BASIN ORIENTED STRATEGIES FOR CO_2 ENHANCED OIL RECOVERY:

ONSHORE GULF COAST

Prepared for:

U.S. Department of Energy

Office of Fossil Energy – Office of Oil and Natural Gas

Prepared by:

Advanced Resources International, Inc.

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1. SUMMARY OF FINDINGS

***1.1 INTRODUCTION**.* The onshore Gulf Coast oil and gas producing region of Louisiana, Mississippi and Texas/District 3 has 36 billion barrels of oil which will be left in the ground, or "stranded", following the use of today's 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 oil recovery potential in the large oil fields of the onshore Gulf Coast region and the barriers that stand in the way of 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.

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. Under this low technology, high-risk scenario, called "Traditional Practices", because of low oil recoveries efficiency there is little potential in this oil-producing region for using CO_2-EOR.

- The second scenario, entitled "State of the Art", assumes that the technology progress in CO_2-EOR, achieved in other areas, is successfully applied to the oil reservoirs of Illinois. In addition, a comprehensive set of research, pilot tests and field demonstrations help lower the risk inherent in applying new technology to these complex oil reservoirs. However, because of limited sources of CO_2, these supply costs are high (equal to $1.25 per Mcf) the oil price) and significantly hamper economic feasibility of using CO_2-EOR.

- 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 be equal to $10 per barrel in the price that the producer receives for produced crude oil.

- In the final scenario, entitled “Ample Supplies of CO_2,” low-cost, “EOR-ready” CO_2 supplies (equal to $0.70 per Mcf) are aggregated from various sources. These include industrial high-concentration CO_2 emissions from hydrogen facilities, gas processing plants and other sources. These would be augmented, in the longer-term, from low CO_2 concentration industrial sources including combustion and electric generation plants. Capture of industrial CO_2 emissions would be part of national efforts for reducing greenhouse gas emissions.

The CO_2-EOR potential of the onshore Gulf Coast region is examined using these four bounding scenarios.

1.3 OVERVIEW OF FINDINGS. Ten major findings emerge from the study of “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Onshore Gulf Coast Oil Basins.”

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 was 61 billion barrels. To date, 25 billion barrels of this original oil in-place (OOIP) has been recovered or proved. Thus, without further oil recovery methods, 36 billion barrels of the Gulf Coast’s oil resource will become “stranded”, Table 1.

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

Region	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves* (Billion Bbls)	ROIP (Billion Bbls)
A. Major Oil Reservoirs				
Louisiana	135	19.2	7.4	11.8
Mississippi	22	2.6	0.9	1.6
Texas/District 3	60	13.2	6.0	7.2
Data Base Total	217	35.0	14.3	20.6
*B. Regional Total**	n/a	60.8	24.5	36.4

**Estimated from State of Louisiana, Mississippi and Texas data on cumulative oil recovery and proved reserves, as of the end of 2002.*

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 address the "stranded oil" issue, Advanced Resources assembled a database that contains 217 major Gulf Coast oil reservoirs, accounting for 58.5% of the region's estimated ultimate oil production. Of these, 205 reservoirs, with 31.1 billion barrels of OOIP and 17.7 billion barrels of "stranded oil" (ROIP)), were found to be favorable for CO_2-EOR, as shown below by region, Table 2.

Table 2. The Gulf Coast'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
Texas/District 3	57	13.1	6.0	7.1
TOTAL	205	31.1	13.4	17.7

3. Application of miscible CO_2-EOR would enable a significant portion of the Gulf Coast's "stranded oil" to be recovered. Of the 205 large Gulf Coast oil reservoirs favorable for CO_2-EOR, 199 reservoirs (with 30.6 billion barrels OOIP) screen as being favorable for miscible CO_2-EOR. The remaining 6 oil reservoirs (with 0.5 billion barrels OOIP) screen as being favorable for immiscible CO_2-EOR. The total technically recoverable resource from applying CO_2-EOR in these 205 large oil reservoirs, ranges from 2,600 million barrels to 5,860 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. Applicability of Miscible and Immiscible CO_2-EOR

	Miscible		Immiscible	
Region	No. of Reservoirs	Technically Recoverable* (MMBbls)	No. of Reservoirs	Technically Recoverable* (MMBbls)
Louisiana	128	1,430 – 3,240	0	-
Mississippi	17	150 – 330	3	0-20
Texas (3)	54	1,020 – 2,290	3	0-30
TOTAL	199	2,600 – 5,860	6	0-50

**Range in technically recoverable oil reflects the performance of "Traditional Practices" and "State of the Art" CO_2-EOR technology.*

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 199 large reservoirs in the data base would enable 2,600 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 (equal to $1.25 per Mcf), uncertainties about future oil prices and the performance of CO_2-EOR technology, only a very small portion, about 70 million barrels, of this "stranded oil" would become economically recoverable at oil prices of $25 per barrel as adjusted for gravity and location, (with most of it from District 3 in Texas), Table 4.

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

Basin	No. of Reservoirs	OOIP (MMBbls)	Technically Recoverable (MMBbls)	Economically* Recoverable (MMBbls)
Louisiana	128	16,035	1,430	**
Mississippi	17	1,717	150	-
Texas (3)	54	12,777	1,020	70
TOTAL	199	30,529	2,600	70

*This case assumes an oil price of $25 per barrel, a CO_2 cost of $1.25 per Mcf, and a ROR hurdle rate of 25% (before tax).
**Less than 5 MMBbls.

5. Introduction of "State of the Art" CO_2-EOR technology, lower CO_2 costs and risk sharing, would enable 4.3 billion barrels of additional oil to become economically recoverable. With "State of the Art" CO_2-EOR technology, and its higher oil recovery efficiency a much larger portion of the oil remaining in the Gulf Coast's reservoirs becomes economically recoverable, equal to 1,860 million barrels. Risk mitigation and higher oil prices, providing revenues equal to $35 per barrel, would enable 3,960 million barrels of oil to become economically recoverable from the Gulf Coast's large oil reservoirs. Lower cost CO_2 supplies (from a large transportation system and incentives for CO2 capture) would enable the economic potential to increase to 4,350 million barrels, Figure 1 and Table 5.

Table 5. Economically Recoverable Resources Under Alternative Scenarios

	Scenario #2: "State of the Art"	Scenario #3: "Risk Mitigation"	Scenario #4: "Ample Supplies of CO_2"
Basin	(Moderate Oil Price/ High CO_2 Cost*) (MMBbls)	(High Oil Price/ High CO_2 Cost**) (MMBbls)	High Oil Price/ Low CO_2 Cost*** (MMBbls)
Louisiana	430	1,800	2,130
Mississippi	50	160	200
Texas (3)	1,380	2,000	2,020
TOTAL	1,860	3,960	4,350

*This case assumes an oil price of $25 per barrel, a CO_2 cost of $1.25/Mcf and a ROR hurdle rate of 15% (before tax).
**This case assumes an oil price of $35 per barrel, a CO_2 cost of $1.25/Mcf and a ROR hurdle rate of 15% (before tax).
***This case assumes an oil price of $35 per barrel, a CO_2 cost of $0.70/Mcf and a ROR hurdle rate of 15% (before tax).

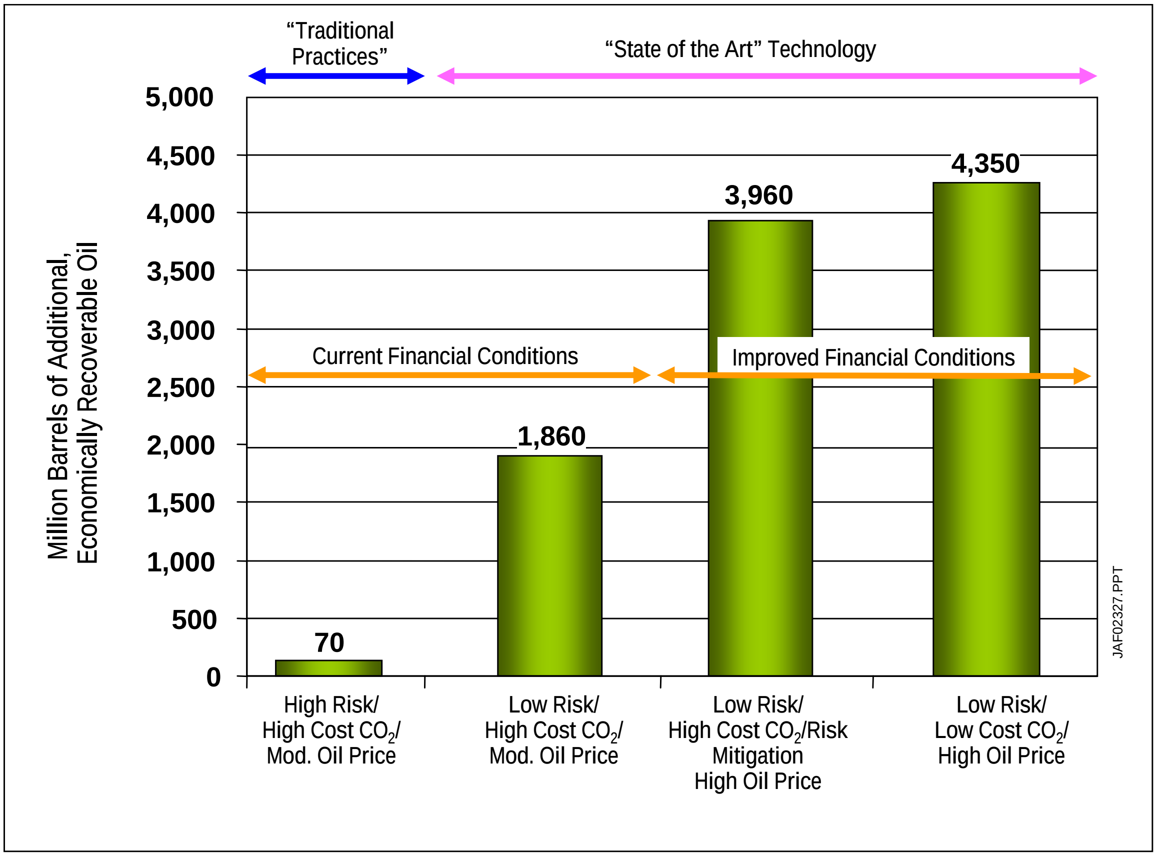


Figure 1. Impact of Technology and Financial Conditions on Economically Recoverable Oil from the Gulf Coast Region's Major Reservoirs Using CO2-EOR (Million Barrels).

6. Once the results from the study's large oil reservoirs database are extrapolated to the region as a whole, the technically recoverable CO_2-EOR potential for the Gulf Coast is estimated at 10 billion barrels. The large Gulf Coast oil reservoirs examined by the study account for 58.5% of the region's oil resource. Extrapolating the 5.9 billion barrels of technically recoverable EOR potential in these 199 oil reservoirs to the total Gulf Coast oil resource provides an estimate of 10.1 billion barrels of technical CO_2-EOR potential. (However, no extrapolation of economic potential has been estimated, as the development costs of the 199 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 CO_2-EOR in the Gulf Coast will, most likely, prove to be higher than defined by this study. Introduction of more "advanced" 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 control agents, could significantly increase recoverable oil volumes while expanding the state's geologic storage capacity for CO_2 emissions. The benefits and impacts of using "advanced" CO_2-EOR technology on Gulf Coast oil reservoirs will be examined in a subsequent study.

8. 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 up to 20 Tcf, plus another 42 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 1 billion tons 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) could double 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)	Purchased CO2 (Bcf)	Recycled CO2 (Bcf)
Louisiana	61	2,130	10,150	20,860
Mississippi	12	200	820	1,760
Texas/District 3	51	2,020	8,680	18,930
TOTAL	125	4,350	19,650	41,550

**Under Scenario #4: "Ample Supplies of CO2."*

9. 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 risk - - 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.

10. 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 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 and Texas.

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 assembling historic data on cumulative natural gas production by field and by area. We recognize and appreciate the considerable assistance provided by Ms. Dixon to assemble the relevant data. We also fully support all efforts to upgrade the SONRIS system as a data source for independent producers seeking to recover more of the oil remaining in the 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 production and guidance on field and reservoir level production and well counts.

In Texas, we would like to thank the Office of the Texas Comptroller of Public Accounts who provided detailed information on the severance taxes relevant to Texas District 3.

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”, and explaining who helped in identifying and explaining the information used in the SPE paper.

2. INTRODUCTION

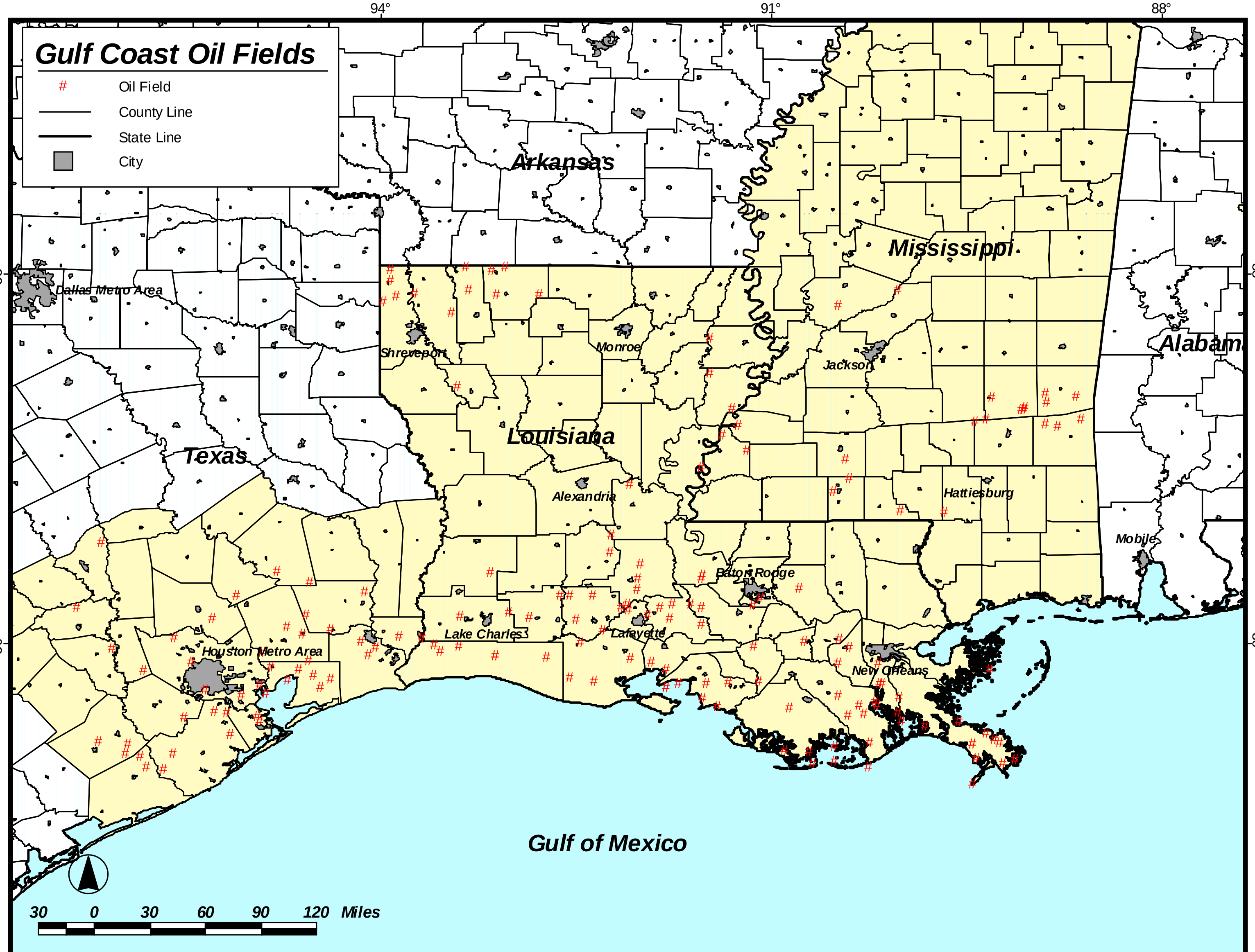
2.1 CURRENT SITUATION. The Gulf Coast oil producing region is mature and in decline. Stemming the decline in oil production will be a major challenge, requiring a coordinated set of actions by numerous parties who have a stake in this problem - - Gulf Coast state revenue and economic development officials; 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 CO_2 enhanced oil recovery (CO_2-EOR) as one option for slowing or potentially stopping the decline in the Gulf Coast’s oil production.

This report, “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Gulf Coast Oil Basins,” provides information on the size of the technical and economic potential for CO_2-EOR in the Gulf Coast oil producing regions of onshore Louisiana, Mississippi and Texas/District 3. It also identifies the many barriers - - insufficient and costly CO_2 supplies, high market and economic risks, and concerns over technology performance - - that currently impede the cost-effective application of CO_2-EOR in the Gulf Coast oil producing region.

2.2 BACKGROUND. The onshore Gulf Coast region of Louisiana, Mississippi and Texas/District 3 was, at one time, one of the largest onshore domestic oil producing regions. With severe declines in crude oil reserves and production capacity, these three areas of the Gulf Coast currently produce only 255 thousand barrels of oil per day (in 2002). However, the deep, light oil reservoirs of this region are ideal candidates for miscible carbon-dioxide based enhanced oil recovery (CO_2-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.



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2.3 PURPOSE. This report, “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Gulf Coast Oil Basins” is part of a larger effort to examine the enhanced oil recovery and CO_2 storage potential in key U.S. oil basins. A previous report addressed the oil fields of California. Subsequent reports will assess the oil fields of the Mid-Continent and Alaska. 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, estimating economic feasibility.

Future studies will also examine: (1) 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 in the major oil basins of the U.S.

An important purpose of the larger study is to develop a desktop modeling and analytical capability for “basin oriented strategies” that would enable DOE/FE 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, from industrial sources such as the hydrogen plants at the refineries in Lake Charles, Louisiana, Pascagoula, Mississippi and Texas City, Texas, or from power plants in the region. The timing of this availability assumes that this CO_2 will be delivered in the near future, as forecasting field life is not part of the study.

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 Denbury Resources press release in the fall of 2004, this operator of the Jackson Dome CO_2 reservoir has moved forward with plans to construct the 84-mile extension from East Mississippi to Eucutta Field in Mississippi.

Figure 4 provides a conceptual illustration of a CO_2 pipeline system that would transport captured CO_2 emissions from the Louisiana's refinery complex at Lake Charles to the nearby oil fields of Louisiana. 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 and makes no warranties to the availability of pipeline right-of-ways due to environmental or landowner constraints.

Figure 3. Location of Existing and Planned CO2 Supply Pipelines in Mississippi and Louisiana.

