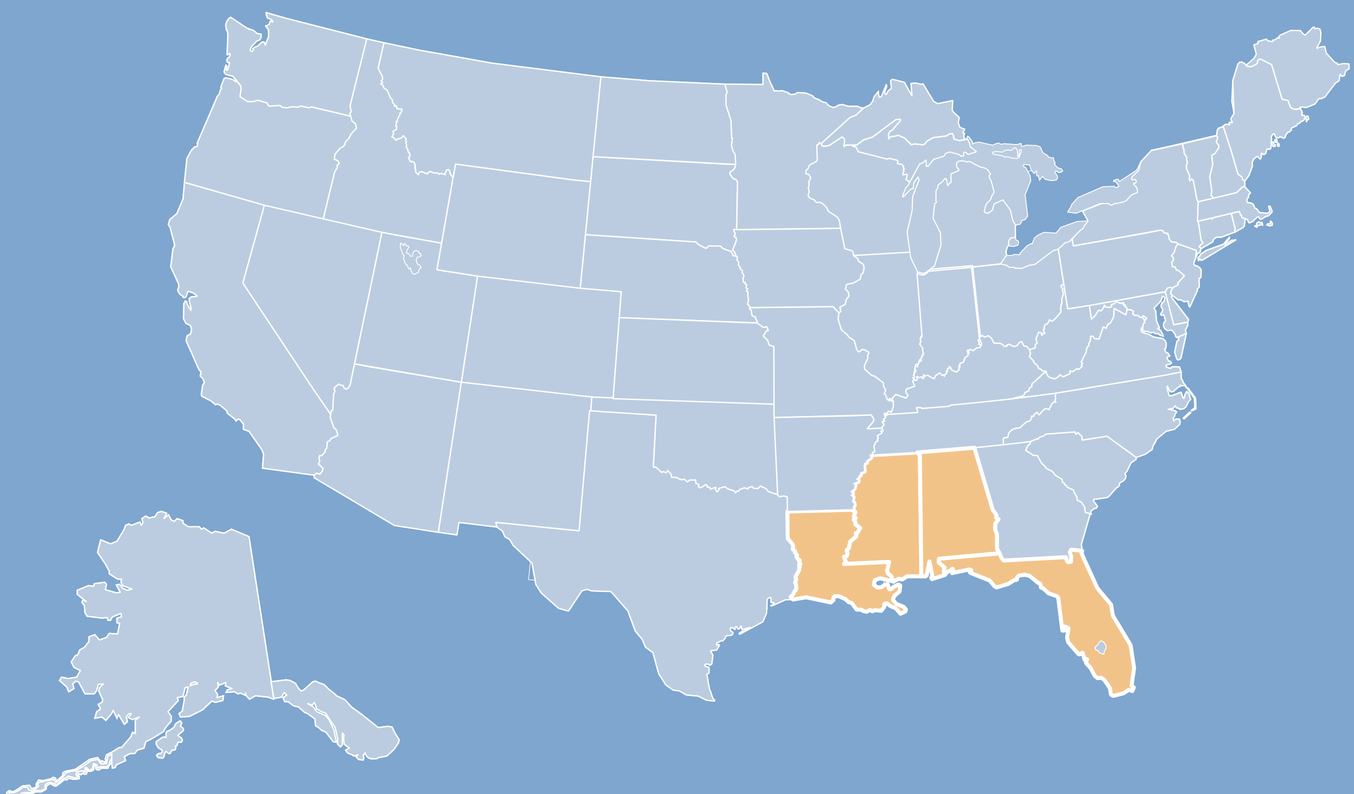
Basin Oriented Strategies for CO_2 Enhanced Oil Recovery:

ONSHORE GULF COAST



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Prepared by

Advanced Resources International

February 2006

BASIN ORIENTED STRATEGIES FOR
CO_2 ENHANCED OIL RECOVERY:
ONSHORE GULF COAST REGION OF ALABAMA, FLORIDA, LOUISIANA AND MISSISSIPPI

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TABLE OF CONTENTS

1. SUMMARY OF FINDINGS
- 1.1 INTRODUCTION
- 1.2 ALTERNATIVE OIL RECOVERY STRATEGIES AND SCENARIOS
- 1.3 OVERVIEW OF FINDINGS
- 1.4. ACKNOWLEDGEMENTS

2. INTRODUCTION
- 2.1 CURRENT SITUATION
- 2.2 BACKGROUND
- 2.3 PURPOSE
- 2.4 KEY ASSUMPTIONS
- 2.5 TECHNICAL OBJECTIVES
- 2.6 OTHER ISSUES

3. OVERVIEW OF GULF COAST OIL PRODUCTION
- 3.1 HISTORY OF OIL PRODUCTION
- 3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY
- 3.3 THE “STRANDED OIL” PRIZE
- 3.4 REVIEW OF PRIOR STUDIES

4. MECHANISMS OF CO_2-EOR
- 4.1 MECHANISMS OF MISCIBLE CO_2-EOR.
- 4.2 MECHANISMS OF IMMISCIBLE CO_2-EOR
- 4.3 INTERACTIONS BETWEEN INJECTED CO_2 AND RESERVOIR OIL.

5. STUDY METHODOLOGY
- 5.1 OVERVIEW
- 5.2 ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE
- 5.3 SCREENING RESERVOIRS FOR CO_2-EOR.
- 5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE
- 5.5 CALCULATING OIL RECOVERY
- 5.6 ASSEMBLING THE COST MODEL
- 5.7 CONSTRUCTING AN ECONOMICS MODEL
- 5.8 PERFORMING SCENARIO ANALYSES

6. RESULTS BY STATE
- 6.1 LOUISIANA
- 6.2 MISSISSIPPI
- 6.3 ALABAMA
- 6.4 FLORIDA

LIST OF FIGURES

Figure 1 Impact of Technology and Financial Conditions on Economically Recoverable Oil from the Gulf Coast Region's Major Reservoirs Using CO_2-EOR (Million Barrels)
Figure 2 Location of Major Gulf Coast Oil Fields
Figure 3 Location of Existing and Planned CO_2 Supply Pipelines in Mississippi and Louisiana
Figure 4 Gulf Coast Production since 1950
Figure 5 One-Dimensional Schematic Showing the CO_2 Miscible Process
Figure 6A Carbon Dioxide, CH_4 and N_2 densities at 105ºF
Figure 6B Carbon Dioxide, CH_4 and N_2 viscosities at 105ºF
Figure 7A Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid
Figure 7B Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey
Figure 8 Viscosity Reduction Versus Saturation Pressure
Figure 9 Estimating CO_2 Minimum Miscibility Pressure
Figure 10 Correlation of MW C5+ to Tank Oil Gravity
Figure 11 Large Louisiana Oil Fields
Figure 12 Large Mississippi Oil Fields
Figure 13 Large Alabama Oil Fields
Figure 14 Large Florida Oil Fields

LIST OF TABLES

Table 1 Size and Distribution of the Gulf Coast Region's Oil Reservoirs Data Base
Table 2 The Gulf Coast Region's "Stranded Oil" Amenable to CO_2-EOR
Table 3 Technically Recoverable Oil Resources from Miscible and Immiscible CO_2-EOR
Table 4 Economically Recoverable Resources - Scenario #1: "Traditional Practices" CO_2-EOR
Table 5 Economically Recoverable Resources - Alternative Scenarios
Table 6 Potential CO_2 Supply Requirements in the Gulf Coast Region: Scenario #4 ("Ample Supplies of CO_2")
Table 7 Matching of CO_2-EOR Technology with the Gulf Coast's Oil Reservoirs
Table 8 Crude Oil Annual Production, Ten Largest Gulf Coast Oil Fields, 2000-2002 (Million Barrels per Year)
Table 9 Selected Major Oil Fields of the Gulf Coast Region
Table 10 Reservoir Data Format: Major Oil Reservoirs Data Base
Table 11 Gulf Coast Oil Reservoirs Screened Amenable for CO_2-EOR
Table 12 Economic Model Established by the Study
Table 13 Recent History of Louisiana Onshore Oil Production
Table 14 Status of Large Louisiana Oil Fields/Reservoirs (as of 2002)
Table 15 Reservoir Properties and Improved Oil Recovery Activity, Large Louisiana Oil Fields/Reservoirs
Table 16 Economic Oil Recovery Potential Under Two Technologic Conditions, Louisiana.

Table 17 Economic Oil Recovery Potential with More Favorable Financial Conditions, Louisiana
Table 18 Recent History of Mississippi Onshore Oil Production
Table 19 Status of Large Mississippi Oil Fields/Reservoirs as of 2002
Table 20 Reservoir Properties and Improved Oil Recovery Activity, Large Mississippi Oil Fields/Reservoirs
Table 21 Reservoir Properties and Improved Oil Recovery Activity Potential, Mississippi "Immiscible-CO_2" Oil Fields/Reservoirs
Table 22 Economic Oil Recovery Potential Under Two Technologic Conditions, Mississippi
Table 23 Economic Oil Recovery Potential with More Favorable Financial Conditions, Mississippi
Table 24 Recent History of Alabama Onshore Oil Production
Table 25 Status of Large Alabama Oil Fields/Reservoirs (as of 2004)
Table 26 Reservoir Properties and Improved Oil Recovery Activity, Large Alabama Oil Fields/Reservoirs
Table 27 Economic Oil Recovery Potential Under Two Technologic Conditions, Alabama
Table 28 Economic Oil Recovery Potential with More Favorable Financial Conditions, Alabama
Table 29 Recent History of Florida Onshore Oil Production
Table 30 Status of Large Florida Oil Fields/Reservoirs, 2004
Table 31 Reservoir Properties and Improved Oil Recovery Activity, Large Florida Oil Fields/Reservoirs
Table 32 Economic Oil Recovery Potential Under Two Technologic Conditions, Florida
Table 33 Economic Oil Recovery Potential with More Favorable Financial Conditions, Florida

1. SUMMARY OF FINDINGS

1.1 INTRODUCTION. The onshore Gulf Coast oil and gas producing region of Louisiana, Mississippi, Alabama and Florida have an original oil endowment of over 44 billion barrels. Of this, nearly 17 billion barrels or 38% will be recovered with primary and secondary (waterflooding) oil recovery. As such, nearly 28 billion barrels of oil will be left in the ground, or "stranded", following the use of traditional oil recovery practices. A major portion of this "stranded oil" is in reservoirs technically and economically amenable to enhanced oil recovery (EOR) using carbon dioxide (CO_2) injection.

This report evaluates the future CO_2-EOR oil recovery potential from the large oil fields of the onshore Gulf Coast region, highlighting the barriers that stand in the way of achieving this potential. The report then discusses how a concerted set of "basin oriented strategies" could help the Gulf Coast's oil production industry overcome these barriers helping increase domestic oil production.

1.2 ALTERNATIVE OIL RECOVERY STRATEGIES AND SCENARIOS. The report sets forth four scenarios for using CO_2-EOR to recover "stranded oil" in the onshore Gulf Coast producing region.

- The first scenario captures how CO_2-EOR technology has been applied and has performed in the past. This low technology, high-risk scenario is called "Traditional Practices".
- The second scenario, entitled "State-of-the-art", assumes that the technology progress in CO_2-EOR, achieved in recent years and in other areas, is successfully applied in the Gulf Coast region. In addition, this scenario assumes that a comprehensive program of research, pilot tests and field demonstrations help lower the risks inherent in applying new technology to these complex Gulf Coast oil reservoirs.

- The third scenario, entitled “Risk Mitigation,” examines how the economic potential of CO_2-EOR could be increased through a comprehensive strategy involving state production tax reductions, federal investment tax credits, royalty relief and/or higher world oil prices that together would add an equivalent $10 per barrel to the price that the producer uses for making capital investment decisions for CO_2-EOR.
- The final scenario, entitled “Ample Supplies of CO_2,” assumes that large volumes of low-cost, “EOR-ready” CO_2 supplies are aggregated from various industrial and natural sources. These low-cost to capture industrial CO_2 sources include high-concentration CO_2 emissions from hydrogen facilities, gas processing plants, chemical plants and other sources in the region. These CO_2 sources would be augmented, in the longer-term, from low concentration CO_2 emissions from refineries and electric power plants. Capture of industrial CO_2 emissions could also be part of a national effort for reducing greenhouse gas emissions.

1.3 OVERVIEW OF FINDINGS. Twelve major findings emerge from the study of “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Onshore Gulf Coast Basins of Alabama, Florida, Louisiana and Mississippi.”

1. Today’s oil recovery practices will leave behind a large resource of “stranded oil” in the onshore Gulf Coast region. The original oil resource in onshore Gulf Coast reservoirs is 44.4 billion barrels. To date, 16.9 billion barrels of this original oil in-place (OOIP) has been recovered or proved. Thus, without further efforts, 27.6 billion barrels of the Gulf Coast’s oil resource will become “stranded”, Table 1. To examine how much of this “stranded oil” could become recoverable, the study assembled a data base of 239 oil reservoirs (in this four state region) holding 15.9 billion barrels of “stranded oil.”

Table 1. Size and Distribution of the Gulf Coast Region's Oil Reservoirs Data Base

Region	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves* (Billion Bbls)	ROIP (Billion Bbls)
A. Major Oil Reservoirs				
Louisiana	178	20.4	7.9	12.5
Mississippi	34	3.0	1.0	2.0
Alabama	20	1.1	0.4	0.7
Florida	7	1.3	0.6	0.7
Data Base Total	239	25.8	9.9	15.9
*B. Regional Total**	n/a	44.4	16.9	27.6

**Estimated from state data on cumulative oil recovery and proved reserves, as of the end of 2002 for Louisiana and Mississippi and 2004 for Alabama and Florida.*

2. The great bulk of the "stranded oil" resource in the large oil reservoirs of the Gulf Coast is amenable to CO_2 enhanced oil recovery. To further address the "stranded oil" issue, Advanced Resources assembled a data base that contains 239 major Gulf Coast oil reservoirs, accounting for about 60% of the region's estimated ultimate oil production. Of these, 158 reservoirs, with 20 billion barrels of OOIP and 11.9 billion barrels of "stranded oil" (ROIP), were found to be favorable for CO_2-EOR, as shown below by state, Table 2.

Table 2. The Gulf Coast Region's "Stranded Oil" Amenable to CO_2-EOR

Region	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
Louisiana	128	16.1	6.7	9.4
Mississippi	20	1.9	0.7	1.2
Alabama	5	0.8	0.3	0.5
Florida	5	1.3	0.5	0.8
TOTAL	158	20.1	8.2	11.9

3. Application of miscible CO_2-EOR would enable a significant portion of the Gulf Coast's "stranded oil" to be recovered. Of the 158 large Gulf Coast oil reservoirs favorable for CO_2-EOR, 154 reservoirs (with 19.7 billion barrels OOIP) screen as being favorable for miscible CO_2-EOR. The remaining 4 oil reservoirs (with 0.2 billion barrels OOIP) screen as being favorable for immiscible CO_2-EOR. The total technically recoverable resource from applying CO_2-EOR in these 158 large oil reservoirs, ranges from 1,800 million barrels to 4,100 million barrels, depending on the type of CO_2-EOR technology that is applied — "Traditional Practices" or "State-of-the-art", Table 3.

Table 3. Technically Recoverable Oil Resources from Miscible and Immiscible CO_2-EOR

	Miscible			Immiscible		
Region	No. of Reservoirs	Technically Recoverable (MMBbls)		No. of Reservoirs	Technically Recoverable (MMBbls)	
		Traditional Practices	State of the Art		Traditional Practices	State of the Art
Louisiana	128	1,430	3,250	-	-	-
Mississippi	17	150	330	3	-	20
Alabama	4	80	170	1	-	*
Florida	5	140	330	-	-	-
TOTAL	154	1,800	4,080	4	0	20

** Less than 5 MMBbls.*

4. With "Traditional Practices" CO_2 flooding technology, high CO_2 costs and high risks, very little of the Gulf Coast's "stranded oil" will become economically recoverable. Traditional application of miscible CO_2-EOR technology to the 154 large reservoirs in the data base would enable 1,800 million barrels of "stranded oil" to become technically recoverable from the Gulf Coast region. However, with the current high costs for CO_2 in the Gulf Coast region (assumed at $1.50 per Mcf), risks surrounding future oil prices, and uncertainties as to the performance of CO_2-EOR technology, very little of this "stranded oil" would become economically recoverable at oil prices of $30 per barrel, as adjusted for gravity and location, Table 4.

Table 4. Economically Recoverable Resources - Scenario #1: "Traditional Practices" CO_2-EOR

Region	No. of Reservoirs	OOIP (Billion Bbls)	Economically* Recoverable	
			(# Reservoirs)	(MMBbls)
Louisiana	128	16.1	1	3
Mississippi	17	1.7	-	-
Alabama	4	0.8	-	-
Florida	5	1.1	-	-
TOTAL	154	19.7	1	3

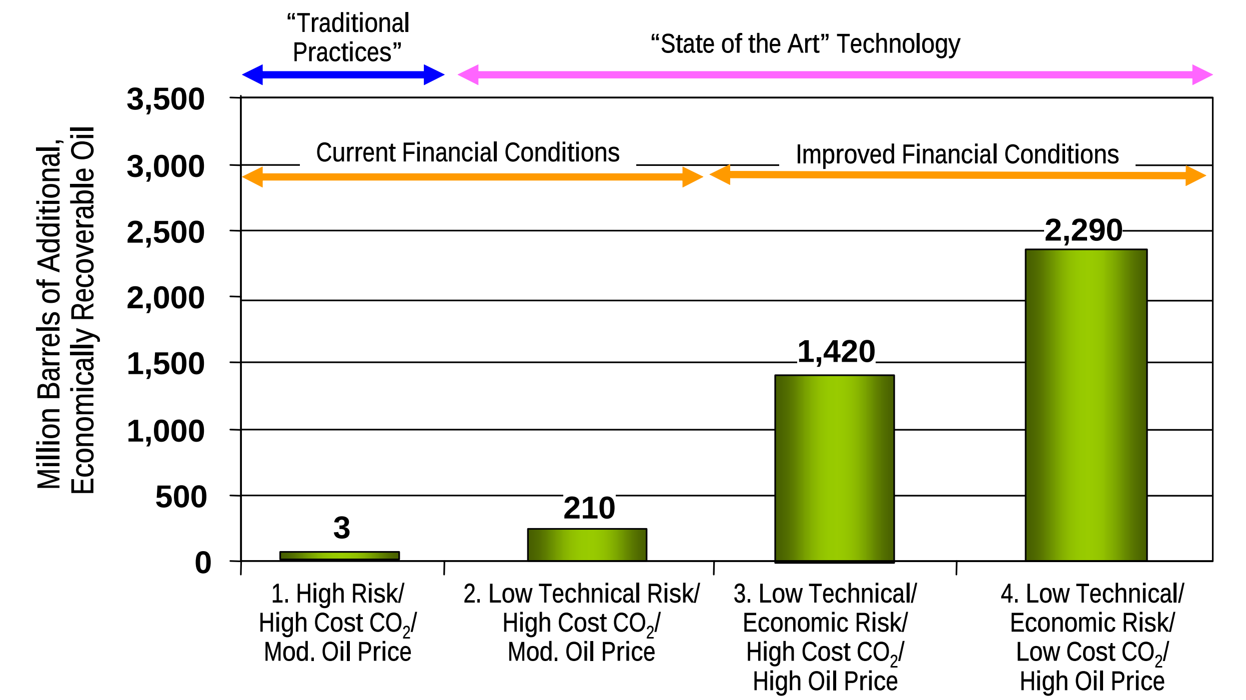
**This case assumes an oil price of $30 per barrel, a CO_2 cost of $1.50 per Mcf, and a ROR hurdle rate of 25% (before tax).*

5. Introduction of "State-of-the-art" CO_2-EOR technology, risk mitigation incentives and lower CO_2 costs would enable 2.6 billion barrels of additional oil to become economically recoverable from the Gulf Coast region. With "State-of-the-art" CO_2-EOR technology, and its higher oil recovery efficiency (oil prices of $30/B and CO_2 costs of $1.50/Mcf), 230 million barrels of the oil remaining in the Gulf Coast's large oil reservoirs becomes economically recoverable - Scenario #2.

Risk mitigation incentives and/or higher oil prices, providing an oil price equal to $40 per barrel, would enable 1,420 million barrels of oil to become economically recoverable from the Gulf Coast's large oil reservoirs — Scenario #3.

With lower cost CO_2 supplies (equal to $0.80 per Mcf, assuming a large-scale CO_2 collection and transportation system) and incentives for capture of CO_2 emissions, the economic potential increases to 2,290 million barrels — Scenario #4 (Figure 1 and Table 5).

Figure 1. Impact of Technology and Financial Conditions on Economically Recoverable Oil from the Gulf Coast Region's Major Reservoirs Using CO_2-EOR (Million Barrels)



1. This case assumes an oil price of $30 per barrel, a CO_2 cost of $1.50/Mcf and a ROR hurdle rate of 25% (before tax).
2. This case assumes an oil price of $30 per barrel, a CO_2 cost of $1.50/Mcf and a ROR hurdle rate of 15% (before tax).
3. This case assumes an oil price of $40 per barrel, a CO_2 cost of $2.00/Mcf and a ROR hurdle rate of 15% (before tax).
4. This case assumes an oil price of $40 per barrel, a CO_2 cost of $0.80/Mcf and a ROR hurdle rate of 15% (before tax).

Table 5. Economically Recoverable Resources - Alternative Scenarios

Region	Scenario #2: "State-of-the-art" (Moderate Oil Price/ High CO_2 Cost)		Scenario #3: "Risk Mitigation" (High Oil Price/ High CO_2 Cost)		Scenario #4: "Ample Supplies of CO_2" (High Oil Price/ Low CO_2 Cost)	
	(# Reservoirs)	(MMBbls)	(# Reservoirs)	(MMBbls)	(# Reservoirs)	(MMBbls)
Louisiana	4	130	24	1,120	52	1,920
Mississippi	6	80	9	160	13	230
Alabama	0	0	1	110	1	110
Florida	-	-	1	30	1	30
TOTAL	10	210	35	1,420	67	2,290

6. Once the results from the study's large oil reservoirs data base are extrapolated to the region as a whole, the technically recoverable CO_2-EOR potential for the Gulf Coast is estimated at nearly 7 billion barrels. The large Gulf Coast oil reservoirs examined by the study account for about 57% of the region's "stranded" oil resource. Extrapolating the 4.1 billion barrels of technically recoverable EOR potential in these oil reservoirs to the total Gulf Coast oil resource provides an estimate of 6.9 billion barrels of technical CO_2-EOR potential. (However, no extrapolation of economic potential has been estimated, as the development costs of the large Gulf Coast oil fields may not reflect the development costs for the smaller oil reservoirs in the region.)

7. The ultimate additional oil recovery potential from applying CO2-EOR in the Gulf Coast will, most likely, prove to be higher than defined by this study. Introduction of more advanced "next generation" CO_2-EOR technologies still in the research or field demonstration stage, such as gravity stable CO_2 injection, extensive use of horizontal or multi-lateral wells and CO_2 miscibility and mobility control agents, could significantly increase recoverable oil volumes. These "next generation" technologies would also expand the state's geologic capacity for storing CO_2 emissions. The benefits and impacts of using "advanced" CO_2-EOR technology on Gulf Coast oil reservoirs have been examined in a separate study.

8. A portion of this CO_2-EOR potential is already being pursued by operators in the Gulf Coast region. Five significant EOR projects are currently underway, four in Mississippi (at Little Creek, West and East Mallalieu, McComb and Brookhaven) and one in Florida/Alabama (at Jay/Little Escambia Creek). Together, these five EOR projects have produced or proven about 200 million barrels of the CO_2-EOR potential set forth in this study.

9. Large volumes of CO_2 supplies will be required in the Gulf Coast region to achieve the CO_2-EOR potential defined by this study. The overall market for purchased CO_2 could be over 10 Tcf, plus another 22 Tcf of recycled CO_2, Table 6. Assuming that the volume of CO_2 stored equals the volume of CO_2 purchased and that the bulk of purchased CO_2 is from industrial sources, applying CO_2-EOR to the Gulf

Coast's oil reservoirs would enable over 460 million metric tonnes of CO_2 emissions to be stored, greatly reducing greenhouse gas emissions. Advanced CO_2-EOR flooding and CO_2 storage concepts (plus incentives for storing CO_2) would significantly increase this amount.

Table 6. Potential CO_2 Supply Requirements in the Gulf Coast Region: Scenario #4 ("Ample Supplies of CO_2")

Region	No. of Reservoirs	Economically Recoverable (MMBbls)	Market for Purchased CO_2 (Bcf)	Market for Recycled CO_2 (Bcf)
Louisiana	52	1,920	9,040	18,620
Mississippi	13	230	1,000	2,270
Alabama	1	110	485	1,140
Florida	1	30	140	240
TOTAL	67	2,290	10,665	22,270

10. Significant supplies of both natural and industrial CO_2 emissions exist in the Gulf Coast region, sufficient to meet the CO_2 needs for EOR. The natural CO_2 deposit at Jackson Dome, Mississippi is estimated to hold between 3 and 12 Tcf of recoverable CO_2. In addition, CO_2 emissions, from gas processing plants, hydrogen plants, ammonia plants and ethylene/ethylene oxide plants could provide 1.5 to 2 Bcf per day of high concentration (relatively low cost) CO_2, equal to 10 to 15 Tcf of CO_2 supply in 20 years. Finally, almost unlimited supplies of low concentration CO_2 emissions (equal to over 100 Tcf of CO_2 supply in 20 years) would become available from the large power plants and refineries in the region, assuming affordable CO_2 capture technology is developed.

11. A public-private partnership will be required to overcome the many barriers facing large scale application of CO_2-EOR in the Gulf Coast Region's oil fields. The challenging nature of the current barriers — lack of sufficient, low-cost CO_2 supplies, uncertainties as to how the technology will perform in the Gulf Coast's complex oil fields, and the considerable market and oil price risks — all argue that a partnership involving the oil production industry, potential CO_2 suppliers and transporters, the Gulf Coast states and the federal government will be needed to overcome these barriers.

12. Many entities will share in the benefits of increased CO_2-EOR based oil production in the Gulf Coast. Successful introduction and wide-scale use of CO_2-EOR in the Gulf Coast will stimulate increased economic activity, provide new higher paying jobs, and lead to higher tax revenues for the state. It will also help revive a declining domestic oil production and service industry.

1.4 ACKNOWLEDGEMENTS. Advanced Resources would like to acknowledge the most valuable assistance provided to the study by a series of individuals and organizations in Louisiana, Mississippi, Alabama and Florida.

In Louisiana, we would like to thank the Department of Natural Resources and particularly Ms. Jo Ann Dixon, Mineral Production Specialist, for help with using the SONRIS system and accessing data on cumulative oil production. We recognize and appreciate the considerable assistance provided by Ms. Dixon for assembling data by oil fields and oil reservoir. We also fully support efforts to upgrade the SONRIS system as a data source for independent producers seeking to recover the oil remaining in Louisiana oil reservoirs.

In Mississippi, we would like to thank the Mississippi Oil and Gas Board, and specifically Ms. Juanita Harper and Mr. Jeff Smith for providing data on statewide annual oil production and guidance on field and reservoir level oil production and well counts.

In Alabama, we would like to thank the Alabama State Oil and Gas Board, in particular Jack Pashin and Richard Hamilton, for providing the state historical oil production data and information on selected oil reservoirs.

In Florida, we would like to thank the Florida Department of Environmental Protection, in particular Ed Garrett and David Taylor, for providing statewide oil production history and oil field descriptions.

Finally, the study would like to acknowledge Mr. William “Clay” Kimbrell of Kimbrell & Associates, LLC, a co-author of SPE 35431, “Screening Criteria for Application of Carbon Dioxide Miscible Displacement in Waterflooded Reservoirs Containing Light Oil”, who helped identify and explain the information used in his most valuable SPE paper.

2. INTRODUCTION

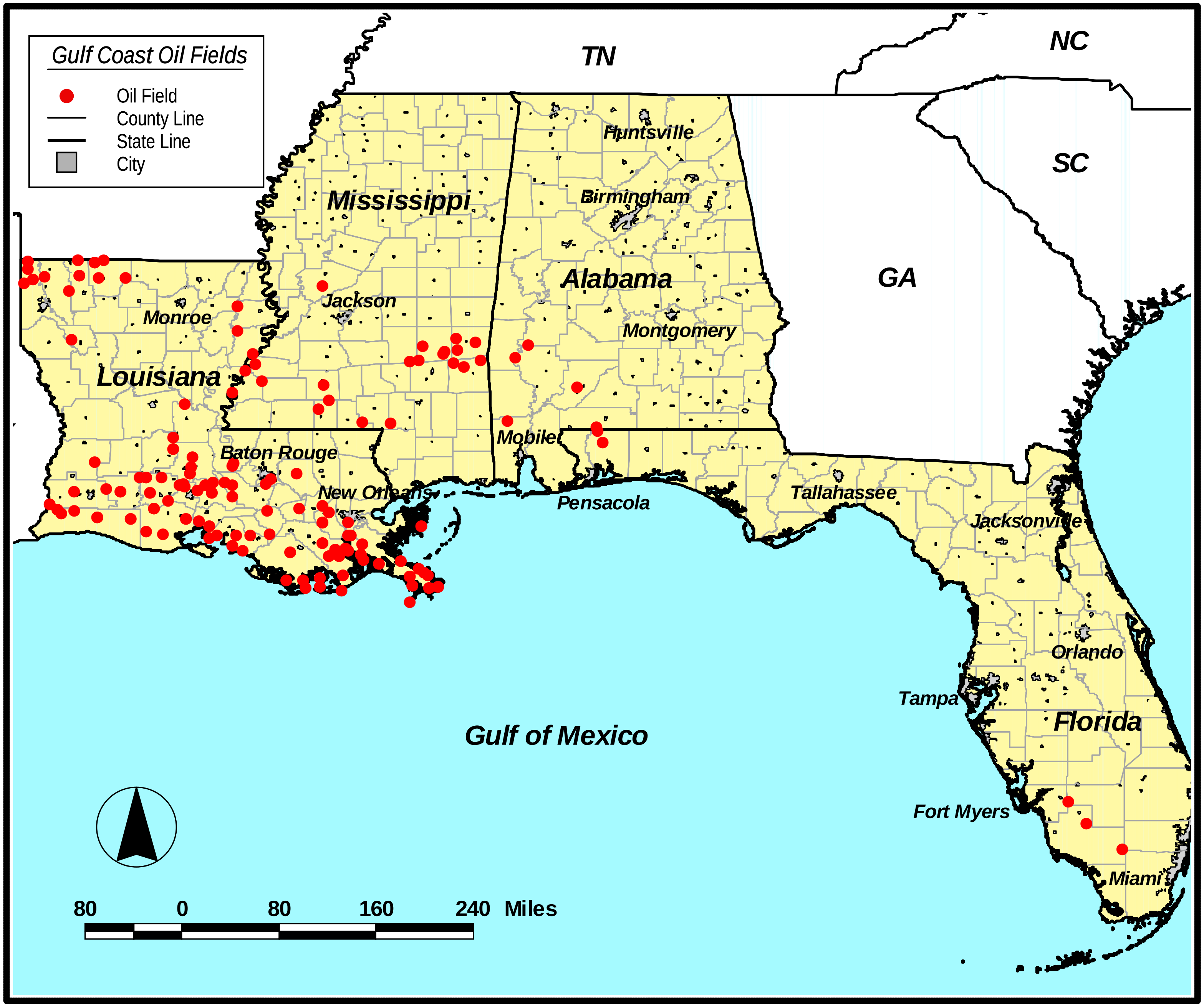
2.1 CURRENT SITUATION. The Gulf Coast oil producing region addressed in the report is mature and in decline. Stemming the decline in oil production will be a major challenge, requiring a coordinated set of actions by numerous parties who have a stake in this problem — Gulf Coast state revenue and economic development officials; private, state and federal royalty owners; the Gulf Coast oil production and refining industry; the public, and the federal government.

