1,035
RRC D6	78	7,729
RRC D7B	28	2,012
RRC D7C	29	1,755
RRC D8	204	12,378
RRC D8A	190	8,775
RRC D9	32	3,186
RRC D10	16	1,939

TABLE A.1. (Contd)

	1988 Production	Cumulative Production
Utah	33	1,016
West Virginia	3	553
Wyoming	112	5,931
Misc.	6	329
Gulf of Mexico		
Louisiana Offshore	290	9,268
Texas Offshore	29	312

Note: Maps identifying those regions that are not states (e.g., RRC D1, which stands for Railroad Commission District) were presented in Figures 3.4 through 3.7.

TABLE A.2. NES Crude Oil Production Forecasts (millions of stock tank barrels)

	Daily Lower 48	Daily[a] EOR	Daily[b] NGL	Daily Total	Annual Total	Annual Change (%)
1985	6.7	0.5	1.6	8.8	3219	--
1986[c]	6.4	0.5	1.6	8.5	3091	--
1987[c]	6.0	0.5	1.6	8.1	2964	--
1988[c]	5.7	0.5	1.6	7.8	2836	--
1989	5.3	0.5	1.6	7.4	2701	-0.048
1990	5.0	0.5	1.5	7.0	2555	-0.054
1995	4.5	0.6	1.7	6.8	2482	-0.029
2000	4.2	0.7	1.9	6.8	2482	0.000
2005	3.9	0.9	1.7	6.5	2373	-0.044
2010	3.4	1.1	1.6	6.1	2227	-0.062
2015	3.0	1.1	1.6	5.7	2081	-0.066
2020	2.6	1.0	1.1	4.7	1716	-0.175
2025	2.0	1.0	0.9	3.9	1424	-0.170
2030	1.4	0.9	0.6	2.9	1059	-0.256

(a) EOR refers to enhanced oil recovery.
(b) NGL refers to natural gas liquids (includes lease condensates).
(c) The NES presented data for 1985, 1989, 1990, 1995, 2000, etc. Production values for 1986, 1987, and 1988 are interpolated.

the years 1988 through 2030 from the NES was applied to the 1988 DOE production data. The application of the NES trend to the DOE data on a national production basis is shown in Figure A.1. Table A.3 applies the NES production trend (shown in Table A.2 as the percentage of annual change) to the 1988 DOE

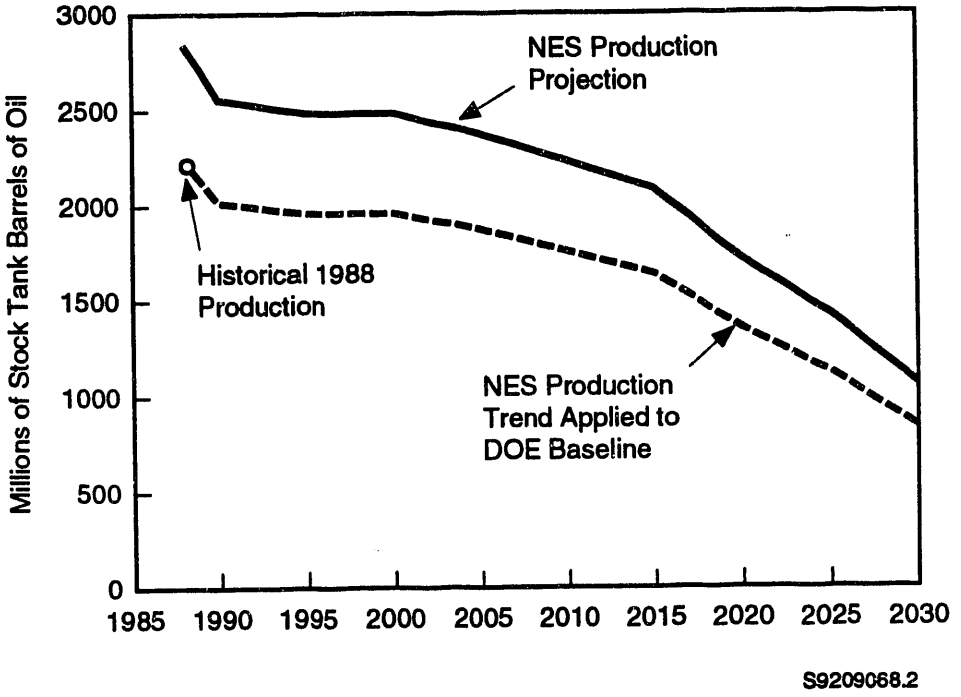

FIGURE A.1. Application of NES Production Forecast to 1988 DOE Production Data

production data. The application of this trend assumes that all geographical regions in the lower 48 states would undergo the same relative increases and decreases in production. In all likelihood, there would be some regional shifting over time; however, regional projections through the year 2030 are unavailable.

Based on the calculated regional production data shown in Table A.3 and the cumulative production data (through 1988) shown in Table A.1, cumulative production by year through the year 2030 was calculated (see Table A.4).

The gas component of oil production is accounted for within the gas production estimates; thus for every stock tank barrel produced, 42 gal of void is created within the reservoir. This assumes that oil is a non-compressible fluid. That is, reservoir pressure does not cause a gallon of surface oil to have significantly less volume within the reservoir. In reality, there is

TABLE A.3. Annual Production by Region (million stock tank barrels)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Total	2236	2130	2015	1957	1957	1871	1755	1640	1353	1122	835
Alabama Onshore	21	20	19	18	18	18	16	15	13	11	8
Arkansas	13	12	12	11	11	11	10	10	8	7	5
California											
Coastal Region Onshore	30	29	27	26	26	25	24	22	18	15	11
Los Angeles Basin Onshore	34	32	31	30	30	28	27	25	21	17	13
San Joaquin Basin	264	251	238	231	231	221	207	194	160	133	99
Offshore	58	55	52	51	51	49	46	43	35	29	22
Colorado	32	30	29	28	28	27	25	23	19	16	12
Florida	9	9	8	8	8	8	7	7	5	5	3
Illinois	23	22	21	20	20	19	18	17	14	12	9
Indiana	4	4	4	4	4	3	3	3	2	2	1
Kansas	55	52	50	48	48	46	43	40	33	28	21
Kentucky	5	5	5	4	4	4	4	4	3	3	2
Louisiana Onshore											
North	27	26	24	24	24	23	21	20	16	14	10
South Onshore	115	110	104	101	101	96	90	84	70	58	43
Michigan	23	22	21	20	20	19	18	17	14	12	9
Mississippi	29	28	26	25	25	24	23	21	18	15	11
Montana	23	22	21	20	20	19	18	17	14	12	9
Nebraska	6	6	5	5	5	5	5	4	4	3	2
New Mexico											
East	67	64	60	59	59	56	53	49	41	34	25
West	7	7	6	6	6	6	5	5	4	4	3
New York											
North Dakota	39	37	35	34	34	33	31	29	24	20	15
Ohio	10	10	9	9	9	8	8	7	6	5	4
Oklahoma	136	130	123	119	119	114	107	100	82	68	51
Pennsylvania	2	2	2	2	2	2	2	1	1	1	1
Texas Onshore											
RRC D1	20	19	18	18	18	17	16	15	12	10	7
RRC D2 Onshore	25	24	23	22	22	21	20	18	15	13	9
RRC D3 Onshore	78	74	70	68	68	65	61	57	47	39	29
RRC D4 Onshore	23	22	21	20	20	19	18	17	14	12	9
RRC D5	8	8	7	7	7	7	6	6	5	4	3
RRC D6	78	74	70	68	68	65	61	57	47	39	29
RRC D7B	28	27	25	25	25	23	22	21	17	14	10
RRC D7C	29	28	26	25	25	24	23	21	18	15	11
RRC D8	204	194	184	179	179	171	160	150	123	102	76
RRC D9A	190	181	171	166	166	159	149	139	115	95	71
RRC D9	32	30	29	28	28	27	25	23	19	16	12
RRC D10	16	15	14	14	14	13	13	12	10	8	6

TABLE A.3. (contd)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Utah	33	31	30	29	29	28	26	24	20	17	12
West Virginia	3	3	3	3	3	3	2	2	2	2	1
Wyoming	112	107	101	98	98	94	88	82	68	56	42
Misc.	6	6	5	5	5	5	5	4	4	3	2
Gulf of Mexico											
Louisiana Offshore	290	276	261	254	254	243	228	213	175	146	108
Texas Offshore	29	28	26	25	25	24	23	21	18	15	11

TABLE A.4. Cumulative Production by Region (million stock tank barrels)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Total	148198	150328	152342	162271	172056	181624	190690	199179	206662	212849	217742
Alabama Onshore	436	456	475	568	660	750	835	915	985	1043	1089
Arkansas	1731	1743	1755	1813	1870	1925	1978	2027	2071	2107	2135
California											
Coastal Region Onshore	3549	3578	3605	3738	3869	3997	4119	4233	4333	4416	4482
Los Angeles Basin Onshore	5496	5528	5559	5710	5859	6004	6142	6271	6385	6479	6553
San Joaquin Basin	10143	10394	10632	11805	12960	14090	15160	16162	17046	17776	18354
Offshore	3049	3104	3156	3414	3668	3916	4151	4371	4566	4726	4853
Colorado	1552	1582	1611	1753	1893	2030	2160	2282	2389	2477	2547
Florida	523	532	540	580	619	658	694	728	758	783	803
Illinois	3967	3989	4010	4112	4212	4311	4404	4491	4568	4632	4682
Indiana	473	477	480	498	516	533	549	564	578	589	597
Kansas	5168	5220	5270	5514	5755	5990	6213	6422	6606	6758	6879
Kentucky	705	710	714	736	758	780	800	819	836	850	861
Louisiana Onshore											
North	3155	3181	3205	3325	3443	3559	3668	3771	3861	3936	3995
South	11412	11522	11625	12136	12639	13131	13597	14034	14419	14737	14989
Michigan	1096	1118	1139	1241	1341	1440	1533	1620	1697	1761	1811
Mississippi	2353	2381	2407	2536	2662	2787	2904	3014	3111	3192	3255
Montana	1312	1334	1355	1457	1557	1656	1749	1836	1913	1977	2027
Nebraska	433	439	444	471	497	523	547	570	590	606	620
New Mexico											
East	4512	4576	4636	4934	5227	5514	5785	6040	6264	6449	6596
West	306	307	313	344	375	405	433	460	483	502	518
New York											
North Dakota	991	1028	1063	1236	1407	1574	1732	1880	2011	2119	2204
Ohio	960	970	979	1023	1067	1109	1150	1188	1221	1249	1271
Oklahoma	11874	12004	12126	12730	13325	13907	14458	14975	15430	15806	16104
Pennsylvania	1322	1324	1326	1335	1343	1352	1360	1368	1374	1380	1384
Texas Onshore											
RRC D1	1058	1077	1095	1184	1271	1357	1438	1514	1581	1636	1680
RRC D2 Onshore	2733	2757	2779	2890	3000	3107	3208	3303	3387	3456	3511
RRC D3 Onshore	8316	8390	8461	8807	9148	9482	9798	10094	10355	10571	10742
RRC D4 Onshore	3361	3383	3404	3506	3606	3705	3798	3885	3962	4026	4076
RRC D5	1035	1043	1050	1085	1120	1155	1187	1217	1244	1266	1284
RRC D6	7729	7803	7874	8220	8561	8895	9211	9507	9768	9984	10155
RRC D7B	2012	2039	2064	2188	2311	2431	2544	2650	2744	2822	2883
RRC D7C	1755	1783	1809	1938	2064	2189	2306	2416	2513	2594	2657
RRC D8	12378	12572	12756	13662	14555	15428	16255	17029	17712	18276	18723
RRC D8A	8775	8956	9127	9971	10802	11615	12386	13107	13743	14269	14684
RRC D9	3186	3216	3245	3387	3527	3664	3794	3916	4023	4111	4181
RRC D10	1939	1954	1969	2040	2110	2178	2243	2304	2357	2402	2437