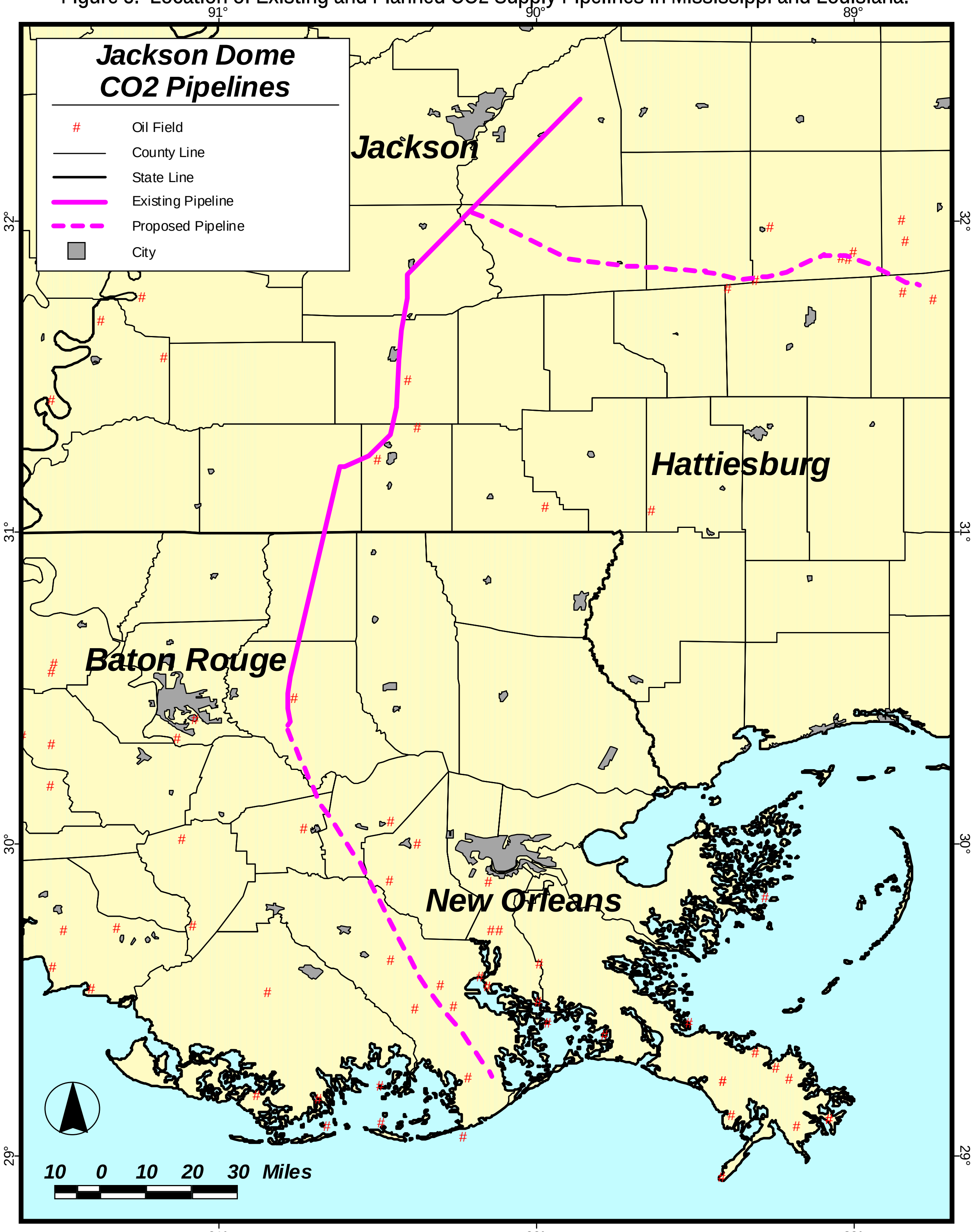

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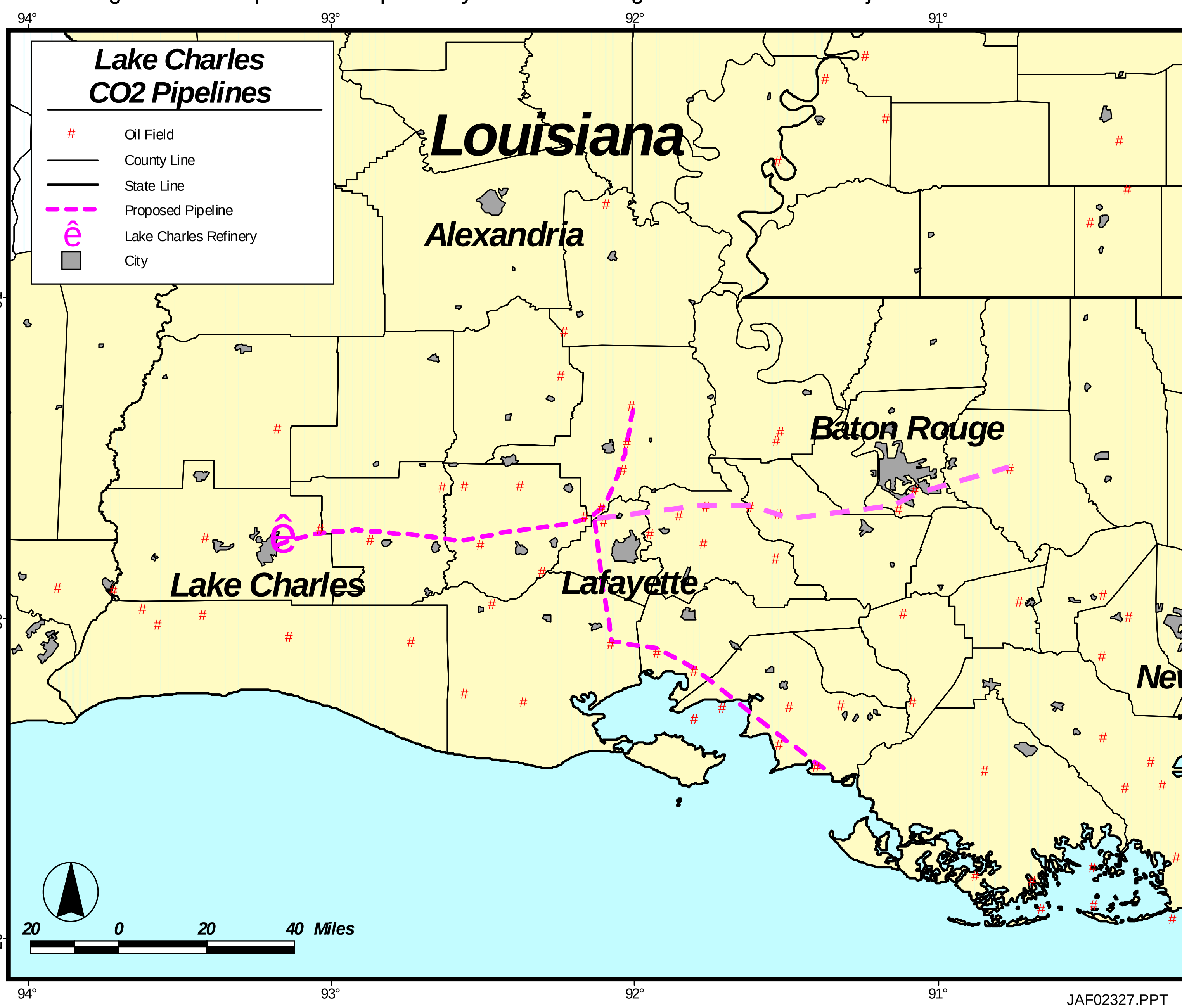
Figure 4. Conceptual CO2 Pipeline System Connecting CO2 Sources with Major Louisiana Oil Fields.



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, economic evaluations typically add a risk factor for making 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 gains in understanding of the CO_2-EOR process and 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", although this concept required further testing. 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 light hydrocarbon components into the CO_2 phase) with the oil remaining in the reservoir. Typically, reservoirs at depths greater than 3,000 feet and with oil gravities greater than 25^o API would be selected for miscible CO_2-EOR. Major Gulf Coast light oil fields such as Webster (TX), West Heidelberg (MS) and Lake Washington (LA) fit into this category. 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^o and 25^o 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 6.

Table 6. 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	▪ Deep, Light Oil Reservoirs
"State of the Art"; Miscible and Immiscible CO_2-EOR	▪ Deep, Light Oil Reservoirs ▪ Deep, Moderately Heavy Oil Reservoirs

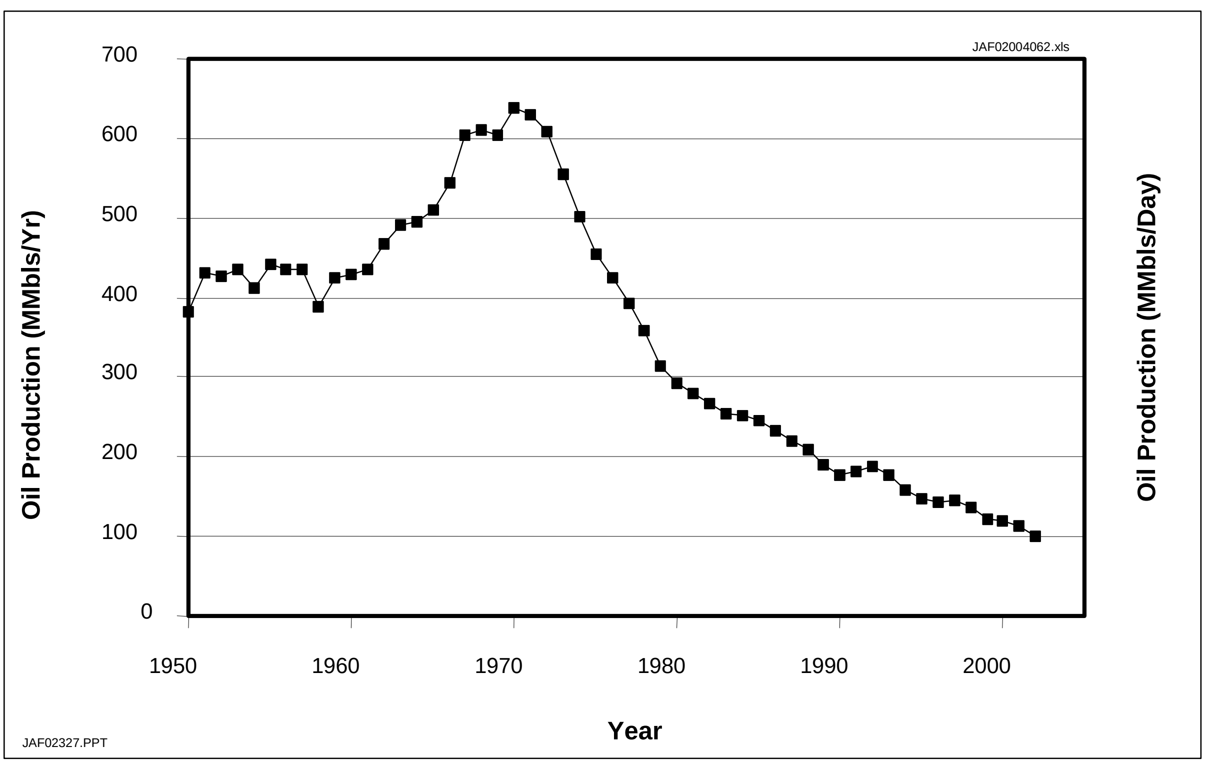
2.6 OTHER ISSUES. This study draws on a series of sources for basic data on the reservoir properties and the expected technical and economic performance of CO_2-EOR in the Gulf Coast's major oil reservoirs. Because of confidentiality and proprietary issues, the results of the study have been aggregated for the three 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 and district level reporting of results in this study.

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, and Railroad District 3 in Texas - - has steadily declined for the past 30 years, Figure 5. Since reaching a peak in 1970, oil production dropped sharply for the next ten years before starting a more gradual decline in the late 1980s due to secondary recovery efforts. Oil production reaching a recent low of 93 million barrels (255,000 barrels per day) in 2002.

- Louisiana onshore areas, with 47 million barrels of oil produced in 2002, has seen its crude oil proved reserves fall in half in the past 20 years.
- Mississippi, with 18 million barrels of oil produced in 2002, has maintained its proved crude oil reserves and oil production for the past ten years.
- The steepest decline in proved crude oil reserves has been in Texas Railroad District 3. This area of the Gulf Coast region produced 28 million barrels in 2002.

Figure 5. History of Gulf Coast Crude Oil Production, 1950 - 2002.



However, the Gulf Coast still holds a rich resource of oil in the ground. With more than 61 billion barrels of original oil in-place (OOIP) and approximately 25 billion barrels expected to be recovered, 36 billion barrels of oil will be "stranded" due to lack of technology, lack of sufficient, affordable CO_2 supplies and high economic and technical risk.

Table 7 presents the status and annual oil production for the ten largest Gulf Coast region oil fields that account for a quarter of the oil production in this region. The table shows that seven of the largest oil fields are in steep 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 7. Crude Oil Annual Production, Ten Largest Gulf Coast Oil Fields, 2000-2002
(Million Barrels per Year)

Major Oil Fields	2000	2001	2002	Production Status
Giddings, TX	11.2	10.4	8.9	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	Declining
Little Creek, MS	0.9	1.1	1.5	Stable
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
West Bay, LA	0.7	1.3	0.9	Declining
Laurel, LA	1.1	1.0	0.8	Declining

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 three regions of onshore production in the Gulf Coast – Louisiana, Mississippi, and Texas Railroad District 3, still contain over 60% of their OOIP after primary and secondary oil recovery. This large volume of remaining oil in-place (ROIP) is the "prize" for CO2-EOR.

Table 8 provides information (as of year 2002) on the maturity and oil production history of 14 large Gulf Coast oil fields, each with estimated ultimate recovery of 200 million barrels or more. Of particular note are the giant light oil fields that may be attractive for miscible CO_2-EOR, including: Conroe (Texas) with 864 million barrels of ROIP, West Hastings (Texas) with 525 million barrels of ROIP, and Caillou Island (Louisiana) with 588 million barrels of ROIP.

Table 8. Selected Major Oil Fields of the Gulf Coast Region

	Field/State	Year Discovered	Cumulative Production (Mbbl)	Estimated Reserves (Mbbl)	Remaining Oil In-Place (MMbbl)
1	CONROE – TX	1931	727,618	4,950	864
2	HASTINGS, WEST - TX	1958	637,124	4,450	525
3	CAILLOU ISLAND - LA	1942	630,000	7,400	648
4	WEBSTER - TX	1936	595,134	3,710	561
5	GIDDINGS - TX	1960	429,580	61,990	601
6	CADDO PINE ISLAND	1905	393,984	11,840	2,067
7	THOMPSON - TX	1921	372,946	4,260	461
8	ANAHUAC - TX	1935	286,769	570	287
9	LAKE WASHINGTON - LA	1931	272,079	13,650	360
10	LAFITTE - LA	1935	268,741	7,420	329
11	WEEKS ISLAND - LA	1945	264,951	18,710	347
12	BAXTERVILLE - MS	1944	252,923	5,770	489
13	WEST BAY - LA	1940	242,070	8,030	336
14	GARDEN ISLAND BAY - LA	1935	221,354	3,040	262

3.4 REVIEW OF PRIOR STUDIES. Past studies of the potential for CO_2 enhanced oil recovery in Gulf Coast region oil reservoirs have shown a range of results and are presented below.

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 was also responsible for the development of *CO2-PROPHET*, Louisiana State University conducted separate studies of Louisiana and Texas to ascertain the impact of miscible CO_2-EOR. The technical and economic parameters of the study were as follows - - 10% recovery factor of ROIP; oil price of $17/bbl, 15% for royalty and taxes; and CO_2 costs of $0.60/Mcf.

- In Louisiana, the investigators began with a database of 499 light-oil waterflooded reservoirs to select candidates acceptable for CO_2-EOR. The database 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.

- In Texas, 378 oil reservoirs were screened for their applicability to CO_2-EOR, with 211 of these reservoirs screening as being economic. For Texas/District 3 (the Gulf Coast area addressed by this study), 33 reservoirs screened as being economic for CO_2-EOR, representing a potential for 2 billion barrels of incremental oil recovery.

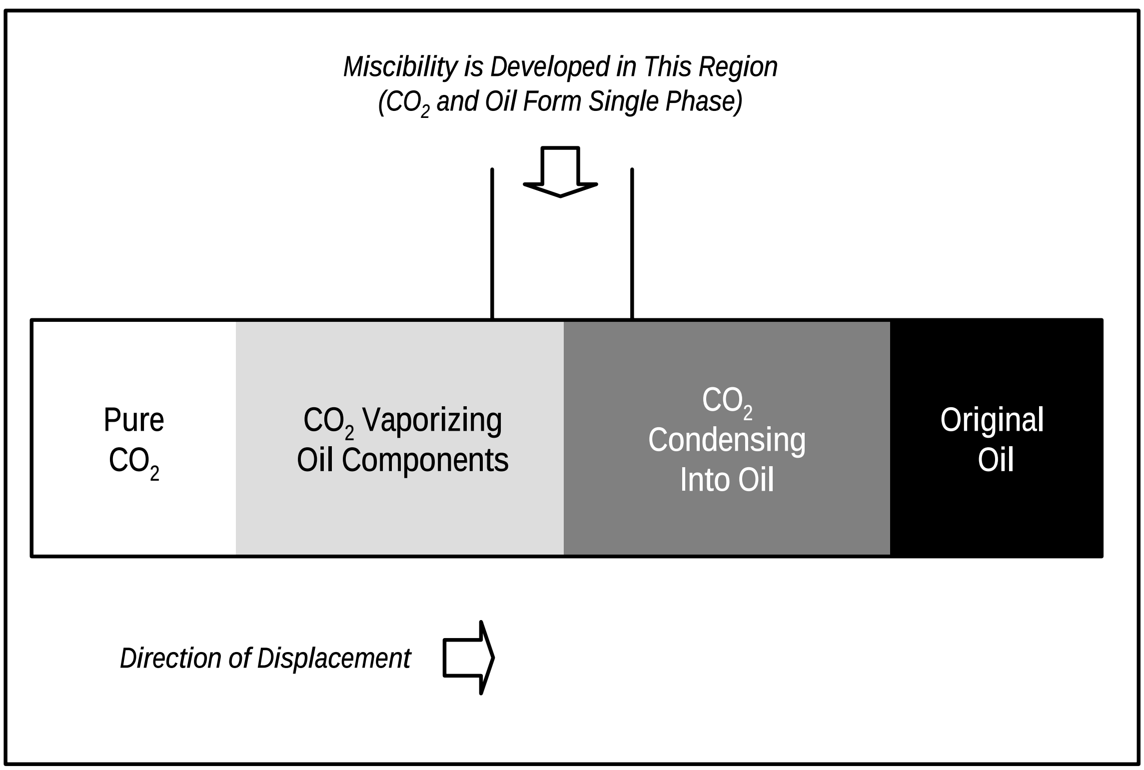
A second study of the CO_2-EOR potential in Texas was performed by the Bureau of Economic Geology in 1999. This study screened over 1,700 Texas oil reservoirs for their applicability to CO_2-EOR. This study identified 80 billion barrels of OOIP, 31 billion barrels of which was considered "residual oil". The largest portion of this stranded resource was judged to exist within the platform carbonates of West Texas and the fluvial-deltaic reservoirs of East Texas. A target of 8 billion barrels of the OOIP was identified to exist within 90 miles of major coal- and lignite-fired power plants that would, in the future, become sources for CO_2 supplies. The study did not provide quantitative data on technical or economic incremental oil production from CO_2-EOR, citing only that technical and economic potential did, in fact, exist in many Texas 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 6 provides a one-dimensional schematic showing the various fluid phases existing in the reservoir and the dynamics of the CO_2 miscible process.

Figure 6. 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 7A and 7B 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 8A and 8B show the oil swelling (and implied residue 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^oAPI) 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 9 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 7A. 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).

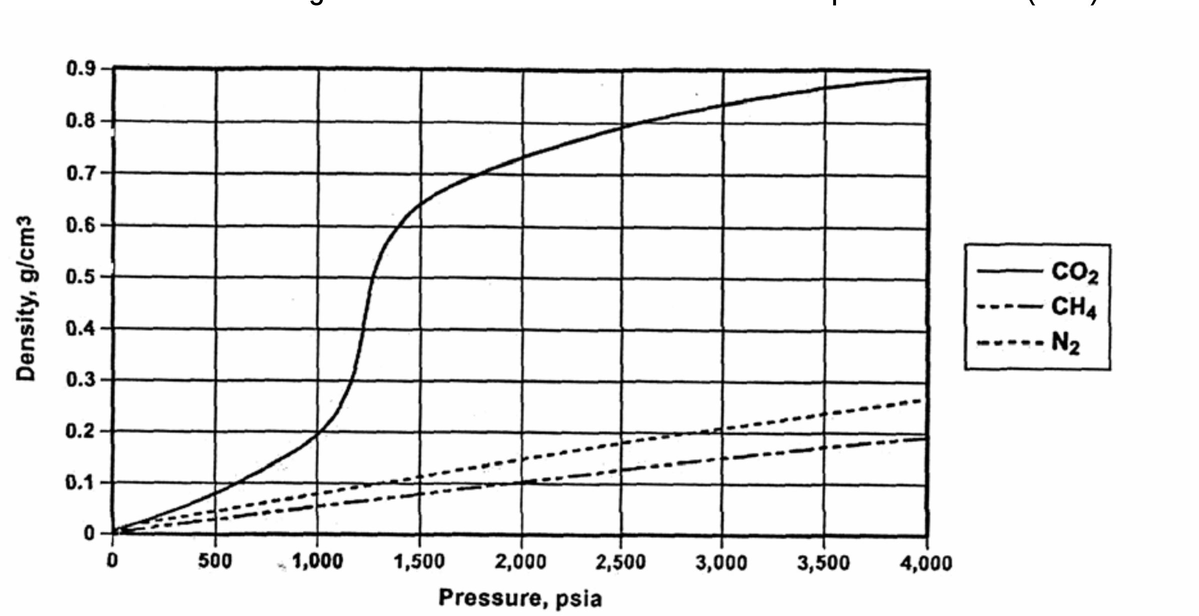

Figure 7B. Carbon Dioxide, CH_4 and N_2 viscosities at 105^0F. At high pressures, the viscosity of CO_2 is also greater then that of methane or nitrogen, although it remains low in comparison to that of liquids. Viscosities were calculated with an EOS.