The main purpose of this report is to provide information to these "stakeholders" on the potential for pursuing CO2 enhanced oil recovery (CO2-EOR) as one option for slowing and potentially stopping the decline in the Gulf Coast's oil production.

This report, "Basin Oriented Strategies for CO2 Enhanced Oil Recovery: Onshore Gulf Coast Region of Alabama, Florida, Louisiana and Mississippi," provides information on the size of the technical and economic potential for CO2-EOR in the Gulf Coast oil producing regions. It also identifies the many barriers — insufficient and costly CO2 supplies, high market and economic risks, and concerns over technology performance — that currently impede the cost-effective application of CO2-EOR in the Gulf Coast oil producing region.

2.2 BACKGROUND. The onshore Gulf Coast region of Louisiana, Mississippi, Alabama and Florida was, at one time, one of the largest onshore domestic oil producing regions. With severe declines in crude oil reserves and production capacity, these four areas of the Gulf Coast currently produce only 192 thousand barrels of oil per day (in 2004). However, the deep, light oil reservoirs of this region are ideal candidates for miscible carbon dioxide-based enhanced oil recovery (CO2-EOR). The Gulf Coast oil producing region and the concentration of its major oil fields are shown in Figure 2.

Figure 2. Location of Major Gulf Coast Oil Fields.



2.3 PURPOSE. This report, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Onshore Gulf Coast Region of Alabama, Florida, Louisiana and Mississippi" is part of a larger effort to examine the enhanced oil recovery and CO_2 storage potential in key U.S. oil basins. The work involves establishing the geological and reservoir characteristics of the major oil fields in the region; examining the available CO_2 sources, volumes and costs; calculating oil recovery and CO_2 storage capacity; and, examining the economic feasibility of applying CO_2-EOR. The aim of this report is to provide information that could assist: (1) formulating alternative public-private partnership strategies for developing lower-cost CO_2 capture technology; (2) launching R&D/pilot projects of advanced CO_2 flooding technology; and, (3) structuring royalty/tax incentives and policies that would help accelerate the application of CO_2-EOR and CO_2 storage.

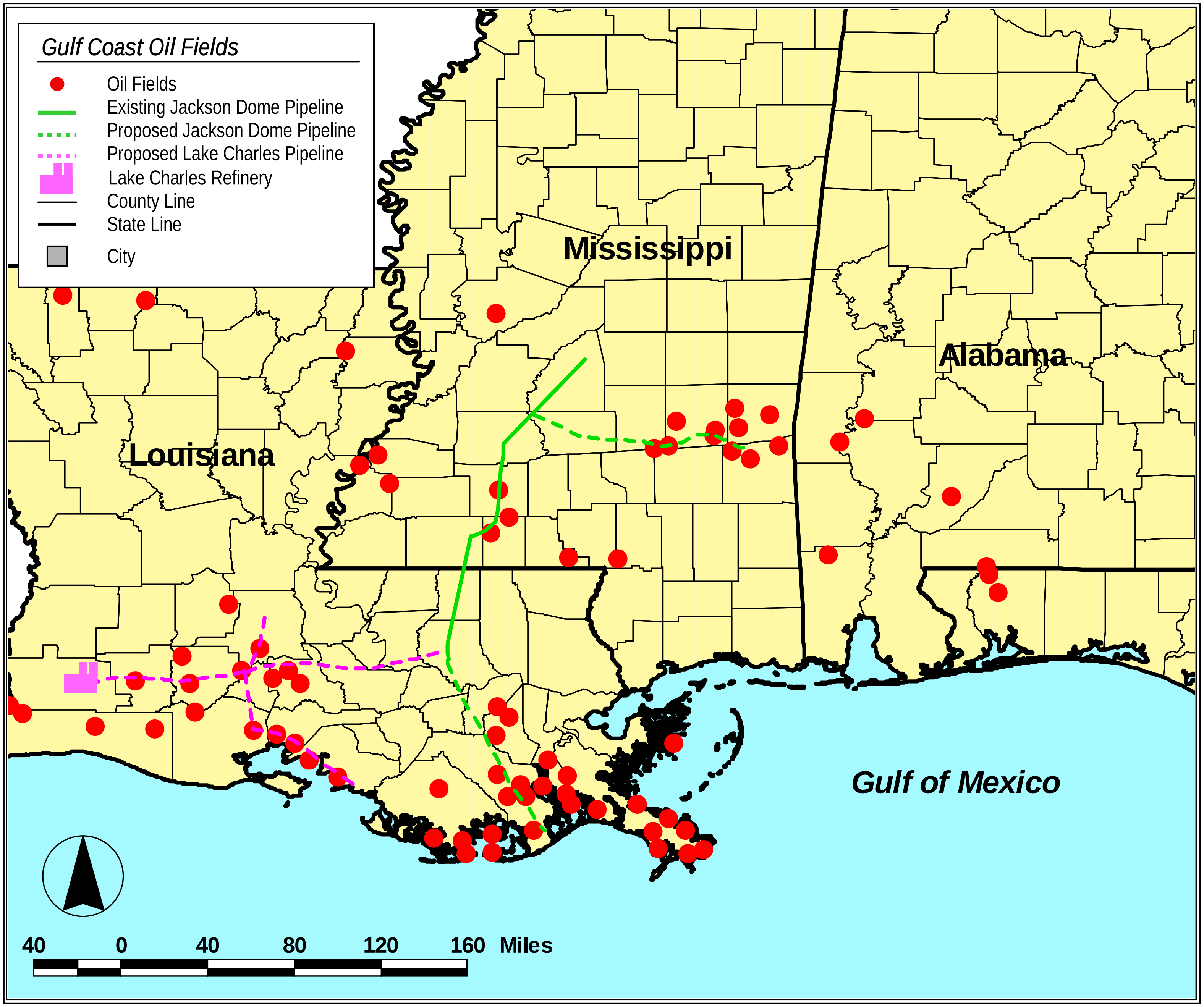
An additional important purpose of the study is to develop a desktop modeling and analytical capability for "basin oriented strategies" that would enable Department of Energy/Fossil Energy (DOE/FE) itself to formulate policies and research programs that would support increased recovery of domestic oil resources. As such, this desktop model complements, but does not duplicate, the more extensive TORIS modeling system maintained by DOE/FE's National Energy Technology Laboratory.

2.4 KEY ASSUMPTIONS. For purposes of this study, it is assumed that sufficient supplies of CO_2 will become available, either by pipeline from natural sources such as Jackson Dome or from the numerous industrial sources in the region. These sources include the hydrogen plants and refineries in Lake Charles, Louisiana; Pascagoula, Mississippi; and Tuscaloosa, Alabama, the large gas processing and chemical plants in the region and particularly the major electric power plants in these four states. The study assumes that this CO_2 will become available in the near future, before the oil fields in the region are plugged and abandoned.

Figure 3 shows the existing pipeline system that transports CO_2 from the natural CO_2 reservoir at Jackson Dome to the oil fields of central Mississippi and northeastern Louisiana. It also shows the proposed extension of this pipeline system to the oil fields of eastern Mississippi and to southeastern Louisiana. According to a press release in the fall of 2005, the operator of the Jackson Dome CO_2 reservoir (Denbury Resources) has initiated constructing of the 84-mile extension from Jackson Dome to oil fields in eastern Mississippi.

Figure 3 also provides a conceptual illustration of a CO_2 pipeline system that would transport captured CO_2 emissions from Louisiana's refinery complex at Lake Charles to the nearby oil fields of Louisiana. Once this primary trunkline is in place, expansion to Alabama's and Florida's large oil fields is a possibility. This conceptual industrial CO_2 pipeline system could link with the existing natural CO_2 pipeline system, providing a more secure overall CO_2 supply system for the Gulf Coast region.

Figure 3. Location of Existing and Planned CO_2 Supply Pipelines in Mississippi and Louisiana.



2.5 TECHNICAL OBJECTIVES. The objectives of this study are to examine the technical and the economic potential of applying CO_2-EOR in the Gulf Coast oil region, under two technology options:

1. *"Traditional Practices" Technology*. This involves the continued use of past CO_2 flooding and reservoir selection practices. It is distinguished by using miscible CO_2-EOR technology in light oil reservoirs and by injecting moderate volumes of CO_2, on the order of 0.4 hydrocarbon pore volumes (HCPV), into these reservoirs. (Immiscible CO_2 is not included in the "Traditional Practices" technology option). Given the still limited application of CO_2-EOR in this region and the inherent technical and geologic risks, operators typically add a risk premium when evaluating this technology option in the Gulf Coast region.

2. *"State-of-the-art" Technology*. This involves bringing to the Gulf Coast the benefits of recent improvements in the performance of the CO_2-EOR process and gains in understanding of how best to customize its application to the many different types of oil reservoirs in the region. As further discussed below, moderately deep, light oil reservoirs are selected for miscible CO_2-EOR and the shallower light oil and the heavier oil reservoirs are targeted for immiscible CO_2-EOR. "State-of-the-art" technology entails injecting much larger volumes of CO_2, on the order of 1 HCPV, with considerable CO_2 recycling.

Under "State-of-the-art" technology, with CO_2 injection volumes more than twice as large, oil recovery is projected to be higher than reported for past field projects using "Traditional Practices". The CO_2 injection/oil recovery ratio may also be higher under this technology option, further spotlighting the importance of lower cost CO_2 supplies. With the benefits of field pilots and pre-commercial field demonstrations, the risk premium for this technology option and scenario would be reduced to conventional levels.

The set of oil reservoirs to which CO_2-EOR would be applied fall into two groups, as set forth below:

1. *Favorable Light Oil Reservoirs Meeting Stringent CO_2 Miscible Flooding Criteria*. These are the moderately deep, higher gravity oil reservoirs where CO_2 becomes miscible (after extraction of hydrocarbon components into the CO_2 phase and solution of CO_2 in the oil phase) with the oil remaining in the reservoir. Typically, reservoirs at depths greater than 3,000 feet and with oil gravities greater than 25 $^{\circ}$API would be selected for miscible CO_2-EOR. Major Gulf Coast light oil fields such as Lake Washington (LA), West Heidelberg (MS), Citronelle (AL) and Jay (FL) fit into this category. Advanced Resources recognizes that the Jay Field is currently being flooded using N_2-EOR. Nevertheless, a comparison between N_2-EOR and CO_2-EOR could be illustrative. The great bulk of past CO_2-EOR floods have been conducted in these types of "favorable reservoirs".

2. *Challenging Reservoirs Involving Immiscible Application of CO_2-EOR*. These are the moderately heavy oil reservoirs (as well as shallower light oil reservoirs) that do not meet the stringent requirements for miscibility. This reservoir set includes the large Gulf Coast oil fields, such as East Heidelberg (MS) and West Eucutta (MS), that still hold a significant portion of their original oil. Although few, Gulf Coast reservoirs at depths greater than 3,000 feet with oil gravities between 17.5° and 25 $^{\circ}$API (or higher) would generally be included in this category.

Combining the technology and oil reservoir options, the following oil reservoir and CO_2 flooding technology matching is applied to the Gulf Coast's reservoirs amenable to CO_2-EOR, Table 7.

Table 7. Matching of CO_2-EOR Technology With the Gulf Coast's Oil Reservoirs

CO_2-EOR Technology Selection	Oil Reservoir Selection
"Traditional Practices"; Miscible CO_2-EOR	▪ 154 Deep, Light Oil Reservoirs
"State-of-the-art"; Miscible and Immiscible CO_2-EOR	▪ 154 Deep, Light Oil Reservoirs ▪ 4 Deep, Moderately Heavy Oil Reservoirs

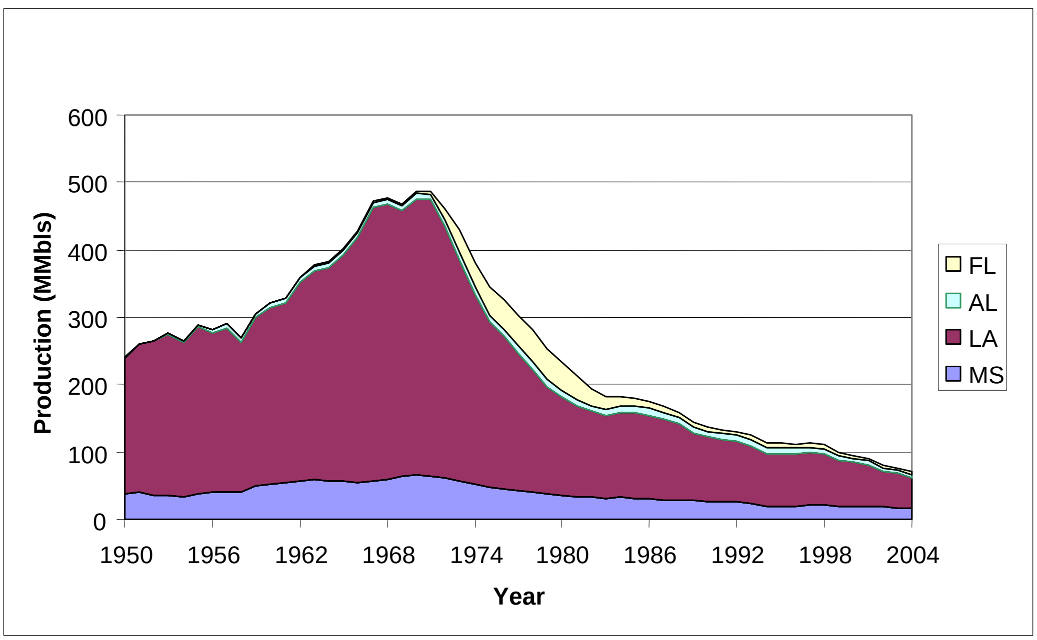
2.6 OTHER ISSUES. This study draws on a series of sources for basic data on the reservoir properties and the expected technical and economic performance of CO_2-EOR in the Gulf Coast's major oil reservoirs. Because of confidentiality and proprietary issues, the results of the study have been aggregated for the four producing areas within the Gulf Coast. As such, reservoir-level data and results are not provided and are not available for general distribution. However, selected non-confidential and non-proprietary information at the field and reservoir level is provided in the report and additional information could be made available for review, on a case by case basis, to provide an improved context for the state level reporting of results in this report.

3. OVERVIEW OF GULF COAST OIL PRODUCTION

3.1 HISTORY OF OIL PRODUCTION. Oil production for the onshore Gulf Coast region of United States — encompassing Mississippi, north and south Louisiana, Alabama and Florida — has steadily declined for the past 30 years, Figure 4. Since reaching a peak in 1970, oil production dropped sharply for the next ten years before starting a more gradual decline in the mid 1980s due to secondary recovery efforts. Oil production reached a recent low of 70 million barrels (192,000 barrels per day) in 2004.

- Louisiana onshore areas, with 45 million barrels of oil produced in 2002, has seen its crude oil proved reserves fall in half in the past 10 years.
- Mississippi, with 17 million barrels of oil produced in 2004, has maintained its proved crude oil reserves and oil production for the past ten years.
- Alabama onshore areas, with 5 million barrels of oil produced in 2004 has seen a steady decline in its proven reserves and production in the last ten years.
- Florida onshore areas, with 3 million barrels of oil produced in 2004 has also seen a steady decline in its proven reserves and production over the past 10 years.

Figure 4. Gulf Coast Production Since 1950



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However, the Gulf Coast still holds a rich resource of oil in the ground. With 44 billion barrels of original oil in-place (OOIP) and approximately 17 billion barrels expected to be recovered, 28 billion barrels of oil will be "stranded" due to lack of technology, lack of sufficient, affordable CO_2 supplies and high economic and technical risks.

Table 8 presents the status and annual oil production for the ten largest Gulf Coast region oil fields that account for about one fifth of the oil production in this region. The table shows that five of the largest oil fields are in production decline. Arresting this decline in the Gulf Coast's oil production could be attained by applying enhanced oil recovery technology, particularly CO_2-EOR.

Table 8. Crude Oil Annual Production, Ten Largest Gulf Coast Oil Fields, 2000-2002
(Million Barrels per Year)

Major Oil Fields	2000	2001	2002	Production Status
Jay, FL*	3.4	3.1	2.5	Declining
Weeks Island, LA	3.4	2.8	2.2	Declining
Heidelberg East, MS	2.0	1.9	1.7	Declining
Black Bay East, LA	1.3	2.0	1.7	Increasing/Stable
Little Creek, MS*	0.9	1.1	1.5	Increasing
Heidelberg West, MS	1.3	1.3	1.3	Stable
Lake Washington, LA	1.3	1.2	1.2	Stable
Masters Creek, LA	1.8	1.3	1.0	Declining
Citronelle, AL	1.0	1.0	1.0	Stable
Laurel, LA	1.1	1.0	0.8	Declining

** Fields under EOR operations*

3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY. Gulf Coast oil producers are familiar with using technology for improving oil recovery. For example, a large number of onshore Louisiana oil fields are currently under waterflood recovery and pilot efforts are underway in applying CO_2 for enhanced oil recovery.

One of the favorable conditions for the area is that the Gulf Coast contains a natural source of CO_2 at Jackson Dome, Mississippi. This natural source of CO_2 enabled CO_2-EOR to be pilot tested at Weeks Island and Little Creek oil fields by Shell Oil in the 1980s. It is also the source for Denbury Resources' CO_2 supplies for a series of new field-scale CO_2 projects in Mississippi including Little Creek, Mallalieu and McComb. Additional discussion of the experience with CO_2-EOR in the Gulf Coast region is provided in Chapter 6.

3.3 THE "STRANDED OIL" PRIZE. Even though the Gulf Coast's oil production is declining, this does not mean that the resource base is depleted. The four regions of onshore production in the Gulf Coast – Louisiana, Mississippi, Alabama and Florida, still contain 62% of their OOIP after primary and secondary oil recovery. This large volume of remaining oil in-place (ROIP) is the "prize" for CO_2-EOR.

Table 9 provides information on the maturity and oil production history of 8 large Gulf Coast oil fields, each with estimated ultimate recovery of 200 million barrels or more.

Table 9. Selected Major Oil Fields of the Gulf Coast Region

	Field/State	Year Discovered	Cumulative Production (MMBbl)	Estimated Primary/ Secondary Reserves (MMBbl)	Remaining Oil In-Place (MMBbl)
1	JAY – FL*	1970	350	28	352**
2	CITRONELLE – AL*	1955	168	7	362
3	LAKE WASHINGTON - LA	1931	272	14	360
4	LAFITTE - LA	1935	269	7	329
5	WEEKS ISLAND - LA	1945	265	19	347
6	BAXTERVILLE - MS	1944	253	6	489
7	WEST BAY - LA	1940	242	8	336
8	GARDEN ISLAND BAY - LA	1935	221	3	262

* *Alabama and Florida production numbers are for 2004.*
***70 MMBbls of this is estimated to be recovered with N_2-EOR*

3.4 REVIEW OF PRIOR STUDIES. As part of the 1993 to 1997 DOE Class I reservoir project, "Post Waterflood, CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir" (which also developed of *CO_2-PROPHET*) Louisiana State University studied the impact of using miscible CO_2-EOR in Louisiana. The technical and economic parameters of the study were as follows — recovery factor of 10% ROIP; oil price of $17/Bbl, royalty and taxes of 15%; and CO_2 costs of $0.60/Mcf:

- In Louisiana, the investigators began with a data base of 499 light-oil waterflooded reservoirs to select candidates acceptable for CO_2-EOR. The data base included three reservoirs in which CO_2 miscible flooding was already occurring — Paradis (Lower 9000 Sand RM), South Pass Block 24 (8800'RD), and West Bay (5 A'B").

- Of the 499 reservoirs screened (representing 5.3 billion Bbl of OOIP), 197 were deemed acceptable for CO_2-EOR and 40 were determined to be economic under the constraints of the study. These 40 reservoirs were estimated to provide a relatively modest volume of incremental oil production — 73 million barrels.

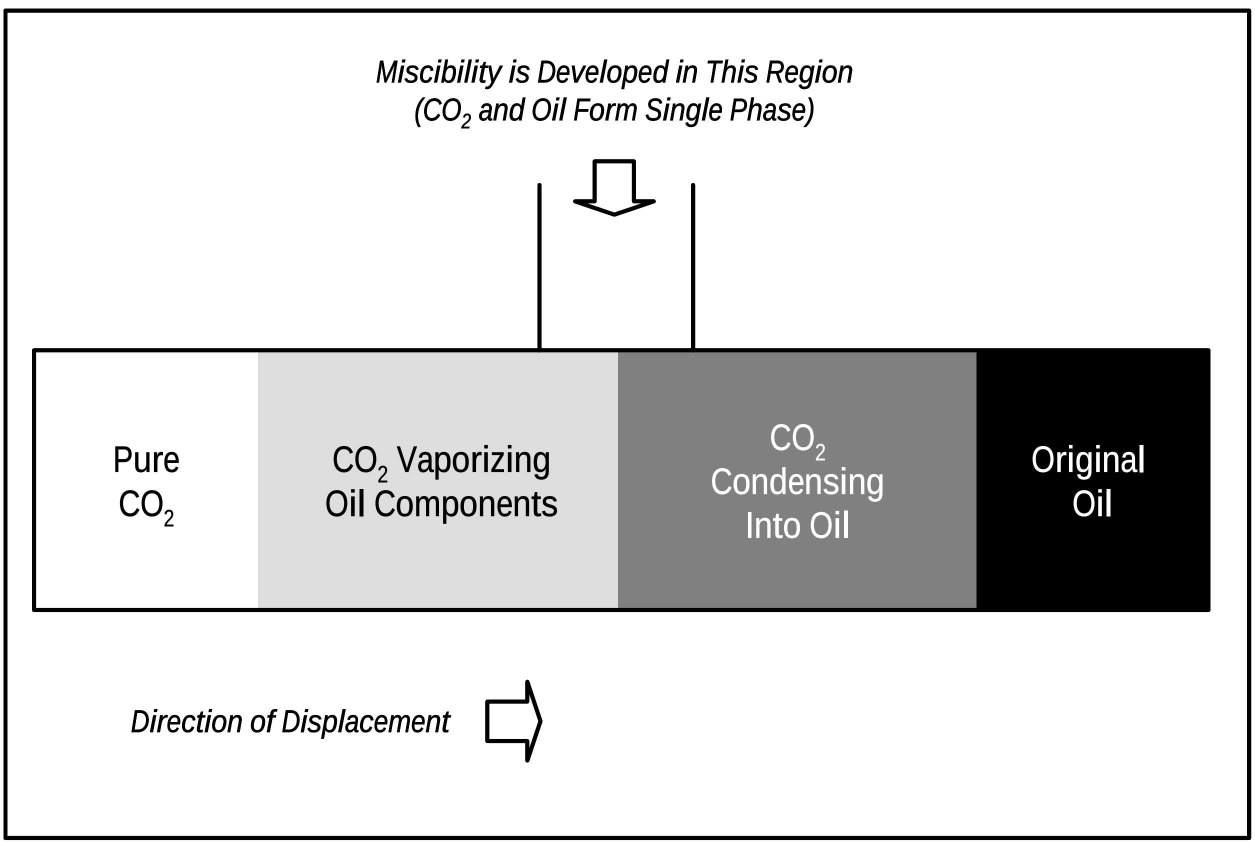
The much larger reservoir data base, the improved capability to calculate oil recovery from miscible and immiscible CO_2-EOR, and the significantly higher oil prices used in the study lead to much higher expectations of oil production from Louisiana onshore oil reservoirs.

4. MECHANISMS OF CO_2-EOR

4.1 MECHANISMS OF MISCIBLE CO_2-EOR. Miscible CO_2-EOR is a multiple contact process, involving the injected CO_2 and the reservoir's oil. During this multiple contact process, CO_2 will vaporize the lighter oil fractions into the injected CO_2 phase and CO_2 will condense into the reservoir's oil phase. This leads to two reservoir fluids that become miscible (mixing in all parts), with favorable properties of low viscosity, a mobile fluid and low interfacial tension.

The primary objective of miscible CO_2-EOR is to remobilize and dramatically reduce the after waterflooding residual oil saturation in the reservoir's pore space. Figure 5 provides a one-dimensional schematic showing the various fluid phases existing in the reservoir and the dynamics of the CO_2 miscible process.

Figure 5. One-Dimensional Schematic Showing the CO_2 Miscible Process



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4.2 MECHANISMS OF IMMISCIBLE CO_2-EOR. When insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier), the injected CO_2 is immiscible with the reservoir's oil. As such, another oil displacement mechanism, immiscible CO_2 flooding, occurs. The main mechanisms involved in immiscible CO_2 flooding are: (1) oil phase swelling, as the oil becomes saturated with CO_2; (2) viscosity reduction of the swollen oil and CO_2 mixture; (3) extraction of lighter hydrocarbon into the CO_2 phase; and, (4) fluid drive plus pressure. This combination of mechanisms enables a portion of the reservoir's remaining oil to be mobilized and produced. In general, immiscible CO_2-EOR is less efficient than miscible CO_2-EOR in recovering the oil remaining in the reservoir.

4.3 INTERACTIONS BETWEEN INJECTED CO_2 AND RESERVOIR OIL. The properties of CO_2 (as is the case for most gases) change with the application of pressure and temperature. Figures 6A and 6B provide basic information on the change in CO_2 density and viscosity, two important oil recovery mechanisms, as a function of pressure.

Oil swelling is an important oil recovery mechanism, for both miscible and immiscible CO_2-EOR. Figures 7A and 7B show the oil swelling (and implied residual oil mobilization) that occurs from: (1) CO_2 injection into a West Texas light reservoir oil; and, (2) CO_2 injection into a very heavy (12 $^{\circ}$API) oil reservoir in Turkey. Laboratory work on the Bradford Field (Pennsylvania) oil reservoir showed that the injection of CO_2, at 800 psig, increased the volume of the reservoir's oil by 50%. Similar laboratory work on Mannville "D" Pool (Canada) reservoir oil showed that the injection of 872 scf of CO_2 per barrel of oil (at 1,450 psig) increased the oil volume by 28%, for crude oil already saturated with methane.

Viscosity reduction is a second important oil recovery mechanism, particularly for immiscible CO_2-EOR. Figure 8 shows the dramatic viscosity reduction of one to two orders of magnitude (10 to 100 fold) that occur for a reservoir's oil with the injection of CO_2 at high pressure.

Figure 6A. Carbon Dioxide, CH_4 and N_2 densities at 105^0F. At high pressures, CO_2 has a density close to that of a liquid and much greater than that of either methane or nitrogen. Densities were calculated with an equation of state (EOS)

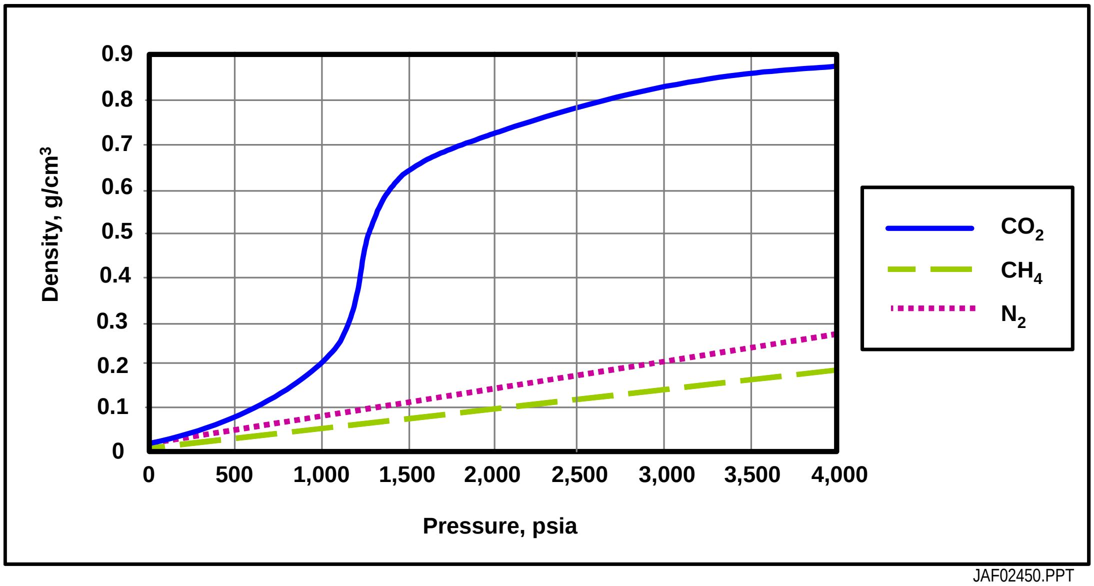


Figure 6B. Carbon Dioxide, CH_4 and N_2 viscosities at 105^0F. At high pressures, the viscosity of CO_2 is also greater then that of methane or nitrogen, although it remains low in comparison to that of liquids. Viscosities were calculated with an EOS.

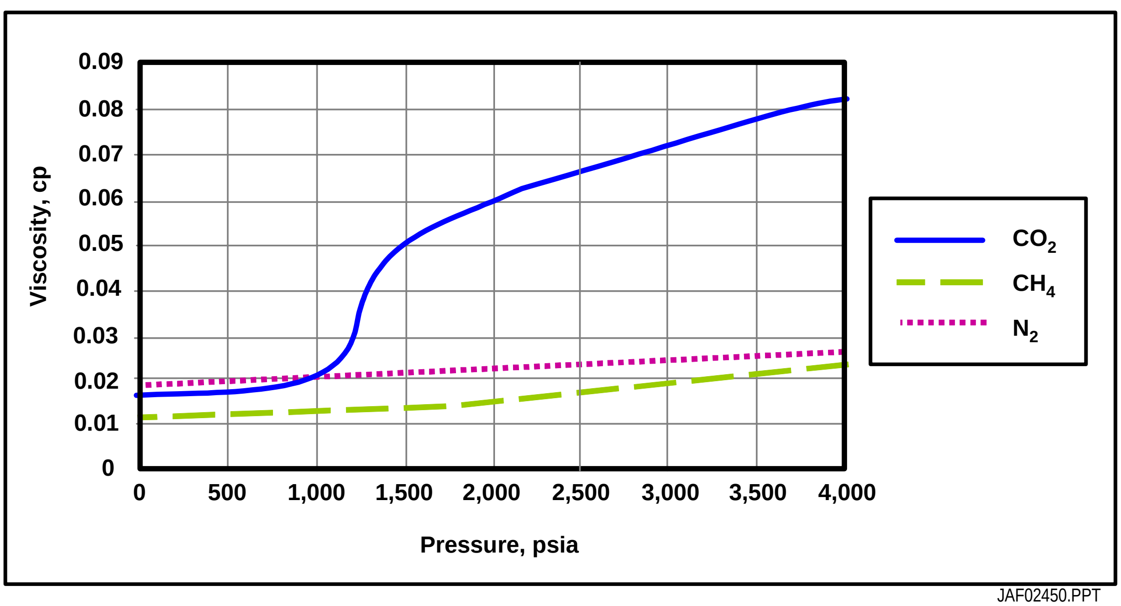


Figure 7A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid (Holm and Josendal).