TABLE A.4. (contd)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Utah	1016	1047	1077	1224	1368	1509	1643	1768	1879	1970	2042
West Virginia	553	556	559	572	585	598	610	621	631	640	646
Wyoming	5931	6038	6139	6636	7126	7605	8059	8485	8859	9169	9414
Misc.	329	335	340	367	393	419	443	466	486	502	516
Gulf of Mexico											
Louisiana Offshore	9268	9544	9805	11093	12362	13603	14779	15880	16851	17653	18288
Texas Offshore	312	340	366	495	621	746	863	973	1070	1151	1214

some compressibility. In addition, as the oil is produced, the reservoir overburden pressure, typically 1 psi per ft of depth, causes the void volume to shrink slightly.

The next step of the analysis was to develop a profile of depth versus capacity for each region shown in Table A.4. This profile is important because pressure and temperature change dramatically with depth, and the amount of CO_2 that can be stored is highly dependent on the storage temperature and pressure. A more simplified approach of assuming an average temperature and pressure is not appropriate, as the relationship between CO_2 storage volume and temperature and pressure is not linear.

To develop the depth profile, producing rate (i.e., barrels per year) versus depth was assumed to be a good proxy for available storage volume by depth. This assumption implies that if 10 barrels of oil are produced above 5000 ft in a year and 90 barrels are produced below 5000 ft in the same year, then 10% of all available storage volume exists above 5000 ft. This assumption appears to be reasonable although imperfect, as production versus depth undoubtably changes over time with early historical production focused on shallow reservoirs and current production moving toward deeper and deeper reservoirs. As DOE's evaluation of producing rate versus depth is published intermittently, the most recent DOE analysis of 1974 data (EIA 1978) was selected as the basis for this analysis. Data summarized from the DOE analysis are presented in Table A.5. Because the DOE analysis of 1974 data uses slightly different regions than the 1988 DOE production data (see Table A.1), it was necessary to "map" the 1974 regional data into the 1988 set of regions. The notes in the last column of Table A.5 detail this mapping exercise.

The producing rate data in Table A.5 were combined with the cumulative production data presented in Table A.4 to calculate cumulative storage volume

TABLE A.5. Producing Rate Data by Region for 1974 (% of total production rate by depth)

	<2000	2000-4000	4000-6000	6000-8000	>8000	
Lower 48 Total						
Alabama Onshore	0.0	1.6	2.1	0.0	96.3	Based on all Alabama (onshore and offshore)
Arkansas	19.0	25.6	11.4	17.3	26.7	
California						
Coastal Region Onshore	28.4	23.1	24.5	13.7	10.4	Average for all of California
Los Angeles Basin Onshore	28.4	23.1	24.5	13.7	10.4	Average for all of California
San Joaquin Basin	28.4	23.1	24.5	13.7	10.4	Average for all of California
Offshore	28.4	23.1	24.5	13.7	10.4	Average for all of California
Colorado	0.7	2.3	20.1	72.0	5.0	
Florida	0.0	0.0	0.0	0.0	100.0	
Illinois	51.4	48.6	0.0	0.0	0.0	
Indiana	51.4	48.6	0.0	0.0	0.0	Copied from Illinois
Kansas	12.1	66.4	21.2	0.2	0.3	
Kentucky	51.4	48.6	0.0	0.0	0.0	Copied from Illinois
Louisiana Onshore						
North	8.1	39.0	36.2	14.6	2.1	
South Onshore	0.5	1.5	9.2	17.2	71.6	Based on all South Louisiana (on and offshore)
Michigan	3.3	43.5	31.4	21.7	0.0	
Mississippi	0.0	3.4	25.5	9.8	61.3	
Montana	1.4	18.0	38.8	13.8	28.0	
Nebraska	40.2	21.8	16.1	9.9	12.0	Copied from Oklahoma
New Mexico						
East	3.7	25.3	21.7	24.0	25.3	Average for all New Mexico
West	3.7	25.3	21.7	24.0	25.3	Average for all New Mexico
New York	0.0	0.0	0.0	0.0	0.0	Copied from Illinois
North Dakota	0.0	10.5	11.7	16.1	61.7	
Ohio	51.4	48.6	0.0	0.0	0.0	Copied from Illinois
Oklahoma	40.2	21.8	16.1	9.9	12.0	
Pennsylvania	51.4	48.6	0.0	0.0	0.0	Copied from Illinois
Texas Onshore						
RRC D1	18.4	39.6	34.0	7.7	0.3	
RRC D2 Onshore	0.1	2.9	80.0	14.1	3.0	
RRC D3 Onshore	0.4	2.2	34.7	47.3	15.4	
RRC D4 Onshore	5.0	14.3	30.4	48.8	1.6	
RRC D5	2.1	86.0	3.2	1.7	7.0	
RRC D6	0.6	48.1	33.9	7.3	10.1	
RRC D7B	18.1	12.6	62.3	7.0	0.0	
RRC D7C	5.1	12.8	28.1	36.1	17.9	
RRC D8	7.4	23.7	28.5	6.3	34.1	
RRC D8A	0.4	1.7	54.4	37.6	5.9	
RRC D9	31.1	21.9	34.1	10.4	2.6	
RRC D10	0.0	63.6	2.4	28.0	6.0	

TABLE A.5. (contd)

	<2000	2000-4000	4000-6000	6000-8000	>8000	
Utah	0.8	0.0	32.5	28.5	38.2	
West Virginia	51.4	48.6	0.0	0.0	0.0	Copied from Illinois
Wyoming	10.4	33.3	16.8	17.1	22.4	
Misc.	51.4	48.6	0.0	0.0	0.0	Copied from Illinois
Gulf of Mexico						
Louisiana Offshore	0.5	1.5	9.2	17.2	71.6	
Texas Offshore	1.0	4.2	45.1	39.4	10.3	Weighted average based on RRC D2, D3, and D4

by region, year, and depth. The following is an example of the type and form of data generated from this calculation:

Texas RRC D1; Year 2030	
Depth[a]	Volume[b]
<2000	1.4
2000-4000	3.0
4000-6000	2.5
6000-8000	0.6
>8000	0.0

(a) ft
(b) millions of stock tank barrels per year (at 42 gal per barrel)

Next, an average temperature and an average pressure gradient were assumed and used to estimate reservoir temperature and pressure at each depth interval. Worldwide, reservoir pressure--the pressure in the pores--is normally about equal to the static pressure caused by a column of fluid that extends to the surface. The water gradient is usually about 0.433 to 0.5 psi/ft (Amyx, Bass and Whiting 1960; Slider 1983). For this analysis, a conservative pressure gradient of 0.433 psi/ft is assumed. For temperature calculations, a mean surface temperature of 60°F (519.7 R) is assumed, with a gradient of 1°F per 100 ft. Based on these gradients, the example data for the Texas RRC D1 region (year 2030) can be enhanced to create the following depth profile:

Year 2030[a]			
Depth (feet)	Volume[b]	Temperature (R)	Pressure (psia)
<2000	7.6×10^6	529.7	447.73
2000-4000	17.0×10^6	549.7	1313.73
4000-6000	14.0×10^6	569.7	2179.73
6000-8000	3.4×10^6	589.7	3045.73
>8000	0.0	609.7	3911.73

(a) Data are assumed to represent depths of 1000, 3000, 5000, 7000, and 9000 ft, which are the midpoints of the indicated depth intervals.
(b) Converted from millions of stock tank barrels per year (at 42 gal per barrel) to annual cubic feet using 5.615 ft^3/barrel.

For each depth interval, year and region, a theoretical CO_2 storage capacity can be estimated from the above data using the following equation:

$$CO_2,\ ft^3 = 358.4n = 358.4P_RV_R/z_RRT_R$$

where: n = lb·mole of CO_2 at 32°F, 14.73 psia

P = reservoir pressure, psia

V = reservoir volume, ft^3

z = compressibility factor

R = gas constant = 10.73 lb·mole-R/psia-ft^3

T = reservoir temperature, degrees Rankine

The compressibility factor, "z-factor," changes dramatically with temperature and pressure as illustrated by the following data:

CO_2 Compressibility Data

z-factor	Temperature (R)	Pressure (psia)
0.814	529.7	447.73
0.234	549.7	1313.73
0.365	569.7	2179.73
0.442	589.7	3045.73
0.543	609.7	3911.73

Table A.6 presents a summary of the theoretical CO_2 storage capacity by region and year, summed over all depth intervals.

A.2 CO_2 STORAGE CAPACITY RESULTING FROM NATURAL GAS PRODUCTION

As with the oil scenario,[a] storage capacity generated by natural gas production is based on DOE production statistics from 1988 (EIA 1990) for the lower 48 states (see Table A.7). The DOE natural gas production values

(a) The phrase "oil scenario" refers to the analysis (presented in the preceding section of this paper) of CO_2 storage capacity resulting from crude oil production.