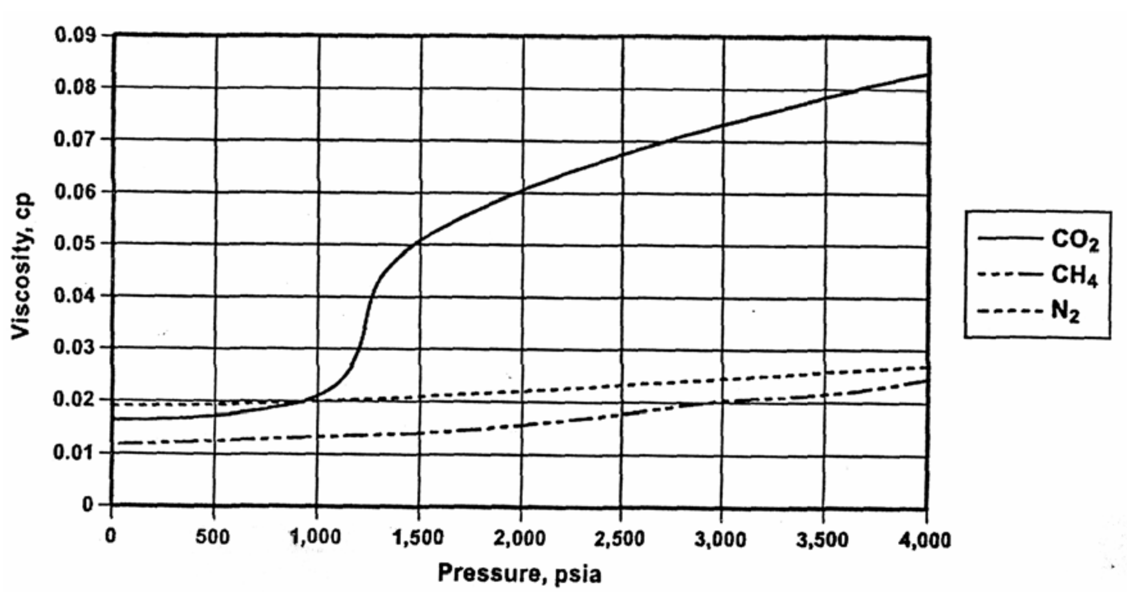

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Figure 8A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid. (Holm and Josendal)

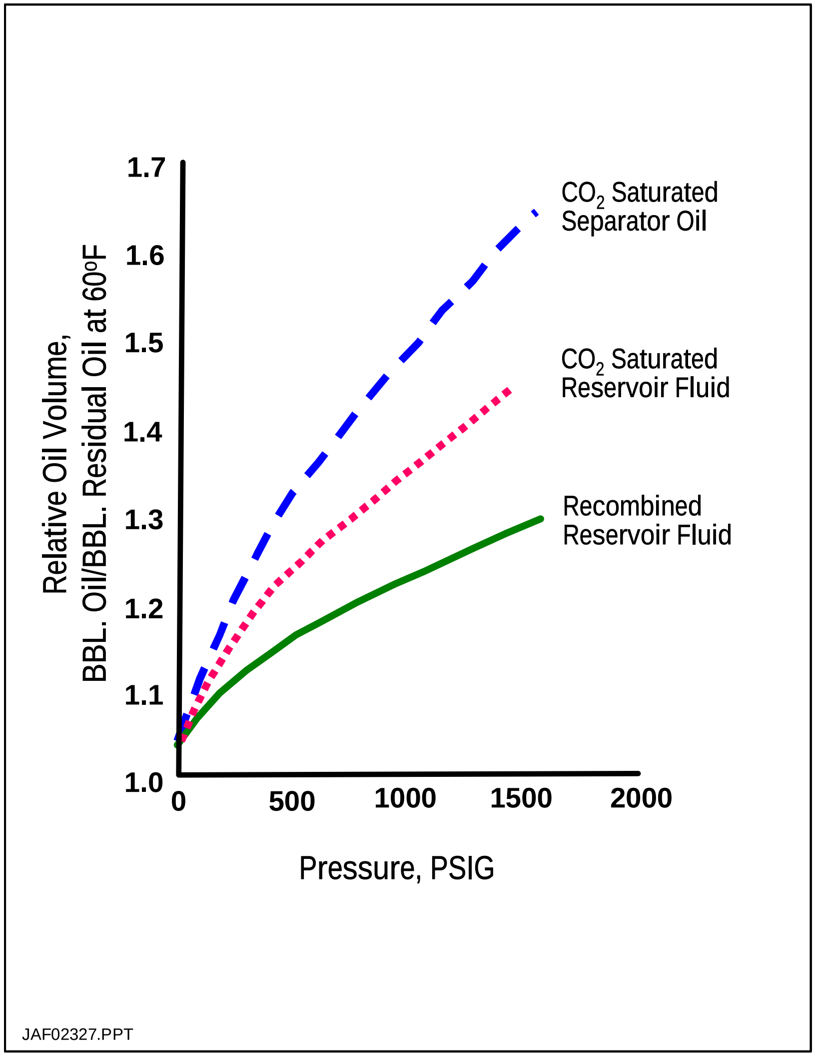

Figure 8B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

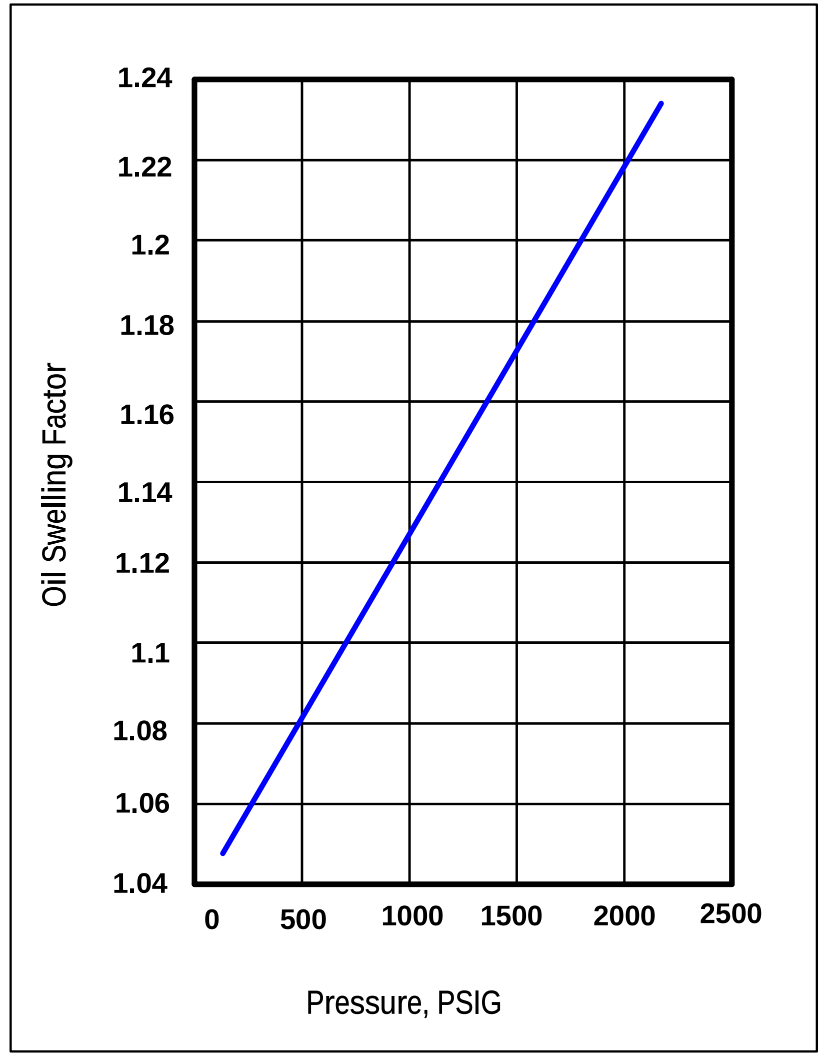

Figure 9. Viscosity Reduction Versus Saturation Pressure. (Simon and Graue)

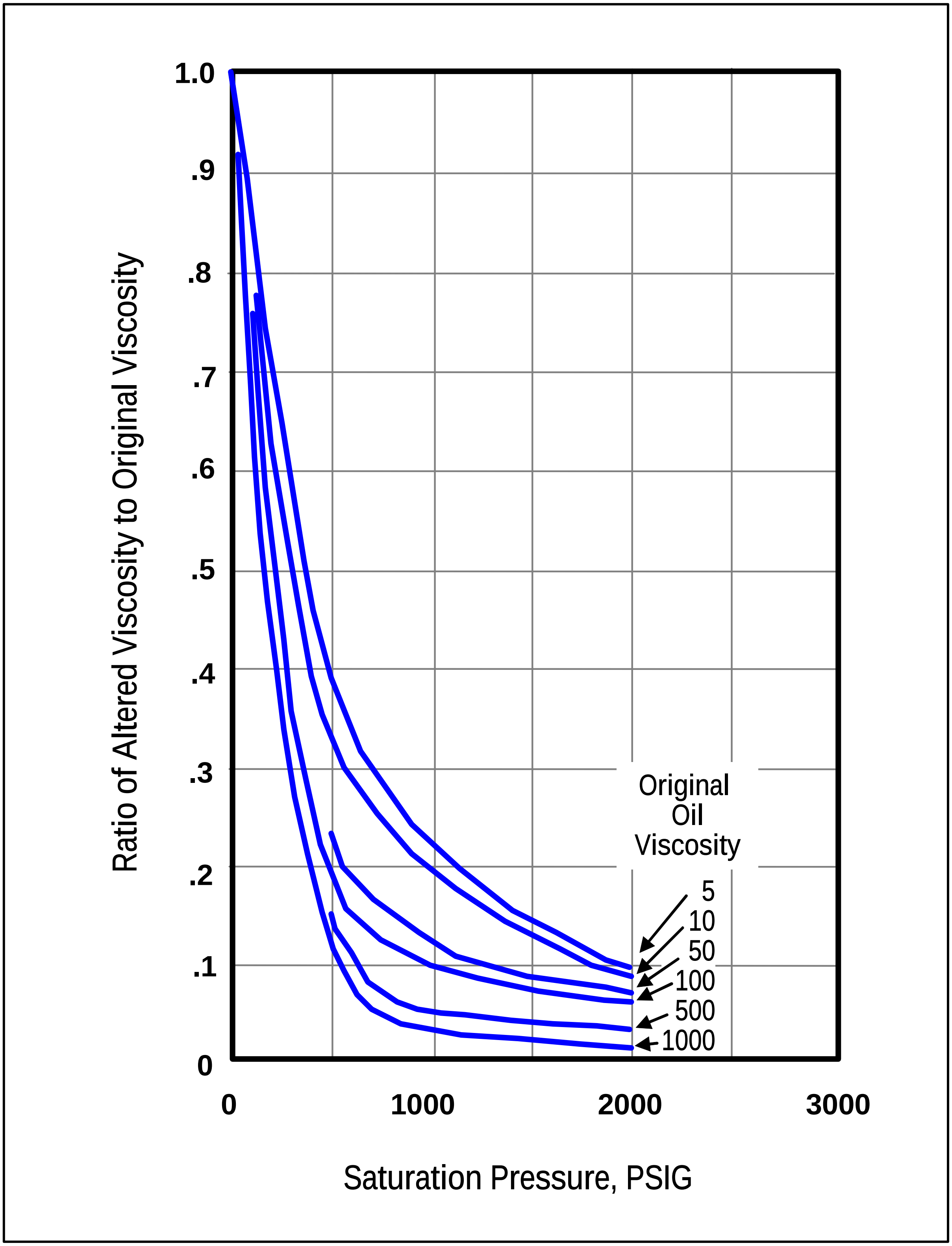

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Table 9. Reservoir Data Format: Major Oil Reservoirs Data Base.

Basin Name	
Field Name	
Reservoir	

Reservoir Parameters:	
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	

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Oil Production	
Producing Wells (active)	
Producing Wells (shut-in)	
2001 Production (Mbbl)	
Daily Prod - Field (Bbl/d)	
Cum Oil Production (MMbbl)	
EOY 2001 Oil Reserves (MMbbl)	
Water Cut	

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

Injection	
Injection Wells (active)	
Injection Wells (shut-in)	
2001 Water Injection (MMbbl)	
Daily Injection - Field (Mbbl/d)	
Cum Injection (MMbbl)	
Daily Inj per Well (Bbl/d)	

Volumes	
OOIP (MMbl)	
Cum Oil (MMbl)	
EOY 2001 Reserves (MMbl)	
Ultimate Recovery (MMbl)	
Remaining (MMbbl)	
Ultimate Recovered (%)	

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

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

ROIP Volume Check	
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^o API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection. Table 10 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 10. Gulf Coast Oil Reservoirs Screened Acceptable for 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 10. Gulf Coast Oil Reservoirs Screened Acceptable for 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 10. Gulf Coast Oil Reservoirs Screened Acceptable for 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 10. Gulf Coast Oil Reservoirs Screened Acceptable for 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
C. Texas Railroad District 3		
Texas RR 3	AMELIA	FRIO

Table 10. Gulf Coast Oil Reservoirs Screened Acceptable for CO_2-EOR

Basin	Field	Formation
Texas RR 3	ANAHUAC	13A-2 FRIO FB
Texas RR 3	BARBERS HILL	MIOCENE-FRIO
Texas RR 3	CLEAR LAKE	FRIO
Texas RR 3	CONROE	CONROE MAIN
Texas RR 3	MAGNET WITHERS	All
Texas RR 3	BRYAN	WOODBINE
Texas RR 3	HUMBLE	All
Texas RR 3	MANVEL	All others
Texas RR 3	ORANGE	All
Texas RR 3	MANVEL (OLIGOCENE)	OLIGOCENE
Texas RR 3	SOUR LAKE	All
Texas RR 3	WEST COLUMBIA	WEST
Texas RR 3	WITHERS, NORTH	NORTH
Texas RR 3	WEST COLUMBIA NEW	NEW
Texas RR 3	GILLOCK	EAST SEGMENT & BIG GAS
Texas RR 3	GILLOCK, SOUTH	BIG GAS
Texas RR 3	GOOSE CREEK	MIOCENE
Texas RR 3	HANKAMER	MIOCENE SAND
Texas RR 3	HASTINGS, EAST	EAST
Texas RR 3	HASTINGS, WEST	WEST
Texas RR 3	HULL MERCHANT	YEGUA
Texas RR 3	LOVELLS LAKE	2FRIO 2
Texas RR 3	MARKHAM, NORTH-BAY CITY	WEST CORNELIUS
Texas RR 3	MARKHAM, NORTH-BAY CITY	CARLSON
Texas RR 3	OLD OCEAN	ARMSTRONG
Texas RR 3	OYSTER BAYOU	SEABREEZE
Texas RR 3	PIERCE JUNCTION	All
Texas RR 3	RACCOON BEND	All
Texas RR 3	RACCOON BEND	COCKFIELD
Texas RR 3	SPINDLETOP	All
Texas RR 3	THOMPSON	All others
Texas RR 3	THOMPSON, NORTH	NORTH
Texas RR 3	THOMPSON, SOUTH	FRIO POOL
Texas RR 3	TOMBALL	COCKFIELD
Texas RR 3	TOMBALL	SCHULTZ, SOUTHEAST
Texas RR 3	WEBSTER	FRIO
Texas RR 3	CHOCOLATE BAYOU	ALIBEL
Texas RR 3	CHOCOLATE BAYOU	UPPER FRIO
Texas RR 3	FAIRBANKS	FAIRBANKS
Texas RR 3	FIG RIDGE	SEABREEZE
Texas RR 3	GIDDINGS	AUSTIN CHALK

Table 10. Gulf Coast Oil Reservoirs Screened Acceptable for CO_2-EOR

Basin	Field	Formation
Texas RR 3	HARDIN	FRAZIER
Texas RR 3	KURTEN	WOODBINE
Texas RR 3	LOVELLS LAKE	FRIO 1
Texas RR 3	MERCHANT	EY 1B
Texas RR 3	SILSBEE	YEGUA
Texas RR 3	TRINITY BAY	FRIO 12
Texas RR 3	HOUSTON, SOUTH	SOUTH
Texas RR 3	SUGARLAND	FRIO
Texas RR 3	THOMPSON, SOUTH	4400 SAND MIOCENE Y
Texas RR 3	LIVINGSTON	WILCOX
Texas RR 3	LIVINGSTON	YEGUA
Texas RR 3	OLD OCEAN	CHENAULT
Texas RR 3	SEGNO	ALL OTHERS
Texas RR 3	SEGNO	WILCOX
Texas RR 3	SARATOGA WEST	UNNAMED

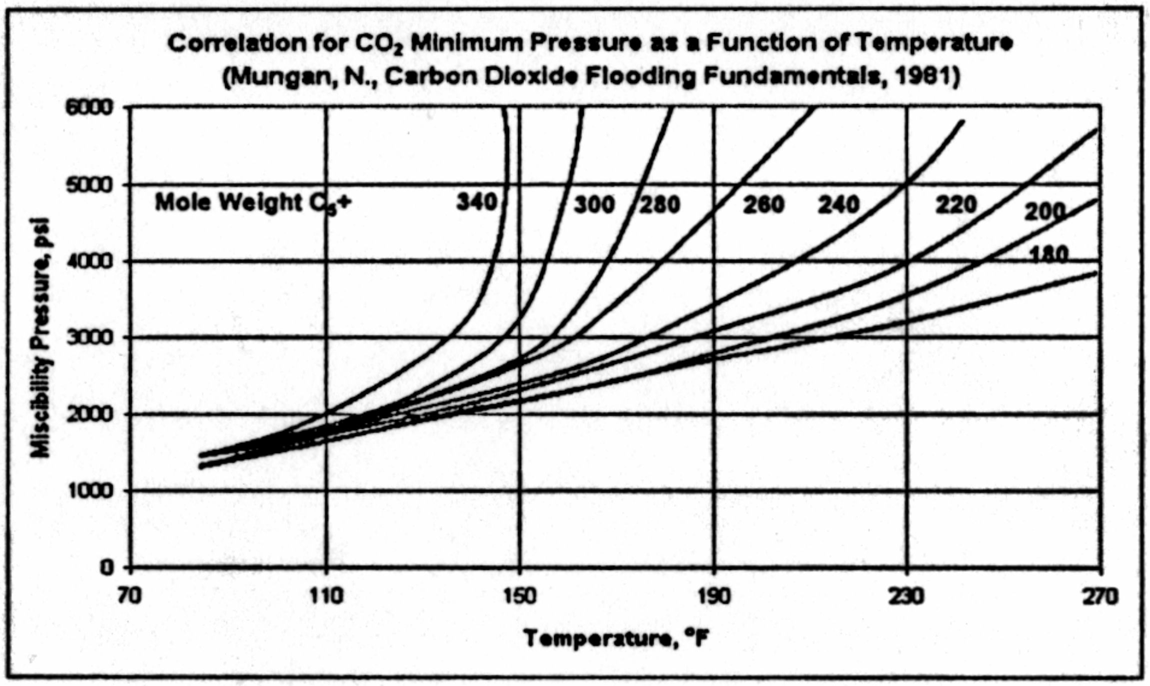
5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and 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 10. 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 10. Estimating CO_2 Minimum Miscibility Pressure