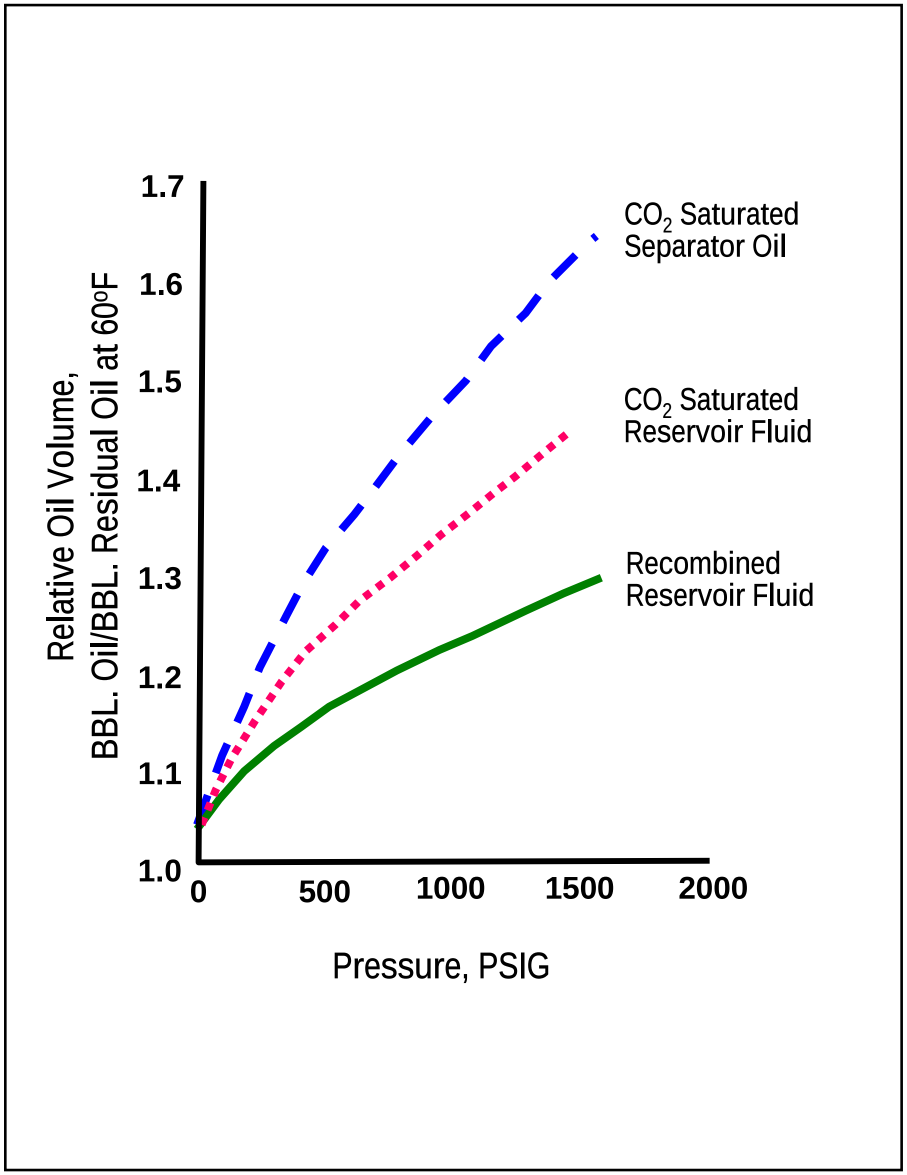


Figure 7B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

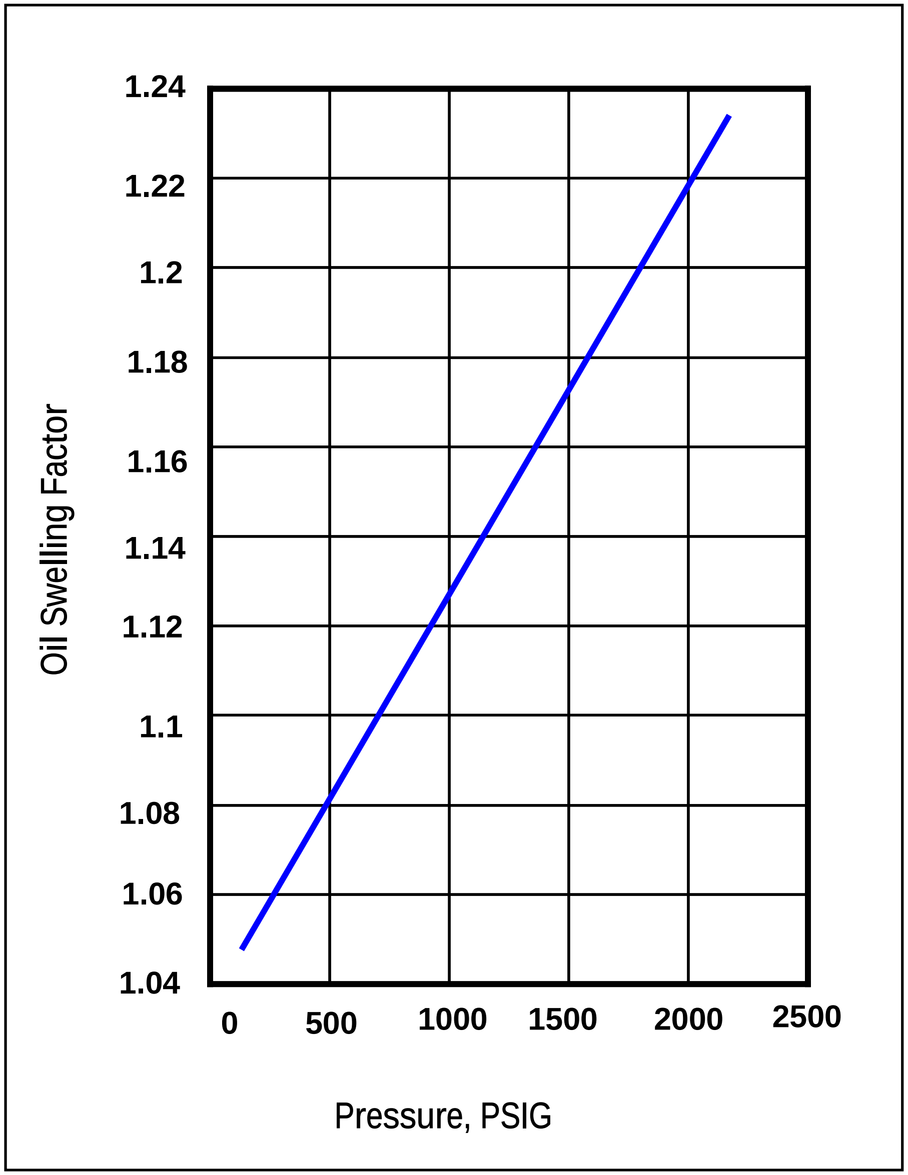
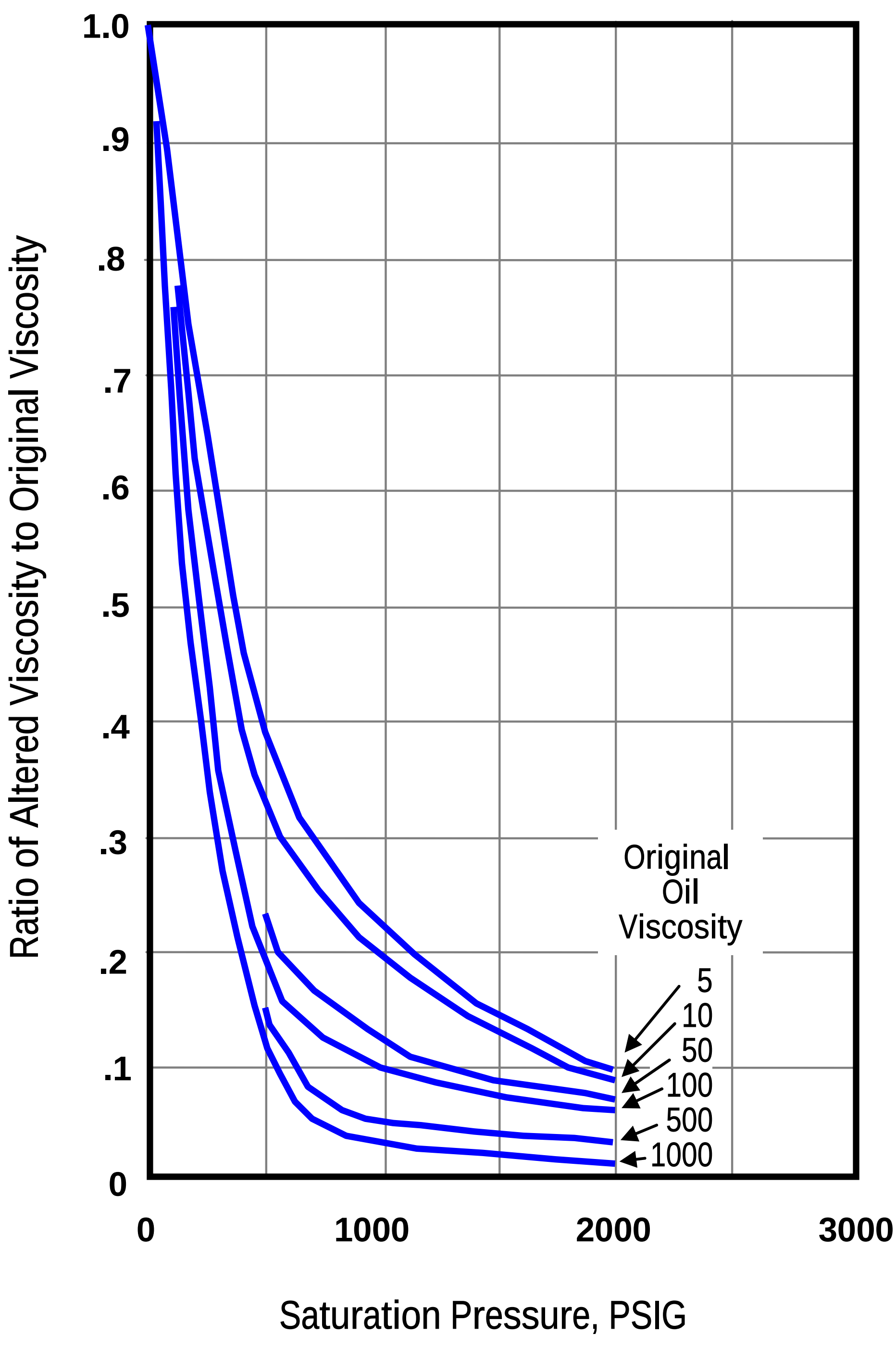


Figure 8. Viscosity Reduction Versus Saturation Pressure (Simon and Graue).



5. STUDY METHODOLOGY

5.1 OVERVIEW. A seven part methodology was used to assess the CO_2-EOR potential of the Gulf Coast's oil reservoirs. The seven steps were: (1) assembling the Gulf Coast Major Oil Reservoirs Data Base; (2) screening reservoirs for CO_2-EOR; (3) calculating the minimum miscibility pressure; (4) calculating oil recovery; (5) assembling the cost model; (6) constructing an economics model; and, (7) performing scenario analyses.

An important objective of the study was the development of a desktop model with analytic capability for "basin oriented strategies" that would enable DOE/FE to develop policies and research programs leading to increased recovery and production of domestic oil resources. As such, this desktop model complements, but does not duplicate, the more extensive TORIS modeling system maintained by DOE/FE's National Energy Technology Laboratory.

5.2 ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE. The study started with the National Petroleum Council (NPC) Public Data Base, maintained by DOE Fossil Energy. The study updated and modified this publicly accessible data base to develop the Gulf Coast Major Oil Reservoirs Data Base for onshore Louisiana, Mississippi, Alabama and Florida.

Table 10 illustrates the oil reservoir data recording format developed by the study. The data format readily integrates with the input data required by the CO_2-EOR screening and oil recovery models, discussed below. Overall, the Gulf Coast Major Oil Reservoirs Data Base contains 239 reservoirs, accounting for 58.5% of the oil expected to be ultimately produced in Gulf Coast by primary and secondary oil recovery processes.

Table 10. Reservoir Data Format: Major Oil Reservoirs Data Base

Basin Name	
Field Name	
Reservoir	

Reservoir Parameters:

	TORIS	ARI
Area (A)		
Net Pay (ft)		
Depth (ft)		
Porosity		
Reservoir Temp (deg F)		
Initial Pressure (psi)		
Pressure (psi)		
B_{oi}		
B_o @ S_o, swept		
S_{oi}		
S_{or}		
Swept Zone S_o		
S_{wi}		
S_w		
API Gravity		
Viscosity (cp)		
Dykstra-Parsons		

Oil Production

	TORIS	ARI
Producing Wells (active)		
Producing Wells (shut-in)		
2003 Production (Mbbl)		
Daily Prod - Field (Bbl/d)		
Cum Oil Production (MMbbl)		
EOY 2003 Oil Reserves (MMbbl)		
Water Cut		

Water Production

	TORIS	ARI
2001 Water Production (Mbbl)		
Daily Water (Mbbl/d)		

Injection

	TORIS	ARI
Injection Wells (active)		
Injection Wells (shut-in)		
2003 Water Injection (MMbbl)		
Daily Injection - Field (Mbbl/d)		
Cum Injection (MMbbl)		
Daily Inj per Well (Bbl/d)		

EOR

Type	
2003 EOR Production (MMbbls)	
Cum EOR Production (MMbbls)	
Reserves (MMbbls)	
Ultimate Recovery (MMbbls)	

Volumes

	TORIS	ARI
OOIP (MMbl)		
Cum P/S Oil (MMbl)		
2003 P/S Reserves (MMbl)		
Ult P/S Recovery (MMbl)		
Remaining (MMbbl)		
Ultimate Recovered (%)		

OOIP Volume Check

	TORIS	ARI
Reservoir Volume (AF)		
Bbl/AF		
OOIP Check (MMbl)		

SROIP Volume Check

	TORIS	ARI
Reservoir Volume (AF)		
Swept Zone Bbl/AF		
SROIP Check (MMbbl)		

ROIP Volume Check

	TORIS	ARI
ROIP Check (MMbl)		

Considerable effort was required to construct an up-to-date, volumetrically consistent data base that contained all of the essential data, formats and interfaces to enable the study to: (1) develop an accurate estimate of the size of the original and remaining oil in-place in the Gulf Coast; (2) reliably screen the reservoirs as to their amenability for miscible and immiscible CO_2-EOR; and, (3) provide the *CO_2-PROPHET* Model (developed by Texaco for the DOE Class I cost-share program) the essential input data for calculating CO_2 injection requirements and oil recovery.

5.3 SCREENING RESERVOIRS FOR CO_2-EOR. The data base was screened for reservoirs that would be applicable for CO_2-EOR. Five prominent screening criteria were used to identify favorable reservoirs. These were: reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition. These values were used to establish the minimum miscibility pressure for conducting miscible CO_2-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the miscibility pressure standard were considered for immiscible CO_2-EOR.

The preliminary screening steps involved selecting the deeper oil reservoirs that had sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet, at the mid-point of the reservoir, was used to ensure the reservoir could accommodate high pressure CO_2 injection. A minimum oil gravity of 17.5 $^{\circ}$API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection. Table 11 tabulates the oil reservoirs that passed the preliminary screening step. Many of these fields contain multiple reservoirs, with each reservoir holding a great number of stacked sands. Because of data limitations, this screening study combined the sands into a single reservoir.

Table 11. Gulf Coast Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
A. Louisiana		
Louisiana	COTTON VALLEY	BODCAW
Louisiana	DELHI	DELHI ALL
Louisiana	HAYNESVILLE	PETTIT
Louisiana	HAYNESVILLE	TOKIO
Louisiana	HAYNESVILLE EAST	BIRDSONG - OWENS
Louisiana	HAYNESVILLE EAST	EAST PETTIT
Louisiana	LISBON	PET LIME
Louisiana	NORTH SHONGALOO - RED ROCK	AAA
Louisiana	RODESSA	RODESSA ALL
Louisiana	AVERY ISLAND	MEDIUM
Louisiana	BARATARIA	24 RESERVOIRS
Louisiana	BAY ST ELAINE	13600 - FT SAND, SEG C & C-1
Louisiana	BAY ST ELAINE	DEEP
Louisiana	BAYOU SALE	SALE DEEP
Louisiana	BONNET-CARRE	OPERCULINOIDES
Louisiana	CAILLOU ISLAND	9400 IT SAND, RBBIC
Louisiana	CAILLOU ISLAND	DEEP
Louisiana	CECELIA	FRIO
Louisiana	COTE BLANCHE BAY WEST	MEDIUM
Louisiana	COTE BLANCHE BAY WEST	WEST
Louisiana	COTE BLANCHE ISLAND	DEEP
Louisiana	CUT OFF	45 RESERVOIRS
Louisiana	EGAN	CAMERINA
Louisiana	EGAN	HAYES
Louisiana	FIELD 6794 -	6794
Louisiana	GARDEN ISLAND BAY	177 RESERVOIR A
Louisiana	GARDEN ISLAND BAY	MEDIUM
Louisiana	GARDEN ISLAND BAY	SHALLOW
Louisiana	GOOD HOPE	P-RESEROIVR NO 45900
Louisiana	GOOD HOPE	S-RESERVOIR NO. 54900
Louisiana	GRAND BAY	10B SAND, FAULT BLOCK A-1
Louisiana	GRAND BAY	21 SAND, FAULT BLOCK B
Louisiana	GRAND BAY	2MEDIUM
Louisiana	GRAND BAY	31 MARKER SAND, FAULT BLOCK A
Louisiana	GRAND BAY	MEDIUM
Louisiana	GRAND LAKE	873
Louisiana	GUEYDAN	ALLIANCE SAND
Louisiana	HACKBERRY WEST	2MEDIUM
Louisiana	HACKBERRY WEST	CAMERINA C SAND - FB 5

Table 11. Gulf Coast Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Louisiana	HACKBERRY WEST	MEDIUM
Louisiana	HACKBERRY WEST	OLIGOCENE AMOCO OPERATED ONLY
Louisiana	LAKE BARRE	LB LM2 SU
Louisiana	LAKE BARRE	LM1 LB SU
Louisiana	LAKE BARRE	UNIT B UPPER M-1 SAND
Louisiana	LAKE BARRE	UPPER MS RESERVOIR D
Louisiana	LAKE PALOURDE EAST	All
Louisiana	LAKE PELTO	PELTO DEEP
Louisiana	LAKE WASHINGTON	21 RESERVOIR A
Louisiana	LAKE WASHINGTON	DEEP
Louisiana	OLD LISBON	PETTIT LIME
Louisiana	PARADIS	DEEP
Louisiana	PARADIS	LOWER 9000 FT SAND RM
Louisiana	PARADIS	PARADIS ZONE, SEG A-B
Louisiana	QUARANTINE BAY	3 SAND, RESERVOIR B
Louisiana	QUARANTINE BAY	8 SAND, RESERVOIR B
Louisiana	QUARANTINE BAY	MEDIUM
Louisiana	ROMERE PASS	28 RESERVOIRS
Louisiana	ROMERE PASS	9700
Louisiana	SATURDAY ISLAND	All others
Louisiana	SATURDAY ISLAND	11 RESERVOIRS
Louisiana	SWEET LAKE	All others
Louisiana	SWEET LAKE	AVG 30 SANDS
Louisiana	VENICE	B-13 SAND
Louisiana	VENICE	B-30 SAND
Louisiana	VENICE	B-6 SAND
Louisiana	VENICE	B-7 SAND
Louisiana	VENICE	M-24 SAND
Louisiana	WEEKS ISLAND	DEEP
Louisiana	WEEKS ISLAND	R-SAND RESERVOIR A
Louisiana	WEEKS ISLAND	S-SAND RESERVOIR A
Louisiana	WEST BAY	11A SAND (RESERVOIR A)
Louisiana	WEST BAY	11B SAND FAULT BLOCK B
Louisiana	WEST BAY	6B RESERVOIR G
Louisiana	WEST BAY	8A SAND FAULT BLOCK A
Louisiana	WEST BAY	8AL SAND
Louisiana	WEST BAY	MEDIUM
Louisiana	WEST BAY	PROPOSED WB68 (RG) SAND UNIT
Louisiana	WEST BAY	WB 1 (FBA) SU
Louisiana	WEST BAY	X-11 (RESERVOIR A)
Louisiana	WEST BAY	X-9 A SAND (RESERVOIR A)

Table 11. Gulf Coast Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Louisiana	WEST DELTA BLOCK 83	10100 C SAND
Louisiana	WHITE LAKE WEST	AMPH B
Louisiana	WHITE LAKE WEST	BIG 3-2, RE, RC
Louisiana	ANSE LABUTTE	MIOCENE AMOCO OPERATED ONLY
Louisiana	BATEMAN LAKE	10400 GRABEN
Louisiana	BLACK BAYOU	FRIO SAND, RESERVOIR A
Louisiana	BLACK BAYOU	T-SAND
Louisiana	BLACK BAYOU	RESERVOIR OT SAND
Louisiana	BLACK BAYOU	T2 SAND RESERVOIR F
Louisiana	BOSCO	DISCORBIS
Louisiana	BULLY CAMP	TEXTULARLA, RL
Louisiana	CAILLOU ISLAND	UPPER 8000 RA SU
Louisiana	CAILLOU ISLAND	53-C RA SU
Louisiana	CHANDELEUR SOUND BLOCK 0025	BB RA SAND
Louisiana	CLOVELY	M RESERVOIR B
Louisiana	CLOVELY	50 SAND, FAULT BLOCK VII
Louisiana	CLOVELY	FAULT BLOCK IV NO. 50 SAND
Louisiana	COTE BLANCHE ISLAND	20 SAND
Louisiana	COTTON VALLEY	BODCAW
Louisiana	DELHI	DELHI ALL
Louisiana	DELTA DUCK CLUB	A SEQ LOWER 6,300' SAND
Louisiana	DELTA DUCK CLUB	B SEQ LOWER 6,300' SAND
Louisiana	DOG LAKE	DGL CC RU SU (REVISION)
Louisiana	ERATH	8,700
Louisiana	ERATH	7,300 SAND
Louisiana	FORDOCHE	WI2 RA
Louisiana	HAYNESVILLE	PETTIT
Louisiana	HAYNESVILLE	TOKIO
Louisiana	HAYNESVILLE EAST	EAST PETTIT
Louisiana	HAYNESVILLE EAST	BIRDSONG-OWENS
Louisiana	LAFITTE	LOWER SF DENNIS SAND, SEQ H
Louisiana	LAKE HATCH	9,850 SAND
Louisiana	LEEVILLE	95 SAND, SEQ B
Louisiana	LEEVILLE	96 SAND, SEQ B
Louisiana	LITTLE LAKE	E-4 SAND, RES A
Louisiana	MAIN PASS BLOCK 0035	90 CHANNEL G2
Louisiana	MAIN PASS BLOCK 0035	G2 RESERVOIR A SAND UNIT
Louisiana	MANILE VILLAGE	29 SAND
Louisiana	NORTH SHOUGALOO-RED ROCK	AAA
Louisiana	LISBON	PET LIME
Louisiana	PARADIS	MAIN PAY, SET T

Table 11. Gulf Coast Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Louisiana	PHOENIX LAKE	BROWN A-1
Louisiana	PORT BARRE	FUTRAL SAND, RESERVOIR A
Louisiana	QUARANTINE BAY	9A SAND, FAULT BLOCK C
Louisiana	QUARANTINE BAY	5 SAND, (REF)
Louisiana	RODESSA	RODESSE ALL
Louisiana	SECTION 28	2ND HACKBERRY, RESERVOIR D
Louisiana	SOUTHEAST PASS	J-5 SAND RA
Louisiana	SOUTHEAST PASS	L RESERVOIR C
Louisiana	TEPETATE	ORTEGO A
Louisiana	TEPETATE WEST	MILLER
Louisiana	VALENTINE	N SAND RESERVOIR A
Louisiana	VALENTINE	VAL N RC SU
Louisiana	VILLE PLATTE	RL BASAL COCKFIELD
Louisiana	VILLE PLATTE	RD BASAL COCKFIELD
Louisiana	VILLE PLATTE	MIDDLE COCKFIELD RA
Louisiana	WELSH	CAMERINA
Louisiana	WHITE CASTLE	01 RF SU
Louisiana	WHITE LAKE EAST	4- SAND
B. Mississippi		
Mississippi	BAY SPRINGS	CVL LOWER COTTON VALLEY
Mississippi	CRANFIELD	LOWER TUSCALOOSA
Mississippi	EUCUTTA EAST	E_EUTAW
Mississippi	HEIDELBERG, EAST	E_CHRISTMAS
Mississippi	HEIDELBERG, EAST	E_EUTAW
Mississippi	HEIDELBERG, EAST	UPPER TUSCALOOSA
Mississippi	HEIDELBERG, WEST	W_CHRISTMAS
Mississippi	LITTLE CREEK	LOWER TUSCALOOSA
Mississippi	MALLALIEU, WEST	LOWER TUSCALOOSA WMU C
Mississippi	MCCOMB	LOWER TUSCALOOSA B
Mississippi	PACHUTA CREEK, EAST	ESOPU RES.
Mississippi	QUITMAN BAYOU	4600 WILCOX
Mississippi	SOSO	BAILEY
Mississippi	TINSLEY	SELMA-EUTAW-TUSCALOOSA
Mississippi	TINSLEY	E_WOODRUFF SAND EAST SEGMENT
Mississippi	TINSLEY	W_WOODRUFF SAND WEST SEGMENT
Mississippi	YELLOW CREEK, WEST	EUTAW
Mississippi	EUCUTTA, WEST	W_EUTAW
Mississippi	FIELD 13	013
Mississippi	HEIDELBERG, WEST	EUTAW

Table 11. Gulf Coast Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
C. Alabama		
Alabama	CITRONELLE	RODESSA
Alabama	GILBERTOWN	LOWER EUTAW
Alabama	LITTLE ESCAMBIA CREEK	SMACKOVER
Alabama	NORTH FRISCO CITY	FRISCO CITY
Alabama	WOMACK HILL	SMACKOVER
D. Florida		
Florida	BLACKJACK CREEK	SMACKOVER
Florida	JAY	SMACKOVER
Florida	RACOON POINT	SUNNILAND
Florida	SUNNILAND	SUNNILAND
Florida	WEST FELDA	ROBERTS

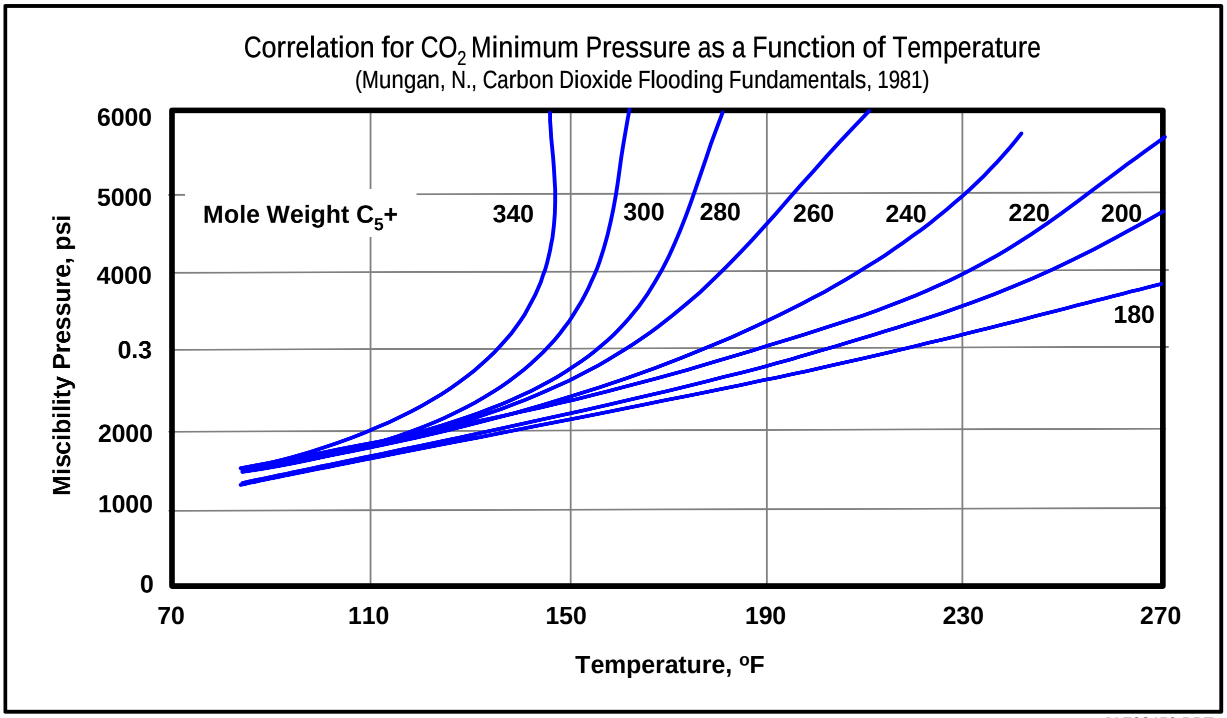
5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and oil composition, was to determine whether the reservoir would hold sufficient pressure to attain miscibility. Where oil composition data was missing, a correlation was used for translating the reservoir's oil gravity to oil composition.