TABLE A.6. Cumulative CO_2 Storage Capacity Resulting From Oil Production (millions of ft^3 at 14.73 psia, 32°F)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Total	2.7E+08	2.7E+08	2.8E+08	2.9E+08	3.1E+08	3.3E+08	3.5E+08	3.6E+08	3.8E+08	3.9E+08	4.0E+08
Alabama Onshore	961772	1005892	1047627	1253322	1456036	1654278	1842086	2017970	2172986	2301173	2402529
Arkansas	2981235	3002559	3022730	3122147	3220123	3315938	3406710	3491719	3566642	3628597	3677586
California											
Coastal Region Onshore	5359425	5402573	5443389	5644554	5842803	6036679	6220351	6392361	6543964	6669327	6768452
Los Angeles Basin Onshore	8299634	8348535	8394793	8622780	8847462	9067188	9275350	9470295	9642111	9784189	9896530
San Joaquin Basin	15317173	15696879	16056059	17826308	19570900	21277009	22893322	24407013	25741113	26844311	27716607
Offshore	4604364	4687784	4766695	5155613	5538895	5913722	6268821	6601374	6894472	7136841	7328482
Colorado	3304620	3369515	3430902	3733452	4031618	4323206	4599448	4858151	5086160	5274706	5423788
Florida	1158946	1177941	1195909	1284466	1371739	1457088	1537944	1613667	1680405	1735593	1779229
Illinois	4089953	4112537	4133901	4239195	4342963	4444441	4540579	4630613	4709964	4775582	4827466
Indiana	487660	491588	495303	513615	531662	549310	566030	581688	595488	606900	615923
Kansas	8905598	8995866	9081255	9502099	9916844	10322440	10706689	11066542	11383700	11645965	11853337
Kentucky	726851	731760	736405	759295	781853	803913	824813	844385	861636	875901	887180
Louisiana Onshore											
North	5808123	5855464	5900245	6120953	6338463	6551174	6752690	6941411	7107742	7245285	7354040
South Onshore	24822221	25060457	25285815	26396510	27491108	28561560	29575673	30525397	31362443	32054615	32601914
Michigan	2118024	2160357	2200402	2397765	2592268	2782480	2962682	3131442	3280179	3403174	3500425
Mississippi	5034457	5093553	5149455	5424970	5696493	5962027	6213585	6449171	6656806	6828504	6964266
Montana	2667540	2712079	2754210	2961856	3166492	3366614	3556204	3733756	3890243	4019645	4121964
Nebraska	560839	568240	575242	609750	643758	677016	708523	738030	764036	785541	802544
New Mexico											
East	9046654	9174599	9295628	9892130	10479987	11054876	11599508	12109561	12559098	12930831	13224759
West	601506	614874	627519	689840	751257	811321	868222	921511	968478	1007316	1038025
New York	0	0	0	0	0	0	0	0	0	0	0
North Dakota	2131856	2211762	2287348	2659883	3027019	3386056	3726196	4044740	4325491	4557651	4741218
Ohio	989754	999574	1008862	1054642	1099758	1143880	1185679	1224824	1259324	1287854	1310412
Oklahoma	15379673	15547445	15706149	16488329	17259174	18013015	18727179	19396000	19985470	20472916	20858338
Pennsylvania	1362974	1364938	1366796	1375952	1384975	1393799	1402159	1409988	1416888	1422594	1427105
Texas Onshore											
RRC D1	1733169	1764374	1793891	1939371	2082743	2222952	2355782	2480178	2589815	2680476	2752162
RRC D2 Onshore	5476866	5524582	5569718	5792178	6011413	6225812	6428927	6619146	6786796	6925430	7035048
RRC D3 Onshore	17488102	17644328	17792110	18520461	19238256	19940218	20605234	21228027	21776929	22230830	22589727
RRC D4 Onshore	6675641	6719150	6760308	6963155	7163063	7358562	7543771	7717220	7870091	7996503	8096457
RRC D5	1973376	1987904	2001646	2069376	2136123	2201399	2263239	2321152	2372195	2414403	2447777
RRC D6	15247284	15393837	15532468	16215722	16889073	17547571	18171411	18755642	19270558	19696353	20033029
RRC D7B	3329412	3373541	3415285	3621024	3823781	4022065	4209913	4385834	4540884	4669098	4770476
RRC D7C	3501806	3556918	3609051	3865990	4119206	4366836	4601434	4821136	5014771	5174893	5301501
RRC D8	23795068	24168574	24521891	26263235	27979343	29657595	31247518	32736494	34048811	35133997	35992051
RRC D8A	18055135	18427474	18779686	20515588	22226332	23899339	25484293	26968616	28276832	29358626	30213998
RRC D9	4574969	4618734	4660133	4864171	5065251	5261896	5448192	5622659	5776426	5903580	6004121
RRC D10	3901231	3931891	3960894	4103837	4244708	4382471	4512984	4635210	4742935	4832016	4902451

TABLE A.6. (contd)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Utah	2145353	2211719	2274498	2583910	2888838	3187039	3469546	3734115	3967295	4160117	4312581
West Virginia	570140	573085	575872	589606	603141	616377	628917	640660	651011	659570	666337
Wyoming	11028658	11227013	11414646	12339410	13250771	14142029	14986379	15777119	16474042	17050344	17506025
Misc.	339197	345089	350662	378130	405200	431672	456752	480239	500939	518057	531592
Gulf of Mexico											
Louisiana Offshore	20158810	20759579	21327874	24128757	26889047	29588449	32145776	34540734	36651544	38397021	39777167
Texas Offshore	642861	699772	753606	1018931	1280411	1536123	1778377	2005249	2205204	2370552	2501292

TABLE A.7. 1988 DOE Gas Production Data (billions of standard cubic feet)

	1988 Production	Cumulative Production
Lower 48 Total	17,750	754,767
Alabama Onshore	105	1,230
Arkansas	192	5,703
California		
Coastal Region Onshore	26	5,359
Los Angeles Basin Onshore	14	4,369
San Joaquin Basin	283	17,566
Offshore	58	2,145
Colorado	202	6,404
Florida	10	540
Illinois	0	0
Indiana	0	0
Kansas	587	28,178
Kentucky	62	3,926
Louisiana Onshore		
North	384	27,289
South Onshore	1,183	92,697
Michigan	164	3,052
Mississippi	221	7,778
Montana	53	1,465
Nebraska	0	0
New Mexico		
East	416	20,090
West	367	15,929
New York		727
North Dakota	69	1,452
Ohio	132	6,834
Oklahoma	2,183	70,861
Pennsylvania	162	10,348
Texas Onshore		
RRC D1	168	4,272
RRC D2 Onshore	353	23,312
RRC D3 Onshore	557	52,061
RRC D4 Onshore	1,244	54,132
RRC D5	177	4,390
RRC D6	433	21,199
RRC D7B	131	4,412
RRC D7C	294	9,397
RRC D8	826	40,927
RRC D8A	101	5,883
RRC D9	126	4,934
RRC D10	579	47,972

TABLE A.7. (Contd)

	1988 Production	Cumulative Production
Utah	60	2,935
West Virginia	182	16,661
Wyoming	581	14,620
Misc.	32	2,285
Gulf of Mexico		
Louisiana Offshore	3,479	96,914
Texas Offshore	1,345	14,519

Note: Maps identifying those regions that are not states (e.g., RRC D1, which stands for Railroad Commission District 1) were presented in Figures 3.4 through 3.7.

include the energy equivalent of natural gas liquids recovered at natural gas processing plants. The production values do not include lease condensates that are accounted for in oil production volumes reported by DOE. The cumulative production values presented in Table A.7 include all recorded historical U.S. production. Both 1988 and cumulative production volumes are measured at standard conditions (i.e., 60°F, 14.73 psia).

The DOE data shown in Table A.7 provide the foundation for estimating CO_2 storage capacity. Similar to the approach used in the oil scenario, estimates of storage capacity resulting from natural gas production from 1989 through 2030 are based on NES forecast data (DOE 1991). These data are presented in Table A.8.

The production trend for the years 1988 through 2030 from the NES was applied to the 1988 DOE production data (see Figure A.2) on a national production basis. Table A.9 applies the NES production trend (shown in Table A.8 as the percentage of annual change) to the 1988 DOE production data.

Based on the calculated regional production data shown in Table A.9 and the cumulative production data (through 1988) shown in Table A.7, cumulative production by year through the year 2030 was calculated (see Table A.10). All figures in Tables A.9 and A.10 are expressed in billion standard cubic feet.

TABLE A.8. NES Natural Gas Production Forecasts (trillions of standard cubic feet)

	Annual Lower 48	Annual Change (%)
1985	16.4	---
1986[a]	16.7	---
1987[a]	16.9	---
1988[a]	17.1	0.013
1989	17.3	0.012
1990	17.4	0.006
1995	18.8	0.080
2000	20.8	0.106
2005	19.5	-0.063
2010	18.5	-0.051
2015	19.4	0.049
2020	18.4	-0.052
2025	18.1	-0.016
2030	16.5	-0.088

(a) The NES presented data for the years 1985, 1989, 1990, 1995, 2000, etc. Production values for 1986, 1987, and 1988 are interpolated.