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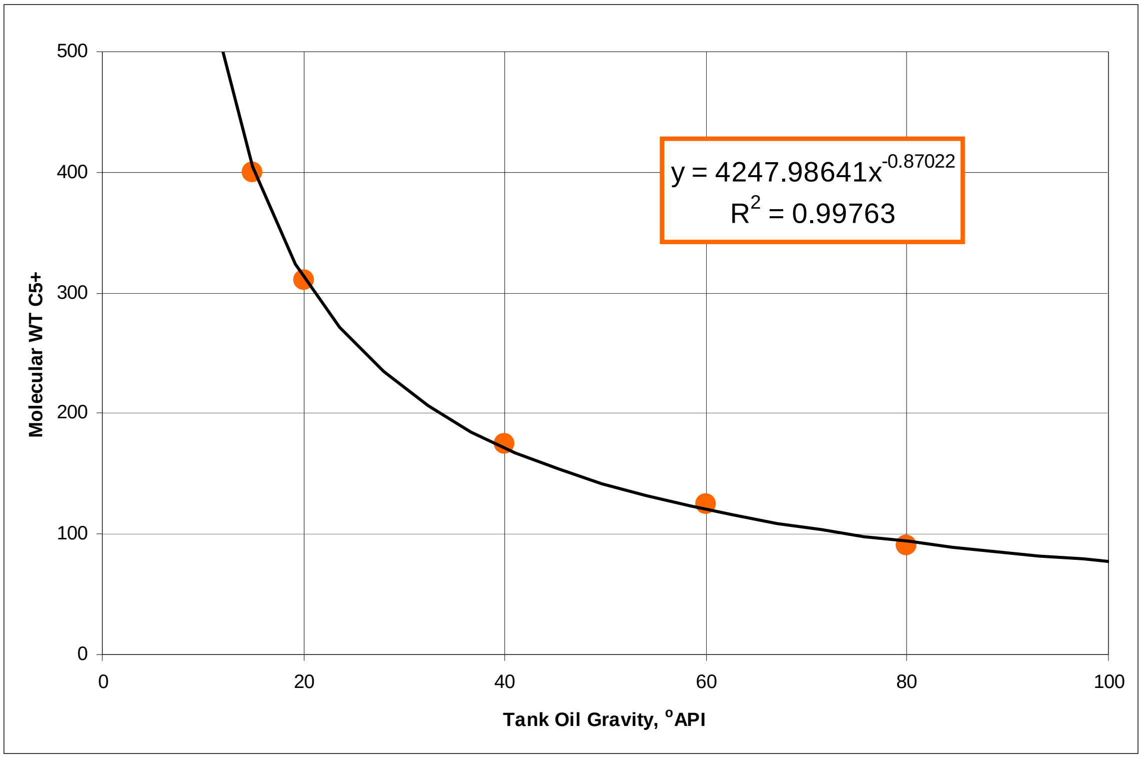
The temperature of the reservoir was taken from the data base or estimated from the thermal gradient in the basin. The molecular weight of the pentanes and heavier fraction of the oil was obtained from the data base or was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure 11.

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 11. Correlation of MW C5+ to Tank Oil Gravity



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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 and D 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.

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.

- <u>Two technology cases were examined</u>. As discussed in more detail in Chapter 2, the study examined the application of two CO2-EOR options - - "Traditional Practices" and "State of the Art" Technology.

- <u>Two oil prices were considered</u>. A $25 per barrel oil price was used to represent the moderate oil price case; a $35 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.

- <u>Two CO_2 supply costs were considered.</u> The high CO_2 cost was set at $1.25 per Mcf (5% of the oil price) 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 $0.50 per Mcf (2% of the oil price) was included to represent the potential future availability of low-cost CO_2 from industrial and power plants as part of CO_2 storage.

- <u>Two minimum rate of return (ROR) hurdles were considered</u>, 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, CO2 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. In this low technology, high risk scenario, called “Traditional Practices”, there is little economically feasible potential in this oil producing region for using CO_2-EOR.
- The second scenario, entitled “State of the Art”, assumes that the technology progress in CO_2-EOR, achieved in other areas, is successfully applied to the oil reservoirs of Illinois. In addition, a comprehensive set of research, pilot tests and field demonstrations help lower the risk inherent in applying new technology to these complex oil reservoirs. However, because of limited sources of CO_2, these supply costs are high (equal to $1.25 per Mcf) the oil price) and significantly hamper economic feasibility of using CO_2-EOR.
- 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 be equal to $10 per barrel in the price that the producer receives for produced crude oil.
- In the final scenario, entitled “Ample Supplies of CO_2,” low-cost, “EOR-ready” CO_2 supplies (equal to $0.70 per Mcf) are aggregated from various sources. These include industrial high-concentration CO_2 emissions from hydrogen facilities, gas processing plants and other sources. These would be augmented, in the longer-term, from low CO_2 concentration industrial sources including combustion and electric generation plants. Capture of industrial CO_2 emissions would be part of national efforts for reducing greenhouse gas emissions.

Table 11. Economic Model Established by the Study

Pattern-Level Cashflow Model		Advanced Technology											
State													
Field				New Injectors	0.51			21					
Formation				Existing Injectors	0.00								
Depth				Convertable Producers	0.49								
Distance from Trunkline (mi)				New Producers	0.0								
# of Patterns				Existing Producers	1.09								
Miscibility:	**Miscible**												
	Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
CO2 Injection (MMcf)			731	731	731	731	731	731	731	682	656	656	656
H2O Injection (Mbw)			183	183	183	183	183	183	183	207	220	220	220
Oil Production (Mbbl)			-	11	136	88	62	76	62	53	38	39	38
H2O Production (MBw)			579	568	339	275	275	249	236	222	246	250	253
CO2 Production (MMcf)			-	0	187	394	444	466	515	556	537	528	524
CO2 Purchased (MMcf)			731	730	543	337	286	265	215	127	119	128	132
CO2 Recycled (MMcf)			-	0	187	394	444	466	515	556	537	528	524
Oil Price ($/Bbl)	**$ 25.00**		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	**35**	Deg	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25
Gross Revenues ($M)			$ -	$ 305	$ 3,714	$ 2,409	$ 1,695	$ 2,066	$ 1,692	$ 1,433	$ 1,033	$ 1,049	$ 1,041
Royalty ($M)	**-12.5%**		$ -	$ (38)	$ (464)	$ (301)	$ (212)	$ (258)	$ (212)	$ (179)	$ (129)	$ (131)	$ (130)
Severance Taxes ($M)	**-5.0%**		$ -	$ (13)	$ (162)	$ (105)	$ (74)	$ (90)	$ (74)	$ (63)	$ (45)	$ (46)	$ (46)
Ad Valorum ($M)	**-2.5%**		$ -	$ (7)	$ (81)	$ (53)	$ (37)	$ (45)	$ (37)	$ (31)	$ (23)	$ (23)	$ (23)
Net Revenue($M)			$ -	$ 247	$ 3,006	$ 1,950	$ 1,372	$ 1,672	$ 1,370	$ 1,160	$ 836	$ 849	$ 843
Capital Costs ($M)													
New Well - D&C		$ (274)											
Reworks - Producers to Producers		$ (54)											
Reworks - Producers to Injectors		$ (23)											
Reworks - Injectors to Injectors		$ -											
Surface Equipment (new wells only)		$ (81)											
Recycling Plant		$ -	$ (1,147)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (4)											
Total Capital Costs		$ (436)	$ (1,147)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)													
Total CO2 Cost ($M)			$ (913.1)	$ (913)	$ (726)	$ (519)	$ (469)	$ (447)	$ (398)	$ (298)	$ (283)	$ (292)	$ (296)
O&M Costs													
Operating & Maintenance ($M)			$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)
Lifting Costs ($/bbl)	**$ 0.25**		$ (145)	$ (145)	$ (119)	$ (91)	$ (84)	$ (81)	$ (75)	$ (69)	$ (71)	$ (72)	$ (73)
G&A	**20%**		(50)	(50)	(44)	(39)	(38)	(37)	(36)	(34)	(35)	(35)	(35)
Total O&M Costs			$ (298)	$ (298)	$ (267)	$ (233)	$ (225)	$ (221)	$ (213)	$ (206)	$ (209)	$ (211)	$ (211)
Net Cash Flow ($M)		$ (436)	$ (2,357)	$ (964)	$ 2,014	$ 1,197	$ 678	$ 1,003	$ 758	$ 656	$ 343	$ 347	$ 335
Cum. Cash Flow		$ (436)	$ (2,794)	$ (3,757)	$ (1,744)	$ (546)	$ 132	$ 1,135	$ 1,893	$ 2,549	$ 2,893	$ 3,240	$ 3,575
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		$ (436)	$ (2,050)	$ (729)	$ 1,324	$ 685	$ 337	$ 434	$ 285	$ 215	$ 98	$ 86	$ 72
Disc. Cum Cash Flow		$ (436)	$ (2,486)	$ (3,215)	$ (1,891)	$ (1,206)	$ (869)	$ (435)	$ (150)	$ 64	$ 162	$ 248	$ 320
NPV (BTx)	25%	($401)											
NPV (BTx)	20%	$79											
NPV (BTx)	15%	$805											
NPV (BTx)	10%	$1,954											JAF2004054.XLS
IRR (BTx)		20.69%											

Table 11. Economic Model Established by the Study (Cont'd)

	Pattern-Level Cashflow Model															
	State															
	Field															
	Formation															
	Depth															
	Distance from Trunkline (mi)															
	# of Patterns															
	Miscibility:	**Miscible**														
		Year	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
1	CO2 Injection (MMcf)		656	656	656	656	656	656	656	656	416	-	-	-	-	-
2	H2O Injection (Mbw)		220	220	220	220	220	220	220	220	340	548	548	161	-	-
3	Oil Production (Mbbl)		41	58	57	52	38	26	23	21	19	19	17	4	-	-
4	H2O Production (MBw)		245	229	224	216	223	224	222	222	226	289	411	131	-	-
5	CO2 Production (MMcf)		533	530	543	565	579	600	608	613	590	442	221	47	-	-
6	CO2 Purchased (MMcf)		123	126	113	91	78	56	48	43	-	-	-	-	-	-
7	CO2 Recycled (MMcf)		533	530	543	565	579	600	608	613	416	-	-	-	-	-
8	Oil Price ($/Bbl)	**$ 25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ -	$ -
	Gravity Adjustment	**35**	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ -	$ -
9	Gross Revenues ($M)		$ 1,109	$ 1,583	$ 1,551	$ 1,420	$ 1,038	$ 695	$ 638	$ 575	$ 523	$ 526	$ 463	$ 120	$ -	$ -
10	Royalty ($M)	**-12.5%**	$ (139)	$ (198)	$ (194)	$ (177)	$ (130)	$ (87)	$ (80)	$ (72)	$ (65)	$ (66)	$ (58)	$ (15)	$ -	$ -
12	Severance Taxes ($M)	**-5.0%**	$ (49)	$ (69)	$ (68)	$ (62)	$ (45)	$ (30)	$ (28)	$ (25)	$ (23)	$ (23)	$ (20)	$ (5)	$ -	$ -
13	Ad Valorum ($M)	**-2.5%**	$ (24)	$ (35)	$ (34)	$ (31)	$ (23)	$ (15)	$ (14)	$ (13)	$ (11)	$ (12)	$ (10)	$ (3)	$ -	$ -
11	Net Revenue($M)		$ 898	$ 1,281	$ 1,255	$ 1,149	$ 840	$ 562	$ 516	$ 465	$ 423	$ 426	$ 375	$ 97	$ -	$ -
	Capital Costs ($M)															
	New Well - D&C															
	Reworks - Producers to Producers															
	Reworks - Producers to Injectors															
	Reworks - Injectors to Injectors															
	Surface Equipment (new wells only)															
	Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Trunkline Construction															
	Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CO2 Costs ($M)															
	Total CO2 Cost ($M)		$ (287)	$ (291)	$ (277)	$ (255)	$ (242)	$ (220)	$ (212)	$ (207)	$ (104)	$ -	$ -	$ -	$ -	$ -
	O&M Costs															
	Operating & Maintenance ($M)		$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ (103)	$ -	$ -
	Lifting Costs ($/bbl)	**$ 0.25**	$ (71)	$ (72)	$ (70)	$ (67)	$ (65)	$ (62)	$ (61)	$ (61)	$ (61)	$ (77)	$ (107)	$ (34)	$ -	$ -
	G&A	**20%**	(35)	(35)	(35)	(34)	(34)	(33)	(33)	(33)	(33)	(36)	(42)	(27)	-	-
	Total O&M Costs		$ (210)	$ (210)	$ (208)	$ (205)	$ (202)	$ (199)	$ (198)	$ (197)	$ (198)	$ (216)	$ (252)	$ (165)	$ -	$ -
	Net Cash Flow ($M)		$ 401	$ 781	$ 769	$ 689	$ 396	$ 143	$ 106	$ 61	$ 122	$ 209	$ 123	$ (68)	$ -	$ -
	Cum. Cash Flow		$ 3,976	$ 4,757	$ 5,526	$ 6,216	$ 6,612	$ 6,755	$ 6,862	$ 6,923	$ 7,045	$ 7,254	$ 7,377	$ 7,309	$ 7,309	$ 7,309
	Discount Factor	**15%**	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		$ 75	$ 127	$ 109	$ 85	$ 42	$ 13	$ 9	$ 4	$ 7	$ 11	$ 6	$ (3)	$ -	$ -
	Disc. Cum Cash Flow		$ 395	$ 521	$ 630	$ 715	$ 757	$ 771	$ 779	$ 783	$ 791	$ 802	$ 808	$ 805	$ 805	$ 805

Table 11. Economic Model Established by the Study (Cont'd)

	Pattern-Level Cashflow Model													
	State													
	Field													
	Formation													
	Depth													
	Distance from Trunkline (mi)													
	# of Patterns													
	Miscibility:	**Miscible**												
		Year	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	
1	CO2 Injection (MMcf)		-	-	-	-	-	-	-	-	-	-	-	13,429
2	H2O Injection (Mbw)		-	-	-	-	-	-	-	-	-	-	-	5,500
3	Oil Production (Mbbl)		-	-	-	-	-	-	-	-	-	-	-	979
4	H2O Production (MBw)		-	-	-	-	-	-	-	-	-	-	-	6,354
5	CO2 Production (MMcf)		-	-	-	-	-	-	-	-	-	-	-	10,022
6	CO2 Purchased (MMcf)		-	-	-	-	-	-	-	-	-	-	-	4,291
7	CO2 Recycled (MMcf)		-	-	-	-	-	-	-	-	-	-	-	9,138
8	Oil Price ($/Bbl)	$ 25.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	Gravity Adjustment	35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
9	Gross Revenues ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,678
10	Royalty ($M)	-12.5%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,335)
12	Severance Taxes ($M)	-5.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,167)
13	Ad Valorum ($M)	-2.5%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (584)
11	Net Revenue($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,592
	Capital Costs ($M)													
	New Well - D&C													$ (274)
	Reworks - Producers to Producers													$ (54)
	Reworks - Producers to Injectors													$ (23)
	Reworks - Injectors to Injectors													$ -
	Surface Equipment (new wells only)													$ (81)
	Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,147)
	Trunkline Construction													$ (4)
	Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,583)
	CO2 Costs ($M)													
	Total CO2 Cost ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,649)
	O&M Costs													
	Operating & Maintenance ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,377)
	Lifting Costs ($/bbl)	$ 0.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,833)
	G&A	20%	-	-	-	-	-	-	-	-	-	-	-	$ (842)
	Total O&M Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,052)
	Net Cash Flow ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,309
	Cum. Cash Flow		$ 7,309	$ 7,309	$ 7,309	$ 7,309	$ 7,309	$7,309	$7,309	$7,309	$7,309	$7,309	$7,309	
	Discount Factor	15%	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		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 805
	Disc. Cum Cash Flow		$ 805	$ 805	$ 805	$ 805	$ 805	$ 805	$ 805	$ 805	$ 805	$ 805	$ 805	

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 sensitivity 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, and Texas/District 3.

Table 9 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 217 reservoirs, accounting for 58% of the oil expected to be ultimately produced in Gulf Coast by primary and secondary oil recovery processes.

6. RESULTS BY STATE

6.1 LOUISIANA. Louisiana is a major oil producing state with a rich history of oil recovery. Crude oil production began in 1902, and has reached a cumulative production of almost 12.9 billion barrels of oil to date. In 2002, it ranks 6th in production in the U.S., producing 47 MMBbls of oil onshore (129 MBbls/day) from 26,814 producing wells, and 7th in reserves at 410 MMBbls. The onshore oil production is divided into a northern and southern division, with 83% coming from the southern portion of the state. The state contains 18 petroleum refineries, predominantly in the southern half, with a crude oil distillation capacity of over 2.7 MMBbls/day.

Despite being one of the top oil producing states, Louisiana has seen a significant decline in production in recent years, Table 12.

Table 12. Recent History of Louisiana Onshore Oil Production

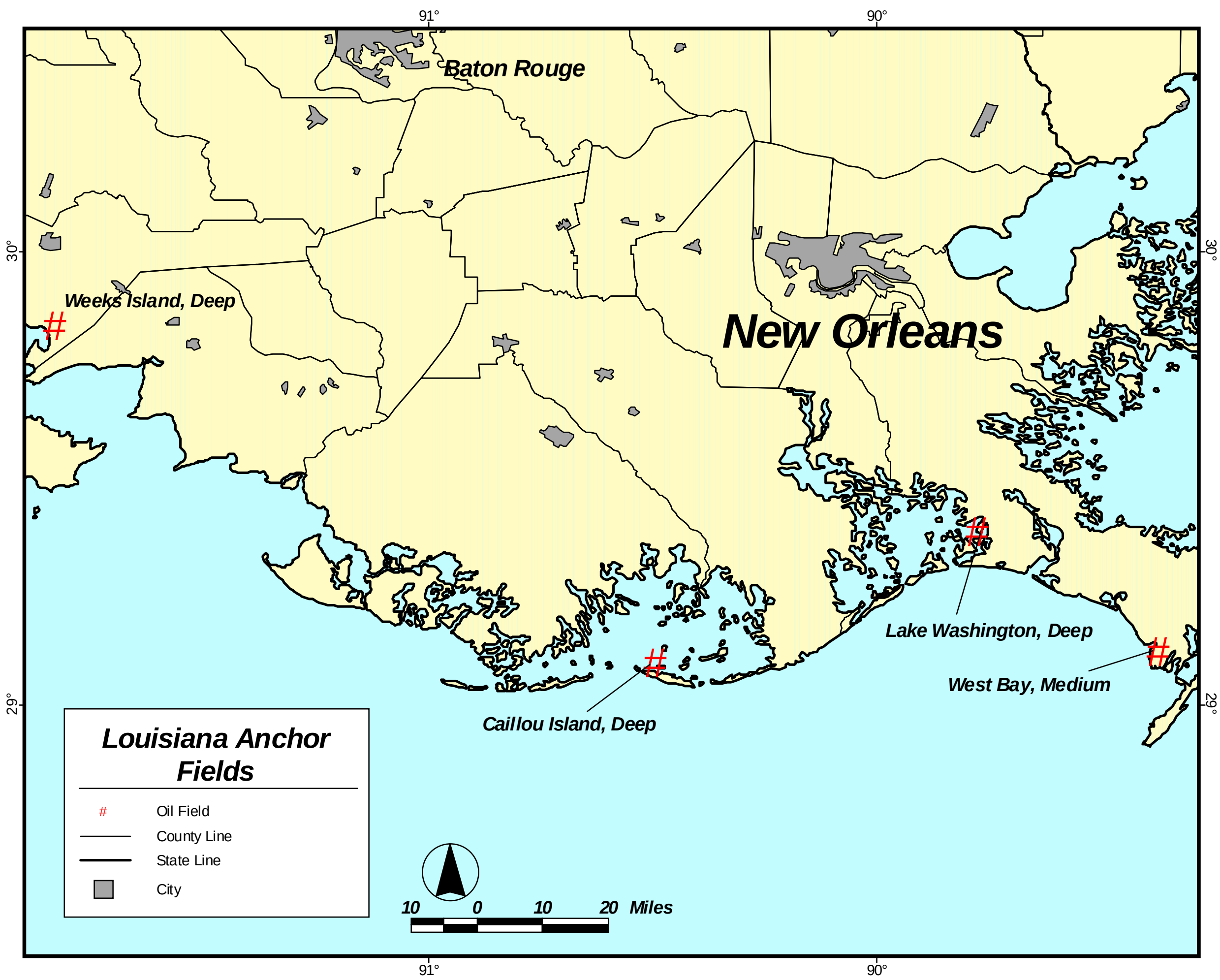
	Annual Oil Production	
	(MMBls/Yr)	(MBbls/D)
1999	70	192
2000	59	162
2001	59	162
2002	47	129

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 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 fields, shown in Figure 12. The stack of individual reservoirs in many of these fields have been grouped into:

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

Figure 12. Louisiana Anchor Fields



These four fields, distributed across southern Louisiana, could serve as the "anchor" sites for the initial CO_2-EOR projects in 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 "anchor" light oil fields are set forth in Table 13.