To determine the minimum miscibility pressure (MMP) for any given reservoir, the study used the Cronquist correlation, Figure 8. This formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, without considering the mole percent of methane. (Most Gulf Coast oil reservoirs have produced the bulk of their methane during primary and secondary recovery.) The Cronquist correlation is set forth below:

$$MMP = 15.988*T^{(0.744206+0.0011038*MW\ C5+)}$$

Where: T is Temperature in ^{o}F, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

Figure 8. Estimating CO_2 Minimum Miscibility Pressure

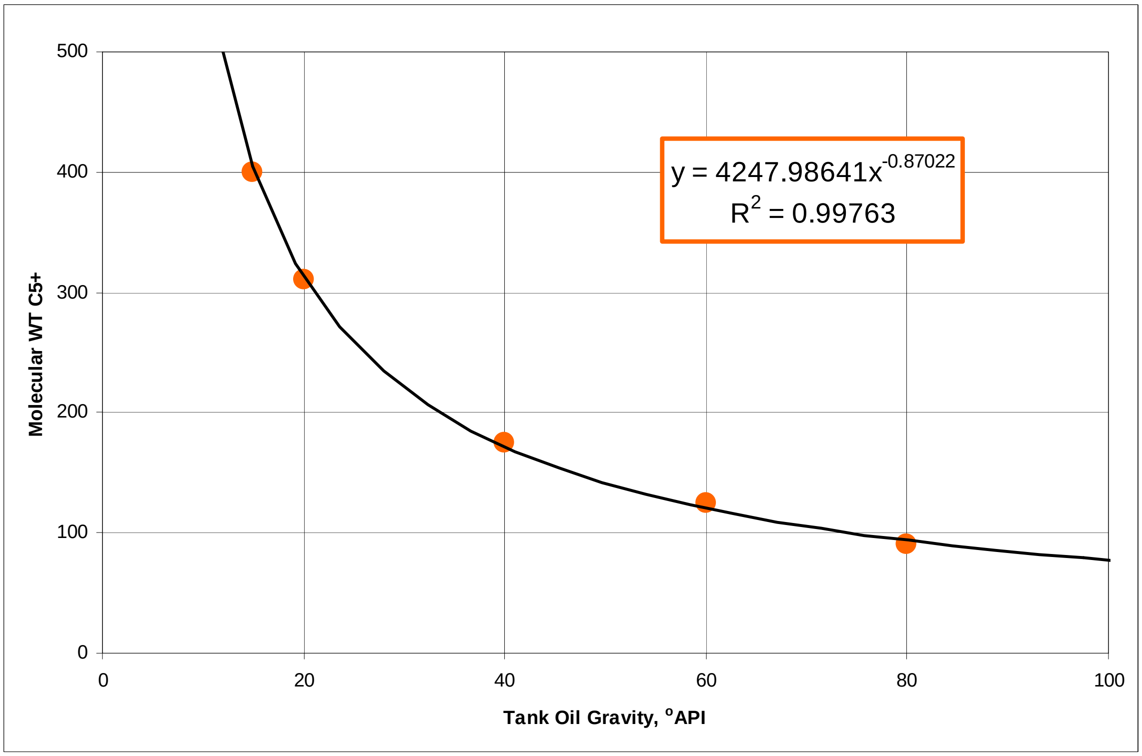


JAF02450.PPT

The temperature of the reservoir was taken from the data base or estimated from the thermal gradient in the basin. The molecular weight of the pentanes and heavier fraction of the oil was obtained from the data base or was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure 9.

The next step was calculating the minimum miscibility pressure (MMP) for a given reservoir and comparing it to the maximum allowable pressure. The maximum pressure was determined using a pressure gradient of 0.6 psi/foot. If the minimum miscibility pressure was below the maximum injection pressure, the reservoir was classified as a miscible flood candidate. Oil reservoirs that did not screen positively for miscible CO_2-EOR were selected for consideration by immiscible CO_2-EOR.

Figure 9. Correlation of MW C5+ to Tank Oil Gravity.
(modified from Mungan, N. Carbon Dioxide Flooding Fundamentals, 1981)



5.5 CALCULATING OIL RECOVERY. The study utilized *CO_2-PROPHET* to calculate incremental oil produced using CO_2-EOR. *CO_2-PROPHET* was developed by the Texaco Exploration and Production Technology Department (EPTD) as part of the DOE Class I cost-share program. The specific project was "Post Waterflood CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir" (DOE Contract No. DE-FC22-93BC14960). *CO_2-PROPHET* was developed as an alternative to the DOE's CO_2 miscible flood predictive model, *CO_2PM*. According to the developers of the model, *CO_2-PROPHET* has more capabilities and fewer limitations than *CO_2PM*. For example, according to the above cited report, *CO_2-PROPHET* performs two main operations that provide a more robust calculation of oil recovery than available from *CO_2PM*:

- *CO_2-PROPHET* generates streamlines for fluid flow between injection and production wells, and

- The model performs oil displacement and recovery calculations along the established streamlines. (A finite difference routine is used for oil displacement calculations.)

Appendix A discusses, in more detail, the *CO_2-PROPHET* model and the calibration of this model with an industry standard reservoir simulator.

Even with these improvements, it is important to note the CO_2-PROPHET is still primarily a "screening-type" model, and lacks some of the key features, such as gravity override and compositional changes to fluid phases, available in more sophisticated reservoir simulators.

5.6 ASSEMBLING THE COST MODEL. A detailed, up-to-date CO_2-EOR Cost Model was developed by the study. The model includes costs for: (1) drilling new wells or reworking existing wells; (2) providing surface equipment for new wells; (3) installing the CO_2 recycle plant; (4) constructing a CO_2 spur-line from the main CO_2 trunkline to the oil field; and, (5) various miscellaneous costs.

The cost model also accounts for normal well operation and maintenance (O&M), for lifting costs of the produced fluids, and for costs of capturing, separating and reinjecting the produced CO_2. A variety of CO_2 purchase and reinjection costs options are available to the model user. (Appendices B, C, D and E provide state-level details on the Cost Model for CO_2-EOR prepared by this study.)

5.7 CONSTRUCTING AN ECONOMICS MODEL. The economic model used by the study is an industry standard cash flow model that can be run on either a pattern or a field-wide basis. The economic model accounts for royalties, severance and ad valorem taxes, as well as any oil gravity and market location discounts (or premiums) from the "marker" oil price. A variety of oil prices are available to the model user. Table 12 provides an example of the Economic Model for CO_2-EOR used by the study.

Table 12. Economic Model Established by the Study

Pattern-Level Cashflow Model		**Advanced**											
State		**SOUTH**											
Field				New Injectors	0.00			21					
Formation				Existing Injectors	0.00								
Depth				Convertable Producers	1.00								
Distance from Trunkline (mi)				New Producers	0.0								
# of Patterns				Existing Producers	1.89								
Miscibility:	**Miscible**												
	Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
CO_2 Injection (MMcf)			731	731	731	731	731	731	731	731	696	656	656
H_2O Injection (Mbw)			183	183	183	183	183	183	183	183	200	220	220
Oil Production (Mbbl)			-	-	76	103	66	61	66	52	46	38	34
H_2O Production (MBw)			475	475	387	264	258	241	224	218	216	234	242
CO_2 Production (MMcf)			-	-	27	264	373	430	461	509	538	524	513
CO_2 Purchased (MMcf)			731	731	704	466	357	301	270	222	158	132	143
CO_2 Recycled (MMcf)			-	-	27	264	373	430	461	509	538	524	513
Oil Price ($/Bbl)	**$ 30.00**		$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Gravity Adjustment	35	Deg	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15
Gross Revenues ($M)			$ -	$ -	$ 2,134	$ 2,885	$ 1,861	$ 1,720	$ 1,844	$ 1,455	$ 1,284	$ 1,056	$ 954
Royalty ($M)	**-12.5%**		$ -	$ -	$ (267)	$ (361)	$ (233)	$ (215)	$ (230)	$ (182)	$ (160)	$ (132)	$ (119)
Severance Taxes ($M)	**-12.5%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (104)
Ad Valorum ($M)	**-1.0%**		$ -	$ -	$ (19)	$ (25)	$ (16)	$ (15)	$ (16)	$ (13)	$ (11)	$ (9)	$ (8)
Net Revenue($M)			$ -	$ -	$ 1,848	$ 2,499	$ 1,612	$ 1,490	$ 1,597	$ 1,261	$ 1,112	$ 914	$ 722
Capital Costs ($M)													
New Well - D&C		$ -											
Reworks - Producers to Producers		$ (438)											
Reworks - Producers to Injectors		$ (100)											
Reworks - Injectors to Injectors		$ -											
Surface Equipment (new wells only)		$ -											
Recycling Plant		$ -	$ -	$ (1,131)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (135)											
Total Capital Costs		$ (672)	$ -	$ (1,131)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO_2 Costs ($M)													
Total CO_2 Cost ($M)			$ (1,095.8)	$ (1,096)	$ (1,063)	$ (779)	$ (648)	$ (580)	$ (543)	$ (485)	$ (398)	$ (355)	$ (368)
O&M Costs													
Operating & Maintenance ($M)			$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)
Lifting Costs ($/bbl)	**$ 0.25**		$ (119)	$ (119)	$ (116)	$ (92)	$ (81)	$ (75)	$ (72)	$ (68)	$ (65)	$ (68)	$ (69)
G&A	**20%**		(61)	(61)	(60)	(55)	(53)	(52)	(51)	(50)	(50)	(50)	(51)
Total O&M Costs			$ (363)	$ (363)	$ (359)	$ (331)	$ (318)	$ (311)	$ (307)	$ (301)	$ (299)	$ (302)	$ (303)
Net Cash Flow ($M)		$ (672)	$ (1,459)	$ (2,590)	$ 426	$ 1,390	$ 646	$ 599	$ 747	$ 474	$ 415	$ 257	$ 50
Cum. Cash Flow		$ (672)	$ (2,131)	$ (4,720)	$ (4,295)	$ (2,905)	$ (2,258)	$ (1,660)	$ (912)	$ (438)	$ (23)	$ 234	$ 284
Discount Factor	**15%**	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25	0.21
Disc. Net Cash Flow		$ (672)	$ (1,269)	$ (1,958)	$ 280	$ 795	$ 321	$ 259	$ 281	$ 155	$ 118	$ 64	$ 11
Disc. Cum Cash Flow		$ (672)	$ (1,941)	$ (3,899)	$ (3,619)	$ (2,824)	$ (2,503)	$ (2,244)	$ (1,963)	$ (1,808)	$ (1,690)	$ (1,626)	$ (1,616)
NPV (BTx)	25%	($1,963)											
NPV (BTx)	20%	($1,765)											
NPV (BTx)	15%	($1,440)											
NPV (BTx)	10%	($906)											
IRR (BTx)		4.88%											

Table 12. Economic Model Established by the Study (cont'd)

Pattern-Level Cashflow Model		Advanced														
State		**SOUTH**														
Field																
Formation																
Depth																
Distance from Trunkline (mi)																
# of Patterns																
Miscibility:	**Miscible**															
	Year	**0**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
CO2 Injection (MMcf)			656	656	656	656	656	656	656	656	656	656	656	518	-	-
H2O Injection (Mbw)			220	220	220	220	220	220	220	220	220	220	220	289	548	548
Oil Production (Mbbl)			34	37	47	46	48	42	33	28	23	19	19	20	20	20
H2O Production (MBw)			240	238	221	223	218	217	221	219	227	228	227	234	312	426
CO2 Production (MMcf)			519	518	531	531	537	556	570	585	581	588	590	604	540	253
CO2 Purchased (MMcf)			137	138	125	125	119	101	87	71	75	68	66	-	-	-
CO2 Recycled (MMcf)			519	518	531	531	537	556	570	585	581	588	590	518	-	-
Oil Price ($/Bbl)	**$ 30.00**		$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Gravity Adjustment	**35**	Deg	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15	$ 28.15
Gross Revenues ($M)			$ 960	$ 1,033	$ 1,334	$ 1,289	$ 1,362	$ 1,191	$ 929	$ 794	$ 633	$ 532	$ 521	$ 557	$ 552	$ 574
Royalty ($M)	**-12.5%**		$ (120)	$ (129)	$ (167)	$ (161)	$ (170)	$ (149)	$ (116)	$ (99)	$ (79)	$ (67)	$ (65)	$ (70)	$ (69)	$ (72)
Severance Taxes ($M)	**-12.5%**		$ (105)	$ (113)	$ (146)	$ (141)	$ (149)	$ (130)	$ (102)	$ (87)	$ (69)	$ (58)	$ (57)	$ (61)	$ (60)	$ (63)
Ad Valorum ($M)	**-1.0%**		$ (8)	$ (9)	$ (12)	$ (11)	$ (12)	$ (10)	$ (8)	$ (7)	$ (6)	$ (5)	$ (5)	$ (5)	$ (5)	$ (5)
Net Revenue($M)			$ 727	$ 782	$ 1,010	$ 976	$ 1,031	$ 901	$ 703	$ 601	$ 479	$ 403	$ 394	$ 422	$ 418	$ 435
Capital Costs ($M)																
New Well - D&C		$ -														
Reworks - Producers to Producers		$ (438)														
Reworks - Producers to Injectors		$ (100)														
Reworks - Injectors to Injectors		$ -														
Surface Equipment (new wells only)		$ -														
Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (135)														
Total Capital Costs		$ (672)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)																
Total CO2 Cost ($M)			$ (361)	$ (362)	$ (347)	$ (347)	$ (340)	$ (317)	$ (301)	$ (282)	$ (287)	$ (278)	$ (276)	$ (155)	$ -	$ -
O&M Costs																
Operating & Maintenance ($M)			$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)	$ (184)
Lifting Costs ($/bbl)	**$ 0.25**		$ (68)	$ (69)	$ (67)	$ (67)	$ (67)	$ (65)	$ (63)	$ (62)	$ (62)	$ (62)	$ (61)	$ (64)	$ (98)	$ (127)
G&A	**20%**		(50)	(50)	(50)	(50)	(50)	(50)	(49)	(49)	(49)	(49)	(49)	(49)	(56)	(62)
Total O&M Costs			$ (303)	$ (303)	$ (301)	$ (301)	$ (300)	$ (298)	$ (297)	$ (295)	$ (295)	$ (294)	$ (294)	$ (297)	$ (337)	$ (373)
Net Cash Flow ($M)		$ (672)	$ 63	$ 117	$ 362	$ 328	$ 391	$ 286	$ 106	$ 24	$ (103)	$ (170)	$ (176)	$ (30)	$ 80	$ 62
Cum. Cash Flow		$ (672)	$ 347	$ 464	$ 826	$ 1,153	$ 1,545	$ 1,830	$ 1,936	$ 1,960	$ 1,857	$ 1,687	$ 1,511	$ 1,481	$ 1,561	$ 1,623
Discount Factor	**15%**	1.00	0.19	0.16	0.14	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05	0.04	0.03	0.03
Disc. Net Cash Flow		$ (672)	$ 12	$ 19	$ 51	$ 40	$ 42	$ 27	$ 9	$ 2	$ (6)	$ (9)	$ (8)	$ (1)	$ 3	$ 2
Disc. Cum Cash Flow		$ (672)	$ (1,604)	$ (1,585)	$ (1,534)	$ (1,493)	$ (1,452)	$ (1,425)	$ (1,417)	$ (1,415)	$ (1,421)	$ (1,430)	$ (1,438)	$ (1,440)	$ (1,437)	$ (1,435)
NPV (BTx)	25%	($1,963)														
NPV (BTx)	20%	($1,765)														
NPV (BTx)	15%	($1,440)														
NPV (BTx)	10%	($906)														
IRR (BTx)		4.88%														

Table 12. Economic Model Established by the Study (cont'd)

Pattern-Level Cashflow Model		**Advanced**												
State		**SOUTH**												
Field														
Formation														
Depth														
Distance from Trunkline (mi)														
# of Patterns														
Miscibility:	**Miscible**													
	Year	**0**	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	
CO_2 Injection (MMcf)			-	-	-	-	-	-	-	-	-	-	-	15,588
H_2O Injection (Mbw)			37	-	-	-	-	-	-	-	-	-	-	5,941
Oil Production (Mbbl)			2	-	-	-	-	-	-	-	-	-	-	977
H_2O Production (MBw)			31	-	-	-	-	-	-	-	-	-	-	6,715
CO_2 Production (MMcf)			13	-	-	-	-	-	-	-	-	-	-	11,155
CO_2 Purchased (MMcf)			-	-	-	-	-	-	-	-	-	-	-	5,325
CO_2 Recycled (MMcf)			-	-	-	-	-	-	-	-	-	-	-	10,263
Oil Price ($/Bbl)	**$ 30.00**		$ 30.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Gravity Adjustment	**35**	Deg	$ 28.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Gross Revenues ($M)			$ 45	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,500
Royalty ($M)	**-12.5%**		$ (6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,437)
Severance Taxes ($M)	**-12.5%**		$ (5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,450)
Ad Valorum ($M)	**-1.0%**		$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (241)
Net Revenue($M)			$ 34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,371
Capital Costs ($M)														
New Well - D&C		$ -												$ -
Reworks - Producers to Producers		$ (438)												$ (438)
Reworks - Producers to Injectors		$ (100)												$ (100)
Reworks - Injectors to Injectors		$ -												$ -
Surface Equipment (new wells only)		$ -												$ -
Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,131)
Trunkline Construction		$ (135)												$ (135)
Total Capital Costs		$ (672)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,803)
CO_2 Costs ($M)														
Total CO_2 Cost ($M)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,066)
O&M Costs														
Operating & Maintenance ($M)			$ (184)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,777)
Lifting Costs ($/bbl)	**$ 0.25**		$ (9)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,954)
G&A	**20%**		(39)	-	-	-	-	-	-	-	-	-	-	$ (1,346)
Total O&M Costs			$ (232)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,077)
Net Cash Flow ($M)		$ (672)	$ (198)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,425
Cum. Cash Flow		$ (672)	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	$ 1,425	
Discount Factor	**15%**	1.00	0.03	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	
Disc. Net Cash Flow		$ (672)	$ (5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,440)
Disc. Cum Cash Flow		$ (672)	$ (1,440)	$ (1,440)	$ (1,440)	$ (1,440)	$ (1,440)	$ (1,440)	$ (1,440)	$ (1,440)	$ (1,440)	$ (1,440)	$ (1,440)	
NPV (BTx)	25%	($1,963)												
NPV (BTx)	20%	($1,765)												
NPV (BTx)	15%	($1,440)												
NPV (BTx)	10%	($906)												
IRR (BTx)		4.88%												

5.8 PERFORMING SCENARIO ANALYSES. A series of analyses were prepared to better understand how differences in oil prices, CO_2 supply costs and financial risk hurdles could impact the volumes of oil that would be economically produced by CO_2-EOR from the Gulf Coast's oil basins and major oil reservoirs.

- Two technology cases were examined. As discussed in more detail in Chapter 2, the study examined the application of two CO_2-EOR options — "Traditional Practices" and "State-of-the-art" Technology.

- Two oil prices were considered. A \$30 per barrel oil price was used to represent the moderate oil price case; a \$40 per barrel oil price was used to represent the availability of federal/state risk sharing and/or the continuation of the current high oil price situation.

- Two CO_2 supply costs were considered. The high CO_2 cost was set at 5% of the oil price (\$1.50 per Mcf at \$30 per barrel) to represent the costs of a new transportation system bringing natural CO_2 to the Gulf Coast's oil basins. A lower CO_2 supply cost equal to 2% of the oil price (\$0.80 per Mcf at \$40 per barrel) was included to represent the potential future availability of low-cost CO_2 from industrial and power plants as part of CO_2 storage.

- Two minimum rate of return (ROR) hurdles were considered, a high ROR of 25%, before tax, and a lower 15% ROR, before tax. The high ROR hurdle incorporates a premium for the market, reservoir and technology risks inherent in using CO_2-EOR in a new reservoir setting. The lower ROR hurdle represents application of CO_2-EOR after the geologic and technical risks have been mitigated with a robust program of field pilots and demonstrations.

These various technology, oil price, CO_2 supply cost and rate of return hurdles were combined into four scenarios, as set forth below:

- The first scenario captures how CO_2-EOR technology has been applied and has performed in the past. This low technology, high risk scenario, is called “Traditional Practices”.
- The second scenario, entitled “State-of-the-art”, assumes that the technology progress in CO_2-EOR, achieved in the past ten years in other areas, is successfully applied to the oil reservoirs of the Gulf Coast. In addition, this scenario assumes that a comprehensive program of research, pilot tests and field demonstrations will help lower the risk inherent in applying new technology to these complex Gulf Coast oil reservoirs.
- The third scenario, entitled “Risk Mitigation,” examines how the economic potential of CO_2-EOR could be increased through a strategy involving state production tax reductions, federal tax credits, royalty relief and/or higher world oil prices that together would add an equivalent $10 per barrel to the price that the producer uses for making capital investment decisions for CO_2-EOR.
- The final scenario, entitled “Ample Supplies of CO_2,” low-cost, “EOR-ready” CO_2 supplies are aggregated from various industrial and natural sources. These include industrial high-concentration CO_2 emissions from hydrogen facilities, gas processing plants, chemical plants and other sources in the region. These would be augmented, in the longer-term, from concentrated CO_2 emissions from refineries and electric power plants. Capture of industrial CO_2 emissions could be part of a national effort for reducing greenhouse gas emissions.

6. RESULTS BY STATE

6.1 LOUISIANA. Louisiana is a major oil producing state with a rich history of oil and gas development. Crude oil production began in 1902, and has reached a cumulative recovery of 13 billion barrels through 2004. In 2004, Louisiana Onshore ranked 6th in oil production in the onshore U.S providing 45 MMBbls of oil (123 MBbls/day). It has about 27,000 producing oil wells and oil reserves of 362 MMBbls. The bulk of oil production is from the southern portion of the state.

Despite still being one of the top oil producing states, Louisiana has seen a significant decline in production in recent years, Table 13.

Table 13. Recent History of Louisiana Onshore Oil Production

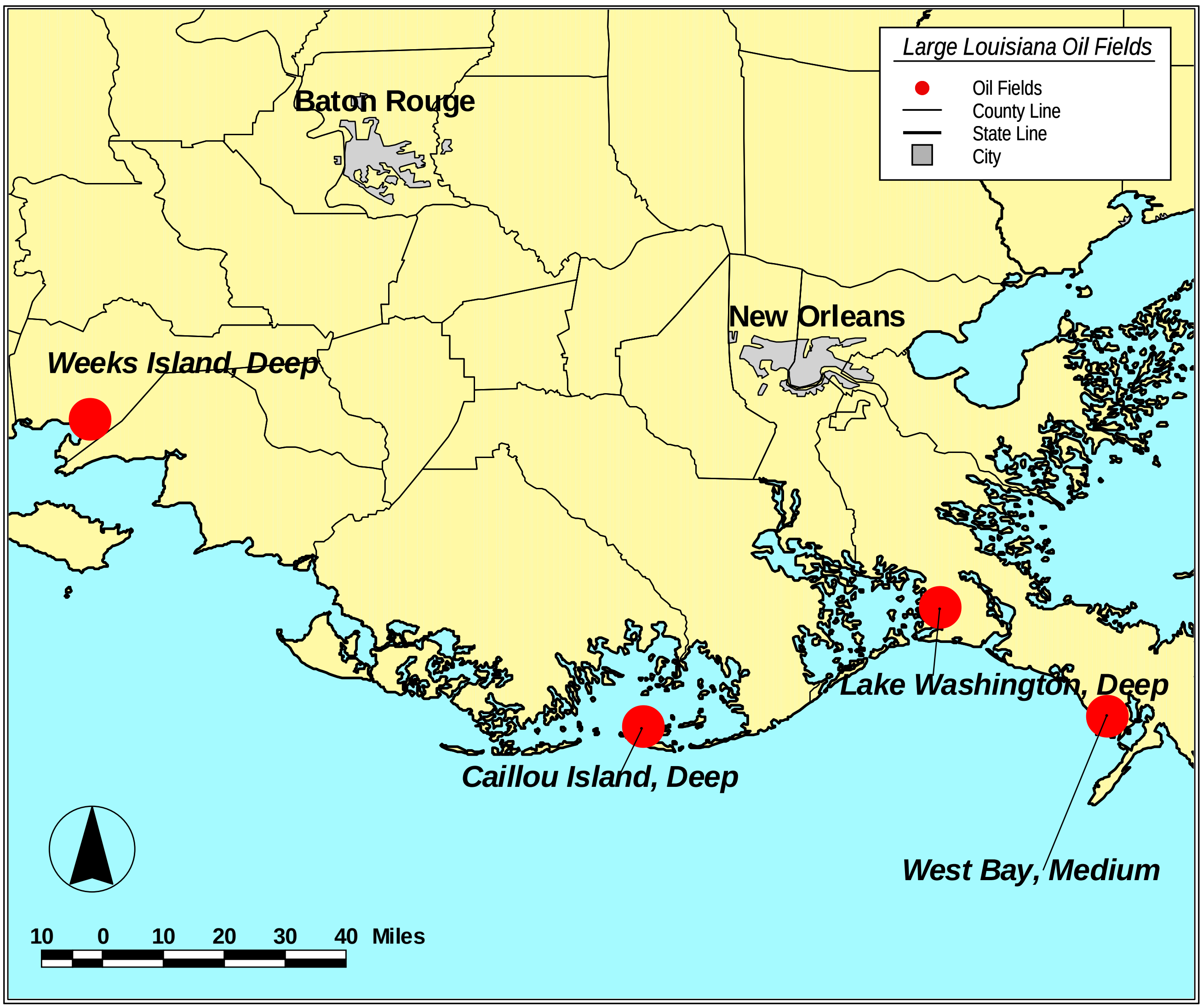
	Annual Oil Production	
	(MMBls/year)	(MBbls/day)
1999	70	192
2000	59	162
2001	59	162
2002	49	134
2003	51	140
2004	45	123

An active program of secondary oil recovery has helped maintain oil production in the state. In 1996, more than 300 onshore oil reservoirs in the state of Louisiana were being waterflooded. However, these waterfloods are now mature, with many of the fields near their production limits, calling for alternative methods for maintaining oil production.

Louisiana Oil Fields. To better understand the potential of using CO_2-EOR in Louisiana's light oil fields, this section examines, in more depth, four large oil fields, shown in Figure 11.

- Caillou Island (Deep Reservoirs)
- Lake Washington (Deep Reservoirs)
- Weeks Island (Deep Reservoirs)
- West Bay (Medium Reservoirs)

Figure 11. Large Louisiana Oil Fields



These four fields, distributed across southern Louisiana, could serve as the "anchor" sites for CO_2-EOR projects in the southern portion of the state that could later be extended to other fields. The cumulative oil production, proved reserves and remaining oil in place (ROIP) for these four large light oil fields are set forth in Table 14.

Table 14. Status of Large Oil Louisiana Fields/Reservoirs (as of 2002)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Primary/Secondary Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Callilou Island (Deep)	1,176	581	7	588
2	Lake Washington (Deep)	566	243	12	311
3	Weeks Island (Deep)	340	143	10	187
4	West Bay (Medium)	325	134	7	183

These four large "anchor" fields, each with 180 or more million barrels of ROIP, appear to be favorable for miscible CO_2 -EOR, based on their reservoir properties, Table 15.

Table 15. Reservoir Properties and Improved Oil Recovery Activity,
Large Louisiana Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Callilou Island (Deep)	13,000	39.0	Undergoing waterflooding
2	Lake Washington (Deep)	12,500	26.0	Undergoing waterflooding
3	Weeks Island (Deep)	14,000	33.0	Past CO_2-EOR Project
4	West Bay (Medium)	9,000	30.0	Undergoing waterflooding

Past CO_2-EOR Projects. Past CO_2-EOR pilot projects in onshore Louisiana have been conducted in Paradis (Lower 9000 Sand RM), Bay St. Elaine (8,000 ft sand),

and West Bay (5 A'B") oil reservoirs. However, perhaps the most notable pilot project has been Shell Oil Company's Weeks Island gravity stable flood, discussed below:

Weeks Island. Beginning in 1978, Shell and the U.S. DOE began a CO_2 gravity stable pilot project at the "S" Sand Reservoir B of Weeks Island field. (Weeks Island field is a piercement type salt dome, with commercial production from 37 Lower Miocene sands.)

- Initial gas injection, containing 853 MMcf of CO_2 (24% HCPV) and 55 MMcf of natural gas, lasted from October 1978 until February 1980. This was followed by re-injection of the produced CO_2 and natural gas (at 761 Mcf/d) through 1987.
- Early production testing revealed that an oil bank was being mobilized in the watered out sand, creating an oil bank measured at 57 feet of thickness.
- Oil production began in early 1981. By 1987, 261,000 barrels of oil, or 64% of ROIP, had been recovered. Subtracting the mobile oil at the start, the project mobalized 205,000 barrels of residual oil, equal to 60% of the oil left after water displacement. As such, the pilot project in the "S" Sand Reservoir B at Weeks Island was considered a success.

The full field application of the CO_2 gravity project at Weeks Island was not successful due to inability of the CO_2 injection design to displace the strong bottom water drive.

Bay St. Elane (8000 Foot Reservoir E Sand Unit). A gravity-stable miscible CO_2 flood was initiated in the Bay St. Elane (RESU) field in 1981. The purpose of the project was to test the effectiveness of CO_2 injection into a steeply dipping (36º), low residual oil (20%) sandstone reservoir.

- Approximately 433 MMcf of CO_2 solvent was injected into an up-dip well over a 9 month period, resulting in a 0.33 PV CO_2 (plus methane/butane) injection. Approximately 300 MMcf of nitrogen was then injected as the drive gas.

- The project expected to recover 75,000 barrels of incremental oil, assuming a residual oil saturation after CO_2 flooding of 5% and a CO_2 sweep efficiency of 53% (based on 75% vertical and 70% areal conformance).
- The operator reports that while an oil bank was mobilized and one of the producing wells flowed at 92% oil cut (previously 100% water cut), there was difficulty in producing the oil bank with the existing well placements. Final performance results for this innovative CO_2-EOR project are not available.

Immiscible CO_2 ("Huff and Puff"). A series of small scale CO_2 well stimulation ("Huff and Puff") tests were conducted in the mid-1980's. This process, similar to using steam stimulation in heavy oil fields, involves injecting a substantial volume of CO_2 into a producing well, allowing the CO_2 to soak into the oil for a few weeks, and then returning the well to production. The operators reported that incremental oil recoveries were achieved at low CO_2/oil ratios. One such project, Paradis (Main Pay Sand, Reservoir T), was conducted in 1984/1985 and involved injecting two cycles of CO_2 into a producing well. A total of 39 MMcf of CO_2 was injected resulting in reported incremental oil recovery of 20,700 barrels. Post project analysis showed that higher CO_2 injection rates would have enabled the CO_2 to contact more of the reservoir's oil.

Future CO_2-EOR Potential. Louisiana contains 128 reservoirs that are candidates for miscible CO_2-EOR. Under "Traditional Practices" (and Base Case financial conditions, defined above), there is one economically attractive oil reservoirs for miscible CO_2 flooding in Louisiana. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection) and lower risk financial conditions, the number of economically favorable oil reservoirs in Louisiana increases to 4, providing 129 million barrels of additional oil recovery, Table 16.

Table 16. Economic Oil Recovery Potential Under Two Technologic Conditions, Louisiana

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential*	
				(No. of Reservoirs)	(MMBbls)
"Traditional Practices"	128	16,050	1,429	1	3
"State-of-the-art" Technology	128	16,050	3,247	4	129

** Oil price of \$30 per barrel; CO_2 costs of \$1.50/Mcf.*

Combining "State-of-the-art" technologies with risk mitigation incentives and/or higher oil prices and lower cost CO_2 supplies would enable CO_2-EOR in Louisiana to recover 1,916 million barrels of CO_2-EOR oil (from 52 major reservoirs), Table 17.