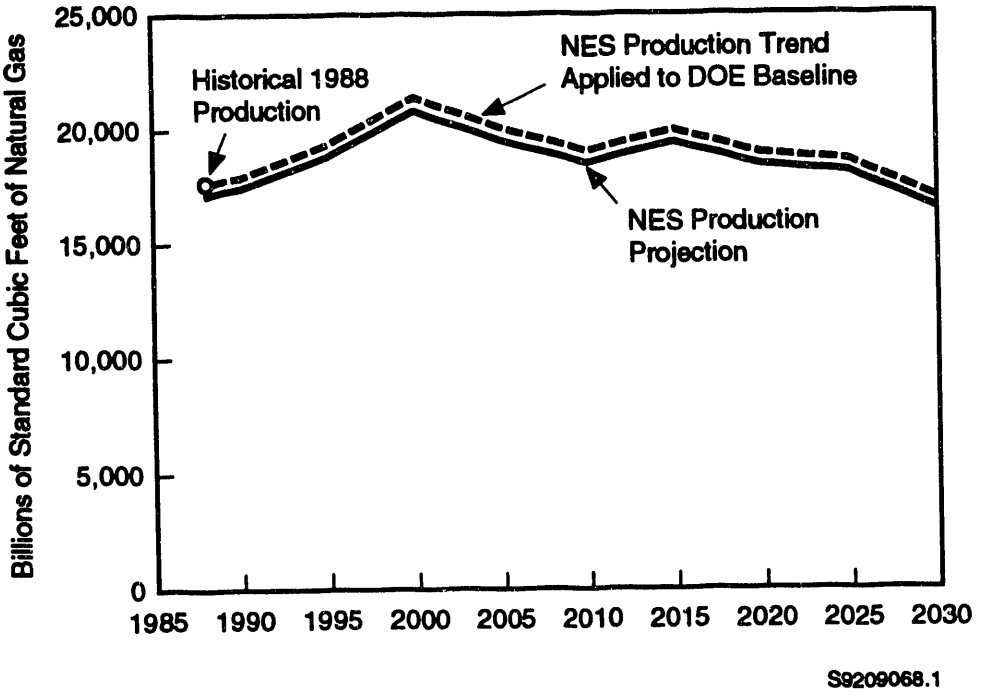

FIGURE A.2. Application of NES Production Forecast to 1988 DOE Natural Gas Production Data

TABLE A.9. Annual Natural Gas Production by Region (billion ft^3 at 14.73 psia, 60°F)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Total	17571	17776	17879	19318	21373	20037	19009	19934	18906	18598	16954
Alabama Onshore	105	106	107	115	128	120	114	119	113	111	101
Arkansas	192	194	195	211	234	219	208	218	207	203	185
California											
Coastal Region Onshore	26	26	26	29	32	30	28	29	28	26	25
Los Angeles Basin Onshore	14	14	14	15	17	16	15	16	15	15	14
San Joaquin Basin	283	286	288	311	344	323	306	321	305	300	273
Offshore	58	59	59	64	71	66	63	66	62	61	56
Colorado	202	204	206	222	246	230	219	229	217	214	195
Florida	10	10	10	11	12	11	11	11	11	11	10
Illinois	0	0	0	0	0	0	0	0	0	0	0
Indiana	0	0	0	0	0	0	0	0	0	0	0
Kansas	587	5[illegible]	597	645	714	669	635	666	632	621	566
Kentucky	62	63	63	68	75	71	67	70	67	66	60
Louisiana Onshore											
North	384	388	391	422	467	438	415	436	413	406	371
South Onshore	1183	1197	1204	1301	1439	1349	1280	1342	1273	1252	1141
Michigan	164	166	167	180	199	187	177	186	176	174	158
Mississippi	221	224	225	243	269	252	239	251	238	234	213
Montana	53	54	54	58	64	60	57	60	57	56	51
Nebraska	0	0	0	0	0	0	0	0	0	0	0
New Mexico											
East	416	421	423	457	506	474	450	472	448	440	401
West	367	371	373	403	[illegible]	419	397	[illegible]	395	388	354
New York	30	30	31	33	36	34	32	34	32	32	29
North Dakota	69	70	70	76	84	79	75	78	74	73	67
Ohio	132	134	134	145	161	151	143	150	142	140	127
Oklahoma	2183	2208	2221	2400	2655	2489	2362	2477	2349	2311	2106
Pennsylvania	162	164	165	178	197	185	175	184	174	171	[illegible]
Texas Onshore											
RRC D1	168	170	171	185	204	192	182	191	181	178	162
RRC D2 Onshore	353	357	359	388	429	403	382	400	380	374	341
RRC D3 Onshore	557	564	567	612	678	635	603	632	599	590	537
RRC D4 Onshore	1244	1259	1266	1368	1513	1419	1346	1411	1339	1317	1200
RRC D5	177	179	180	195	215	202	191	201	190	187	171
RRC D6	433	438	441	476	527	494	468	491	466	458	418
RRC D7B	131	133	133	144	159	149	142	149	141	139	126
RRC D7C	294	297	299	323	358	335	318	334	316	311	284
RRC D8	826	836	840	908	1005	942	894	937	889	874	797
RRC D8A	101	102	103	111	123	115	109	115	109	107	97
RRC D9	126	127	128	139	153	144	136	143	136	133	122
RRC D10	579	586	589	637	704	660	626	657	623	613	559

TABLE A.9. (contd)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Utah	59	61	61	66	73	68	65	68	65	64	58
West Virginia	182	184	185	200	221	208	197	206	196	193	176
Wyoming	581	588	591	639	707	663	629	659	625	615	561
Misc.	32	32	33	35	39	36	35	36	34	34	31
Gulf of Mexico											
Louisiana Offshore	3479	3520	3540	3825	4232	3967	3764	3947	3743	3682	3357
Texas Offshore	1345	1361	1369	1479	1636	1534	1455	1526	1447	1424	1298

TABLE A.10. Cumulative Natural Gas Production by Region (billion ft^3 at 14.73 psia, 60°F)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Total	754767	772543	790422	883413	985139	1088662	1186277	1283635	1380736	1474498	1563379
Alabama Onshore	1230	1336	1443	1999	2607	3225	3809	4390	4971	5531	6062
Arkansas	5703	5897	6093	7109	8220	9352	10418	11482	12543	13568	14539
California											
Coastal Region Onshore	5359	5385	5412	5549	5700	5853	5998	6142	6285	6424	6556
Los Angeles Basin Onshore	4369	4383	4397	4472	4553	4635	4713	4790	4868	4942	5013
San Joaquin Basin	17566	17852	18140	19638	21276	22944	24516	26084	27648	29158	30590
Offshore	2145	2204	2263	2570	2905	3247	3569	3891	4211	4521	4814
Colorado	6404	6608	6814	7883	9052	10243	11365	12484	13600	14678	15700
Florida	540	550	560	613	671	730	786	841	896	950	1000
Illinois	0	0	0	0	0	0	0	0	0	0	0
Indiana	0	0	0	0	0	0	0	0	0	0	0
Kansas	28178	28772	29369	32476	35874	39333	42594	45846	49090	52222	55192
Kentucky	3926	3989	4052	4380	4739	5104	5449	5792	6135	6466	6779
Louisiana Onshore											
North	27289	27677	28068	30100	32324	34586	36719	38847	40969	43018	44961
South Onshore	92697	93894	95098	101358	108207	115177	121749	128304	134842	141154	147138
Michigan	3052	3218	3385	4253	5202	6168	7080	7988	8895	9770	10599
Mississippi	7778	8002	8226	9396	10676	11978	13205	14430	15651	16830	17948
Montana	1465	1519	1573	1853	2160	2472	2767	3060	3353	3636	3904
Nebraska	0	0	0	0	0	0	0	0	0	0	0
New Mexico											
East	20090	20511	20934	23136	25544	27995	30306	32611	34910	37130	39234
West	15929	16300	16674	18616	20741	22903	24942	26975	29003	30962	32818
New York	727										
North Dakota	1452	1522	1592	1957	2357	2763	3147	3529	3910	4278	4627
Ohio	6834	6968	7102	7800	8565	9342	10076	10807	11537	12241	12909
Oklahoma	70861	73069	75291	86844	99482	112344	124471	136567	148631	160280	171322
Pennsylvania	10348	10512	10677	11534	12472	13426	14326	15224	16119	16984	17803
Texas Onshore											
RRC D1	4272	4442	4613	5502	6475	7464	8398	9329	10257	11154	12003
RRC D2 Onshore	23312	23669	24028	25896	27940	30020	31981	33937	35888	37771	39557
RRC D3 Onshore	52061	52625	53191	56139	59364	62645	65740	68826	71904	74876	77694
RRC D4 Onshore	54132	55391	56656	63240	70442	77771	84682	91575	98450	105088	111381
RRC D5	4390	4569	4749	5686	6711	7753	8737	9718	10696	11640	12535
RRC D6	21199	21637	22078	24369	26876	29427	31833	34232	36625	38935	41126
RRC D7B	4412	4545	4678	5371	6130	6901	7629	8355	9079	9778	10441
RRC D7C	9397	9694	9994	11550	13252	14984	16617	18246	19871	21440	22927
RRC D8	40927	41763	42603	46975	51757	56623	61212	65789	70353	74761	78939
RRC D8A	5883	5985	6088	6622	7207	7802	8363	8923	9481	10020	10531
RRC D9	4934	5061	5190	5857	6586	7328	8028	8726	9423	10095	10732
RRC D10	47972	48558	49147	52211	55563	58975	62191	65399	68599	71689	74617

TABLE A.10. (contd)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Utah	2935	2996	3057	3374	3722	4075	4408	4741	5073	5393	5696
West Virginia	16661	16845	17030	17994	19047	20119	21131	22139	23145	24116	25037
Wyoming	14620	15208	15799	18874	22237	25661	28888	32107	35318	38419	41357
Misc.	2285	2317	2350	2519	2705	2893	3071	3248	3425	3596	3758
Gulf of Mexico											
Louisiana Offshore	96914	100434	103974	122386	142527	163024	182352	201628	220854	239418	257017
Texas Offshore	14519	15880	17248	24366	32153	40078	47550	55002	62435	69612	76416

Similar to the oil scenario, the next step of the analysis was to develop a profile of depth versus capacity for each region. Unfortunately, a producing rate profile similar to that presented in Table A.5 for crude oil is not available for gas. Consequently, the crude oil profile was assumed to apply equally well to natural gas. Implicit in this assumption is that gas will be produced at the same general depths and have a production volume that is proportional to the volume of crude oil produced at that same depth. This implication is not entirely correct, but should be adequate for the purposes of this analysis.

The producing rate data in Table A.5 were combined with the cumulative production data presented in Table A.10 to calculate cumulative storage volume by region, year, and depth. The following is an example of the type and form of data generated from this calculation.

Texas RRC D1; Year 2030

Depth[a]	Volume[b]
<2000	29.8
2000-4000	64.2
4000-6000	55.1
6000-8000	12.5
>8000	0.5

(a) ft
(b) billion ft^3 at 60°F, 14.73 psia

Following this, the average temperature gradient of 1°F per 100 ft and the average pressure gradient of 0.433 psi/ft were applied to the depth profile.