Table 13. Status of Louisiana "Anchor" Fields/Reservoirs, 2002

Anchor Fields/Reservoirs		Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In Place (MMBbls)
1	Callilou Island (Deep)	581	7	588
2	Lake Washington (Deep)	242	12	311
3	Weeks Island (Deep)	143	10	187
4	West Bay (Medium)	134	7	183

These four large "anchor" fields, each with 150 or more million barrels of ROIP, may be favorable for miscible CO_2 -EOR, based on their reservoir properties, Table 14.

Table 14. Reservoir Properties and Improved Oil Recovery Activity, "Anchor" Oil Fields/Reservoirs

	Anchor Fields	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 studies in Louisiana have been conducted in Paradis (Lower 9000 Sand RM), South Pass Block 24 (8800'RD), Timbalier Bay (4,900 ft sand), 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 flood project at the "S" Sand Reservoir B of Weeks Island field. Weeks Island field is a piercement type salt dome and had commercial production from 37 Lower Miocene sands.

- A CO_2 slug of 853 MMcf (24% HCPV) and 55 MMcf of natural gas was injected from October 1978 until February 1980 and was followed by an average injection rate of 761 Mcfd through 1987.
- Early production testing revealed that an oil bank was being mobilized in the watered out sand, reading a thickness of 57 feet in early 1981.
- Efficient gravity stable displacement of the oil bank was achieved. Oil production began in early 1981 and by 1987, 261,000 barrels of oil, or 64% of ROIP, had been recovered. Subtracting the mobile oil at the start of the project provides tertiary oil recovery of about 205,000 barrels or 60% of the oil not recovered by water displacement.
- An issue being further examined is the slow oil production response, in gravity stable floods, to CO_2 injection and the economic challenge this presents.

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 1 economically attractive oil reservoir 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 427 million barrels of additional oil recovery, Table 15.

Table 15. Economic Oil Recovery Potential Under Current Conditions, Louisiana.

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"	128	16,035	1,428	1	3
"State of Art Technology"	128	16,035	3,244	8	427

Lower cost CO_2 supplies and risk mitigation/higher oil prices would enable CO_2-EOR in Louisiana to recover up to 2,128 million barrels of oil (from 61 major reservoirs), Table 16.

Table 16. Economic Oil Recovery Potential with More Favorable Financial Conditions, Louisiana

More Favorable Financial Conditions	No. of Economic Reservoirs	Economic Potential (MMBbls)
Plus: Risk Mitigation*	46	1,800
Plus: Low Cost CO_2**	61	2,128

** Higher oil price of $35 per barrel, adjusted for market factors*

*** Reduced CO_2 supply costs, $0.70/Mcf*

6.2 MISSISSIPPI. Mississippi is the 10th largest oil producing state, producing 18 MMBbls (49 MBbls/day) of oil in 2002, from 1,474 producing wells. Oil production in the state of Mississippi began in 1889, and cumulative oil production has reached almost 2.3 billion barrels. Mississippi has 179 MMBbls of crude oil reserves, ranking 14th in the U.S. Mississippi has 4 oil refineries, most notably the Chevron refinery at Pascagoula with distillation capacity totaling nearly 365,000 barrels/day. Despite having many old fields, oil production in Mississippi has remained fairly consistent in recent years, due to improved oil recovery efforts, Table 17.

Table 17. Recent History of Mississippi Oil Production

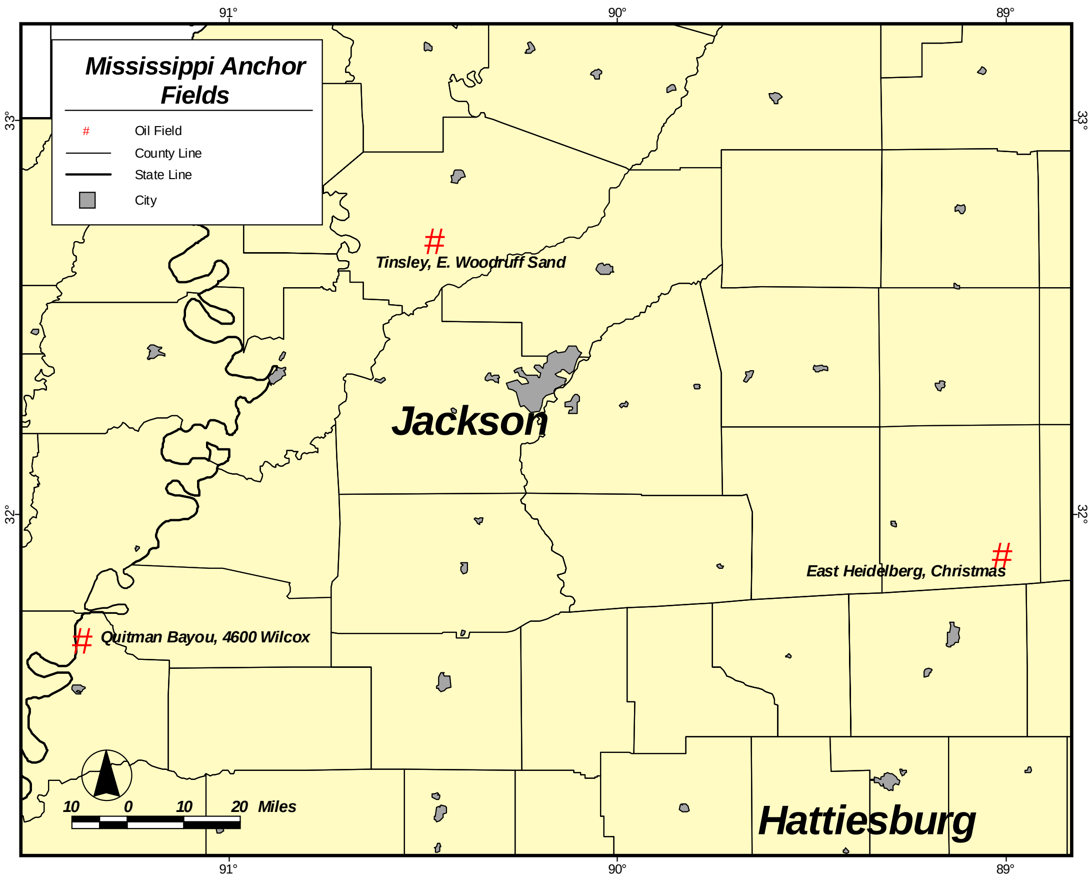
	Annual Oil Production	
	(MMBbls/Yr)	(MBbls/D)
1999	15	41
2000	18	49
2001	18	49
2002	18	49

Denbury Resources has been instrumental in revitalizing aging fields in Mississippi. They purchased the Heidelberg field in 1997 from Chevron, a field that has produced almost 200 MMBbls of oil since discovery in 1944, predominantly from three main reservoirs, Eutaw, Selma, and Christmas. Currently, oil production is from five waterflood units producing from the Eutaw formation. Production in 1997 was approximately 2,800 Bbls/day and has climbed to 7,500 Bbls/day as a result of waterflooding by Denbury.

Mississippi Oil Fields. Mississippi contains a number of large oil fields that may be amenable to miscible CO_2- EOR, Figure 13. These include:

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

Figure 13. Mississippi Anchor Fields



These three major oil fields could serve as the "anchor" sites for the initial CO_2 projects that could later extend to other fields in the basin. The cumulative oil production, proved reserves and remaining oil in-place (ROIP) for these three major "anchor" light oil reservoirs are set forth in Table 18.

Table 18. Status of Mississippi "Anchor" Fields/Reservoirs, 2001

	Anchor Fields/Reservoirs	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Tinsley (E. Woodruff Sand)	50	1.6	111
2	Quitman Bayou (4600 Wilcox)	21	0.1	54
3	East Heidelberg (Christmas)	36	6.2	51

These three large "anchor" reservoirs, ranging from just over 50 to over 100 million barrels of ROIP, are amenable to CO_2-EOR. Table 19 provides the reservoir and oil properties for these three reservoirs and their current secondary oil recovery activities.

Table 19. Reservoir Properties and Improved Oil Recovery Activity, "Anchor" Oil Fields/Reservoirs

	Anchor 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 "anchor" light oil reservoirs, several fields in Mississippi have reservoirs containing heavier oils, such as West Heidelberg and West Eucutta. These fields could become "secondary targets" fields for immiscible CO_2-EOR.

These "secondary target" fields, with 75 million barrels or more of OOIP are shown on Table 20. These two fields may be amenable to immiscible CO_2-EOR based on their reservoir properties.

Table 20. Reservoir Properties and Improved Oil Recovery Activity Potential, Mississippi "Immiscible-CO_2" Oil Fields/Reservoirs

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

Past CO_2-EOR Projects. Mississippi has also seen an active history of CO_2 based enhanced oil recovery, particularly at Little Creek and Mallalieu fields in west Mississippi. Additionally a two-pattern pilot project was begun at the McComb field in 2003.

Little Creek. In 1974 Shell Oil initiated the pilot phases of CO_2 flooding and expanded the project in1985. Currently, Denbury is further expanding the CO_2-EOR effort at Little Creek field, with 29 producing wells and 28 injection wells, expecting to recover 17% of OOIP.

- Production increased from 1,350 Bbls/day in 1999 to an average 3,200 Bbls/day in the 2004.
- As of December 31, 2003 Denbury had reserves of 35.3 MMBbls in Western Mississippi (includes E. Mallalieu, McComb and Brookhaven) as a result of CO_2-EOR, with an estimated 10MMBbls of oil reserves at Little Creek.

E. and W. Mallalieu. Purchased in 2001 by Denbury, and also originally owned by Shell Oil Company, West Mallalieu field underwent its first CO_2 pilot project in 1986.

- Consisting of four 5-spot patterns, the original CO_2-EOR project produced 2.1 MMBbls of oil as a result of CO_2-EOR.
- After purchase of the property, Denbury added an additional four CO_2-EOR patterns in 2001, four patterns in 2002, three patterns in 2003 and further development in 2004.
- The West Mallalieu field unit CO_2-EOR flood was producing an estimated 4,200 Bbls/day and had already recovered 3.5% of the OOIP(122 MMBbls) as of October 2004.
- Since the West Mallalieu field had not been previously waterflooded, Denbury expects that CO_2-EOR could exceed the 17% recovery of OOIP projected for Little Creek.

Smaller CO_2-EOR projects have been conducted at Tinsley, Olive and Heidelberg fields.

Future CO_2-EOR Potential. Mississippi contains 18 large light oil reservoirs, such as Heidelberg, East (E. Eutaw) and Little Creek (Lower Tuscaloosa), that are candidates for miscible CO_2-EOR. In addition, the state has 3 oil fields, Heidelberg, West (Eutaw) and Eucutta, West (W. Eutaw), that could benefit from immiscible CO_2-EOR.

Under "Traditional Practices" (and Base Case financial conditions, defined above), miscible CO_2 flooding would not be economic in Mississippi. Applying "State of the Art Technology" (involving higher volume CO_2 injection, immiscible EOR, and lower risk) the number of economically favorable oil reservoirs in Mississippi increases to 4, providing 51 million barrels of additional oil recovery, Table 21.

Table 21. Economic Oil Recovery Potential Under
Base Case Financial 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 Art Technology"	20	1,871	350	4	51

Improved financial conditions, including lower-cost CO_2 supplies and risk mitigation/ higher oil prices, combined with "State of the Art" CO_2-EOR Technology, would significantly increase economically-produced oil volumes in Mississippi. These scenarios would allow up to 200 million barrels of additional oil recovery (from 12 major oil reservoirs) in Mississippi, Table 22.

Table 22. Economic Oil Recovery Potential with
More Favorable Financial Conditions, Mississippi

More Favorable Financial Conditions	No. of Reservoirs	(Million Bbls)
Plus: Risk Mitigation*	9	163
Plus: Low Cost CO_2**	12	200

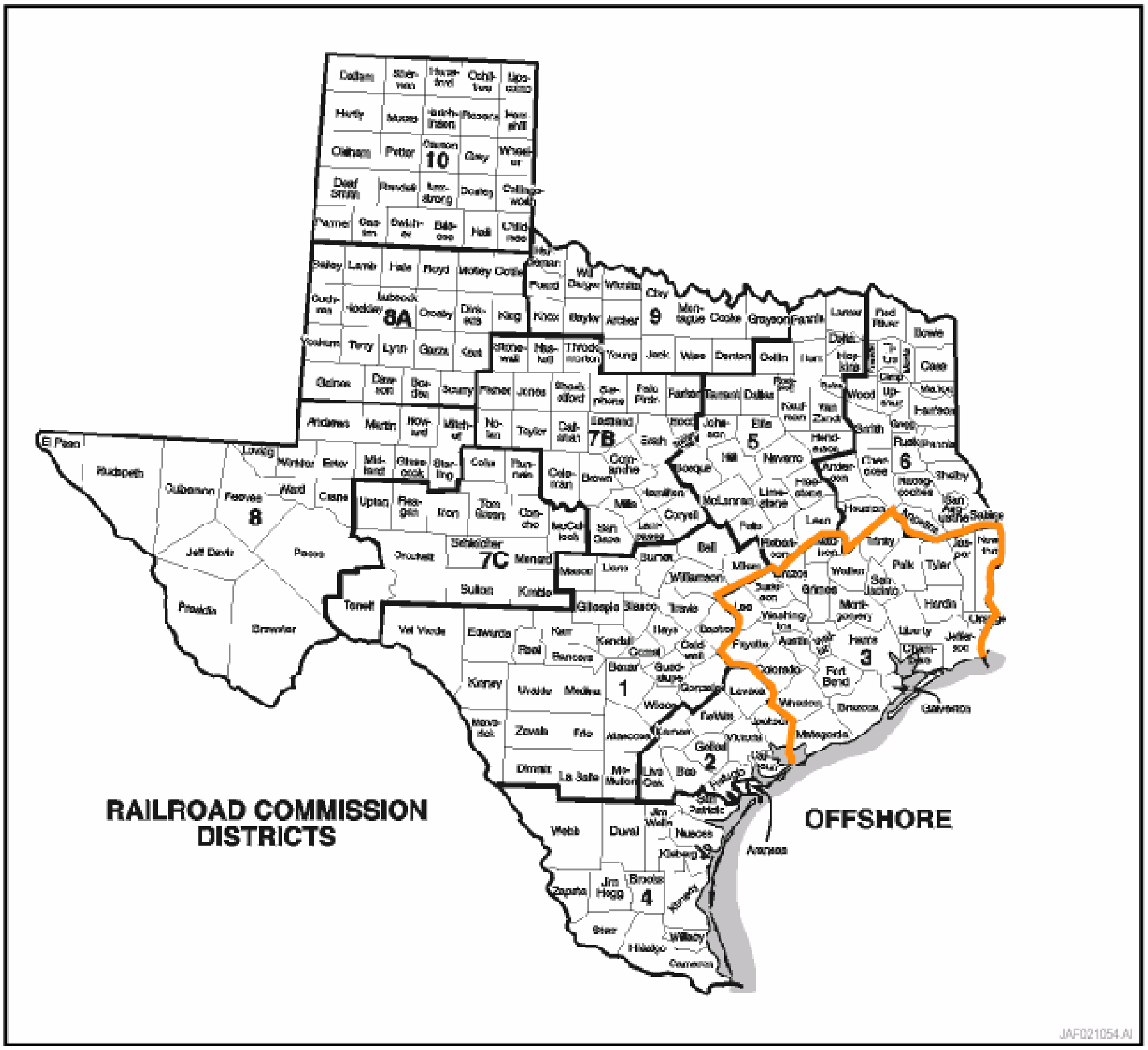
** Higher oil price of $35 per barrel, adjusted for market factors*
*** Reduced CO_2 supply costs, $0.70/Mcf*

6.3 TEXAS/DISTRICT 3. Texas/District 3 is located in southeast Texas along the Gulf of Mexico, Figure 14. It is the third largest producing district in Texas, producing 28 MMBbls (77 MBbls/day) of oil in 2002 from 8,055 wells and home to such prolific oil reservoirs as the Austin Chalk in the Giddings field. Cumulative oil production for District 3 is over 8 BBbls out of the state's 58 BBbls, and reserves are 218 MMBbls. Oil production in Texas Railroad District 3 has declined steadily in recent years, Table 23.