Table 17. Economic Oil Recovery Potential with
More Favorable Financial Conditions, Louisiana

More Favorable Financial Conditions	Technical Potential (MMBbls)	Economic Potential	
		(No. of Reservoirs)	(MMBbls)
Plus: Risk Mitigation Incentives*	3,247	24	1,117
Plus: Low Cost CO_2 Supplies**	3,247	52	1,916

** Oil price of \$40 per barrel, adjusted for gravity and location differentials; CO_2 supply costs, \$2/Mcf*

*** CO_2 supply costs, \$0.80/Mcf*

6.2 MISSISSIPPI. Mississippi is the 10th largest oil producing state, providing 17 MMBbls (47 MBbls/day) of oil (in 2004), from about 1,500 producing wells and 178 MMBbls of crude oil reserves. Oil production in the state of Mississippi began in 1889, and cumulative oil recovery has reached almost 2.3 billion barrels. Despite having many old fields, oil production in Mississippi has remained level in recent years, due to improved oil recovery efforts, Table 18.

Table 18. Recent History of Mississippi Onshore Oil Production

	Annual Oil Production	
	(MMBbls/year)	(MBbls/day)
1999	15	41
2000	18	49
2001	18	49
2002	18	49
2003	16	44
2004	17	47

Denbury Resources has been instrumental in revitalizing the aging oil fields of Mississippi. They purchased the Heidelberg field in 1997 from Chevron, a field that has produced almost 200 MMBbls of oil since discovery in 1944. Currently, oil production is from five waterflood units producing from the Eutaw Formation. Production at Heidelburg in 1997 was approximately 2,800 Bbls/day and has increased to 7,500 Bbls/day as a result of waterflooding. In addition, Denbury Resources has initiated a series of CO_2-EOR projects that produced 6,800 barrels per day in 2004.

Mississippi Oil Fields. Mississippi has a number of large oil fields that may be amenable to miscible CO_2- EOR, Figure 12. These include:

- Tinsley (E. Woodruff Sand)
- Quitman Bayou (4600 Wilcox)
- East Heidelberg (Christmas)

These three major oil fields could serve sites for the CO_2 projects that could later extend to small fields in the state. The cumulative oil production, proved reserves and remaining oil in-place (ROIP) for these three major light oil reservoirs are set forth in Table 19.

Figure 12. Large Mississippi Oil Fields

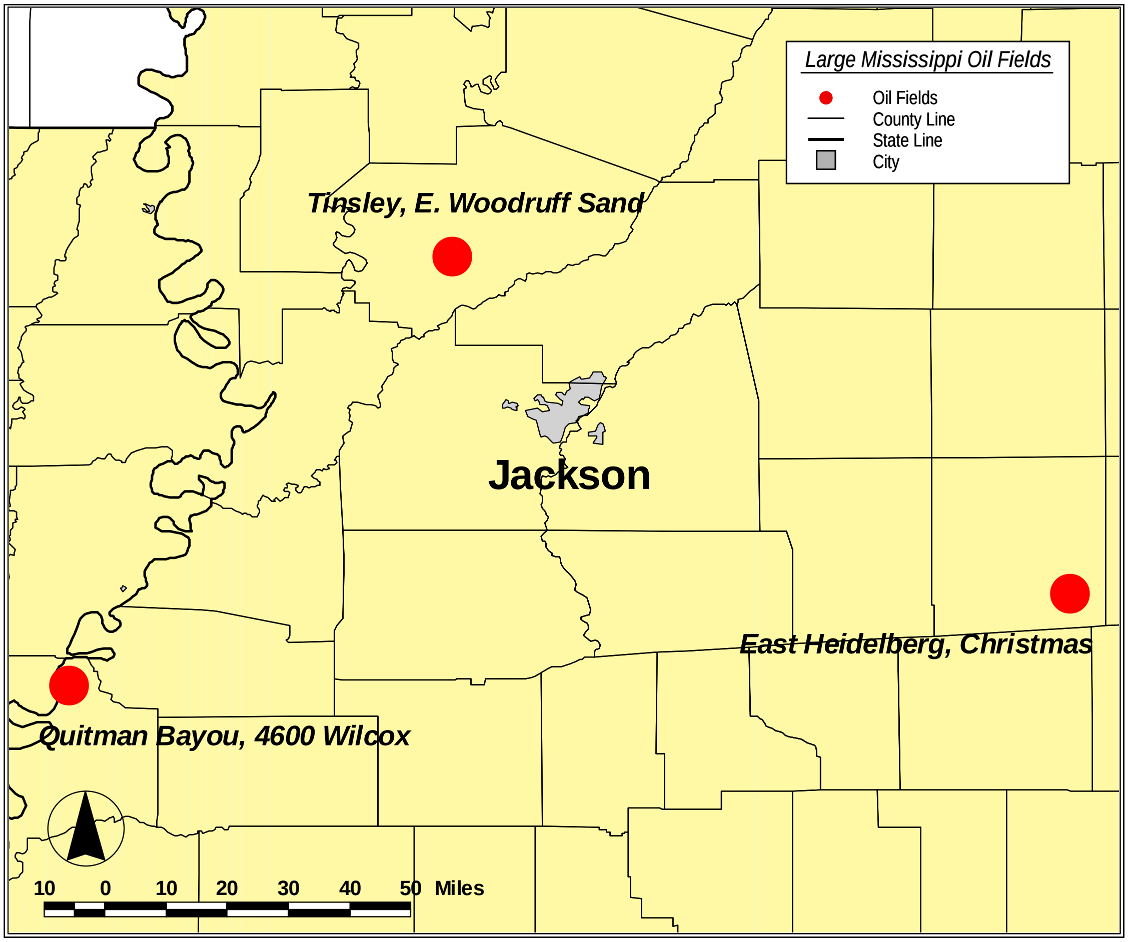


Table 19. Status of Large Mississippi Oil Fields/Reservoirs (as of 2002)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Primary/Secondary Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Tinsley (E. Woodruff Sand)	163	50	2	111
2	Quitman Bayou (4600 Wilcox)	75	21	*	54
3	East Heidelberg (Christmas)	93	36	6	51

**Less than 0.5 MMBbls.*

These three large oil reservoirs, with 50 to over 100 million barrels of ROIP, are amenable to CO_2-EOR. Table 20 provides the reservoir and oil properties for these three reservoirs and their current secondary oil recovery activities.

Table 20. Reservoir Properties and Improved Oil Recovery Activity, Large Mississippi Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Tinsley (E. Woodruff Sand)	4,900	33	Active Waterflood
2	Quitman Bayou (4600 Wilcox)	4,700	39	Active Waterflood
3	East Heidelberg (Christmas)	4,827	25	Active Waterflood

In addition to the three major light oil reservoirs, several fields in Mississippi have reservoirs containing heavier oils, such as West Heidelberg and West Eucutta. These fields could become candidate fields for immiscible CO_2-EOR, Table 21.

Table 21. Reservoir Properties and Improved Oil Recovery Activity Potential, Mississippi "Immiscible-CO_2" Oil Fields/Reservoirs

	Candidate Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	West Eucutta (Eutaw)	4,900	23	None
2	West Heidelberg (Eutaw)	5,000	22	Active waterflood

Past and Current CO_2-EOR Projects. Mississippi has also seen an active history of CO_2 enhanced oil recovery, particularly at Little Creek and Mallalieu fields in western Mississippi.

<u>Little Creek (Lower Tuscaloosa Denkman).</u> An experimental CO_2 pilot was conducted by Shell Oil in the Little Creek oil field from 1974 to 1977. The purpose of

this pilot test was to determine the effectiveness of using CO_2-EOR to recover immobile residual oil from a thoroughly waterflood depleted, deep (10,400 feet) sandstone reservoir.

- The project involved one injection and three producing wells, essentially one-quarter of an inverted nine-spot on a 40-acre spacing. The pilot area was confined by surrounding water injection wells and a field pinchout.
- Prior to the CO_2-flood, the field had recovered 47 million barrels of its 130 million barrels initially in place, leaving behind a low 21% residual oil saturation.
- A large volume of CO_2 (1,590 MMcf of purchased and 1,783 MMcf of recycled CO_2) equal to 1.6 HCPV was first injected and then followed by 1 PV of water.
- The pilot produced 124,000 barrels of oil (through March 1978), equal to 21% of OOIP (and 45% of ROIP). Post-flood reservoir simulation showed that gravity segregation and lack of vertical conformance reduced the effectiveness of the CO_2 flood. Post project reservoir simulation of operating flood on WAG (rather than straight CO_2) indicated that CO_2 channeling could have been reduced, increasing volumetric sweep efficiency and oil recovery.
- Given the large CO_2 slug and less than optimum sweep efficiency, the project had a high CO_2 to oil ratio of 27 Mcf/Bbl gross and 13 Mcf/Bbl net. The producing well (Well 11-1) closest to the CO_2 injector experienced early CO_2 breakthrough contributing to the high CO_2 to oil ratio.

In 1999, Denbury Resources Inc. acquired the Little Creek Field and expanded the field-scale CO_2 flood (started in 1985) to the current 34 injectors and 28 producers.

- The CO_2 flood (at Little Creek plus Lazy Creek) is expected to recover 22 million barrels of incremental oil (17% OOIP) in addition to 37% from primary/secondary recovery operations.
- Oil production at the end of 2004 was about 2,990 barrels per day, up from 1,350 barrels per day in 1999.

<u>West Mallalieu Field Unit (WMU)</u>. The West Mallalieu Field (Lower Tuscaloosa Sand), located in Lincoln Co., MS, has produced 35 million barrels (or 26% of the OOIP)

with primary recovery, natural waterflood and a limited CO_2 project. (The existence of a strong natural water drive substituted for the waterflood.) New well drilling, in preparation for the CO_2 flood, showed that the reservoir was at residual oil saturation. The field has experienced three phases of CO_2-EOR:

1) Initial CO_2-EOR Project. A CO_2-EOR pilot was initiated in the WMU by Shell Oil in 1986. The project involved four inverted five-spot patterns surrounded by water injection barrier wells. By the end of 1988, because only three of the producers showed oil response, the water injection wells were converted to production wells. Oil production, due to CO_2 injection, peaked at 1,200 B/D in mid-1989 and then declined rapidly to about 200 B/D in mid-1991. As of the end of 1997 when the field was shut-in, the WMU had produced 2.1 MMBbls due to CO_2-EOR.

2) Cyclic CO_2 Pilot. In August 2000, in an effort to revitalize the field, J.P. Oil Company initiated a USDOE sponsored cyclic CO_2 pilot involving injection of 63 MMcf of CO_2 into one producing well, WMU 17-2B. While all of the injected CO_2 was produced back in the next three months, only negligible volumes of liquid were produced.

3) Expanded CO_2-EOR Project. Following the purchase of the WMU by Denbury Resources, in mid-2001, Denbury expanded the initial CO_2-EOR project by adding four patterns in 2001, four patterns in 2002, three patterns in 2003 and two patterns in 2004. (One additional pattern was started at East Mallalieu in 2004.)

    - Initial oil production to CO_2 injection occurred in 2002, with an average of 718 B/D in the fourth quarter of 2002, reaching 2,712 B/D in the fourth quarter of 2004.
    - At the end of 2004, Denbury had booked 14.9 MMBbls of proved reserves at E and W Mallalieu fields.

- The operator anticipated an EOR oil recovery efficiency in excess of 17% OOIP.

Other Current CO_2-EOR Projects. Two recently started CO_2-EOR projects are underway in Western Mississippi at McComb and Brookhaven fields. The McComb field produced 540 B/D in the fourth quarter of 2004 and has 11 million barrels of proved reserves, with upward revisions expected in future years. Oil production response from the Brookhaven field is expected in early 2006. The field contains 19 million barrels of proved reserves. Smaller CO_2-EOR projects have been conducted in the past at Tinsley, Olive and Heidelberg oil fields.

Future CO_2-EOR Potential. Mississippi contains 17 large light oil reservoirs that are candidates for miscible CO_2-EOR. In addition, the state has three heavy oil fields, including West Heidelberg, (Eutaw) and West Eucutta, (Eutaw) that could benefit from immiscible CO_2-EOR.

Under "Traditional Practices" (involving a small volume of high cost CO_2 injection and high risk financial conditions), miscible CO_2 flooding would not be economically attractive in Mississippi. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection, immiscible EOR, and lower risk), the number of economically feasible oil reservoirs in Mississippi increases to 6, providing 79 million barrels of additional oil recovery, Table 22.

Table 22. Economic Oil Recovery Potential Under Two Technologic Conditions, Mississippi

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential* (No. of Reservoirs)	Economic Potential* (MMBbls)
"Traditional Practices"	17	1,717	152	0	0
"State-of-the-art" Technology	20	1,879	351	6	79

** Oil price of $30 per barrel; CO_2 costs of $1.50/Mcf.*

Combining "State-of-the-art" technology with risk mitigation incentives and/or higher oil prices plus lower cost CO_2 supplies, would enable CO_2-EOR Mississippi to recover an additional 227 million barrels of CO_2-EOR oil (from 14 major oil reservoirs), Table 23. A portion of this CO_2-EOR potential is already being developed in Mississippi, as discussed above.

Table 23. Economic Oil Recovery Potential with More Favorable Financial Conditions, Mississippi

More Favorable Financial Conditions	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
Plus: Risk Mitigation Incentives*	1,879	9	163
Plus: Low Cost CO_2 Supplies**	1,879	13	227

** Oil price of $40 per barrel, adjusted for gravity and location differentials; CO_2 supply costs, $2/Mcfs*

*** CO_2 supply costs, $0.80/Mcf*

6.3 ALABAMA. Alabama is the 16th largest oil producing state, providing 5 MMBbls (13 MBbls/day) of oil in 2004, from 824 producing wells. Oil production in the state of Alabama began in 1944, and cumulative oil recovery has reached 0.4 billion barrels with 52 MMBbls of crude oil reserves. Oil production in Alabama has remained relatively stable in recent years, Table 24.

Table 24. Recent History of Alabama Onshore Oil Production

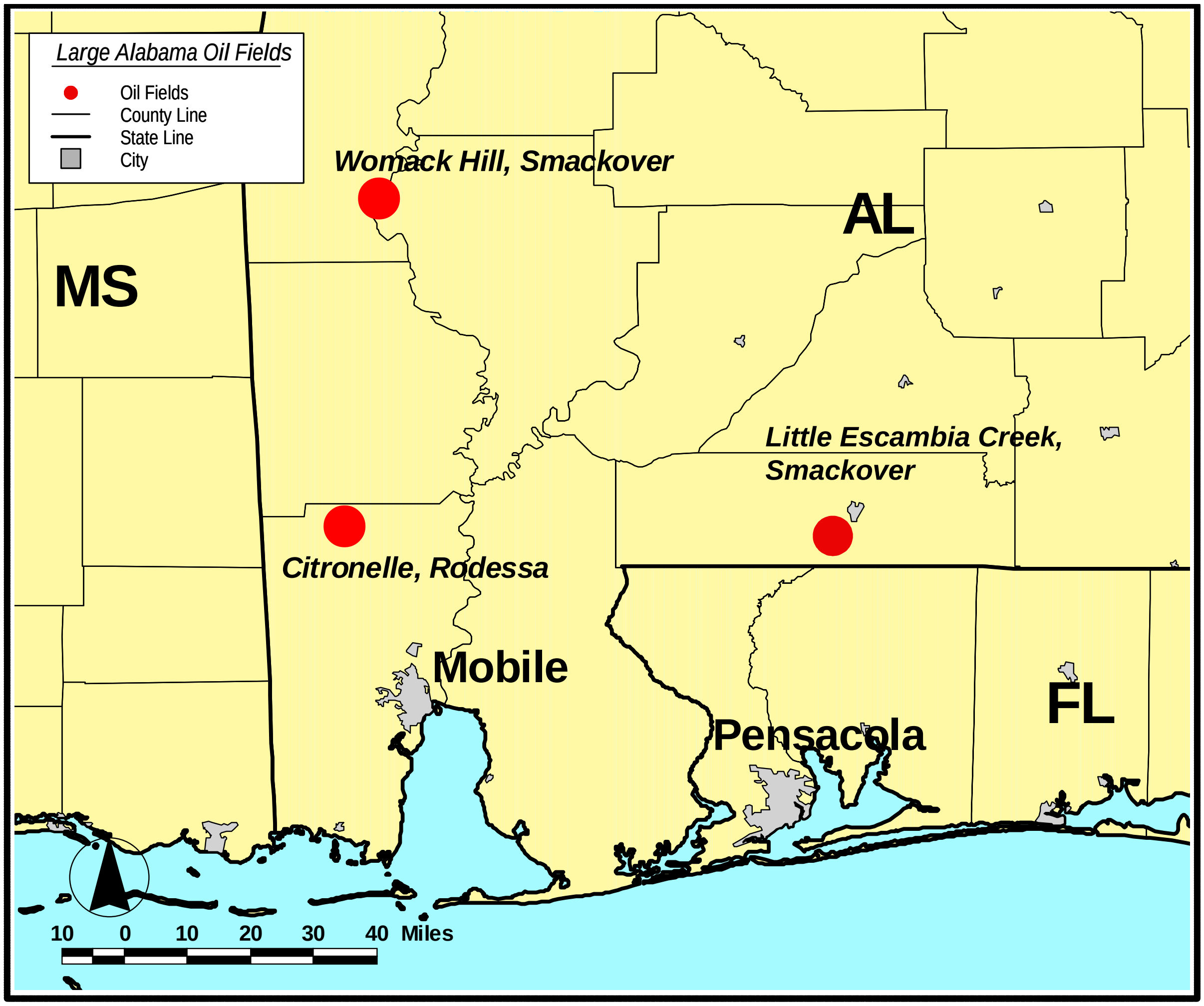
	Annual Oil Production	
	(MMBbls/year)	(MBbls/day)
1999	6	18
2000	6	16
2001	5	15
2002	5	14
2003	6	16
2004	5	13

Alabama Fields. Alabama contains several large oil fields that may be amenable to miscible CO_2-EOR, Figure 13. These include:

- Citronelle (Rodessa)
- Womack Hill (Smackover)

In addition, Alabama contains the deep Little Escambia Creek (Smackover) oil field (part of the greater Jay oil field) that, while technically amenable to CO_2-EOR, is currently being produced with N_2-EOR (see discussion under Florida).

Figure 13. Large Alabama Oil Fields



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The cumulative oil production, proved reserves and remaining oil in-place (ROIP) in these two large oil reservoirs are provided in Table 25.

Table 25. Status of Large Alabama Oil Fields/Reservoirs (as of 2004)

Large Fields/Reservoirs		Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Primary/Secondary Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Citronelle (Rodessa)	537	168	7	362
2	Womack Hill (Smackover)	94	31	2	61

These two large oil reservoirs, with 60 to 360 million barrels of ROIP, are technically amenable for miscible CO_2-EOR. Table 26 provides the reservoir and oil properties for these reservoirs and their current oil recovery activities.

Table 26. Reservoir Properties and Improved Oil Recovery Activity, Large Alabama Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Citronelle (Rodessa)	11,085	43	Active waterflood
2	Womack Hill (Smackover)	11,432	37	Active waterflood

Future CO_2-EOR Potential. Alabama contains 5 oil reservoirs that are candidates for miscible or immiscible CO_2-EOR technology. The potential for economically developing these oil reservoirs is examined first under Base Case financial criteria that combine an oil price of $30 per barrel, CO_2 supply costs ($1.50/Mcf), and a high risk rate of return (ROR) hurdle (25% before tax).

Under “Traditional Practices” (and Base Case financial conditions, defined above), CO_2-EOR would not be economic in Alabama, Table 27. In addition, applying “state-of-the-art” technology (including higher volume CO_2 injection) and the low risk financial condition, CO_2-EOR in Alabama is still not economically favorable.

Table 27. Economic Oil Recovery Potential Under Two Technologic Conditions, Alabama.

CO_2-EOR Technology	No. of Reservoirs	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential* (No. of Reservoirs)	Economic Potential* (MMBbls)
“Traditional Practices”	4	752	76	0	0
“State-of-the-art” Technology	5	807	172	0	0

** Oil price of $30 per barrel.*

Combining "State-of-the-art" technologies with risk mitigation incentives and/or higher oil prices plus lower cost CO_2 supplies would enable CO_2-EOR Alabama to recover an additional 111 million barrels of CO_2-EOR oil (from 1 major oil reservoir), Table 28. (The EOR project at Little Escambia Creek is included in the estimate of technical potential but not in the economic potential numbers.)

Table 28. Economic Oil Recovery Potential with More Favorable Financial Conditions, Alabama

More Favorable Conditions	Technical Potential (MMBbls)	Economic Potential	
		(No. of Reservoirs)	(MMBbls)
Plus: Risk Mitigation*	172	1	111
Plus: Low Cost CO_2**	172	1	111

Oil price of $40 per barrel, adjusted for gravity differential; CO_2 supply costs, $2/Mcf

*** CO_2 supply costs, to $0.80/Mcf*

6.3 FLORIDA. Florida is the 20th largest oil producing state, providing 3 MMBbls (8 MBbls/day) of oil in 2004, from 70 producing wells. Oil production in the state of Florida began in 1943, and cumulative oil recovery has reached almost 0.6 billion barrels. Florida has 68 MMBbls of crude oil reserves, ranking 17th in the U.S. Oil production in Florida has declined in recent years, Table 29.

Table 29. Recent History of Florida Onshore Oil Production

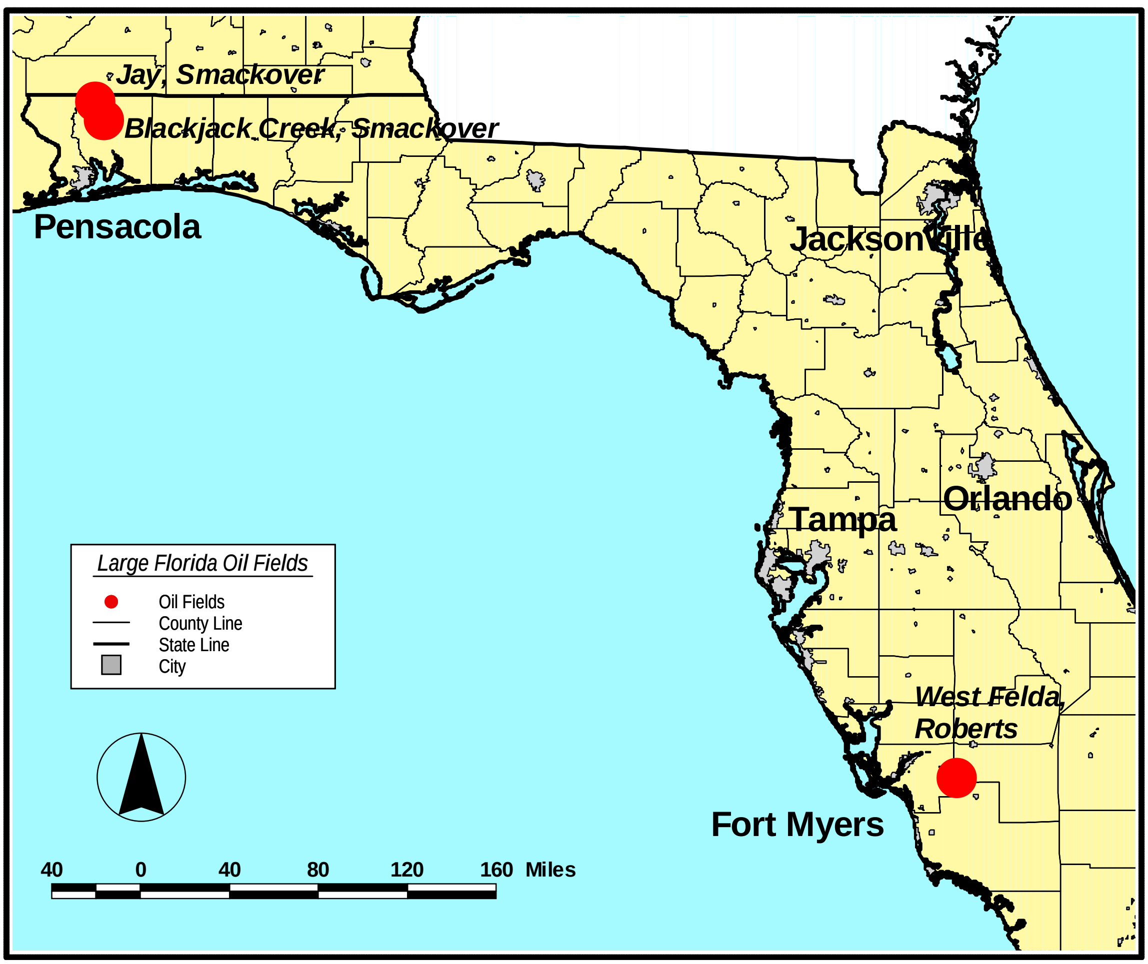
	Annual Oil Production	
	(MMBbls/year)	(MBbls/day)
1999	5	13
2000	5	13
2001	4	12
2002	4	10
2003	3	9
2004	3	8

Florida Fields. Florida contains two large oil fields that may be amenable to miscible CO_2-EOR, Figure 14. These include:

- Blackjack Creek (Smackover)
- West Felda (Roberts)

In addition, Florida contains the deep Jay (Smackover) oil field that, while technically amenable to CO_2-EOR, is currently being produced with N_2-EOR.

Figure 14. Large Florida Oil Fields



The cumulative oil production, proved reserves and remaining oil in-place (ROIP) in these three major oil reservoirs are provided in Table 30.

Table 30. Status of Large Florida Oil Fields/Reservoirs (as of 2004)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Primary/ Secondary Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Blackjack Creek (Smackover)	119	57	1	61
2	West Felda (Roberts)	209	46	6	157
3	Jay (Smackover)	730	378	0	352*

** 70 MMBbls of this is estimated to be recovered by N_2-EOR from the Florida portion of this field.*

These three large oil fields, with 60 to over 300 million barrels of ROIP, are technically amenable for miscible CO_2-EOR. Table 31 provides the reservoir and oil properties for these reservoirs and their current secondary oil recovery activities.

Table 31. Reservoir Properties and Improved Oil Recovery Activity,
Large Florida Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Blackjack Creek (Smackover)	15,700	48	Active Waterflood
2	West Felda (Roberts)	11,400	26	None
3	Jay (Smackover)	15,400	51	Active N_2-EOR

Past CO_2-EOR Projects. The most notable EOR project in Alabama is at the Jay/Little Escambia Creek Field (Smackover Formation), which straddles the Alabama-Florida border. This EOR project involves nitrogen enhanced oil recovery (N_2-EOR).

<u>Jay/Little Escambia Field.</u> ExxonMobil initiated a N_2 miscible WAG flood in 1981 following seven years of waterflooding. The target formation (Smackover) is a deep (15,000+ ft), geologically complex carbonate reservoir. Favorable geologic characteristics (natural vertical flow restrictions) and the use state-of-the-art

technologies provide expectations of 10% OOIP oil recovery due to N_2 injection and overall 60% OOIP recovery from the field.

Evaluation of applying CO_2-EOR to the Jay/Little Escambia oil field indicates potential recovery of about 20% OOIP about twice the volume currently expected from N_2-EOR. However, the high cost of adding deep CO_2 injection and oil production wells indicates that, at the oil prices and CO_2 costs examined by the study, the economics of CO_2-EOR in this oil field may be marginal.

Future CO_2-EOR Potential. Florida contains 5 light oil reservoirs that are candidates for miscible CO_2-EOR technology. The potential for economically developing these oil reservoirs is examined first under Base Case financial criteria that combine an oil price of $30 per barrel, CO_2 supply costs ($1.50/Mcf), and a high risk rate of return (ROR) hurdle (25% before tax).

Under "Traditional Practices" or "State-of-the Art" technology (and Base Case financial conditions, defined above), CO_2-EOR would not be economic in Alabama, Table 32.

Table 32. Economic Oil Recovery Potential Under Two Technologic Conditions, Florida

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential*	
				(No. of Reservoirs)	(MMBbls)
"Traditional Practices"	5	1,265	141	0	0
"State-of-the-art" Technology*	5	1,265	329	0	0

** Oil price of $30 per barrel.*

Combining "State-of-the-art" technologies with risk mitigation incentives and/or higher oil prices plus lower cost CO_2 supplies would enable Florida to recover an additional 29 million barrels of CO_2-EOR oil (from 1 major oil reservoir), Table 33. (The EOR project at Jay is included in the estimate of technical potential, but not in the economic potential numbers.)

Table 33. Economic Oil Recovery Potential with More Favorable Financial Conditions, Florida

More Favorable Conditions	Technical Potential (MMBbls)	Economic Potential	
		(No. of Reservoirs)	(MMBbls)
Plus: Risk Mitigation*	329	1	29
Plus: Low Cost CO_2**	329	1	29

** Oil price of $40 per barrel, adjusted for gravity differential; CO_2 supply costs, $2/Mcf*

*** CO_2 supply costs, $0.80/Mcf*

Appendix A

Using *CO_2-PROPHET* for Estimating Oil Recovery

Model Development

The study utilized the *CO_2-PROPHET* model to calculate the incremental oil produced by CO_2-EOR from the large Gulf Coast Basin oil reservoirs. *CO_2-PROPHET* was developed by the Texaco Exploration and Production Technology Department (EPTD) as part of the DOE Class I cost share program. The specific project was "Post Waterflood CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir" (DOE Contract No. DE-FC22-93BC14960). *CO_2-PROPHET* was developed as an alternative to the DOE's CO_2 miscible flood predictive model, *CO_2PM*.

Input Data Requirements

The input reservoir data for operating *CO_2-PROPHET* are from the Major Oil Reservoirs Data Base. Default values exist for input fields lacking data. Key reservoir properties that directly influence oil recovery are:

- Residual oil saturation,
- Dykstra-Parsons coefficient,
- Oil and water viscosity,
- Reservoir pressure and temperature, and
- Minimum miscibility pressure.

A set of three relative permeability curves for water, CO_2 and oil are provided (or can be modified) to ensure proper operation of the model.

Calibrating CO_2-PROPHET

The *CO_2-PROPHET* model was calibrated by Advanced Resources with an industry standard reservoir simulator, *GEM*. The primary reason for the calibration was to determine the impact on oil recovery of alternative permeability distributions within a multi-layer reservoir. A second reason was to better understand how the absence of a gravity override function in *CO_2-PROPHET* might influence the calculation of oil recovery. *CO_2-PROPHET* assumes a fining upward permeability structure.

The California San Joaquin Basin's Elk Hills (Stevens) reservoir data set was used for the calibration. The model was run in the miscible CO_2-EOR model using one hydrocarbon pore volume of CO_2 injection.

The initial comparison of *CO_2-PROPHET* with *GEM* was with fining upward and coarsening upward (opposite of fining upward) permeability cases in *GEM*. All other reservoir, fluid and operational specifications were kept the same. As Figure A-1 depicts, the *CO_2-PROPHET* output is bounded by the two *GEM* reservoir simulation cases of alternative reservoir permeability structures in an oil reservoir.

A second comparison of *CO_2-PROPHET* and *GEM* was for randomized permeability (within the reservoir modeled with multiple layers). The two *GEM* cases are High Random, where the highest permeability value is at the top of the reservoir, and Low Random, where the lowest permeability is at the top of the reservoir. The permeability values for the other reservoir layers are randomly distributed among the remaining layers. As Figure A-2 shows, the *CO_2-PROPHET* results are within the envelope of the two *GEM* reservoir simulation cases of random reservoir permeability structures in an oil reservoir.