Natural gas production is expressed in cubic feet at standard conditions. Natural gas is highly compressible; consequently, unlike the oil scenario where the production of a barrel of oil was assumed to create one barrel (i.e., 42 gal) of void volume in the reservoir, a standard ft^3 of gas produced at the surface creates a much smaller reservoir void volume because the gas is highly compressed while in its original reservoir space. The compressibility of the natural gas is adjusted for through the following equation:

$$V_R = P_{sc}V_{sc}Z_RT_R \;/\; Z_{sc}T_{sc}P_R$$

where: V_R = reservoir void volume, ft^3

V_{sc} = gas volume at standard conditions, ft^3

P_R = reservoir pressure, psia

P_{sc} = standard pressure, 14.73 psia

T_R = reservoir temperature, Rankine

T_{sc} = standard temperature, 520 Rankine

z_R = compressibility factor at T_R and P_R

z_{sc} = compressibility factor at 520 R and 14.73 psia = 1

Because reservoir temperature, pressure, and, consequently, the compressibility factor change for each depth interval, the reservoir void volume must be independently calculated for each depth, year and region.

While the compressibility factors for CO_2 can be obtained from tables published in a variety of chemical engineering handbooks, compressibility factors for natural gas must be calculated. Natural gas is a blend of hydrocarbon gases that varies from reservoir to reservoir with an infinite number of gas compositions possible. As a result, standard tables for all blends of natural gas are not available.

To calculate natural gas compressibility factors, the pseudocritical temperature and pressure for the gas must first be calculated.[a] This calculation can be accomplished using the following relationships:

$$\text{Pseudocritical pressure} = P_{pc} = 709.604 - 58.718 * \text{gas gravity}$$

$$\text{Pseudocritical temperature} = T_{pc} = 170.491 - 307.344 * \text{gas gravity}$$

(a) Pseudocritical temperature and pressure relate to the physical characteristics of the constituent hydrocarbons in the natural gas and the nearness of the actual temperature and pressure to the critical point of each respective constituent hydrocarbon. For further explanation, the reader is referred to texts (e.g., Ikoku 1984 or McLain 1973) that discuss multi-phase gas systems.

The gas gravity (i.e., the molecular weight of the gas relative to the molecular weight of the air) is assumed to be 0.7, which is representative of many natural gases. This assumption results in pseudocritical properties of

$$P_{pc} = 668.5$$

$$T_{pc} = 385.6$$

The next step is to calculate the pseudo-reduced pressure and temperature:

$$P_{pr} = P/P_{pc}$$

$$T_{pr} = T/T_{pc}$$

P and T are the absolute pressure (psia) and absolute temperature (Rankine) at which the z-factor is required (Ikoku 1984). These pseudo-reduced values can be indexed on a chart to find the z-factor (see Figure A.3). The z-factors for natural gas with a specific gravity of 0.7 at each depth interval (and corresponding absolute temperatures and pressures) are as follows:

Natural Gas Compressibility Data

z-factor	Temperature (R)	Pressure (psia)
0.91	529.7	447.73
0.80	549.7	1313.73
0.76	569.7	2179.73
0.81	589.7	3045.73
0.85	609.7	3911.73

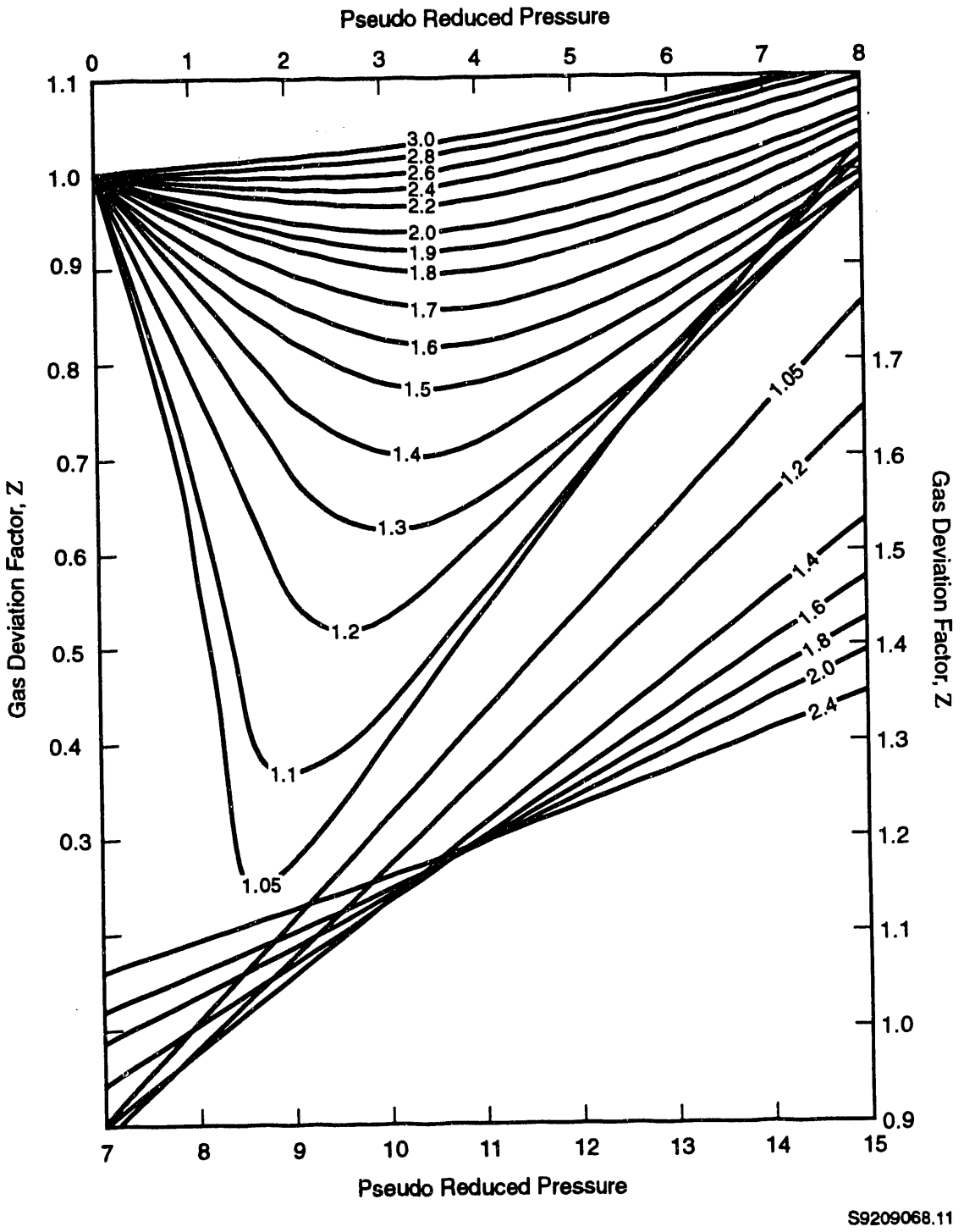

FIGURE A.3. Z-factor chart for natural gases (after Ikoku 1984)

Based on the calculated reservoir void volume (i.e., V_R), the volume of CO_2 (measured at 32°F and 14.73 psia) that can stored in the void volume can be calculated.

$$CO_2,\ ft^3 = 358.4n = 358.4P_RV_R\ /\ z_RRT_R$$

where: n = lb·mole of CO_2 at 32°F, 14.73 psia

P_R = reservoir pressure, psia

V_R = reservoir void volume, ft^3

Z_R = compressibility factor at T_R and P_R

T_R = reservoir temperature, Rankine

R = gas constant = 10.73 lb·mole-R/psia-ft^3

As described in the oil scenario discussion, the compressibility factors for CO_2 are as follows:

CO_2 Compressibility		
z-factor	Pressure (psia)	Temperature (R)
0.814	529.7	447.73
0.234	549.7	1313.73
0.365	569.7	2179.73
0.442	589.7	3045.73
0.543	609.7	3911.73

Table A.11 presents a summary of the theoretical CO_2 storage capacity by region and year summed over all depth intervals.

A.3 TOTAL CO_2 STORAGE CAPACITY RESULTING FROM ALL PETROLEUM PRODUCTION

The estimates for CO_2 storage capacity resulting from crude oil production (see Table A.6) and natural gas (see Table A.11) can be summed to estimate a total theoretical CO_2 storage capacity resulting from all petroleum production through the year 2030, including historical production. Table A.12 presents the final results by region and year.