Table 23. Recent History of Texas/District 3 Oil Production

	Annual Oil Production	
	(MMBbls/Yr)	(MBbls/D)
1999	33	90
2000	34	93
2001	31	85
2002	28	77

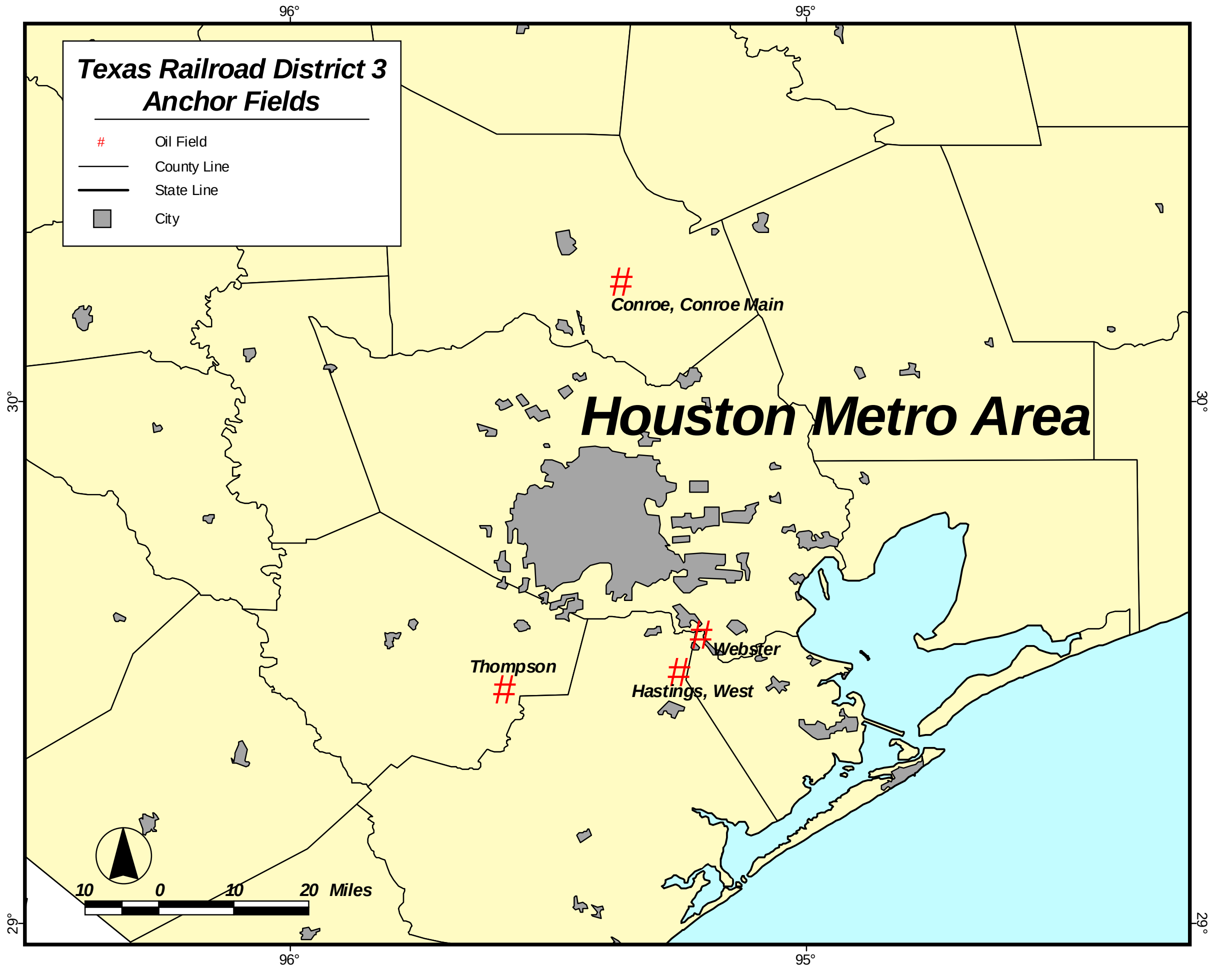
Figure 14. Texas/District 3



Texas/District 3 Oil Fields. Texas/District 3 contains several large oil fields that may be amenable to miscible CO_2-EOR, Figure 15. These include:

- Hastings, West
- Webster
- Conroe, Conroe Main
- Thompson

Figure 15. Texas/District 3 Anchor Fields



Assuming adequate oil prices and availability of low-cost CO_2 supplies, these four fields could serve as "anchors" for the initial CO_2-EOR activity in the district that then could extend to other fields. The cumulative oil production, proved reserves and remaining oil in-place (ROIP) in these four major "anchor" oil reservoirs are provided in Table 24.

Table 24. Status of Texas Railroad District 3 “Anchor” Fields/Reservoirs, 2002

Anchor Fields/Reservoirs		Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Hastings, West (West)	637	4.4	525
2	Webster	595	4	561
3	Conroe (Conroe Main)	728	5	864
4	Thompson	373	4	461

These four large “anchor” reservoirs, ranging from over 400 to almost 900 million barrels of ROIP, are technically amenable for miscible CO_2-EOR. Table 25 provides the reservoir and oil properties for these reservoirs and their current secondary oil recovery activities.

Table 25. Reservoir Properties and Improved Oil Recovery Activity,
“Anchor” Oil Fields/Reservoirs

Anchor Fields		Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Hastings, West (West)	6,200	31	Undergoing waterflooding.
2	Webster	5,750	29	Undergoing waterflooding.
3	Conroe (Conroe Main)	5,000	38	Undergoing waterflooding.
4	Thompson	5,300	43	Undergoing waterflooding.

Past CO_2-EOR Projects. A study done by the Bureau of Economic Geology, University of Texas in 1999 screened over 1,700 oil reservoirs in Texas as possible candidates for CO_2-EOR, representing 80 billion barrels of OOIP, 31 billion barrels of which was residual oil. A large portion of this resource was defined as being within the fluvial-deltaic reservoirs of the Texas Gulf Coast.

<u>Port Neches Field</u>. The most notable CO_2-EOR project completed in Texas/District 3 took place in Texaco's Port Neches Field, in Orange County, Texas, where CO_2-EOR was combined with horizontal drilling to increase oil production. Texaco and the DOE initiated a CO_2 injection project in the Marginulina sand of the Port Neches field in 1993:

- The project planned to recover 19% OOIP or 2 MMBbl of by-passed oil, based on reservoir modeling, by the injection of nearly 5 HCPV of CO_2, at a peak CO_2 injection rate of 15 MMcfd, with a WAG ratio of 0.05.
- Actual performance of the CO_2-EOR was reasonably in line with the forecast, at 14% of OOIP or 1.5 MMBbl.

In addition, two CO_2-EOR floods were conducted at Rose City South and Rose City North and one CO_2-EOR project was initiated in the Kurten field. While cited as successful by the operator, no public information could be found on these projects.

Future CO_2-EOR Potential. Texas/District 3 contains 53 light oil reservoirs that are candidates for miscible CO_2-EOR technology. In addition, the district has 3 reservoirs that could benefit from immiscible CO_2-EOR. The potential for economically developing these oil reservoirs is examined first under Base Case financial criteria that combine an oil price of $25 per barrel, CO_2 supply costs ($1.25/Mcf), and a high risk rate of return (ROR) hurdle (25% before tax).

Under "Traditional Practices", with Base Case financial conditions, 2 reservoirs are economic, providing 66 million barrels of additional oil recovery from Texas/District 3. Applying "State of the Art" technology, involving miscible EOR with high volume CO_2 injection and a lower-risk rate of return hurdle of 15% before tax, 26 reservoirs are economic providing nearly 1,400 million barrels, Table 26.

Table 26. Economic Oil Recovery Potential Under
Base Case Financial Conditions, Texas/District 3.

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"	54	12,777	1,019	2	66
"State of Art" Technology	57	13,073	2,316	26	1,378

Improved financial conditions of lower-cost CO_2 supplies and risk mitigation/higher oil prices would significantly increase the economically recoverable oil volumes in Texas/District 3, particularly when applied with "State of the Art" CO_2-EOR Technology. With the benefit of these two more favorable financial conditions, 2 billion barrels of additional oil (in 51 major oil reservoirs) would be economically recoverable in Texas/District 3, Table 27.

Table 27. Economic Oil Recovery Potential with
More Favorable Financial Conditions, Texas Railroad District 3

More Favorable Conditions	No. of Economic Reservoirs	Economic Potential (MMBbls)
Plus: Risk Mitigation*	48	2,001
Plus: Low Cost CO_2**	51	2,021

** Higher oil price of $35 per barrel, adjusted for market factors*
*** Reduced CO_2 supply costs, to $0.70/Mcf*

7. IMPACT OF STATE RISK SHARING ACTIONS

Each of the three states - - Louisiana, Mississippi and Texas - - already provide some form of risk sharing actions or incentives for enhanced oil recovery. These risk sharing actions are incorporated into the assessments of economically viable CO_2-EOR projects and volumes set forth in this report.

7.1 LOUISIANA. 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 $2.73 per barrel of incrementally produced oil (assuming a sales price of $25 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.

7.2 MISSISSIPPI. 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 $0.66 per barrel of incrementally produced oil (assuming a sales price of $25 per barrel of oil and a royalty rate of 12.5%).

7.3 TEXAS. The Statewide Rule 50 and the Texas Tax Code Ann. 2(I), 202.054 is effective as of 1989 for new projects and 1991 for expanded projects. (The statue is due to expire on January 1, 2007). Its stated goals is:

"To encourage additional recovery of the state's oil reserves through the use of enhanced oil recovery technology, and to extend the lives of wells with the resulting benefit to the Texas economy through job creation and additional severance taxes."

In the "Enhanced Oil Recovery Statute", the state severance tax is reduced by 50% (from 4.6% to 2.3%) for oil production from new enhanced oil recovery projects and incremental production from expanded projects. A two-step Railroad Commission certification is required. First, the operator must obtain approval and area certification for the new/expanded project; second, the operator seeks Railroad Commission certification that the project evidences a positive production response (an increased rate of production attributable to the project). The application for positive production response certification must be filed within five years for a tertiary oil recovery project.

The regular state oil severance tax rate in Texas is 4.6% of the value of the produced oil. Reduction of the severance tax to 2.3% provides a modest risk sharing equal to $0.50 per barrel of incrementally produced oil (assuming a sales price of $25 per barrel of oil and a royalty rate of 12.5%).

7.4 POTENTIAL BENEFITS OF RISK SHARING

Risk Sharing for CO_2-EOR. Risk and revenue sharing actions stimulate increased CO_2-enhanced oil recovery activity and oil production in four distinct ways:

- First, the reduction (or front-end elimination) of the severance tax improves the rate of return of a CO_2-EOR project. This enables a certain number of projects, that are close to the minimum economic threshold, to cross this threshold and be placed on a company's list of potential investments.

- Second, the front-end elimination of the severance tax until project payout significantly reduces economic risk, enabling the project to compete with a lower risk hurdle rate. An across the board reduction of the severance tax helps reduce risk by providing additional downside protection against lower future oil prices.

- Third, the reduction or front-end elimination of the severance tax will help accelerate the selection and implementation of CO_2-EOR projects. This occurs because with a boost in the rate of return the project moves higher on the list of priority investments.

- Fourth, a reduction (or front-end elimination) of the severance tax will increase the cash flow and thus the investment capital available for expanding the approved project and initiating new CO_2-EOR projects.

7.5 ESTIMATED IMPACTS OF STATE RISK SHARING FOR CO_2-EOR. This section provides quantitative data on the increase in the number of CO_2-EOR projects and the additional volume of benefits and impacts from the risk sharing actions of lowering the state severance tax rates in Louisiana, Mississippi and Texas District #3. Additional impacts could occur due to accelerated and expanded application of CO_2-EOR, as discussed above.

Table 28 tabulates the impacts and benefits from the existing risk sharing action of reduced state severance taxes. (The analysis assumes $25 per barrel oil, $1.25 per Mcf for the cost of CO_2, a high financial risk hurdle rate without risk sharing and a lower financial risk hurdle with risk sharing.) The table shows that:

- The number of CO_2-EOR projects in the Gulf Coast Region increases to 38 with risk sharing from 13 without risk sharing. The largest increase is in Texas/District 3 with a gain of 16 projects.

- The volume of economically recoverable resource from CO_2-EOR increases to 1,610 million barrels with risk sharing from 830 million barrels without risk sharing. The largest relative increase is in Louisiana where severance tax front-end elimination, when paired with “state-of-the-art” technology and a solid oil price, could launch a viable CO_2-EOR industry, assuming availability of affordable CO_2 supplies.

Table 28. Impacts of State Risk Sharing for CO_2-EOR		
	Without Risk Sharing* (SOA Technology/High Risk)	With Risk Sharing** (SOA Technology/Low Risk)
1. No. of CO_2-EOR Projects		
▪ Louisiana	2	8
▪ Mississippi	1	4
▪ Texas/District 3	10	26
TOTAL	13	38
2. Volume of CO_2-EOR Economic Resource (MMBbls)		
▪ Louisiana	20	430
▪ Mississippi	***	50
▪ Texas/District 3	810	1,380
TOTAL	830	1,610

**Assumes $25 per barrel oil price, $1.25/Mcf CO_2 cost and 25% (BT) ROR.*
***Assumes $25 per barrel oil price, $1.25/Mcf CO_2 cost and 15% (BT) ROR.*
***Less than 5 MMBbls.*

Appendix A

Using *CO_2-PROPHET* for Estimating Oil Recovery

March 2005

Model Development

The study utilized the *CO_2-PROPHET* model to calculate the incremental oil produced by CO_2-EOR from the large California 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 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*

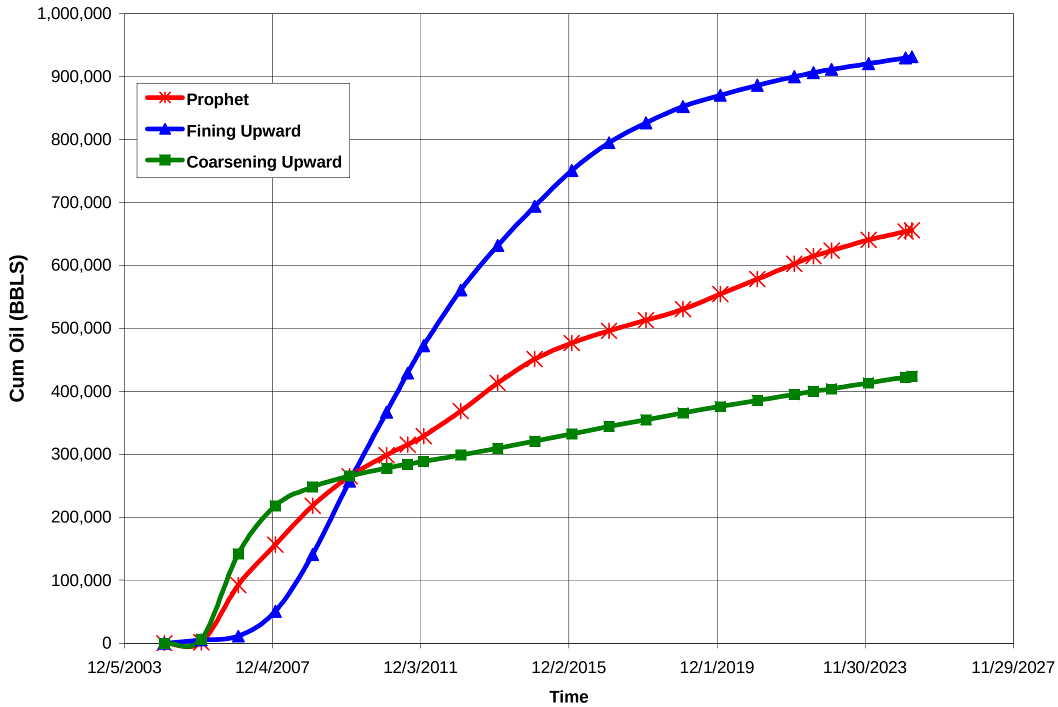
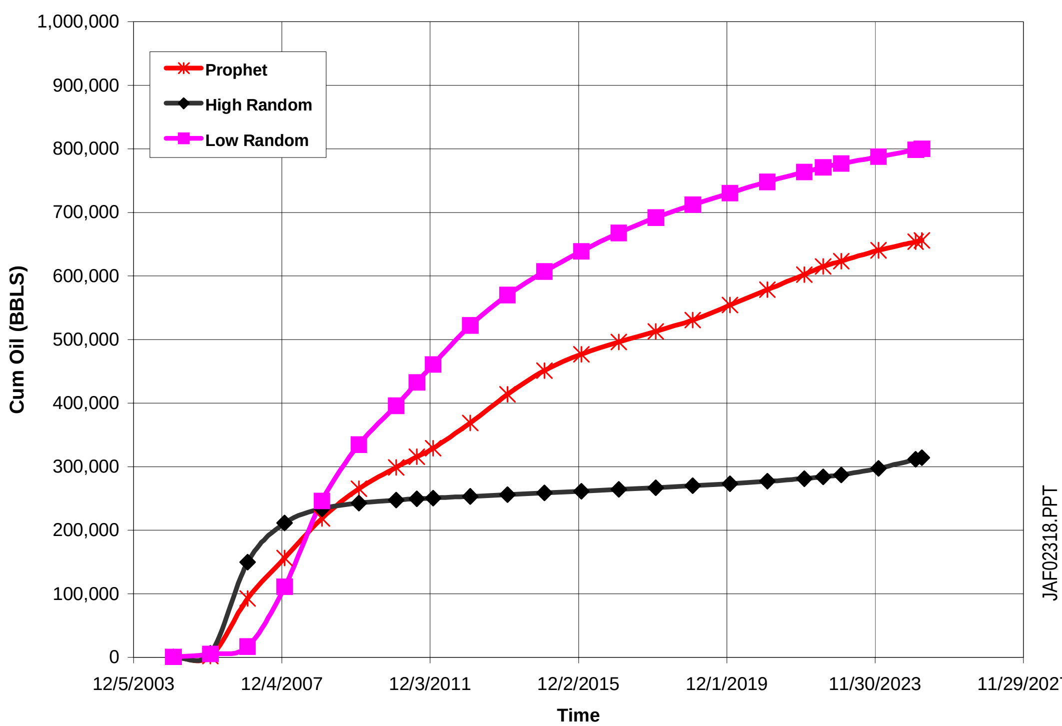


Figure A-2. CO_2*-PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



- *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

March 2005

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 = $a_0 D^{a1}$
Where: a_0 is 0.1626 (South) or 0.6103 (North), depending on location
a_1 is 1.8228 (South) or 1.5459 (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

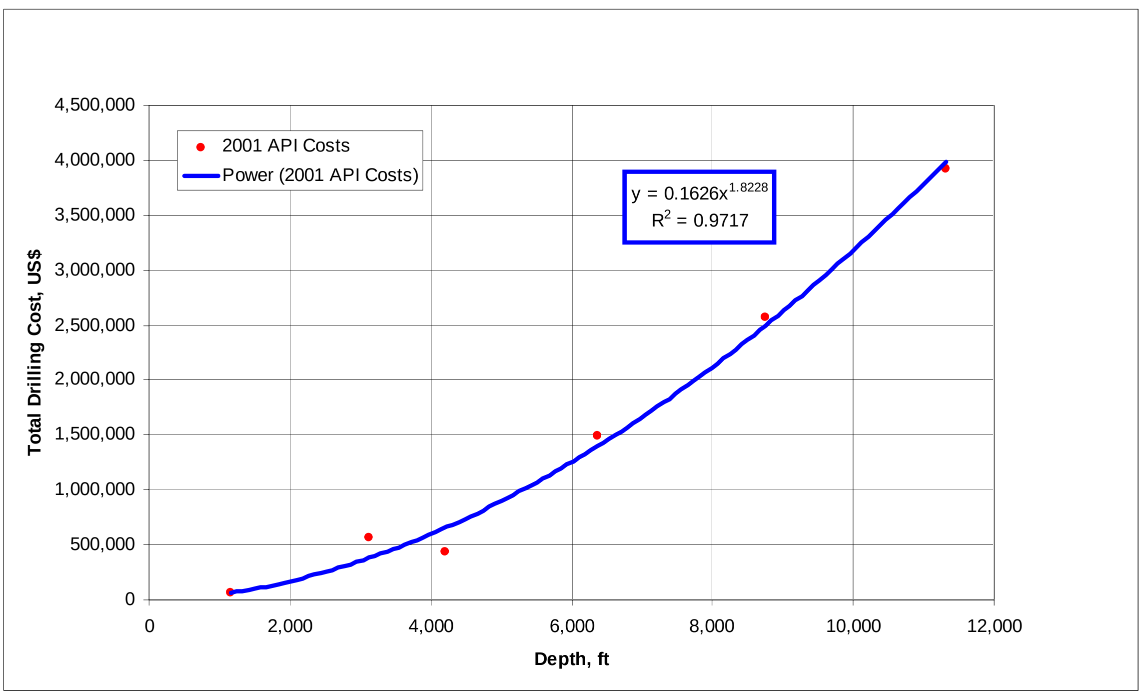


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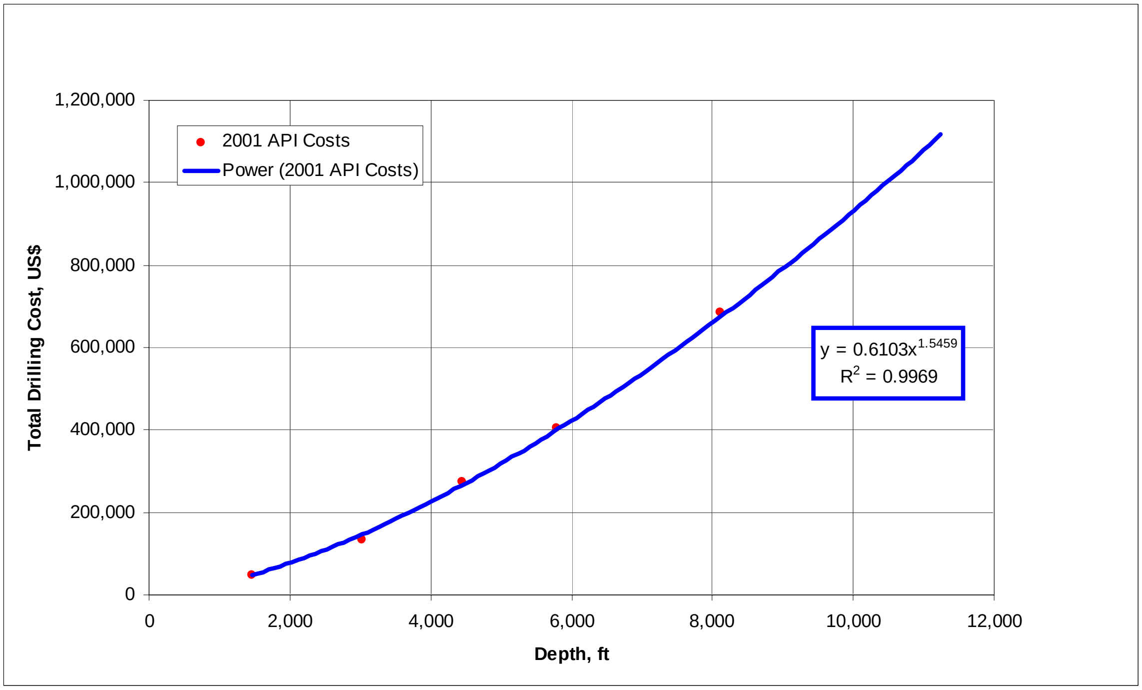
Figure B-1b – Oil Well D&C Costs for North Louisiana