Based on the calibration, the *CO_2-PROPHET* model seems to internally compensate for the lack of a gravity override feature and appears to provide an average calculation of oil recovery, neither overly pessimistic nor overly optimistic. As such, *CO_2-PROPHET* seems well suited for what it was designed — providing project scoping and preliminary results to be verified with more advanced evaluation and simulation models.

Comparison of *CO_2-PROPHET* and *CO_2PM*

According to the *CO_2-PROPHET* developers, the model performs two main operations that provide a more robust calculation of oil recovery than available from *CO_2PM*:

Figure A-1. *CO2-PROPHET* and *GEM*: Comparison to Upward Fining and Coarsening Permeability Cases of *GEM*

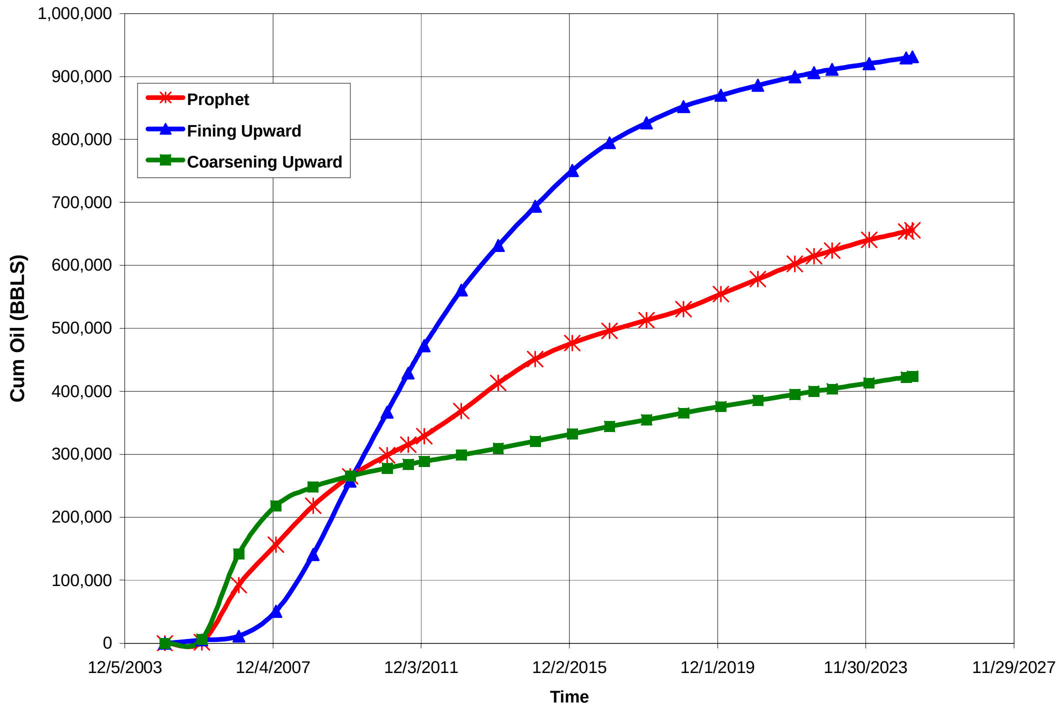
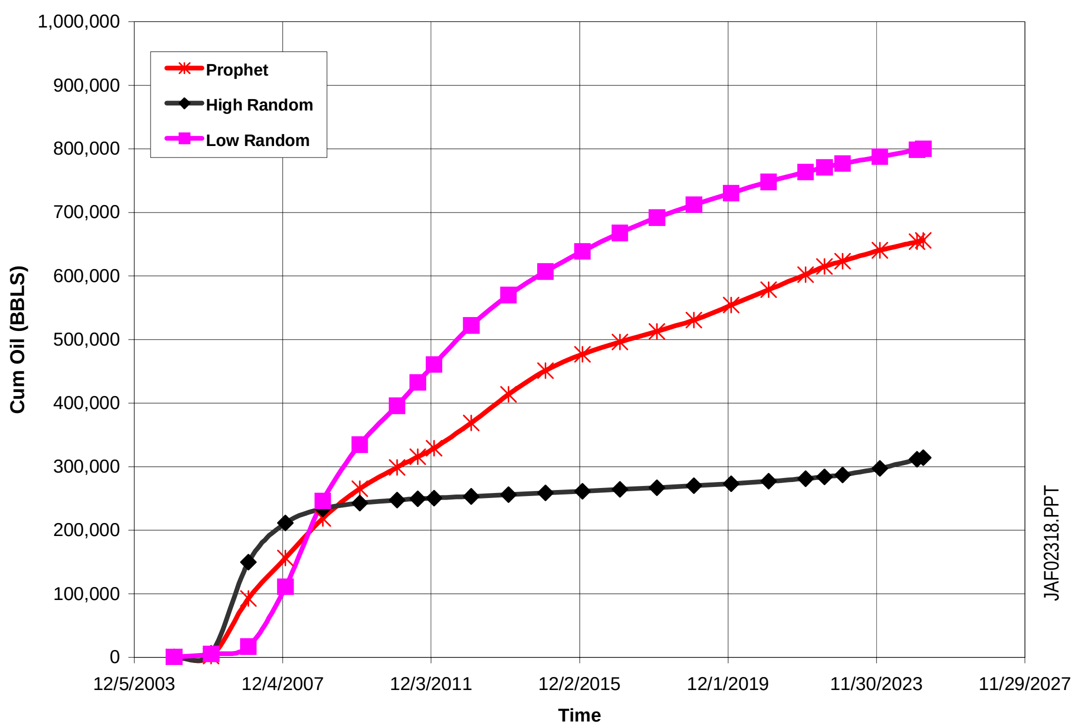


Figure A-2. CO_2-*PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



JAF02318.PPT

- *CO_2-PROPHET* generates streamlines for fluid flow between injection and production wells, and
- The model then performs oil displacement and recovery calculations along the streamlines. (A finite difference routine is used for the oil displacement calculations.)

Other key features of *CO_2-PROPHET* and its comparison with the technical capability of *CO_2PM* are also set forth below:

- Areal sweep efficiency in *CO_2-PROPHET* is handled by incorporating streamlines that are a function of well spacing, mobility ratio and reservoir heterogeneity, thus eliminating the need for using empirical correlations, as incorporated into *CO_2PM*.
- Mixing parameters, as defined by Todd and Longstaff, are used in *CO_2-PROPHET* for simulation of the miscible CO_2 process, particularly CO_2/oil mixing and the viscous fingering of CO_2.
- A series of reservoir patterns, including 5 spot, line drive, and inverted 9 spot, among others, are available in *CO_2-PROPHET*, expanding on the 5 spot only reservoir pattern option available in *CO_2PM*.
- *CO_2-PROPHET* can simulate a variety of recovery processes, including continuous miscible CO_2, WAG miscible CO_2 and immiscible CO_2, as well as waterflooding. *CO_2PM* is limited to miscible CO_2.

Appendix B

Louisiana CO_2-EOR Cost Model

Cost Model for CO_2-Based Enhanced Oil Recovery (CO_2-EOR)

This appendix provides documentation for the cost module of the desktop CO_2-EOR policy and analytical model (COTWO) developed by Advanced Resources for DOE/FE-HQ. The sections of this cost documentation report are organized according to the normal sequence of estimating the capital and operating expenditures for a CO_2-EOR project:

1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for Louisiana.

The well D&C cost equation has a fixed cost constant for site preparation and other fixed cost items and a variable cost equation that increases exponentially with depth. The total equation is:

Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 0.1933 (South) or 2.7405 (North), depending on location
a_1 is 1.8234 (South) or 1.3665 (North), depending on location
D is well depth

Figure B-1a and Figure B-1b provides the details for the cost equation and illustrates the "goodness of fit" for the well D&C cost equation for Louisiana.

Figure B-1a. – Oil Well D&C Costs for South Louisiana

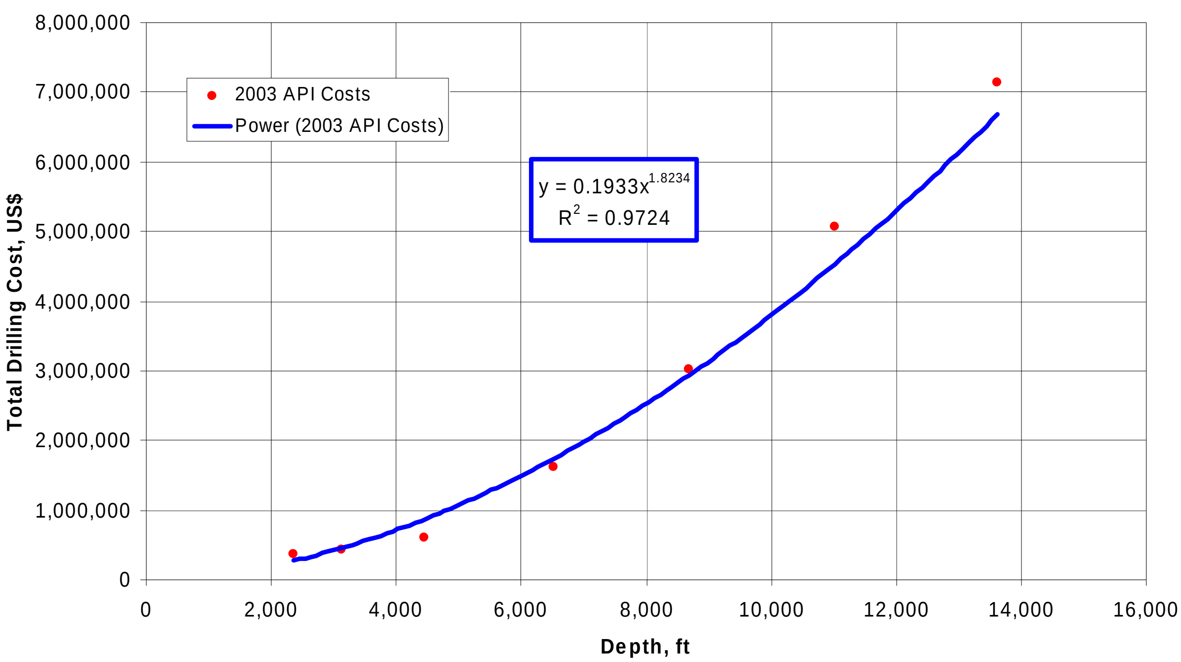
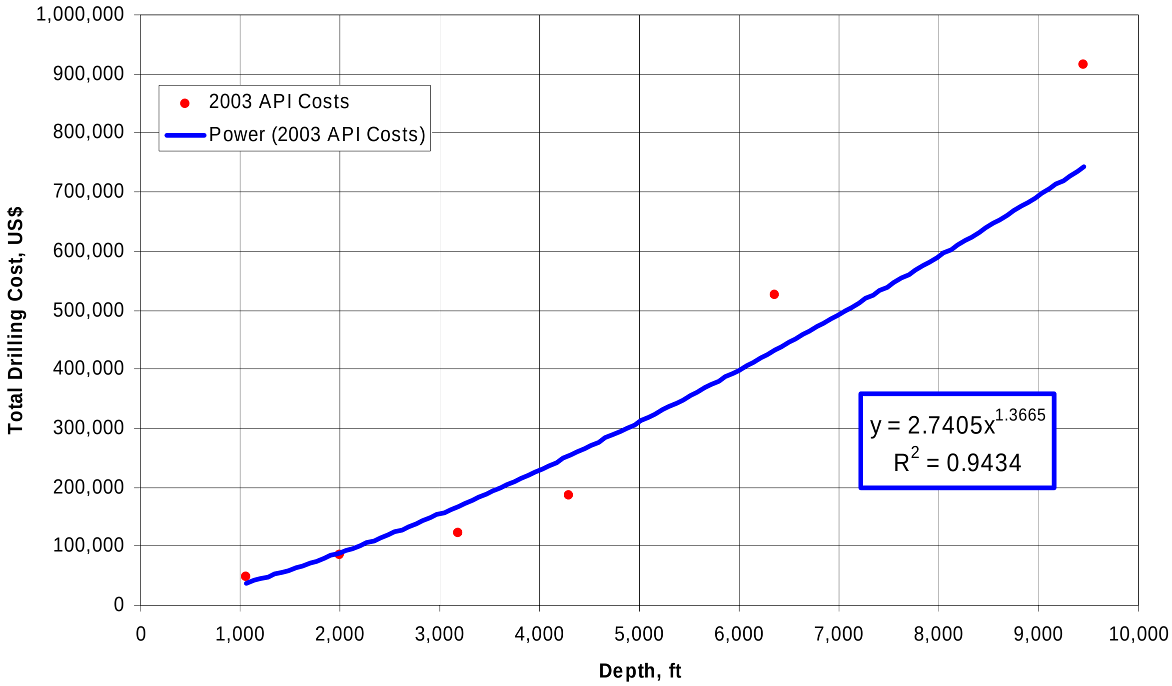


Figure B-1b. Oil Well D&C Costs for North Louisiana



In order to bring the 2003 API drilling costs (the most recent available) into 2004 numbers where increased oil prices are expected to result in significantly increased drilling costs, a relationship was established between average drilling costs and average annual oil prices. Drillings costs from the ten year period of 1994-2003 (API data) were plotted versus the three year weighted average annual oil prices for those years (EIA Annual Energy Review, 2004) and the following relationship was established:

Drilling costs (per foot) = \$5.04(annual oil price) – \$3.2116.

Applying the 2004 average oil price of \$36.77 gives a drilling cost of \$182 per foot and an increase of 25.6% over the 2003 cost of \$145 per foot. Therefore, drilling and completion costs were increased by 25% over the Louisiana D&C cost calculations to reflect this increase in 2004 drilling costs.

2. <u>Lease Equipment Costs for New Producing Wells.</u> The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 EIA “Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations” report. This survey provides estimated lease equipment costs for 10 wells producing with artificial lift, from depths ranging from 2,000 to 12,000 feet, into a central tank battery.

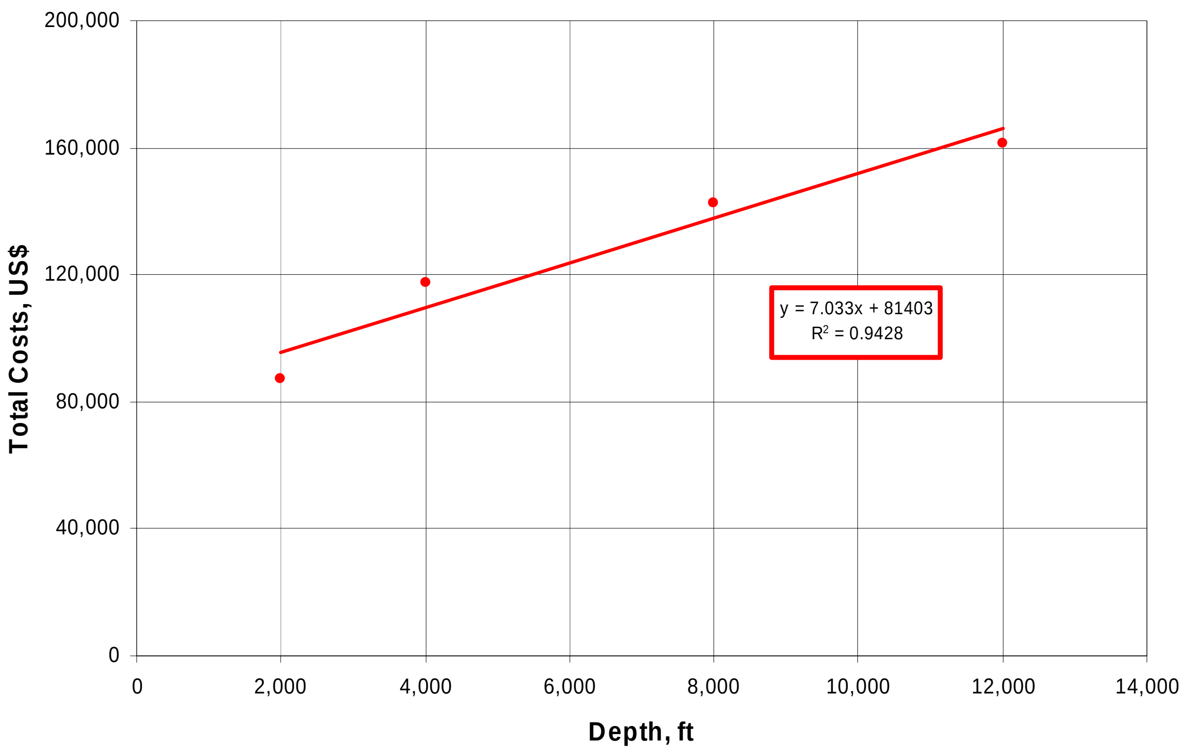
The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

Production Well Equipping Costs = $c_0 + c_1D$

Where: c_o = \$81,403 (fixed)
c_1 = \$7.033 per foot
D is well depth

Figure B-2 illustrates the application of the lease equipping cost equation for a new oil production well as a function of depth.

Figure B-2. Lease Equipping Cost for a New Oil Production Well in Louisiana vs. Depth



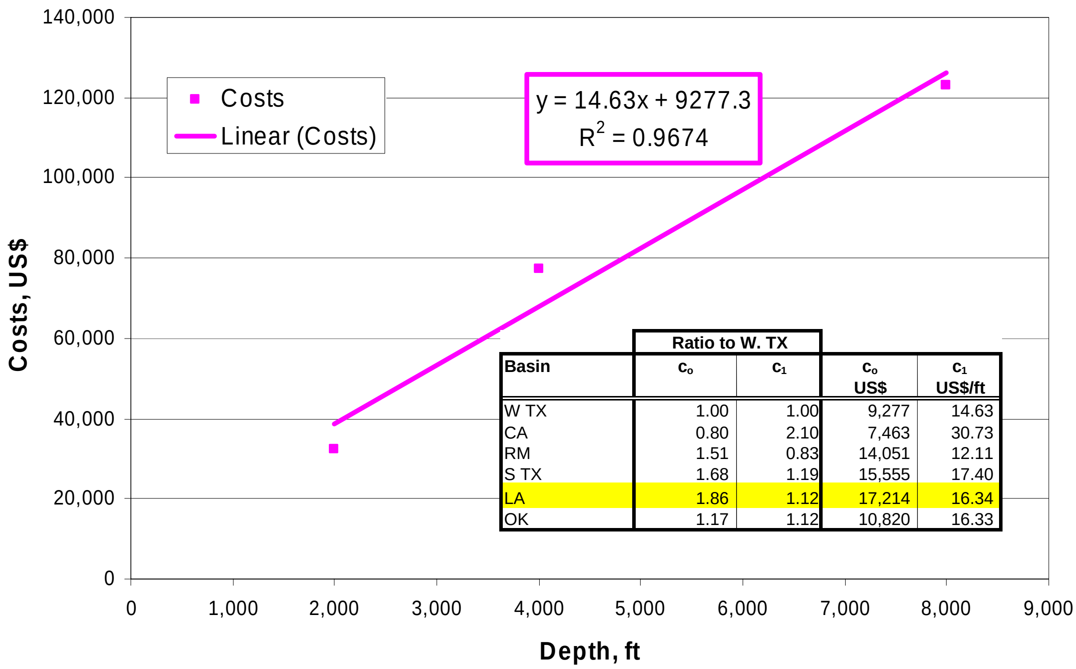
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Louisiana include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation for Louisiana is:

Injection Well Equipping Costs = $c_0 + c_1 D$
Where: c_o = \$17,214 (fixed)
c_1 = \$16.34 per foot
D is well depth

Figure B-3 illustrates the application of the lease equipping cost equation for a new injection well as a function of depth for West Texas. The West Texas cost data for lease equipment provides the foundation for the Louisiana cost equation.

Figure B-3. Lease Equipping Costs for a New Injection Well in West Texas vs. Depth



Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	9,277	14.63
CA	0.80	2.10	7,463	30.73
RM	1.51	0.83	14,051	12.11
S TX	1.68	1.19	15,555	17.40
LA	1.86	1.12	17,214	16.34
OK	1.17	1.12	10,820	16.33

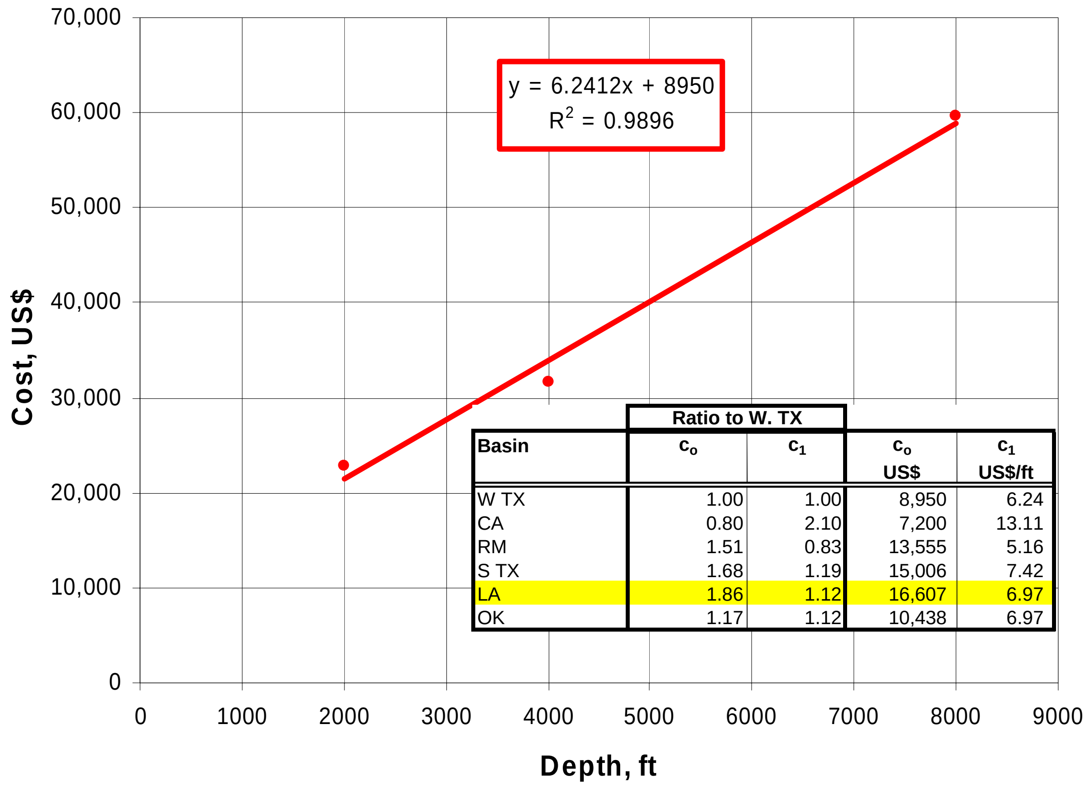
4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are already in place on the lease.

The existing well conversion costs include a fixed cost component and a depth-related cost component, which varies based on the required surface pressure and tubing length. The equation for Louisiana is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_0 = \$16,607 (fixed)
c_1 = \$6.973 per foot
D is well depth

Figure B-4 illustrates the average cost of converting an existing producer into an injection well for West Texas. The West Texas cost data for converting wells provide the foundation for the Louisiana cost equation.

Figure B-4. Cost of Converting Existing Production Wells into Injection Wells in West Texas vs. Depth



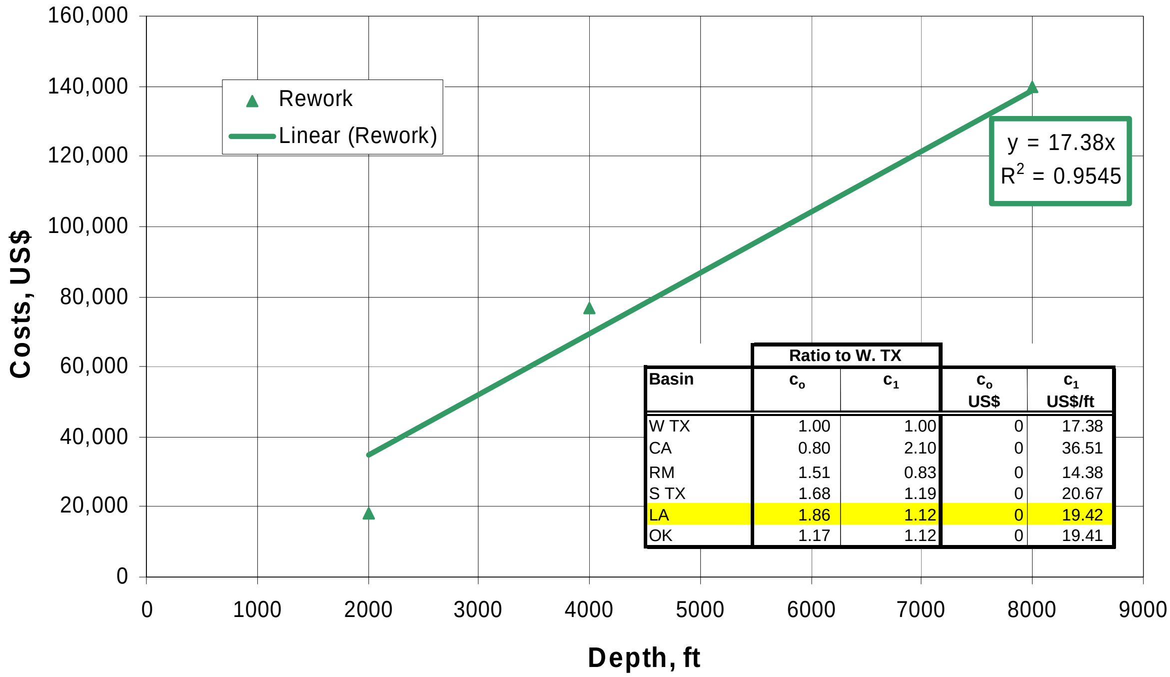
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
OK	1.17	1.12	10,438	6.97

5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework). The reworking of existing oil production or CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for Louisiana is:

Well Rework Costs = c_1D
Where: c_1 = $19.42 per foot)
D is well depth

Figure B-5 illustrates the average cost of well conversion as a function of depth for West Texas. The West Texas cost data for reworking wells provides the foundation for the Louisiana cost equation.

Figure B-5. Cost of an Existing Waterflood Production or Injection Well for CO_2-EOR in West Texas vs. Depth



Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	0	17.38
CA	0.80	2.10	0	36.51
RM	1.51	0.83	0	14.38
S TX	1.68	1.19	0	20.67
LA	1.86	1.12	0	19.42
OK	1.17	1.12	0	19.41

6. Annual O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides secondary operating and maintenance (O&M) costs only for West Texas. As such, West Texas and Louisiana primary oil production O&M costs (Figure B-6) are used to estimate Louisiana secondary recovery O&M costs. Linear trends are used to identify fixed cost constants and variable cost constants for each region, Table B-1.

Figure B-6. Annual Lease O&M Costs for Primary Oil Production by Area

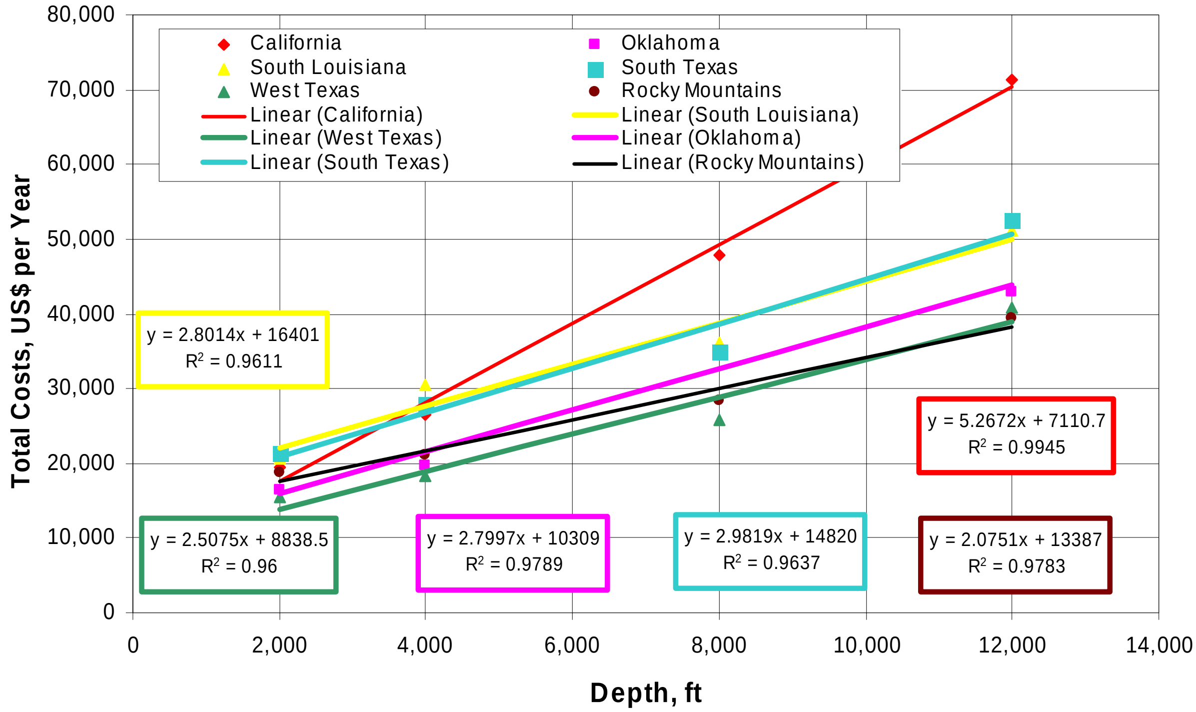


Table B-1. Regional Lease O&M Costs and Their Relationship to West Texas

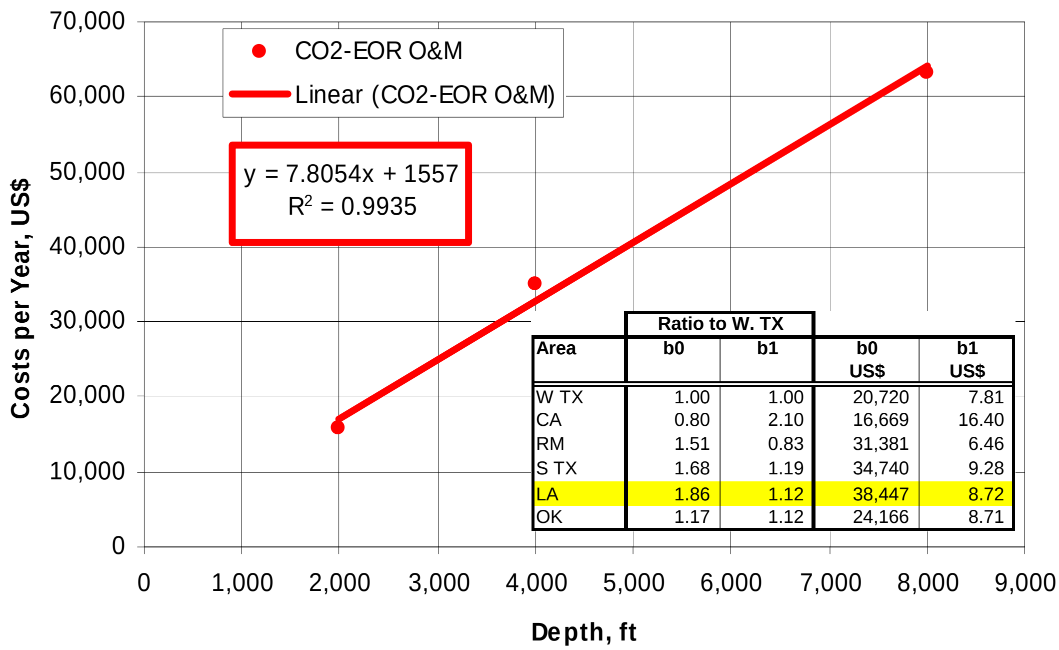
			Ratio to W. TX	
Basin	**c0 US$**	**c1 US$**	**c0**	**c1**
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Rocky Mountain	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

To account for the O&M cost differences between waterflooding and CO_2-EOR, two adjustments are made to the EIA's reported O&M costs for secondary recovery. Workover costs, reported as surface and subsurface maintenance, are doubled to reflect the need for more frequent remedial well work in CO_2-EOR projects. Liquid lifting are subtracted from annual waterflood O&M costs to allow for the more rigorous accounting of liquid lifting volumes and costs for CO_2-EOR. (Liquid lifting costs for CO_2-EOR are discussed in a later section of this appendix.)