TABLE A.11. Cumulative CO_2 Storage Capacity Resulting from Gas Production (10^6 ft^3 at 14.73 psia, 32°F)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Total	1.48E+09	1.52E+09	1.55E+09	1.73E+09	1.93E+09	2.13E+09	2.32E+09	2.50E+09	2.69E+09	2.87E+09	3.04E+09
Alabama Onshore	1.87E+06	2.03E+06	2.19E+06	3.04E+06	3.96E+06	4.90E+06	5.79E+06	6.67E+06	7.55E+06	8.40E+06	9.21E+06
Arkansas	1.11E+07	1.15E+07	1.19E+07	1.39E+07	1.60E+07	1.82E+07	2.03E+07	2.24E+07	2.44E+07	2.64E+07	2.83E+07
California											
Coastal Region Onshore	1.03E+07	1.03E+07	1.04E+07	1.07E+07	1.10E+07	1.12E+07	1.15E+07	1.18E+07	1.21E+07	1.23E+07	1.26E+07
Los Angeles Basin Onshore	8.40E+06	8.42E+06	8.45E+06	8.59E+06	8.75E+06	8.91E+06	9.06E+06	9.21E+06	9.36E+06	9.50E+06	9.63E+06
San Joaquin Basin	3.38E+07	3.43E+07	3.49E+07	3.77E+07	4.09E+07	4.41E+07	4.71E+07	5.01E+07	5.31E+07	5.60E+07	5.88E+07
Offshore	4.12E+06	4.24E+06	4.35E+06	4.94E+06	5.58E+06	6.24E+06	6.86E+06	7.48E+06	8.09E+06	8.69E+06	9.25E+06
Colorado	1.15E+07	1.19E+07	1.23E+07	1.42E+07	1.63E+07	1.84E+07	2.05E+07	2.25E+07	2.45E+07	2.64E+07	2.83E+07
Florida	8.00E+05	8.15E+05	8.30E+05	9.08E+05	9.94E+05	1.08E+06	1.16E+06	1.25E+06	1.33E+06	1.41E+06	1.48E+06
Illinois	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Indiana	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.60E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Kansas	7.61E+07	7.77E+07	7.93E+07	8.77E+07	9.69E+07	1.06E+08	1.15E+08	1.24E+08	1.33E+08	1.41E+08	1.49E+08
Kentucky	8.31E+06	8.44E+06	8.57E+06	9.27E+06	1.00E+07	1.08E+07	1.15E+07	1.23E+07	1.30E+07	1.37E+07	1.43E+07
Louisiana Onshore											
North	6.40E+07	6.49E+07	6.58E+07	7.06E+07	7.58E+07	8.11E+07	8.61E+07	9.11E+07	9.61E+07	1.01E+08	1.05E+08
South Onshore	1.48E+08	1.50E+08	1.52E+08	1.62E+08	1.72E+08	1.84E+08	1.94E+08	2.05E+08	2.15E+08	2.25E+08	2.35E+08
Michigan	7.44E+06	7.84E+06	8.25E+06	1.04E+07	1.27E+07	1.50E+07	1.73E+07	1.95E+07	2.17E+07	2.38E+07	2.58E+07
Mississippi	1.31E+07	1.35E+07	1.39E+07	1.59E+07	1.80E+07	2.02E+07	2.23E+07	2.44E+07	2.65E+07	2.84E+07	3.03E+07
Montana	2.95E+06	3.06E+06	3.17E+06	3.73E+06	4.35E+06	4.98E+06	5.58E+06	6.17E+06	6.76E+06	7.33E+06	7.87E+06
Nebraska	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
New Mexico											
East	4.17E+07	4.26E+07	4.35E+07	4.80E+07	5.30E+07	5.81E+07	6.29E+07	6.77E+07	7.25E+07	7.71E+07	8.14E+07
West	3.31E+07	3.38E+07	3.46E+07	3.86E+07	4.31E+07	4.75E+07	5.18E+07	5.60E+07	6.02E+07	6.43E+07	6.81E+07
New York	1.54E+06	1.60E+06	1.67E+06	2.00E+06	2.37E+06	2.74E+06	3.10E+06	3.45E+06	3.80E+06	4.14E+06	4.46E+06
North Dakota	2.56E+06	2.68E+06	2.81E+06	3.45E+06	4.16E+06	4.87E+06	5.55E+06	6.22E+06	6.89E+06	7.54E+06	8.16E+06
Ohio	1.45E+07	1.47E+07	1.50E+07	1.65E+07	1.81E+07	1.98E+07	2.13E+07	2.29E+07	2.44E+07	2.59E+07	2.73E+07
Oklahoma	1.27E+08	1.31E+08	1.35E+08	1.56E+08	1.79E+08	2.02E+08	2.24E+08	2.45E+08	2.67E+08	2.88E+08	3.08E+08
Pennsylvania	2.19E+07	2.22E+07	2.26E+07	2.44E+07	2.64E+07	2.84E+07	3.03E+07	3.22E+07	3.41E+07	3.59E+07	3.77E+07
Texas Onshore											
RRC D1	9.75E+06	1.01E+07	1.05E+07	1.26E+07	1.48E+07	1.70E+07	1.92E+07	2.13E+07	2.34E+07	2.55E+07	2.74E+07
RRC D2 Onshore	4.57E+07	4.64E+07	4.71E+07	5.08E+07	5.48E+07	5.88E+07	6.27E+07	6.65E+07	7.03E+07	7.40E+07	7.75E+07
RRC D3 Onshore	9.41E+07	9.51E+07	9.61E+07	1.01E+08	1.07E+08	1.13E+08	1.19E+08	1.24E+08	1.30E+08	1.35E+08	1.40E+08
RRC D4 Onshore	1.07E+08	1.10E+08	1.12E+08	1.25E+08	1.40E+08	1.54E+08	1.68E+08	1.82E+08	1.95E+08	2.09E+08	2.21E+08
RRC D5	1.32E+07	1.37E+07	1.42E+07	1.71E+07	2.01E+07	2.33E+07	2.62E+07	2.92E+07	3.21E+07	3.49E+07	3.76E+07
RRC D6	5.31E+07	5.42E+07	5.53E+07	6.11E+07	6.74E+07	7.38E+07	7.98E+07	8.58E+07	9.18E+07	9.76E+07	1.03E+08
RRC D7B	8.59E+06	8.85E+06	9.11E+06	1.05E+07	1.19E+07	1.34E+07	1.49E+07	1.63E+07	1.77E+07	1.90E+07	2.03E+07
RRC D7C	1.80E+07	1.85E+07	1.91E+07	2.21E+07	2.53E+07	2.87E+07	3.18E+07	3.49E+07	3.80E+07	4.10E+07	4.39E+07
RRC D8	8.27E+07	8.44E+07	8.61E+07	9.49E+07	1.05E+08	1.14E+08	1.24E+08	1.33E+08	1.42E+08	1.51E+08	1.60E+08
RRC D8A	1.10E+07	1.12E+07	1.14E+07	1.24E+07	1.35E+07	1.46E+07	1.56E+07	1.67E+07	1.77E+07	1.87E+07	1.97E+07
RRC D9	9.51E+06	9.76E+06	1.00E+07	1.13E+07	1.27E+07	1.41E+07	1.55E+07	1.68E+07	1.82E+07	1.95E+07	2.07E+07
RRC D10	1.29E+08	1.30E+08	1.32E+08	1.40E+08	1.49E+08	1.58E+08	1.67E+08	1.75E+08	1.84E+08	1.92E+08	2.00E+08

TABLE A.11. (contd)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Utah	5.01E+06	5.12E+06	5.22E+06	5.77E+06	6.36E+06	6.96E+06	7.53E+06	8.10E+06	8.67E+06	9.21E+06	9.73E+06
West Virginia	3.53E+07	3.56E+07	3.60E+07	3.81E+07	4.03E+07	4.26E+07	4.47E+07	4.68E+07	4.90E+07	5.10E+07	5.30E+07
Wyoming	3.14E+07	3.26E+07	3.39E+07	4.05E+07	4.77E+07	5.51E+07	6.20E+07	6.89E+07	7.58E+07	8.25E+07	8.88E+07
Misc.	4.83E+06	4.90E+06	4.97E+06	5.33E+06	5.72E+06	6.12E+06	6.50E+06	6.87E+06	7.25E+06	7.61E+06	7.95E+06
Gulf of Mexico											
Louisiana Offshore	1.54E+08	1.60E+08	1.66E+08	1.95E+08	2.27E+08	2.60E+08	2.91E+08	3.21E+08	3.52E+08	3.82E+08	4.10E+08
Texas Offshore	2.72E+07	2.97E+07	3.23E+07	4.56E+07	6.02E+07	7.50E+07	8.90E+07	1.03E+08	1.17E+08	1.30E+08	1.43E+08

In addition, some analysts may be interested in the total void volume present in the reservoir that accommodates the stored CO_2. As described earlier in this appendix, the void volume is an interim result in the calculational process. Table A.13 presents the void volume resulting from crude oil production, and Table A.14 presents similar information for natural gas production.