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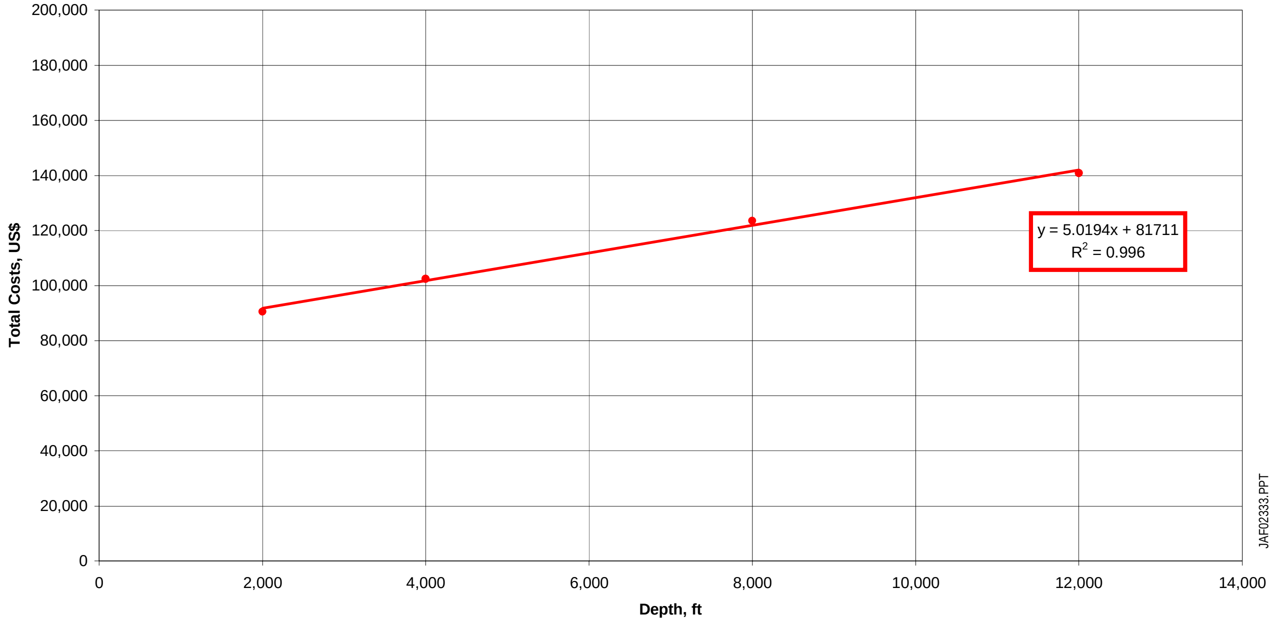
Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2002 EIA "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report. This survey provides estimated lease equipment costs for 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 = $c_0 + c_1 D$
Where: c_o = \$81,711 (fixed)
c_1 = \$5.02 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 South Louisiana vs. Depth



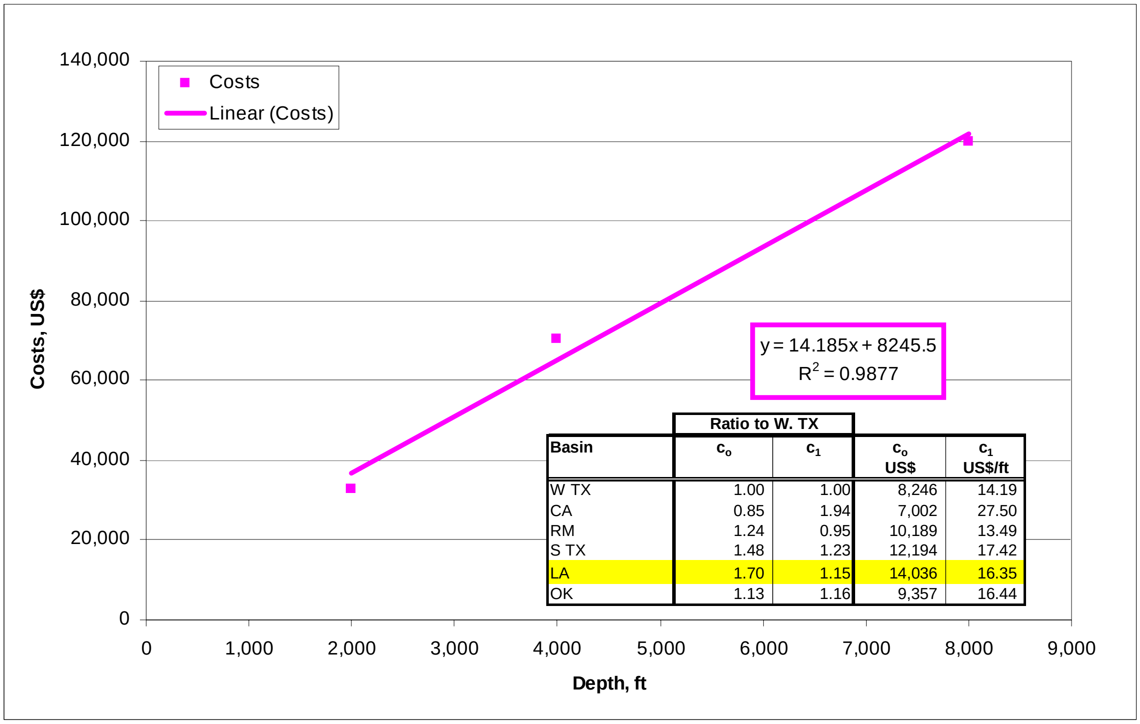
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Louisiana include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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 = $c_0 + c_1D$
Where: c_o = \$14,036 (fixed)
c_1 = \$16.35 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	8,246	14.19
CA	0.85	1.94	7,002	27.50
RM	1.24	0.95	10,189	13.49
S TX	1.48	1.23	12,194	17.42
LA	1.70	1.15	14,036	16.35
OK	1.13	1.16	9,357	16.44

JAF02333.PPT

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 = $c_0 + c_1 D$

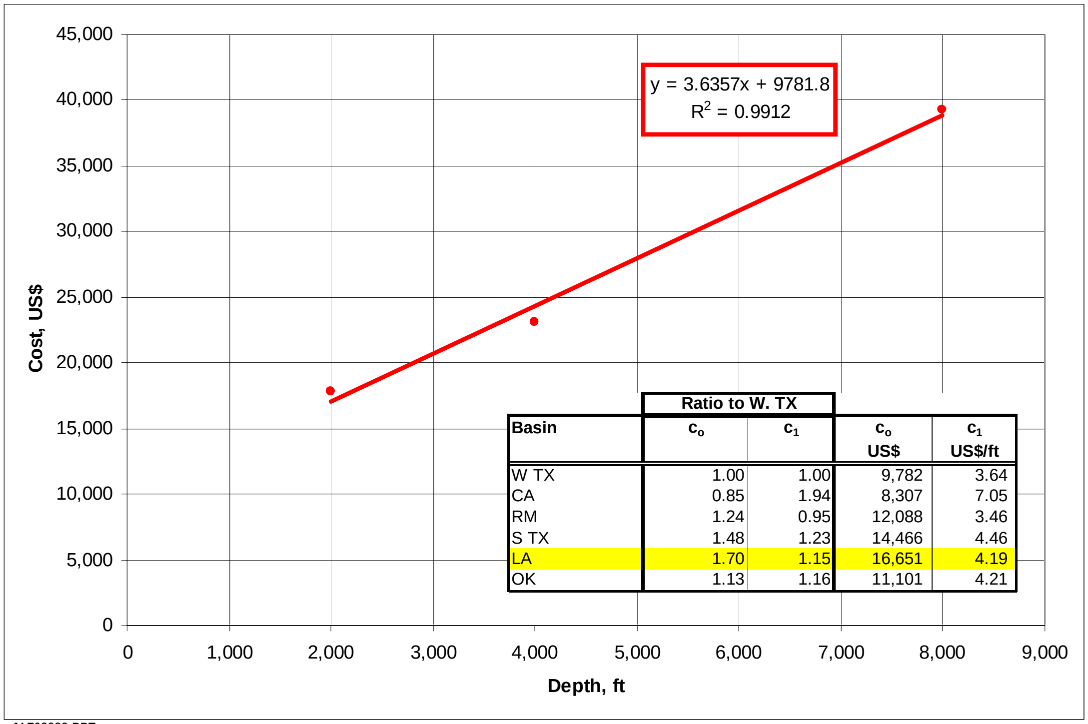
Where: c_o = \$16,651 (fixed)

c_1 = \$4.19 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	9,782	3.64
CA	0.85	1.94	8,307	7.05
RM	1.24	0.95	12,088	3.46
S TX	1.48	1.23	14,466	4.46
LA	1.70	1.15	16,651	4.19
OK	1.13	1.16	11,101	4.21

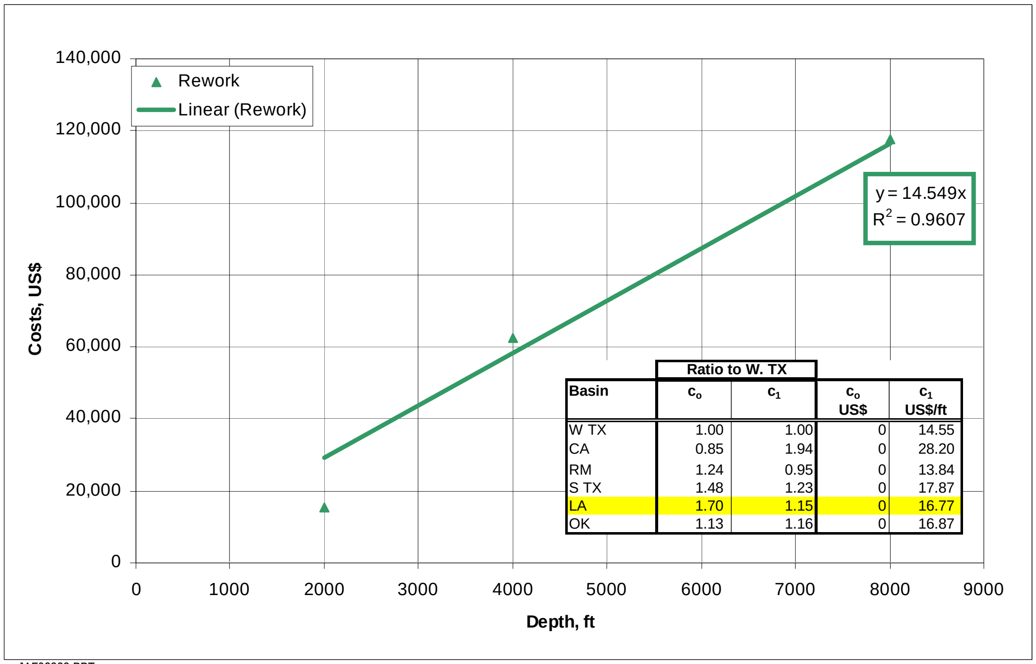
JAF02333.PPT

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 = \$16.77 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	14.55
CA	0.85	1.94	0	28.20
RM	1.24	0.95	0	13.84
S TX	1.48	1.23	0	17.87
LA	1.70	1.15	0	16.77
OK	1.13	1.16	0	16.87

JAF02333.PPT

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

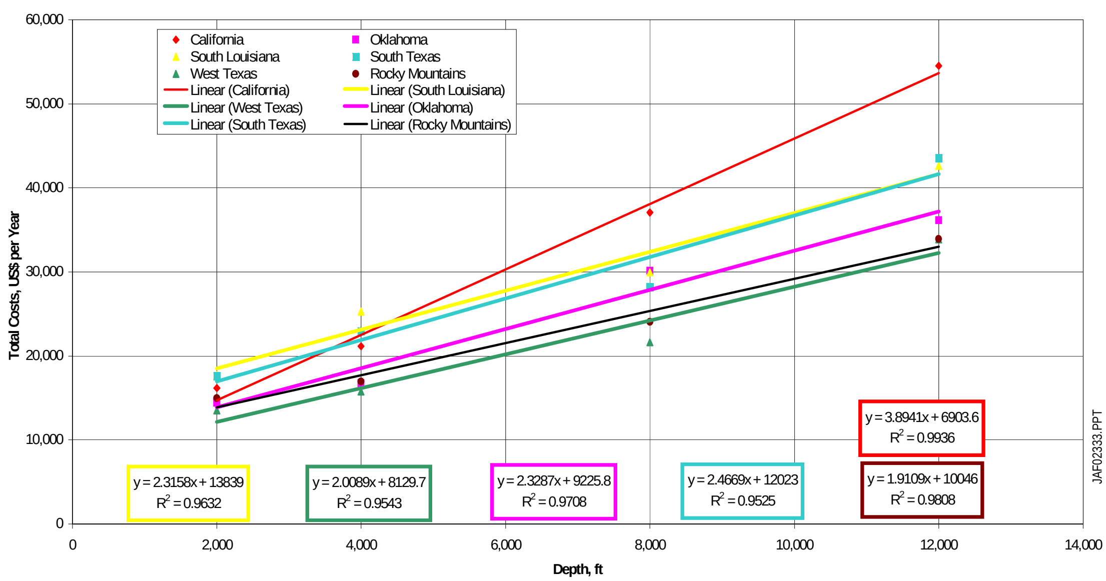


Table B-1 – Regional Lease O&M Costs and Their Relationship to West Texas

			Ratio to W. TX	
Basin	c_o US$	c_1 US$/ft	c_o	c_1
West Texas	8,130	2.01	1.00	1.00
California	6,904	3.89	0.85	1.94
Rocky Mountain	10,046	1.91	1.24	0.95
South Texas	12,023	2.47	1.48	1.23
Louisiana	13,839	2.32	1.70	1.15
Oklahoma	9,226	2.33	1.13	1.16

JAF02333.PPT

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.)

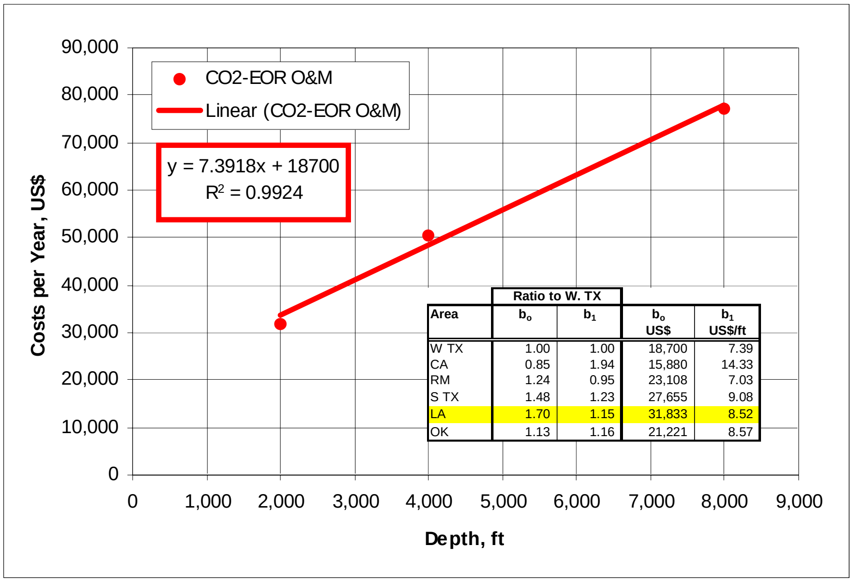
Figure B-7 shows the depth-relationship for CO_2-EOR O&M costs in West Texas. These costs were adjusted to develop O&M for Louisiana, shown in the inset of Figure B-7. The equation for Louisiana is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = $31,833 (fixed)
b_1 = $8.52 per foot
D is well depth

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 recycle requirements.

The cost of the recycling plant is set at $700,000 per MMcfd of CO_2 capacity. As such, small CO_2-EOR project in the Tokio formation of the Haynesville field, with 14 MMcfd of CO_2 reinjection, will require a recycling plant costing $9.5 million. A large project in the Delhi field, with 177 MMcfd of peak CO_2 reinjection and 112 injectors, requires a recycling plant costing $124 million.

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



Area	Ratio to W. TX b_o	Ratio to W. TX b_1	b_o US$	b_1 US$/ft
W TX	1.00	1.00	18,700	7.39
CA	0.85	1.94	15,880	14.33
RM	1.24	0.95	23,108	7.03
S TX	1.48	1.23	27,655	9.08
LA	1.70	1.15	31,833	8.52
OK	1.13	1.16	21,221	8.57

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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 15MMcfd), $120,000 per mile for 6” pipe (CO_2 rate of 15 to 35 MMcfd), $160,000 per mile for 8” pipe (CO_2

rate of 35 to 60 MMcfd), and $200,000 per mile for pipe greater than 8” diameter (CO_2 rate greater than 60 MMcfd). Aside from the injection volume, cost 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> Severance and ad valorum taxes are set at 5.0% and 2.5%, respectively, for a total production tax of 7.5% on the oil production stream. 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 Louisiana (-$0.60 per barrel) and the current gravity differential (-$0.25 per ^{o}API, from a basis of 40 ^{o}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 - ^{o}API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
^{o}API is oil gravity

If the oil gravity is less than 40 ^{o}API, the wellhead oil price is reduced; if the oil gravity is greater than 40 ^{o}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

March 2005

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:

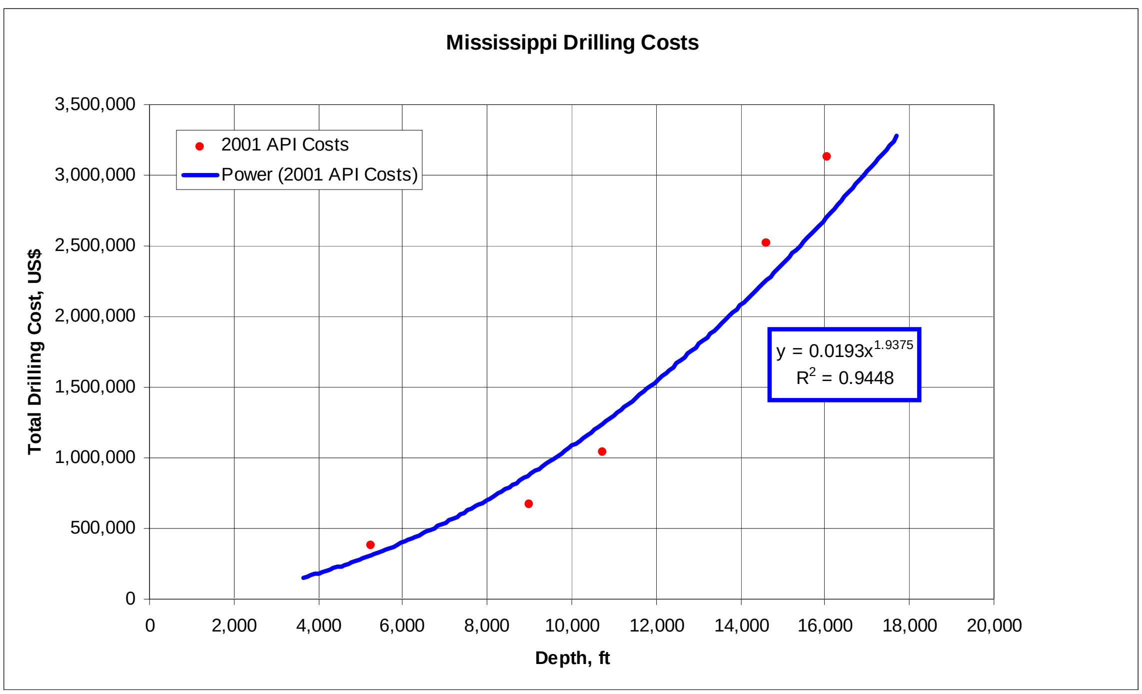
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for Mississippi.