Figure B-7 shows the depth-relationship for CO_2-EOR O&M costs in West Texas. These costs were adjusted to develop O&M for Louisiana, shown in the inset of Figure B-7. The equation for Louisiana is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = $38,447 (fixed)
b_1 = $8.72 per foot
D is well depth

Figure B-7. Annual CO_2-EOR O&M Costs for West Texas



Area	Ratio to W. TX b0	Ratio to W. TX b1	b0 US$	b1 US$
W TX	1.00	1.00	20,720	7.81
CA	0.80	2.10	16,669	16.40
RM	1.51	0.83	31,381	6.46
S TX	1.68	1.19	34,740	9.28
LA	1.86	1.12	38,447	8.72
OK	1.17	1.12	24,166	8.71

7. CO_2 Recycle Plant Investment Cost. Operation of CO_2-EOR requires a recycling plant to capture and reinject the produced CO_2. The size of the recycle plant is based on peak CO_2 production and recycling requirements.

The cost of the recycling plant is set at $700,000 per MMcf/d of CO_2 capacity. As such, small CO_2-EOR project in the Tokio formation of the Haynesville field, with 16 MMcf/d of CO_2 reinjection, will require a recycling plant costing $11 million. A large project in the Delhi field, with 177 MMcf/d of peak CO_2 reinjection and 112 injectors requires a recycling plant costing $124 million.

The model has three options for installing a CO_2 recycling plant. The default setting costs the entire plant one year prior to CO_2 breakthrough. The second option places the full CO_2 recycle plant cost at the beginning of the project (Year 0). The third option installs the CO_2 recycle plant in stages. In this case, half the plant is built (and half the cost is incurred) in the year of CO_2 breakthrough. The second half of the plant is built when maximum recycle capacity requirements are reached.

8. Other COTWO Model Costs.

a. <u>CO_2 Recycle O&M Costs.</u> The O&M costs of CO_2 recycling are indexed to energy costs and set at 1% of the oil price ($0.25 per Mcf @ $25 Bbl oil).

b. <u>Lifting Costs.</u> Liquid (oil and water) lifting costs are calculated on total liquid production and costed at $0.25 per barrel. This cost includes liquid lifting, transportation and re-injection.

c. <u>CO_2 Distribution Costs.</u> The CO_2 distribution system is similar to the gathering systems used for natural gas. A distribution "hub" is constructed with smaller pipelines delivering purchased CO_2 to the project site.

The distribution pipeline cost is dependent on the injection requirements for the project. The fixed component is $150,000. The variable cost component accounts for increasing piping diameters associated with increasing CO_2 injection requirements. These range from $80,000 per mile for 4" pipe (CO_2 rate less than 15MMcf/d), $120,000 per mile for 6" pipe (CO_2 rate of 15 to 35 MMcf/d), $160,000 per mile for 8" pipe (CO_2 rate of 35 to 60 MMcf/d), and $200,000 per mile for pipe greater than 8" diameter (CO_2 rate greater than 60 MMcf/d). Aside from the injection volume, costs also depend on the distance from the CO_2 "hub" (transfer point) to the oil field. Currently, the distance is set at 10 miles.

The CO_2 distribution cost equation for Louisiana is:

Pipeline Construction Costs = $150,000 + C_D*Distance

Where: C_D is the cost per mile of the necessary pipe diameter (from the CO_2 injection rate)
Distance = 10.0 miles

d. <u>G&A Costs.</u> General and administrative (G&A) costs of 20% are added to well O&M and lifting costs.

e. <u>Royalties.</u> Royalty payments are assumed to be 12.5%.

f. <u>Production Taxes.</u> Louisiana has enacted risk sharing actions for enhanced oil recovery. The Louisiana Revenue Statute Ann. 47:633.4 is effective as of July, 1984 with no sunset. Its stated goal is:

"To provide an economic incentive to producers to invest in tertiary recovery projects to enhance Louisiana's crude oil production, to the ultimate benefit of the state and the people."

The provisions of the "Tertiary Recovery Statute" are that no severance tax shall be due on production from a qualified tertiary recovery project approved by the Secretary of the Department of Natural Resources until the project has reached payout. Payout is calculated using investment costs; expenses particular to the tertiary project, not to include charges attributed to primary and secondary options on that reservoir; and interest at commercial rates.

The regular state oil severance tax rate in Louisiana is 12.5% of the value of the produced oil. As such, eliminating the severance tax until payout for CO_2-EOR projects would provide front-end risk sharing equal to $3.28 per barrel of incrementally produced oil (assuming a sales price of $30 per barrel of oil and a royalty rate of 12.5%).

To the extent that this reduction in state severance taxes stimulates new projects and incremental oil production that otherwise would not occur, the State of Louisiana gains substantial new tax revenues. In the model, Severance and ad valorum taxes are set at 1% and 12.5% (after payout), respectively, for a total production tax of 13.5% on the oil production stream. Production taxes are taken following royalty payments.

g. Crude Oil Price Differential. To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis differential for Louisiana (-$0.60 per barrel) and the current gravity differential (-$0.25 per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for Louisiana is:

Wellhead Oil Price = Oil Price + (-$0.60) – [$0.25*(40 - °API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
°API is oil gravity

If the oil gravity is less than 40 °API, the wellhead oil price is reduced; if the oil gravity is greater than 40 °API, the wellhead oil price is increased. In addition, some fields within Louisiana contain very light oil (>45 API). In order to keep the economics of these fields level with the rest of the fields, we imposed a ceiling of 45 API for all fields with lighter oil when applying the Crude Oil Price Differential.

Appendix C

Mississippi CO_2-EOR Cost Model

Cost Model for CO_2-Based Enhanced Oil Recovery (CO_2-EOR)

This appendix provides documentation for the cost module of the desktop CO_2-EOR policy and analytical model (COTWO) developed by Advanced Resources for DOE/FE-HQ. The sections of this cost documentation report are organized according to the normal sequence of estimating the capital and operating expenditures for a CO_2-EOR project:

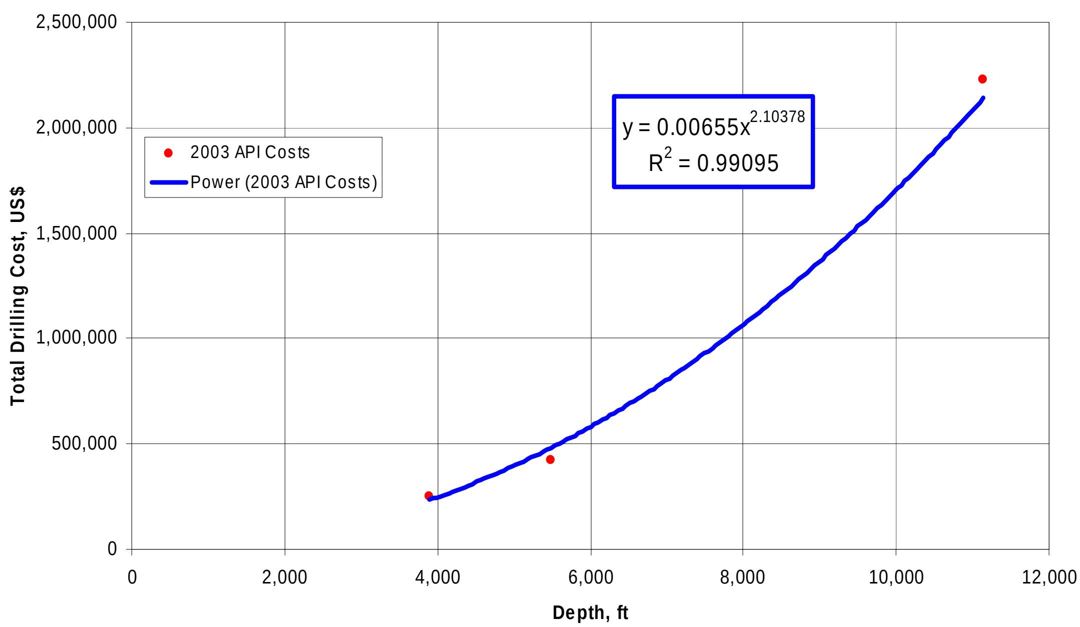
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for Mississippi.

The well D&C cost equation has a fixed cost constant for site preparation and other fixed cost items and a variable cost equation that increases exponentially with depth. The total equation is:

Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 0.00655
a_1 is 2.104
D is well depth

Figure C-1 provides the details for the cost equation and illustrates the "goodness of fit" for the well D&C cost equation for Mississippi.

Figure C-1. Oil Well D&C Costs for Mississippi



In order to bring the 2003 API drilling costs (the most recent available) into 2004 numbers where increased oil prices are expected to result in significantly increased drilling costs, a relationship was established between average drilling costs and average annual oil prices. Drillings costs from the ten year period of 1994-2003 (API data) were plotted versus the three year weighted average annual oil prices for those years (EIA Annual Energy Review, 2004) and the following relationship was established:

Drilling costs (per foot) = \$5.04(annual oil price) – \$3.2116.

Applying the 2004 average oil price of \$36.77 gives a drilling cost of \$182 per foot and an increase of 25.6% over the 2003 cost of \$145 per foot. Therefore, drilling and completion costs were increased by 25% over the Mississippi D&C cost calculations to reflect this increase in 2004 drilling costs.

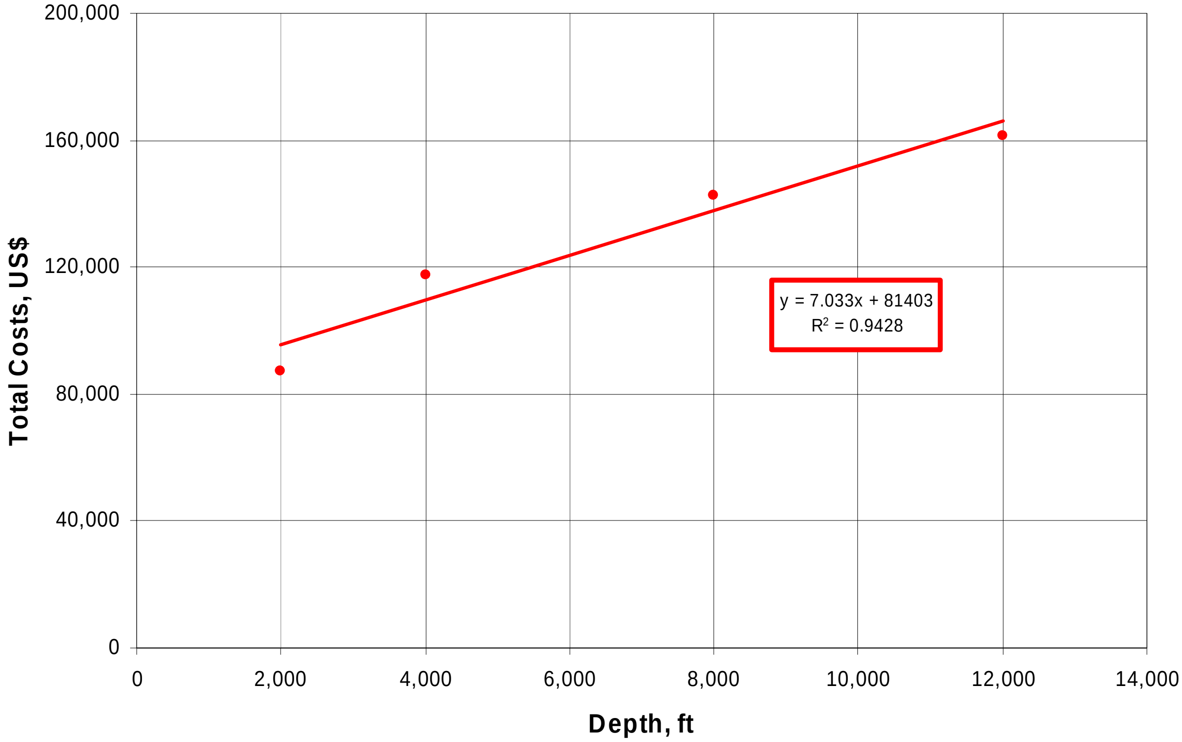
2. <u>Lease Equipment Costs for New Producing Wells.</u> The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 EIA "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report for South Louisiana. This survey provides estimated lease equipment costs for 10 wells producing with artificial lift, from depths ranging from 2,000 to 12,000 feet, into a central tank battery.

The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$81,403 (fixed)
c_1 = \$7.033 per foot
D is well depth

Figure C-2 illustrates the application of the lease equipping cost equation for a new oil production well as a function of depth.

Figure C-2. Lease Equipping Cost for a New Oil Production Well
in Mississippi vs. Depth



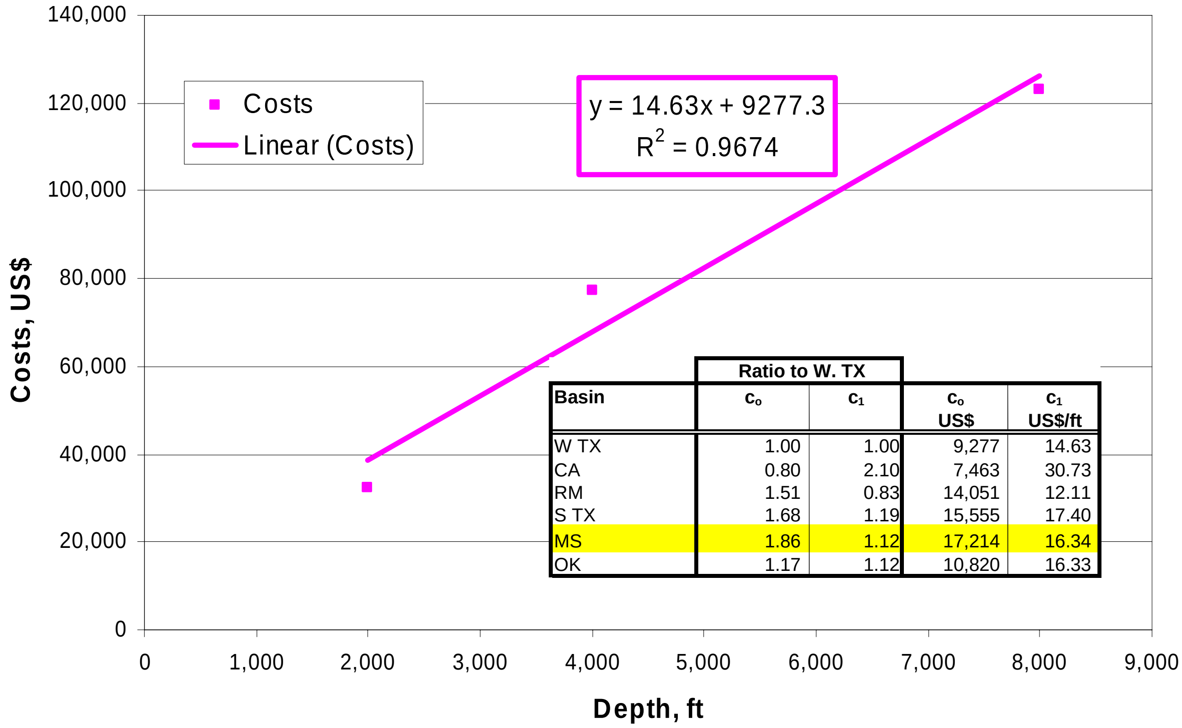
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Mississippi include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation for Mississippi is:

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = $17,214 (fixed)
c_1 = $16.34 per foot
D is well depth

Figure C-3 illustrates the application of the lease equipping cost equation for a new injection well as a function of depth for West Texas. The West Texas cost data for lease equipment provides the foundation for the Mississippi cost equation.

Figure C-3. Lease Equipping Costs for a New Injection Well in West Texas vs. Depth



Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	9,277	14.63
CA	0.80	2.10	7,463	30.73
RM	1.51	0.83	14,051	12.11
S TX	1.68	1.19	15,555	17.40
MS	1.86	1.12	17,214	16.34
OK	1.17	1.12	10,820	16.33

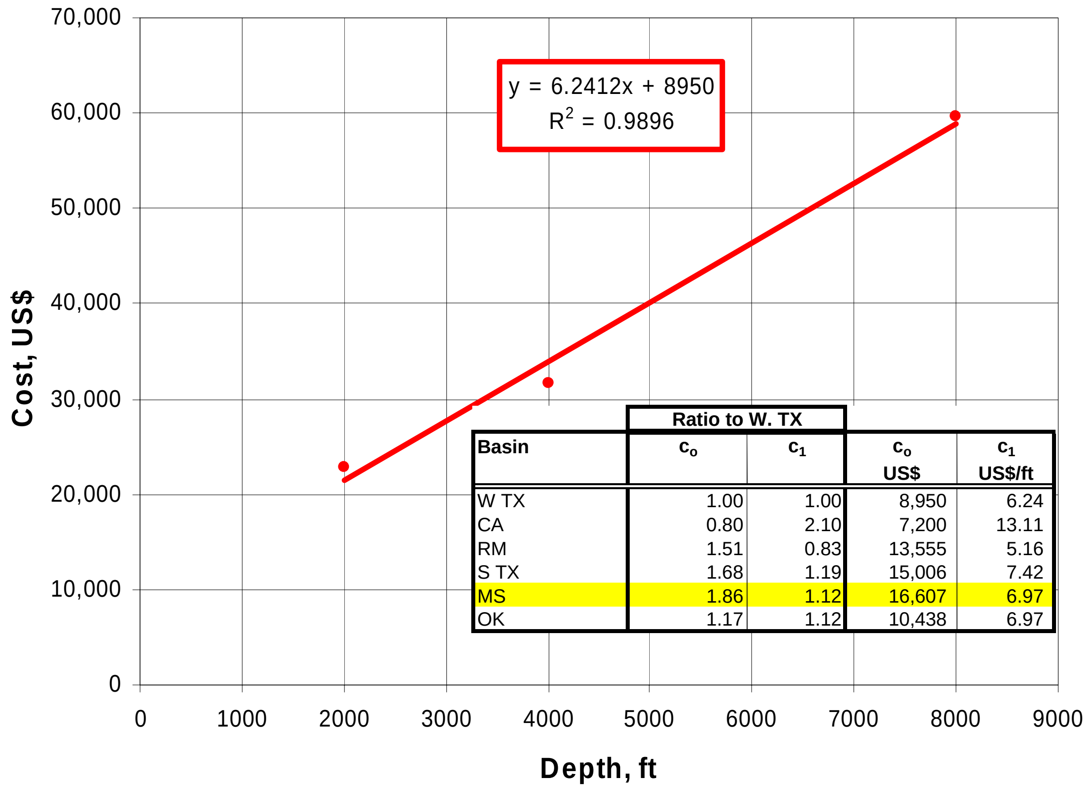
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are already in place on the lease.

The existing well conversion costs include a fixed cost component and a depth-related cost component, which varies based on the required surface pressure and tubing length. The equation for Mississippi is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$16,607 (fixed)
c_1 = \$6.973 per foot
D is well depth

Figure C-4 illustrates the average cost of converting an existing producer into an injection well for West Texas. The West Texas cost data for converting wells provide the foundation for the Mississippi cost equation.

Figure C-4. Cost of Converting Existing Production Wells into Injection Wells in West Texas vs. Depth



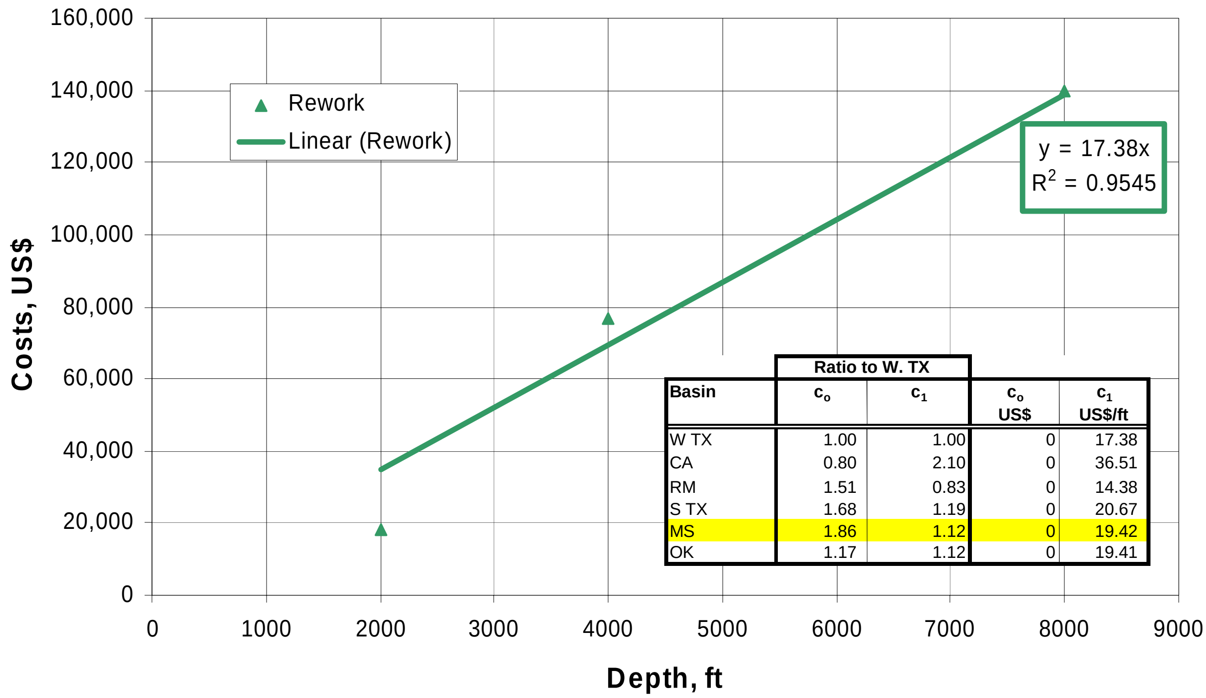
	Ratio to W. TX			
Basin	c_o	c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
MS	1.86	1.12	16,607	6.97
OK	1.17	1.12	10,438	6.97

5. <u>Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework).</u> The reworking of existing oil production or CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for Mississippi is:

Well Rework Costs = c_1D
Where: c_1 = \$19.42 per foot)
D is well depth

Figure C-5 illustrates the average cost of well conversion as a function of depth for West Texas. The West Texas cost data for reworking wells provides the foundation for the Mississippi cost equation.

Figure C-5. Cost of an Existing Waterflood Production or Injection Well for CO_2-EOR in West Texas vs. Depth



	Ratio to W. TX			
Basin	c_o	c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	0	17.38
CA	0.80	2.10	0	36.51
RM	1.51	0.83	0	14.38
S TX	1.68	1.19	0	20.67
MS	1.86	1.12	0	19.42
OK	1.17	1.12	0	19.41

6. Annual O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides secondary operating and maintenance (O&M) costs only for West Texas. As such, West Texas and Mississippi primary oil production O&M costs (Figure C-6) are used to estimate Mississippi secondary recovery O&M costs. Linear trends are used to identify fixed cost constants and variable cost constants for each region, Table C-1.

Figure C-6. Annual Lease O&M Costs for Primary Oil Production by Area

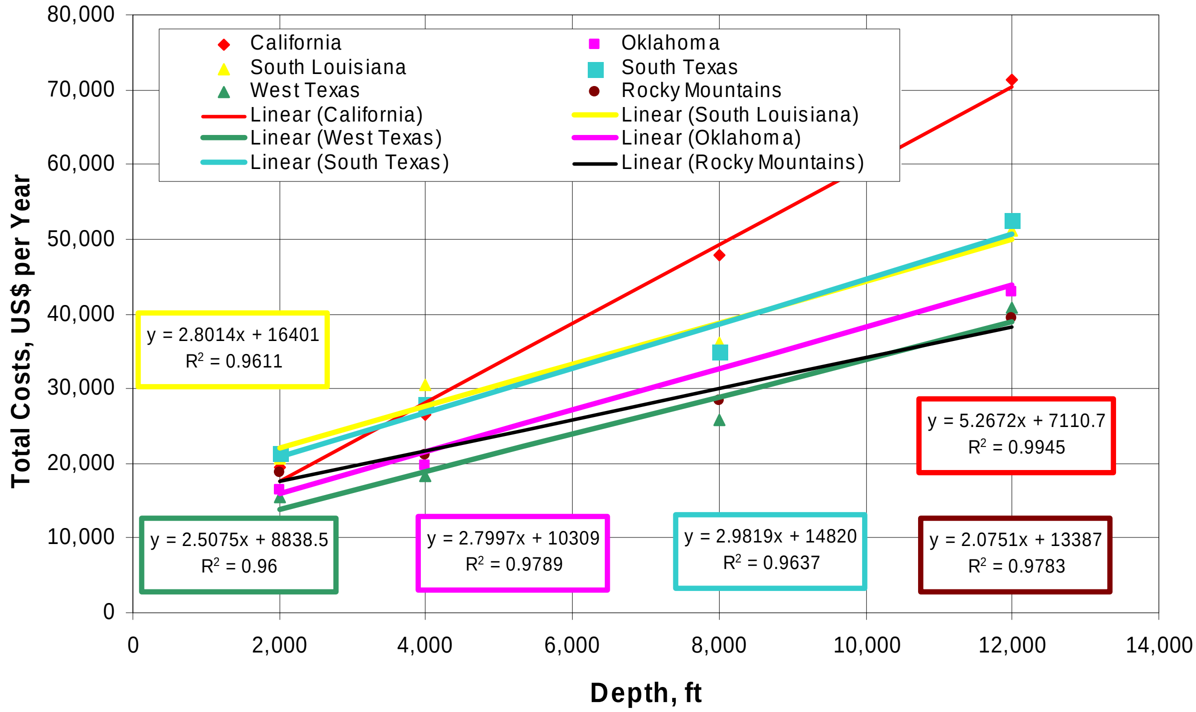


Table C-1. Regional Lease O&M Costs and Their Relationship to West Texas

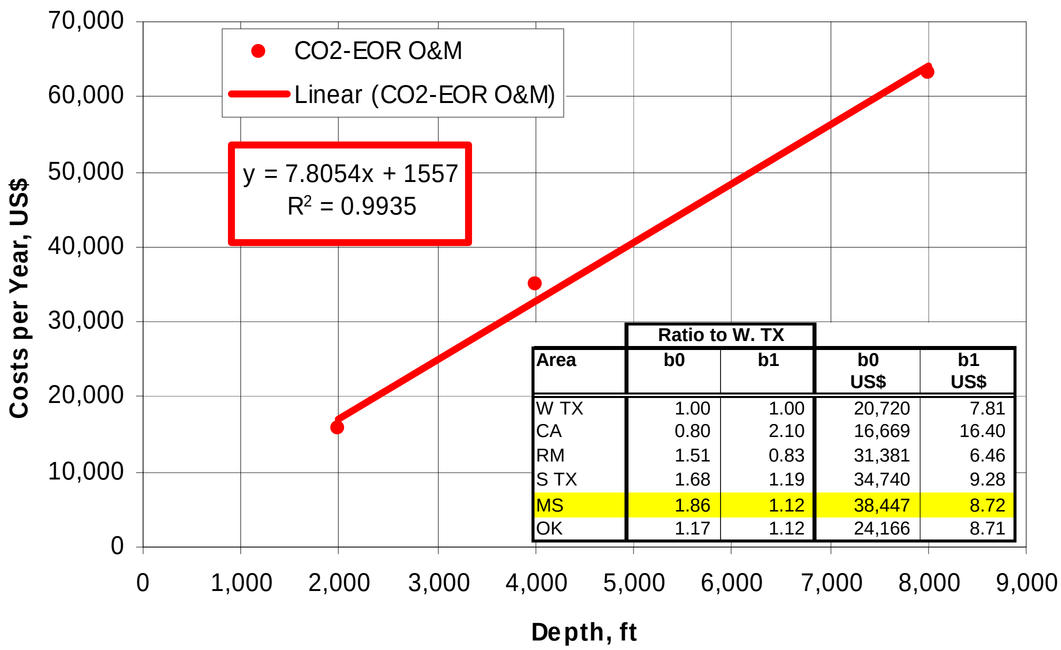
			Ratio to W. TX	
Basin	c0 US$	c1 US$	c0	c1
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Rocky Mountain	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Mississippi	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

To account for the O&M cost differences between waterflooding and CO_2-EOR, two adjustments are made to the EIA's reported O&M costs for secondary recovery. Workover costs, reported as surface and subsurface maintenance, are doubled to reflect the need for more frequent remedial well work in CO_2-EOR projects. Liquid lifting are subtracted from annual waterflood O&M costs to allow for the more rigorous accounting of liquid lifting volumes and costs for CO_2-EOR. (Liquid lifting costs for CO_2-EOR are discussed in a later section of this appendix.)

Figure C-7 shows the depth-relationship for CO_2-EOR O&M costs in West Texas. These costs were adjusted to develop O&M for Mississippi, shown in the inset of Figure C-7. The equation for Mississippi is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$38,447 (fixed)
b_1 = \$8.72 per foot
D is well depth

Figure C-7. Annual CO_2-EOR O&M Costs for West Texas



Area	Ratio to W. TX b0	Ratio to W. TX b1	b0 US$	b1 US$
W TX	1.00	1.00	20,720	7.81
CA	0.80	2.10	16,669	16.40
RM	1.51	0.83	31,381	6.46
S TX	1.68	1.19	34,740	9.28
MS	1.86	1.12	38,447	8.72
OK	1.17	1.12	24,166	8.71

7. <u>CO_2 Recycle Plant Investment Cost.</u> Operation of CO_2-EOR requires a recycling plant to capture and reinject the produced CO_2. The size of the recycle plant is based on peak CO_2 production and recycling requirements.