TABLE A.12. Cumulative CO_2 Storage Capacity Resulting from Petroleum Production (10^6 ft^3 at 14.73 psia, 32°F)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Total	1.75E+09	1.79E+09	1.83E+09	2.03E+09	2.24E+09	2.46E+09	2.66E+09	2.87E+09	3.07E+09	3.26E+09	3.44E+09
Alabama Onshore	2.83E+06	3.04E+06	3.24E+06	4.29E+06	5.42E+06	6.55E+06	7.63E+06	8.69E+06	9.73E+06	1.07E+07	1.16E+07
Arkansas	1.41E+07	1.45E+07	1.49E+07	1.70E+07	1.92E+07	2.15E+07	2.37E+07	2.59E+07	2.80E+07	3.01E+07	3.20E+07
California											
Coastal Region Onshore	1.57E+07	1.58E+07	1.58E+07	1.63E+07	1.68E+07	1.73E+07	1.77E+07	1.82E+07	1.86E+07	1.90E+07	1.94E+07
Los Angeles Basin Onshore	1.67E+07	1.68E+07	1.68E+07	1.72E+07	1.76E+07	1.80E+07	1.83E+07	1.87E+07	1.90E+07	1.93E+07	1.95E+07
San Joaquin Basin	4.91E+07	5.00E+07	5.09E+07	5.56E+07	6.05E+07	6.54E+07	7.00E+07	7.45E+07	7.89E+07	8.29E+07	8.65E+07
Offshore	8.73E+06	8.92E+06	9.12E+06	1.01E+07	1.11E+07	1.22E+07	1.31E+07	1.41E+07	1.50E+07	1.58E+07	1.66E+07
Colorado	1.48E+07	1.53E+07	1.57E+07	1.79E+07	2.03E+07	2.28E+07	2.51E+07	2.73E+07	2.96E+07	3.17E+07	3.37E+07
Florida	1.96E+06	1.99E+06	2.03E+06	2.19E+06	2.37E+06	2.54E+06	2.70E+06	2.86E+06	3.01E+06	3.14E+06	3.26E+06
Illinois	4.09E+06	4.11E+06	4.13E+06	4.24E+06	4.34E+06	4.44E+06	4.54E+06	4.63E+06	4.71E+06	4.78E+06	4.83E+06
Indiana	4.88E+05	4.92E+05	4.95E+05	5.14E+05	5.32E+05	5.49E+05	5.66E+05	5.82E+05	5.95E+05	6.07E+05	6.16E+05
Kansas	8.50E+07	8.67E+07	8.84E+07	9.72E+07	1.07E+08	1.17E+08	1.26E+08	1.35E+08	1.44E+08	1.53E+08	1.61E+08
Kentucky	9.03E+06	9.17E+06	9.31E+06	1.00E+07	1.08E+07	1.16E+07	1.24E+07	1.31E+07	1.38E+07	1.46E+07	1.52E+07
Louisiana Onshore											
North	6.98E+07	7.08E+07	7.17E+07	7.67E+07	8.21E+07	8.77E+07	9.29E+07	9.80E+07	1.03E+08	1.08E+08	1.13E+08
South Onshore	1.73E+08	1.75E+08	1.77E+08	1.88E+08	2.00E+08	2.12E+08	2.24E+08	2.35E+08	2.46E+08	2.57E+08	2.67E+08
Michigan	9.56E+06	1.00E+07	1.04E+07	1.28E+07	1.53E+07	1.78E+07	2.02E+07	2.26E+07	2.50E+07	2.72E+07	2.93E+07
Mississippi	1.82E+07	1.86E+07	1.91E+07	2.13E+07	2.37E+07	2.62E+07	2.85E+07	3.08E+07	3.31E+07	3.53E+07	3.73E+07
Montana	5.62E+06	5.77E+06	5.92E+06	6.70E+06	7.52E+06	8.35E+06	9.13E+06	9.90E+06	1.06E+07	1.13E+07	1.20E+07
Nebraska	5.61E+05	5.68E+05	5.75E+05	6.10E+05	6.44E+05	6.77E+05	7.09E+05	7.38E+05	7.64E+05	7.86E+05	8.03E+05
New Mexico											
East	5.08E+07	5.18E+07	5.28E+07	5.79E+07	6.35E+07	6.92E+07	7.45E+07	7.98E+07	8.50E+07	9.00E+07	9.47E+07
West	3.37E+07	3.45E+07	3.52E+07	3.93E+07	4.38E+07	4.84E+07	5.26E+07	5.69E+07	6.12E+07	6.53E+07	6.92E+07
New York	1.54E+06	1.60E+06	1.67E+06	2.00E+06	2.37E+06	2.74E+06	3.10E+06	3.45E+06	3.80E+06	4.14E+06	4.46E+06
North Dakota	4.69E+06	4.89E+06	5.09E+06	6.11E+06	7.18E+06	8.26E+06	9.27E+06	1.03E+07	1.12E+07	1.21E+07	1.29E+07
Ohio	1.54E+07	1.57E+07	1.60E+07	1.76E+07	1.92E+07	2.09E+07	2.25E+07	2.41E+07	2.57E+07	2.72E+07	2.86E+07
Oklahoma	1.43E+08	1.47E+08	1.51E+08	1.73E+08	1.96E+08	2.20E+08	2.42E+08	2.65E+08	2.87E+08	3.08E+08	3.29E+08
Pennsylvania	2.33E+07	2.36E+07	2.40E+07	2.58E+07	2.78E+07	2.98E+07	3.17E+07	3.36E+07	3.55E+07	3.74E+07	3.91E+07
Texas Onshore											
RRC D1	1.15E+07	1.19E+07	1.23E+07	1.45E+07	1.69E+07	1.93E+07	2.15E+07	2.38E+07	2.60E+07	2.81E+07	3.02E+07
RRC D2 Onshore	5.12E+07	5.19E+07	5.27E+07	5.65E+07	6.09E+07	6.51E+07	6.91E+07	7.31E+07	7.71E+07	8.10E+07	8.46E+07
RRC D3 Onshore	1.12E+08	1.13E+08	1.14E+08	1.20E+08	1.27E+08	1.33E+08	1.39E+08	1.46E+08	1.52E+08	1.58E+08	1.63E+08
RRC D4 Onshore	1.14E+08	1.17E+08	1.19E+08	1.32E+08	1.47E+08	1.62E+08	1.76E+08	1.89E+08	2.03E+08	2.17E+08	2.29E+08
RRC D5	1.51E+07	1.57E+07	1.63E+07	1.91E+07	2.23E+07	2.55E+07	2.85E+07	3.15E+07	3.45E+07	3.73E+07	4.01E+07
RRC D6	6.84E+07	6.96E+07	7.09E+07	7.73E+07	8.42E+07	9.13E+07	9.80E+07	1.05E+08	1.11E+08	1.17E+08	1.23E+08
RRC D7B	1.19E+07	1.22E+07	1.25E+07	1.41E+07	1.58E+07	1.75E+07	1.91E+07	2.07E+07	2.22E+07	2.37E+07	2.51E+07
RRC D7C	2.15E+07	2.21E+07	2.27E+07	2.60E+07	2.95E+07	3.30E+07	3.64E+07	3.97E+07	4.30E+07	4.62E+07	4.92E+07
RRC D8	1.06E+08	1.09E+08	1.11E+08	1.21E+08	1.33E+08	1.44E+08	1.55E+08	1.66E+08	1.76E+08	1.86E+08	1.96E+08
RRC D8A	2.91E+07	2.96E+07	3.02E+07	3.29E+07	3.57E+07	3.85E+07	4.11E+07	4.37E+07	4.60E+07	4.81E+07	4.99E+07
RRC D9	1.41E+07	1.44E+07	1.47E+07	1.62E+07	1.78E+07	1.94E+07	2.09E+07	2.24E+07	2.39E+07	2.54E+07	2.67E+07
RRC D10	1.32E+08	1.34E+08	1.36E+08	1.44E+08	1.53E+08	1.62E+08	1.71E+08	1.80E+08	1.89E+08	1.97E+08	2.05E+08

TABLE A.12. (contd)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Utah	7.16E+06	7.33E+06	7.50E+06	8.35E+06	9.25E+06	1.02E+07	1.10E+07	1.18E+07	1.26E+07	1.34E+07	1.40E+07
West Virginia	3.58E+07	3.62E+07	3.66E+07	3.87E+07	4.09E+07	4.32E+07	4.53E+07	4.75E+07	4.96E+07	5.17E+07	5.36E+07
Wyoming	4.24E+07	4.39E+07	4.53E+07	5.29E+07	6.10E+07	6.92E+07	7.70E+07	8.47E+07	9.23E+07	9.95E+07	1.06E+08
Misc.	5.17E+06	5.25E+06	5.32E+06	5.71E+06	6.13E+06	6.55E+06	6.95E+06	7.35E+06	7.75E+06	8.13E+06	8.48E+06
Gulf of Mexico											
Louisiana Offshore	1.75E+08	1.81E+08	1.87E+08	2.19E+08	2.54E+08	2.89E+08	3.23E+08	3.56E+08	3.89E+08	4.20E+08	4.49E+08
Texas Offshore	2.78E+07	3.04E+07	3.30E+07	4.66E+07	6.14E+07	7.65E+07	9.07E+07	1.05E+08	1.19E+08	1.33E+08	1.45E+08

TABLE A.13. Cumulative Reservoir Void Volume Resulting from Crude Oil Production (ft^3)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Total	6.26E+06	6.40E+06	6.55E+06	7.30E+06	8.13E+06	8.97E+06	9.77E+06	1.06E+07	1.14E+07	1.21E+07	1.28E+07
Alabama Onshore	4777	5190	5605	7763	10124	12527	14792	17052	19306	21482	23545
Arkansas	60648	62713	64791	75597	87417	99447	110790	122103	133387	144282	154610
California											
Coastal Region Onshore	70897	71245	71595	73416	75407	77434	79345	81251	83151	84987	86727
Los Angeles Basin Onshore	57800	57988	58176	59156	60229	61320	62349	63375	64398	65387	66324
San Joaquin Basin	232391	236179	239989	259803	281478	303537	324336	345081	365771	385750	404688
Offshore	28378	29154	29935	33995	38438	42959	47221	51473	55713	59808	63689
Colorado	31692	32704	33721	39011	44799	50689	56242	61781	67305	72640	77697
Florida	2027	2065	2103	2301	2519	2740	2948	3156	3364	3564	3754
Illinois	0	0	0	0	0	0	0	0	0	0	0
Indiana	0	0	0	0	0	0	0	0	0	0	0
Kansas	315586	322237	328926	363719	401780	440513	477036	513463	549794	584875	618130
Kentucky	79638	80911	82190	88846	96127	103537	110524	117493	124443	131154	137516
Louisiana Onshore											
North	243802	247272	250763	268919	288781	308994	328053	347061	366020	384327	401681
South Onshore	394045	399132	404249	430863	459977	489605	517542	545406	573196	600031	625469
Michigan	23995	25300	26612	33436	40900	48497	55660	62805	69930	76811	83333
Mississippi	34948	35952	36963	42218	47967	53817	59333	64835	70323	75622	80645
Montana	8762	9083	9405	11083	12918	14786	16547	18303	20055	21746	23350
Nebraska	0	0	0	0	0	0	0	0	0	0	0
New Mexico											
East	135893	138740	141603	156495	172786	189365	204997	220589	236139	251155	265389
West	107747	110259	112785	125923	140295	154921	168712	182467	196196	209432	221990
New York	14747	15363	15982	19203	22726	26311	29692	33064	36427	39674	42752
North Dakota	6602	7129	7458	9169	11040	12945	14741	16532	18318	20043	21678
Ohio	138627	141336	144060	158231	173733	189508	204384	219220	234017	248305	261849
Oklahoma	1142548	1178157	1213972	1400252	1604028	[illegible]	2006948	2201976	2396489	2584313	2762360
Pennsylvania	209908	213232	216576	233967	252992	272353	290609	308817	326977	344513	361135
Texas Onshore											
RRC D1	49697	51675	53663	64006	75321	86836	97693	108522	119323	129752	139638
RRC D2 Onshore	129287	131267	133259	143620	154954	166488	177364	188211	199030	209477	219380
RRC D3 Onshore	258346	261142	263955	278583	294585	310870	326225	341541	356815	371565	385546
RRC D4 Onshore	369152	377734	386366	431263	480377	530359	577488	624493	671375	716644	759556
RRC D5	40887	42555	44232	52956	62500	72213	81371	90505	99615	108412	116751
RRC D6	155916	159138	162378	179232	197670	216433	234125	251771	269370	286364	302473
RRC D7B	46465	47861	49265	56566	64553	72682	80346	87991	95615	102977	109956
RRC D7C	62263	64234	66216	76525	87803	99280	110102	120896	131661	142056	151909
RRC D8	313808	320216	326660	360178	396844	434159	469344	504436	539435	573231	605268
RRC D8A	30803	31338	31876	34675	37737	40853	43790	46721	49643	52465	55140
RRC D9	69274	71064	72864	82226	92468	102891	112719	122521	132297	141737	150686
RRC D10	366263	370735	375234	398629	424222	450267	474825	499319	523749	547338	569699

TABLE A.13. (contd)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Utah	14007	14297	14588	16104	17761	19448	21039	22626	24208	25736	27185
West Virginia	337966	341701	345458	364996	386370	408121	428631	449087	469489	489189	507864
Wyoming	129755	134971	140218	167508	197361	227741	256388	284959	313455	340970	367054
Misc.	46351	47008	47668	51103	54861	58686	62292	65889	69476	72940	76223
Gulf of Mexico											
Louisiana Offshore	411971	426932	441980	520247	605866	692997	775156	857099	938825	1017741	1092549
Texas Offshore	78134	85457	92822	131128	173033	215678	255889	295994	335994	374618	411231