The cost of the recycling plant is set at \$700,000 per MMcf/d of CO_2 capacity. As such, small CO_2-EOR project in the Christmas formation of the West Heidelberg field, with 11 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$7.7 million. A large project in the Lower Tuscaloosa formation of the Little Creek field, with 92 MMcf/d of peak CO_2 reinjection and 86 injectors requires a recycling plant costing \$64 million.

The model has three options for installing a CO_2 recycling plant. The default setting costs the entire plant one year prior to CO_2 breakthrough. The second option places the full CO_2 recycle plant cost at the beginning of the project (Year 0). The third option installs the CO_2 recycle plant in stages. In this case, half the plant is built (and half the cost is incurred) in the year of CO_2 breakthrough. The second half of the plant is built when maximum recycle capacity requirements are reached.

8. Other COTWO Model Costs.

a. CO_2 Recycle O&M Costs. The O&M costs of CO_2 recycling are indexed to energy costs and set at 1% of the oil price ($0.25 per Mcf @ $25 Bbl oil).

b. Lifting Costs. Liquid (oil and water) lifting costs are calculated on total liquid production and costed at $0.25 per barrel. This cost includes liquid lifting, transportation and re-injection.

c. CO_2 Distribution Costs. The CO_2 distribution system is similar to the gathering systems used for natural gas. A distribution "hub" is constructed with smaller pipelines delivering purchased CO_2 to the project site.

The distribution pipeline cost is dependent on the injection requirements for the project. The fixed component is $150,000. The variable cost component accounts for increasing piping diameters associated with increasing CO_2 injection requirements. These range from $80,000 per mile for 4" pipe (CO_2 rate less than 15MMcf/d), $120,000 per mile for 6" pipe (CO_2 rate of 15 to 35 MMcf/d), $160,000 per mile for 8" pipe (CO_2 rate of 35 to 60 MMcf/d), and $200,000 per mile for pipe greater than 8" diameter (CO_2 rate greater than 60 MMcf/d). Aside from the injection volume, costs also depend on the distance from the CO_2 "hub" (transfer point) to the oil field. Currently, the distance is set at 10 miles.

The CO_2 distribution cost equation for Mississippi is:

Pipeline Construction Costs = $150,000 + C_D*Distance

Where: C_D is the cost per mile of the necessary pipe diameter (from the CO_2 injection rate)
Distance = 10.0 miles

d. G&A Costs. General and administrative (G&A) costs of 20% are added to well O&M and lifting costs.

e. Royalties. Royalty payments are assumed to be 12.5%.

f. Production Taxes. Mississippi has provided a risk sharing incentive for enhanced oil recovery. The Mississippi Code Ann. 27-25-503(i) (1972) is effective as of April, 1994 with no sunset. Its stated goal is:

"Encourage the use of enhanced recovery methods of production."

The "Enhanced Oil Recovery Statute" reduces the assessed severance tax rate to 3% of the value of the oil produced by an enhanced oil recovery method. The original statute, only covering use of carbon dioxide transported by a pipeline to the oil well, was expanded to include any other enhanced oil recovery method approved and permitted by the State Oil and Gas Board on or after April 1, 1994.

The regular state oil severance tax rate in Mississippi is 6% of the value of the produced oil. Reduction of the severance tax to 3% provides a modest risk sharing equal to $0.78 per barrel of incrementally produced oil (assuming a sales price of $30 per barrel of oil and a royalty rate of 12.5%).

Severance and ad valorum taxes are set at 6.0% and 0.2%, respectively, for a total production tax of 6.2% on the oil production stream. Production taxes are taken following royalty payments.

g. Crude Oil Price Differential. To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis differential for Mississippi ($0.00 per barrel) and the current gravity differential (-$0.25 per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for Mississippi is:

Wellhead Oil Price = Oil Price + ($0.00) – [$0.25*(40 - °API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
°API is oil gravity

If the oil gravity is less than 40 °API, the wellhead oil price is reduced; if the oil gravity is greater than 40 °API, the wellhead oil price is increased. In addition, some fields within Mississippi contain very light oil (>45 API). In order to keep the economics of these fields level with the rest of the fields, we imposed a ceiling of 45 API for all fields with lighter oil when applying the Crude Oil Price Differential.

Appendix D

Alabama CO_2-EOR
Cost Model

Cost Model for CO_2-Based Enhanced Oil Recovery (CO_2-EOR)

This appendix provides documentation for the cost module of the desktop CO_2-EOR policy and analytical model (COTWO) developed by Advanced Resources for DOE/FE-HQ. The sections of this cost documentation report are organized according to the normal sequence of estimating the capital and operating expenditures for a CO_2-EOR project:

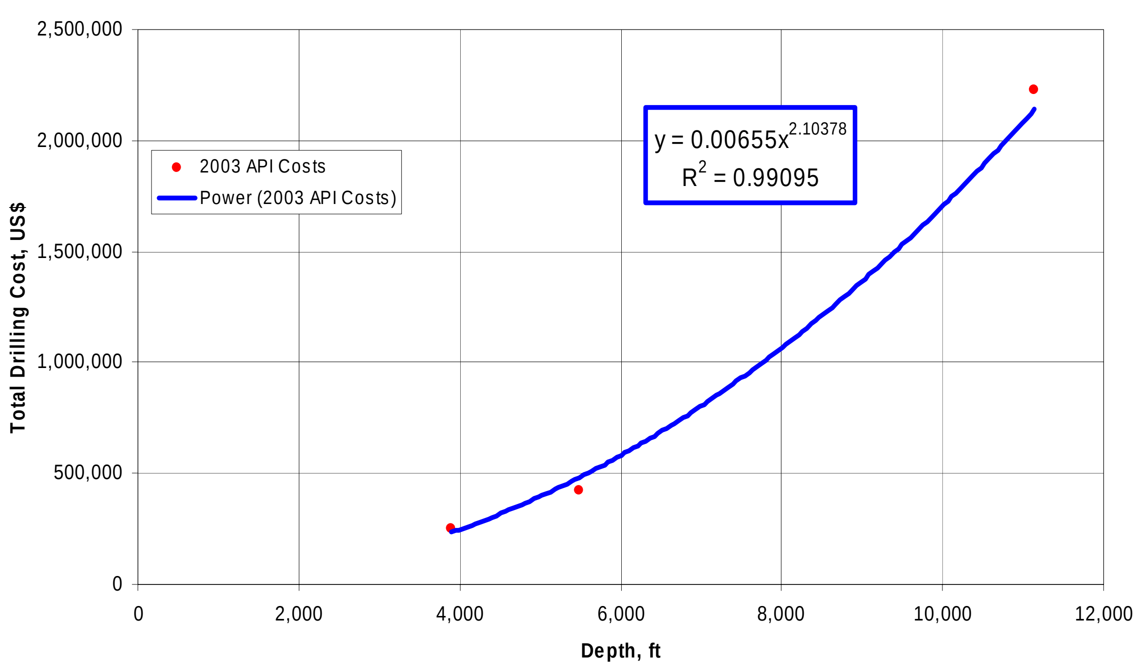
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for Mississippi and are applied to Alabama.

The well D&C cost equation has a fixed cost constant for site preparation and other fixed cost items and a variable cost equation that increases exponentially with depth. The total equation is:

Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 0.00655
a_1 is 2.104
D is well depth

Figure D-1 provides the details for the cost equation and illustrates the "goodness of fit" for the well D&C cost equation for Alabama.

Figure-D1 - Oil Well D&C Costs for Alabama



In order to bring the 2003 API drilling costs (the most recent available) into 2004 numbers where increased oil prices are expected to result in significantly increased drilling costs, a relationship was established between average drilling costs and average annual oil prices. Drillings costs from the ten year period of 1994-2003 (API data) were plotted versus the three year weighted average annual oil prices for those years (EIA Annual Energy Review, 2004) and the following relationship was established:

Drilling costs (per foot) = \$5.04(annual oil price) – \$3.2116.

Applying the 2004 average oil price of \$36.77 gives a drilling cost of \$182 per foot and an increase of 25.6% over the 2003 cost of \$145 per foot. Therefore, drilling and completion costs were increased by 25% over the Alabama D&C cost calculations to reflect this increase in 2004 drilling costs.

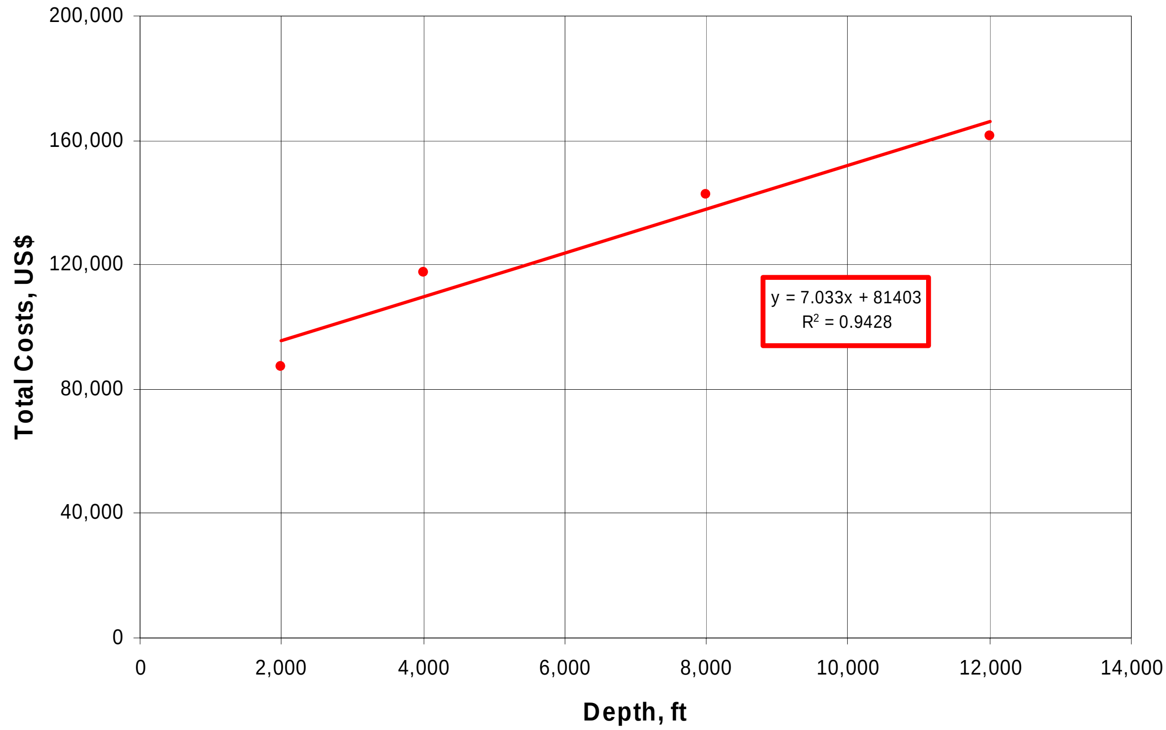
2. <u>Lease Equipment Costs for New Producing Wells.</u> The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 EIA "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report for South Louisiana. This survey provides estimated lease equipment costs for 10 wells producing with artificial lift, from depths ranging from 2,000 to 12,000 feet, into a central tank battery.

The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

Production Well Equipping Costs = $c_0 + c_1 D$
Where: c_o = \$81,403 (fixed)
c_1 = \$7.033 per foot
D is well depth

Figure D-2 illustrates the application of the lease equipping cost equation for a new oil production well as a function of depth.

Figure D-2. Lease Equipping Cost for a New Oil Production Well in Alabama vs. Depth



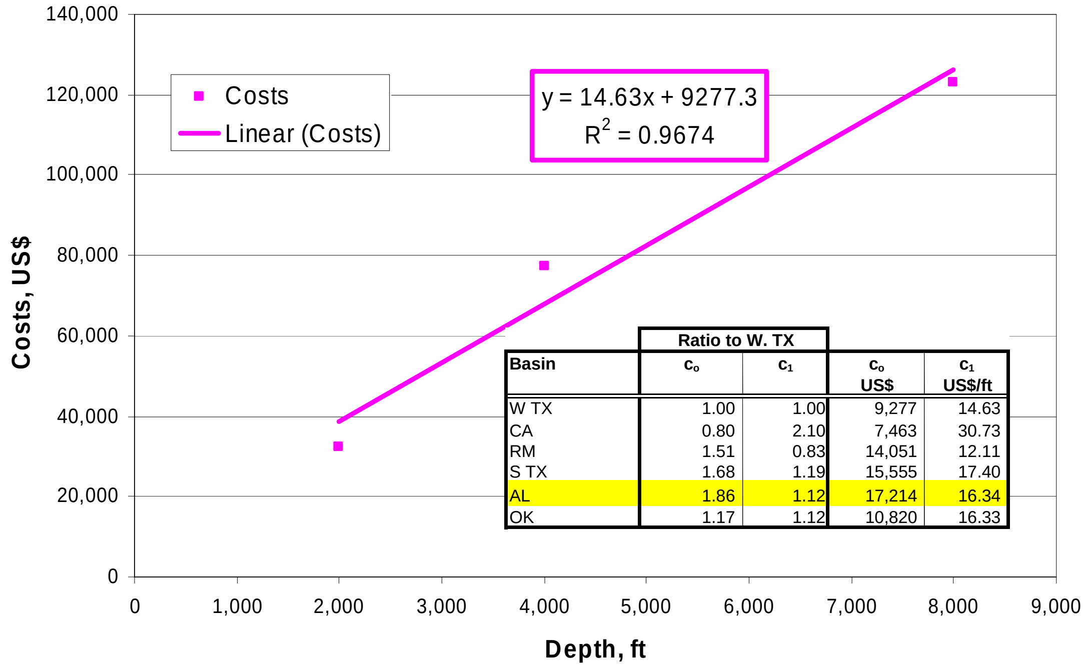
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Alabama include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation for Alabama is:

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = $17,214 (fixed)
c_1 = $16.34 per foot
D is well depth

Figure D-3 illustrates the application of the lease equipping cost equation for a new injection well as a function of depth for West Texas. The West Texas cost data for lease equipment provides the foundation for the Alabama cost equation.

Figure D-3. Lease Equipping Costs for a New Injection Well in West Texas vs. Depth



Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	9,277	14.63
CA	0.80	2.10	7,463	30.73
RM	1.51	0.83	14,051	12.11
S TX	1.68	1.19	15,555	17.40
AL	1.86	1.12	17,214	16.34
OK	1.17	1.12	10,820	16.33

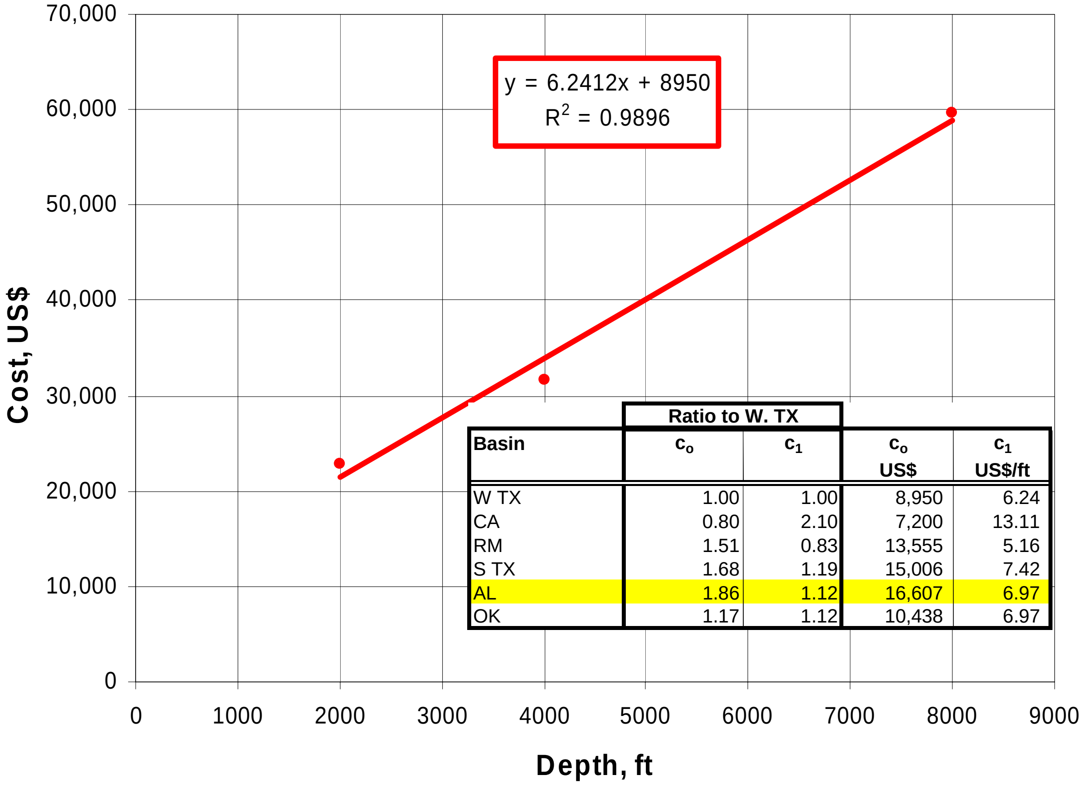
4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are already in place on the lease.

The existing well conversion costs include a fixed cost component and a depth-related cost component, which varies based on the required surface pressure and tubing length. The equation for Alabama is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$16,607 (fixed)
c_1 = \$6.973 per foot
D is well depth

Figure D-4 illustrates the average cost of converting an existing producer into an injection well for West Texas. The West Texas cost data for converting wells provide the foundation for the Alabama cost equation.

Figure D-4. Cost of Converting Existing Production Wells into Injection Wells in West Texas vs. Depth



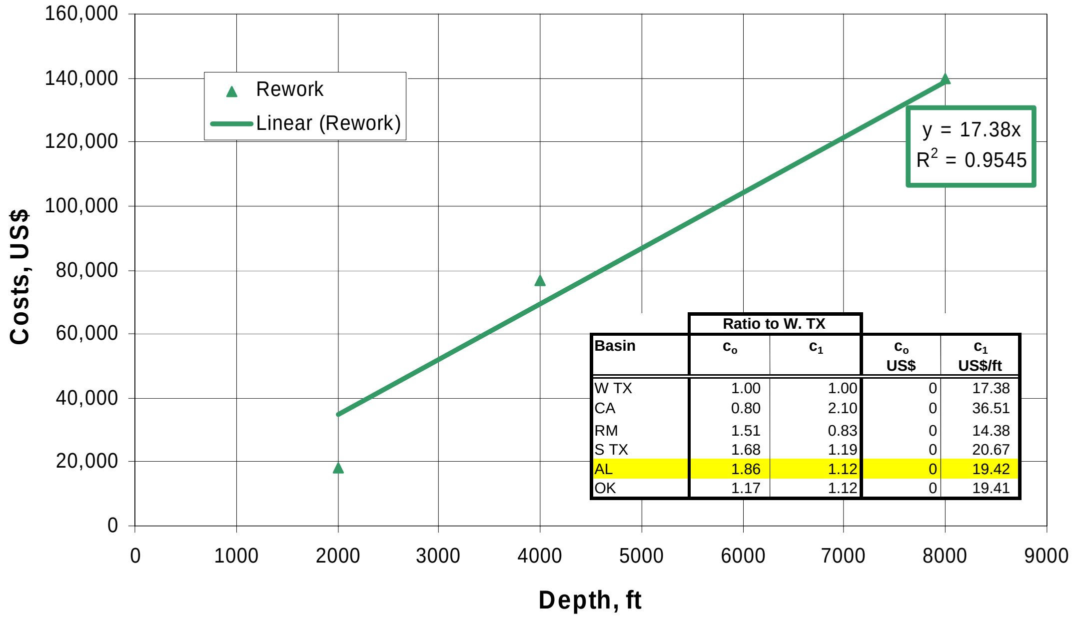
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
AL	1.86	1.12	16,607	6.97
OK	1.17	1.12	10,438	6.97

5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework). The reworking of existing oil production or CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for Alabama is:

Well Rework Costs = c_1D
Where: c_1 = \$19.42 per foot)
D is well depth

Figure D-5 illustrates the average cost of well conversion as a function of depth for West Texas. The West Texas cost data for reworking wells provides the foundation for the Alabama cost equation.

Figure D-5. Cost of an Existing Waterflood Production or Injection Well for CO_2-EOR in West Texas vs. Depth



Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	0	17.38
CA	0.80	2.10	0	36.51
RM	1.51	0.83	0	14.38
S TX	1.68	1.19	0	20.67
AL	1.86	1.12	0	19.42
OK	1.17	1.12	0	19.41

6. Annual O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides secondary operating and maintenance (O&M) costs only for West Texas. As such, West Texas and Alabama primary oil production O&M costs (Figure D-6) are used to estimate Alabama secondary recovery O&M costs. Linear trends are used to identify fixed cost constants and variable cost constants for each region, Table D-1.

Figure D-6. Annual Lease O&M Costs for Primary Oil Production by Area

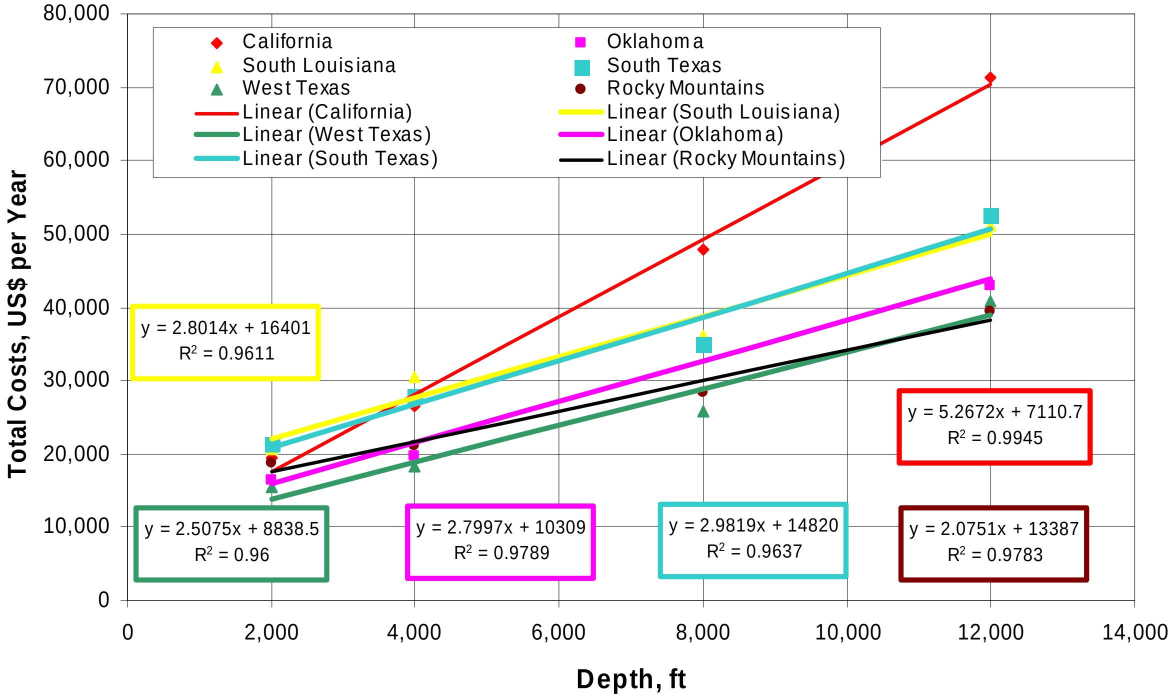


Table D-1. Regional Lease O&M Costs and Their Relationship to West Texas

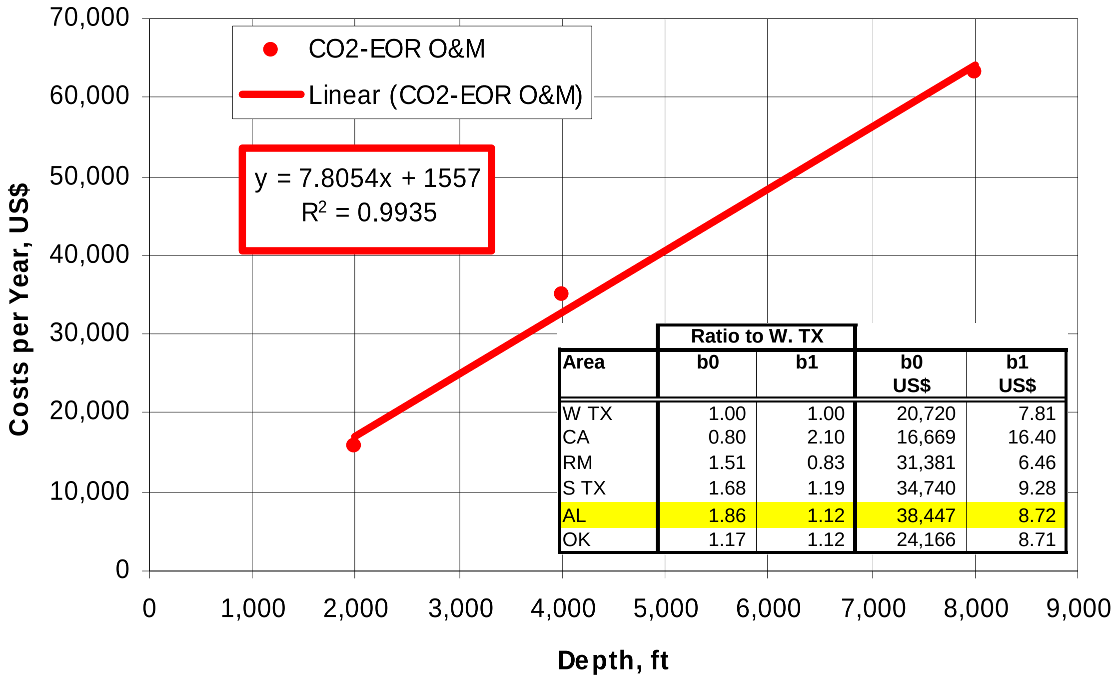
			Ratio to W. TX	
Basin	**c0 US$**	**c1 US$**	**c0**	**c1**
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Rocky Mountain	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Alabama	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

To account for the O&M cost differences between waterflooding and CO_2-EOR, two adjustments are made to the EIA's reported O&M costs for secondary recovery. Workover costs, reported as surface and subsurface maintenance, are doubled to reflect the need for more frequent remedial well work in CO_2-EOR projects. Liquid lifting are subtracted from annual waterflood O&M costs to allow for the more rigorous accounting of liquid lifting volumes and costs for CO_2-EOR. (Liquid lifting costs for CO_2-EOR are discussed in a later section of this appendix.)

Figure D-7 shows the depth-relationship for CO_2-EOR O&M costs in West Texas. These costs were adjusted to develop O&M for Alabama, shown in the inset of Figure D-7. The equation for Alabama is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = $38,447 (fixed)
b_1 = $8.72 per foot
D is well depth

Figure D-7. Annual CO_2-EOR O&M Costs for West Texas



Area	Ratio to W. TX b0	Ratio to W. TX b1	b0 US$	b1 US$
W TX	1.00	1.00	20,720	7.81
CA	0.80	2.10	16,669	16.40
RM	1.51	0.83	31,381	6.46
S TX	1.68	1.19	34,740	9.28
AL	1.86	1.12	38,447	8.72
OK	1.17	1.12	24,166	8.71

7. <u>CO_2 Recycle Plant Investment Cost.</u> Operation of CO_2-EOR requires a recycling plant to capture and reinject the produced CO_2. The size of the recycle plant is based on peak CO_2 production and recycling requirements.

The cost of the recycling plant is set at $700,000 per MMcf/d of CO_2 capacity. As such, a project in the Rodessa formation of the Citronelle field, with 114 MMcf/d of peak CO_2 reinjection and 203 injectors requires a recycling plant costing $80 million.

The model has three options for installing a CO_2 recycling plant. The default setting costs the entire plant one year prior to CO_2 breakthrough. The second option places the full CO_2 recycle plant cost at the beginning of the project (Year 0). The third option installs the CO_2 recycle plant in stages. In this case, half the plant is built (and half the cost is incurred) in the year of CO_2 breakthrough. The second half of the plant is built when maximum recycle capacity requirements are reached.

8. Other COTWO Model Costs.

a. CO_2 Recycle O&M Costs. The O&M costs of CO_2 recycling are indexed to energy costs and set at 1% of the oil price ($0.25 per Mcf @ $25 Bbl oil).

b. Lifting Costs. Liquid (oil and water) lifting costs are calculated on total liquid production and costed at $0.25 per barrel. This cost includes liquid lifting, transportation and re-injection.

c. CO_2 Distribution Costs. The CO_2 distribution system is similar to the gathering systems used for natural gas. A distribution "hub" is constructed with smaller pipelines delivering purchased CO_2 to the project site.

The distribution pipeline cost is dependent on the injection requirements for the project. The fixed component is $150,000. The variable cost component accounts for increasing piping diameters associated with increasing CO_2 injection requirements. These range from $80,000 per mile for 4" pipe (CO_2 rate less than 15MMcf/d), $120,000 per mile for 6" pipe (CO_2 rate of 15 to 35 MMcf/d), $160,000 per mile for 8" pipe (CO_2 rate of 35 to 60 MMcf/d), and $200,000 per mile for pipe greater than 8" diameter (CO_2 rate greater than 60 MMcf/d). Aside from the injection volume, costs also depend on the distance from the CO_2 "hub" (transfer point) to the oil field. Currently, the distance is set at 10 miles.

The CO_2 distribution cost equation for Alabama is:

Pipeline Construction Costs = $150,000 + C_D*Distance

Where: C_D is the cost per mile of the necessary pipe diameter (from the CO_2 injection rate)
Distance = 10.0 miles

d. G&A Costs. General and administrative (G&A) costs of 20% are added to well O&M and lifting costs.

e. Royalties. Royalty payments are assumed to be 12.5%.

f. Production Taxes. Alabama has enacted a risk sharing action for enhanced oil recovery. The Alabama Severance Tax Law Chapter 20, Article 1, Section 40-20-2 is effective May 1, 1985. It states:

"…the incremental oil or gas production produced during a given year resulting from a qualified enhanced recovery project shall be taxed at the rate of four percent of gross value at the point of production of said incremental oil or gas production."

The severance tax in the model was therefore set at 6.0% (the 4% privilege tax plus a 2% production tax). The conventional oil severance tax rate in Alabama is 10% of the value of the produced oil. Reduction in the severance tax by 4% for enhanced oil recovery provides a savings of $1.05 per barrel of incrementally produced oil (assuming a sales price of $30 per barrel of oil and a royalty rate of 12.5%). Production taxes are taken following royalty payments.

g. <u>Crude Oil Price Differential.</u> To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis differential for Alabama ($0.00 per barrel) and the current gravity differential (-$0.25 per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for Alabama is:

Wellhead Oil Price = Oil Price + ($0.00) – [$0.25*(40 - °API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
°API is oil gravity

If the oil gravity is less than 40 °API, the wellhead oil price is reduced; if the oil gravity is greater than 40 °API, the wellhead oil price is increased. In addition, some fields within Alabama contain very light oil (>45 API). In order to keep the economics of these fields level with the rest of the fields, we imposed a ceiling of 45 API for all fields with lighter oil when applying the Crude Oil Price Differential.