TABLE A.14. Cumulative Reservoir Void Volume Resulting from Gas Production (ft^3)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Lower 48 Total	8.32E+05	8.44E+05	8.56E+05	9.11E+05	9.66E+05	1.02E+06	1.07E+06	1.12E+06	1.16E+06	1.20E+06	1.22E+06
Alabama Onshore	2448	2560	2667	3190	3706	4211	4689	5137	5531	5858	6116
Arkansas	9720	9789	9855	10179	10498	10811	11107	11384	11628	11830	11990
California											
Coastal Region Onshore	19948	20108	20260	21009	21747	22468	23152	23792	24356	24823	25192
Los Angeles Basin Onshore	30891	31073	31245	32094	32930	33748	34522	35248	35888	36416	36834
San Joaquin Basin	57010	58423	59760	66349	72842	79192	85208	90842	95807	99913	103160
Offshore	17137	17448	17741	19189	20616	22011	23332	24570	25661	26563	27276
Colorado	8723	8894	9057	9855	10642	11412	12141	12824	13426	13924	14317
Florida	2937	2985	3030	3255	3476	3692	3897	4089	4258	4398	4508
Illinois	22275	22398	22514	23088	23653	24205	24729	25219	25651	26009	26291
Indiana	2656	2677	2698	2797	2896	2992	3083	3168	3243	3305	3354
Kansas	29076	29371	29650	31024	32378	33702	34957	36132	37167	38024	38701
Kentucky	3959	3985	4011	4135	4258	4378	4492	4599	4693	4770	4832
Louisiana Onshore											
North	17715	17860	17996	18669	19333	19982	20596	21172	21679	22099	22431
South Onshore	64078	64693	65275	68143	70968	73732	76350	78801	80962	82749	84162
Michigan	6148	6271	6387	6960	7524	8077	8600	9089	9521	9878	10161
Mississippi	13212	13367	13514	14237	14950	15646	16307	16925	17470	17920	18277
Montana	7367	7490	7606	8180	8745	9297	9821	10311	10744	11101	11384
Nebraska	2431	2463	2494	2643	2791	2935	3072	3199	3312	3405	3479
New Mexico											
East	25335	25693	26032	27703	29349	30959	32484	33912	35171	36212	37036
West	1685	1722	1757	1932	2104	2272	2431	2581	2712	2821	2907
New York	0	0	0	0	0	0	0	0	0	0	0
North Dakota	5564	5773	5970	6943	7901	8838	9726	10557	11290	11896	12375
Ohio	5390	5444	5494	5744	5990	6230	6457	6671	6859	7014	7137
Oklahoma	66673	67400	68088	71479	74820	78088	81184	84084	86639	88752	90423
Pennsylvania	7423	7434	7444	7494	7543	7591	7636	7679	7717	7748	7772
Texas Onshore											
RRC D1	5941	6048	6149	6647	7139	7619	8075	8501	8877	9188	9433
RRC D2 Onshore	15361	15495	15622	16246	16860	17462	18031	18565	19035	19424	19731
RRC D3 Onshore	46694	47111	47506	49451	51367	53242	55017	56680	58146	59358	60316
RRC D4 Onshore	18891	19014	19130	19705	20270	20823	21348	21838	22271	22629	22912
RRC D5	5812	5854	5895	6094	6291	6483	6665	6836	6986	7110	7209
RRC D6	43398	43815	44210	46155	48071	49946	51721	53384	54850	56062	57020
RRC D7B	11297	11447	11589	12287	12975	13648	14285	14882	15408	15843	16187
RRC D7C	9854	10009	10156	10879	11592	12289	12949	13567	14112	14563	14919
RRC D8	69502	70593	71625	76712	81724	86626	91270	95619	99452	102622	105128
RRC D8A	49272	50288	51249	55986	60655	65220	69545	73596	77166	80118	82453
RRC D9	17907	18079	18241	19039	19826	20596	21325	22008	22610	23108	23501
RRC D10	10887	10973	11054	11453	11846	12231	12595	12936	13236	13485	13682

TABLE A.14. (contd)

	1988	1989	1990	1995	2000	2005	2010	2015	2020	2025	2030
Utah	5705	5881	6048	6871	7682	8475	9226	9930	10550	11062	11468
West Virginia	3105	3121	3136	3211	3285	3357	3425	3489	3546	3592	3629
Wyoming	33303	33902	34468	37261	40013	42704	45253	47641	49746	51486	52862
Misc.	1847	1879	1910	2059	2207	2351	2488	2615	2728	2821	2895
Gulf of Mexico											
Louisiana Offshore	52040	53591	55058	62288	69414	76382	82984	89167	94616	99122	102685
Texas Offshore	1752	1907	2054	2777	3489	4186	4846	5465	6009	6460	6816

APPENDIX B

PIPELINE DESIGN DETAILS

APPENDIX B

PIPELINE DESIGN DETAILS

Heat transfer and pressure drop equations used for designing the CO_2 transmission pipelines are presented in this appendix. Equations for overland transmission are presented first. Modifications required for ocean transmission follow.

The Darcy-Weisbach formula (Equation B.1) was used for calculating the head loss due to friction. The pressure loss is simply the head loss multiplied by the fluid density. While this equation is normally used for calculating head loss for incompressible flow, reasonable accuracy can be obtained by averaging the fluid properties at the inlet and outlet of the pipe if the overall pressure (density) change is less than 40% (Crane 1986). If the overall pressure (density) change is greater than 40%, the Darcy-Weisbach formula can still be used if applied consecutively to sufficiently small segments of the pipe.

$$h_1 = fLv^2/2Dg \tag{B.1}$$

where h_1 = head loss

f = friction factor

L = pipe length

v = fluid velocity

D = pipe diameter

g = acceleration of gravity

The CO_2 exit temperature per segment of pipe was determined by equating the change in enthalpy of the CO_2 with the heat transfer through the pipe wall as defined by Equations B.2 and B.3.

$$Q = m*C_p*(T_{C2}-T_{C1}) \tag{B.2}$$

where Q =heat transfer per pipe segment

m =CO_2 mass flow rate

C_p =average CO_2 heat capacity

T_{C2} =CO_2 exit temperature

T_{C1} =CO_2 inlet temperature

$$Q = U*A*[(T_{C1}-T_{S1})-(T_{C2}-T_{S2})]/\{\ln[(T_{C1}-T_{S1})/(T_{C2}-T_{S2})]\} \quad (B.3)$$

where U = overall heat transfer coefficient

A = reference heat transfer area

T_{S1} = soil temperature at pipe segment inlet

T_{S2} = soil temperature at pipe segment exit

The overall heat transfer rate for a pipe segment is equal to the reciprocal of the sum of the individual heat transfer resistances, as indicated in Equation B.4. Equations B.5, B.6, and B.7 define the internal convective resistance, the conductive resistance through the pipe wall, and the external conductive resistance.

$$U*A = 1/(R_1+R_2+R_3) \quad (B.4)$$

where R_1 = internal heat transfer resistance

R_2 = pipe wall heat transfer resistance

R_3 = external heat transfer resistance

$$R_1 = 1/(h_i*A_i) \quad (B.5)$$

where h_i = inside heat transfer coefficient

A_i = inside surface area

$$R_2 = \ln(r_o/r_i)/(2*pi*k_p*L) \quad (B.6)$$

where r_o = outside pipe radius

r_i = inside pipe radius

k_p = pipe wall thermal conductivity

L = pipe segment length

$$R_3 = \cosh^{-1}(D/r_o)/(2*pi*k_s*L) \tag{B.7}$$

where D = pipe depth from ground surface to pipe centerline

k_s = soil thermal conductivity

The internal heat transfer coefficient was estimated using the Dittus-Boelter equation (Welty, Wicks and Wilson 1976) for forced convection for internal flow under turbulent conditions (Equation B.8).

$$Nu_{di} = h_i D_i / k_C = 0.023*Re_{di}^{0.8} Pr_C^{0.3} \tag{B.8}$$

where Nu_{di} = Nusselt number based on inside pipe diameter

D_i = inside pipe diameter

k_C = thermal conductivity of CO_2

Re_{di} = Reynolds number based on inside pipe diameter

Pr_C = Prandtl number of CO_2

Note that exponent on the Prandtl number equals 0.3 if fluid in pipe is being cooled; 0.4 if being warmed.

The calculational procedure requires the following nested iterative solution to solve simultaneously for the exit CO_2 pressure and temperature for a pipe segment, given entrance conditions:

1. Assume exit temperature.
2. Assume exit pressure.
3. Look up entrance and exit fluid properties.
4. Calculate average fluid properties.

5. Calculate frictional head loss and elevation head gain.

6. Compare calculated exit pressure to assumed exit pressure.

7. Repeat steps 2-6 until calculated pressure equals assumed pressure.

8. Calculate overall heat transfer coefficient (U).

9. Calculate overall heat transfer rate.

10. Calculate exit temperature.

11. Compare calculated exit temperature to assumed exit temperature.

12. Repeat steps 1-11 until calculated temperature equals assumed temperature.

An analysis of heat transfer between CO_2 and the ocean water was conducted by modifying the external resistance equation (Equation B.7) to reflect a convective heat transfer mode. Equation B.9 describes the external convective resistance. The external heat transfer coefficient was estimated using the McAdams equation (Welty, Wicks and Wilson 1976) for forced convection for external cross flow (Equation B.10). Forced (rather than natural) external convection was presumed, due to ocean currents.

$$R_3 = 1/(h_o * A_o) \tag{B.9}$$

Where h_o = outside heat transfer coefficient

A_o = outside surface area

$$Nu_{do} = h_o D_o / k_w = 0.02629 * Re_{di}^{0.805} * Pr_w^{0.333} \tag{B.10}$$

Where Nu_{do} = Nusselt number based on outside pipe diameter

D_o = outside pipe diameter

k_w = thermal conductivity of sea water

Re_{di} = Reynolds number based on inside pipe diameter

Pr_w = Prandtl number of sea water

The 12-step iterative procedure described above for overland pipes was repeated for ocean pipes.

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