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 = $a_0 D^{a1}$
Where: a_0 is 0.0193
a_1 is 1.9375
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



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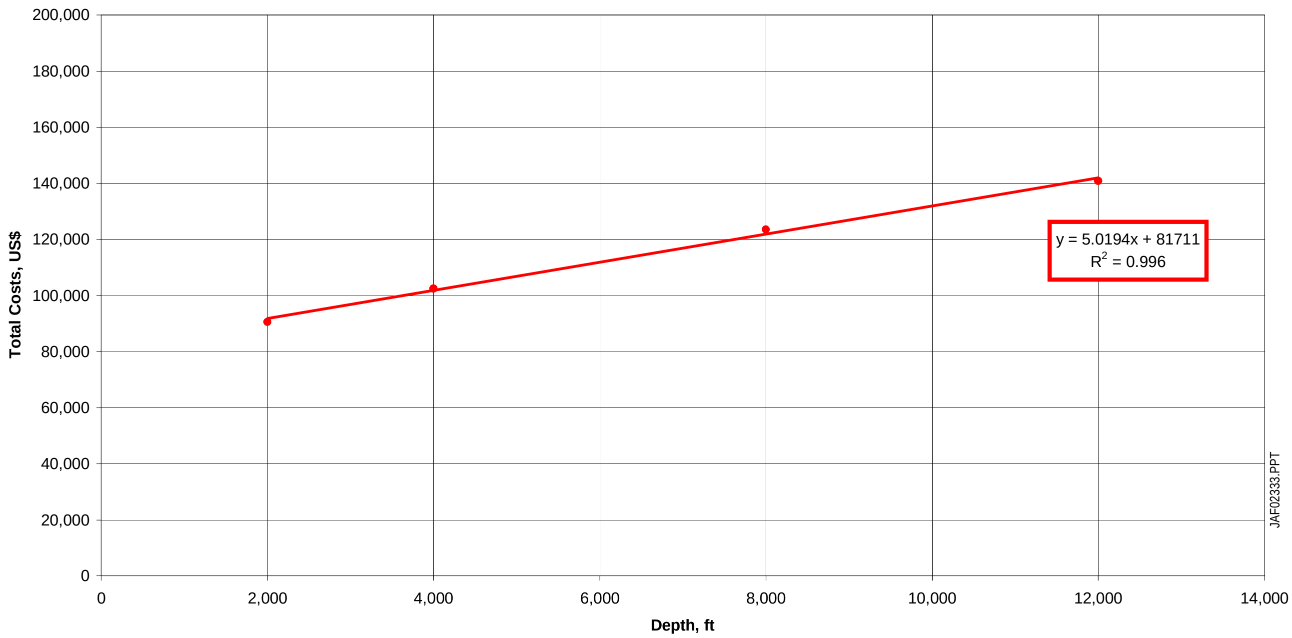
2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2002 EIA "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report. This survey provides estimated lease equipment costs 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 = $81,711 (fixed)
c_1 = $5.02 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



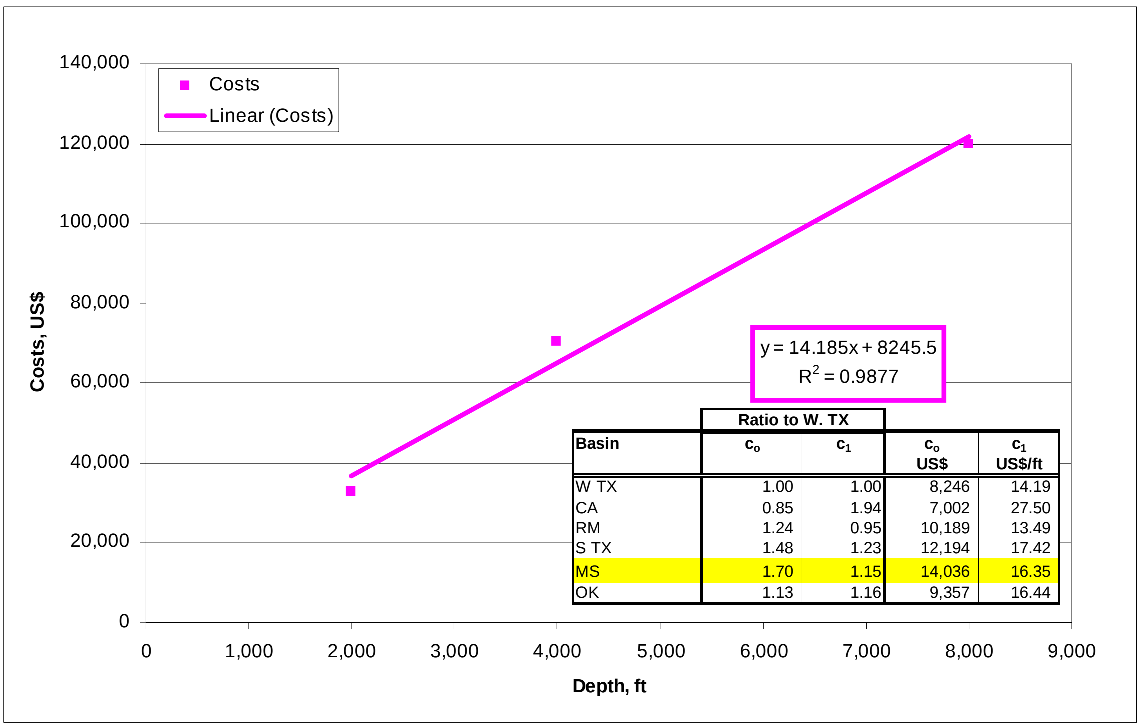
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in Mississippi include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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 = \$14,036 (fixed)
c_1 = \$16.35 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	8,246	14.19
CA	0.85	1.94	7,002	27.50
RM	1.24	0.95	10,189	13.49
S TX	1.48	1.23	12,194	17.42
MS	1.70	1.15	14,036	16.35
OK	1.13	1.16	9,357	16.44

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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 Mississippi is:

Well Conversion Costs = $c_0 + c_1D$

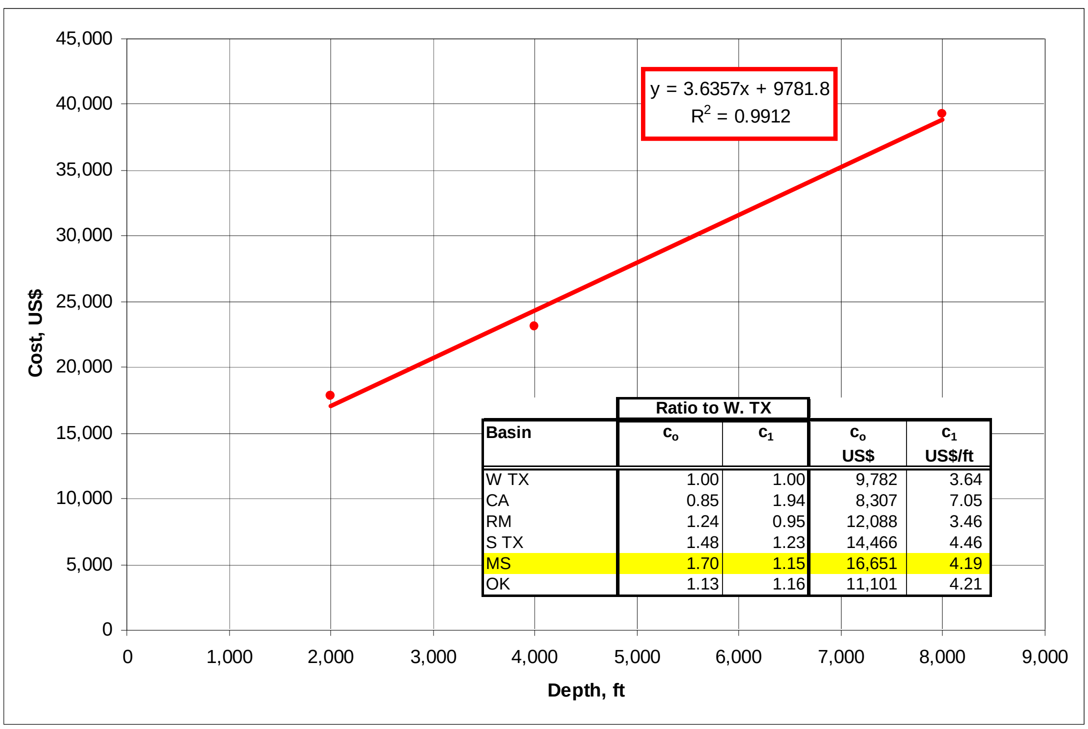
Where: c_o = \$16,651 (fixed)

c_1 = \$4.19 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



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	9,782	3.64
CA	0.85	1.94	8,307	7.05
RM	1.24	0.95	12,088	3.46
S TX	1.48	1.23	14,466	4.46
MS	1.70	1.15	16,651	4.19
OK	1.13	1.16	11,101	4.21

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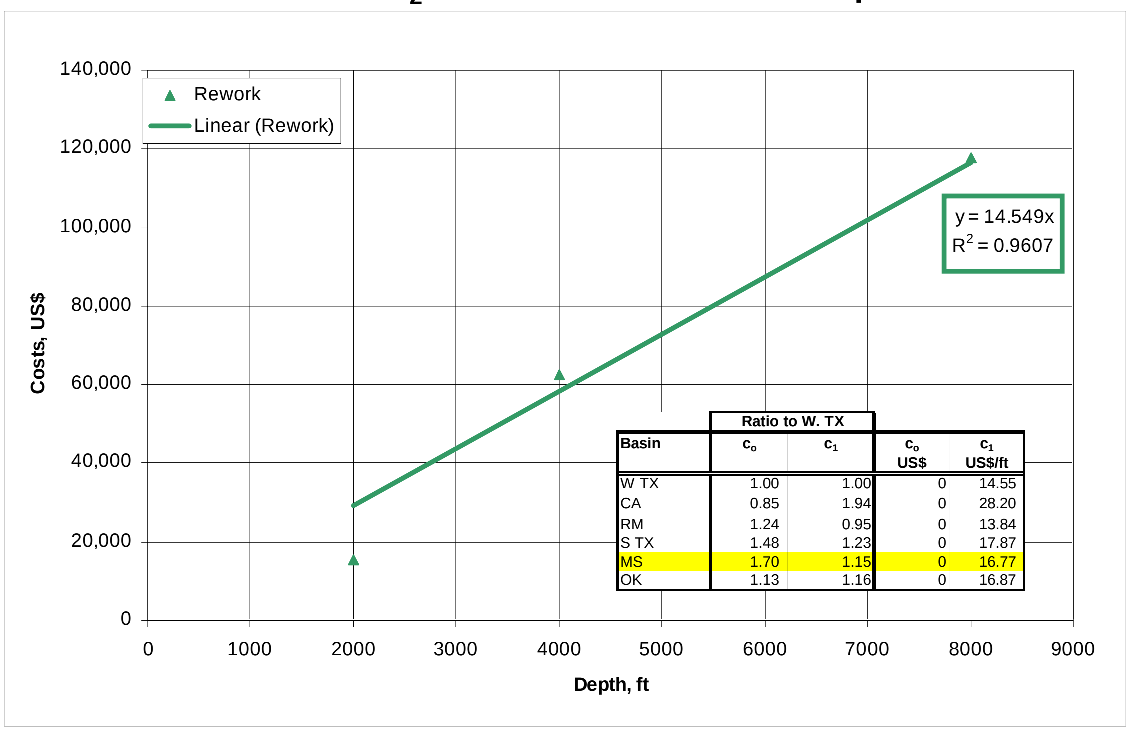
5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework). The reworking of existing oil production or CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation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

Well Rework Costs = c_1D
Where: c_1 = $16.77 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



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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

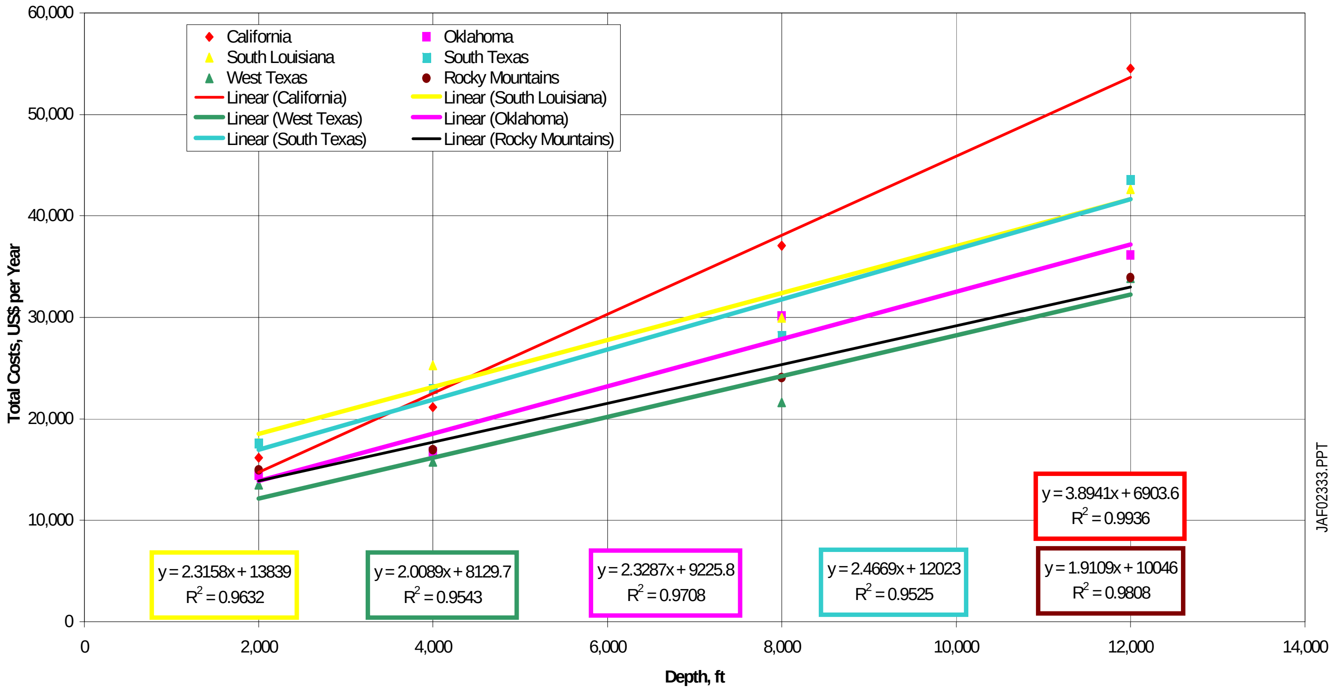


Table C-1 – Regional Lease O&M Costs and Their Relationship to West Texas

Basin	c_o US$	c_1 US$/ft	Ratio to W. TX c_o	Ratio to W. TX c_1
West Texas	8,130	2.01	1.00	1.00
California	6,904	3.89	0.85	1.94
Rocky Mountain	10,046	1.91	1.24	0.95
South Texas	12,023	2.47	1.48	1.23
Mississippi	13,839	2.32	1.70	1.15
Oklahoma	9,226	2.33	1.13	1.16

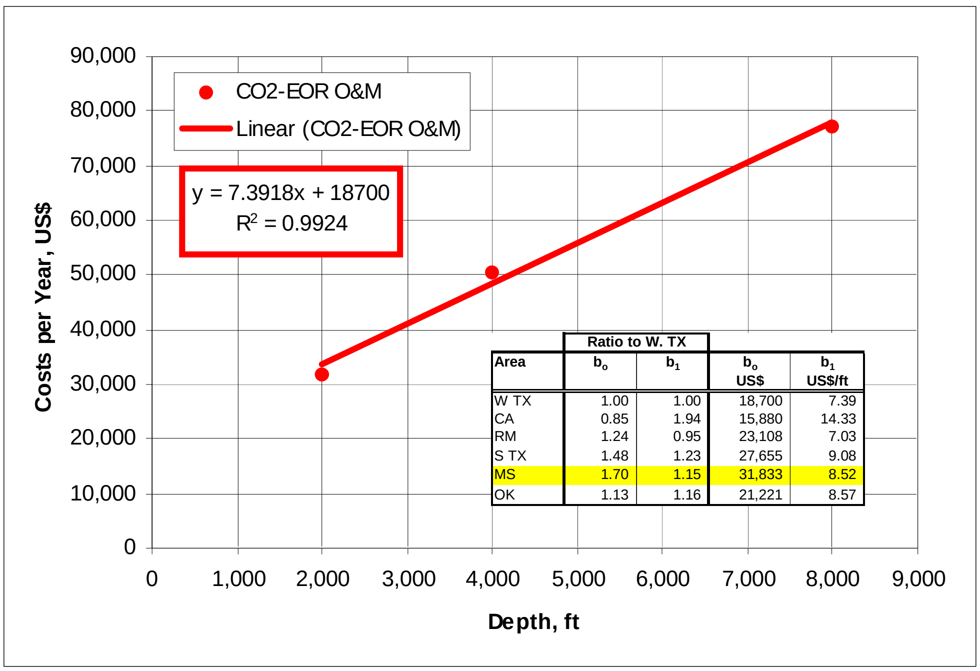
JAF02333.PPT

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 = \$31,833 (fixed)
b_1 = \$8.52 per foot
D is well depth

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



Area	Ratio to W. TX b_o	Ratio to W. TX b_1	b_o US\$	b_1 US\$/ft
W TX	1.00	1.00	18,700	7.39
CA	0.85	1.94	15,880	14.33
RM	1.24	0.95	23,108	7.03
S TX	1.48	1.23	27,655	9.08
MS	1.70	1.15	31,833	8.52
OK	1.13	1.16	21,221	8.57

JAF02333.PPT

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 recycle requirements.

The cost of the recycling plant is set at \$700,000 per MMcfd of CO_2 capacity. As such, small CO_2-EOR project in the Christmas formation of the West Heidelberg field, with 11 MMcfd 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 127 MMcfd of peak CO_2 reinjection and 119 injectors, requires a recycling plant costing \$89 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 15MMcfd), $120,000 per mile for 6" pipe (CO_2 rate of 15 to 35 MMcfd), $160,000 per mile for 8" pipe (CO_2 rate of 35 to 60 MMcfd), and $200,000 per mile for pipe greater than 8" diameter (CO_2 rate greater than 60 MMcfd). Aside from the injection volume, cost 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. Severance and ad valorum taxes are set at 5.0% and 2.5%, respectively, for a total production tax of 7.5% 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 Mississippi ($0.00 per barrel) and the current gravity differential (-$0.25 per ^{o}API, from a basis of 40 ^{o}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 - ^{o}API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
^{o}API is oil gravity

If the oil gravity is less than 40 ^{o}API, the wellhead oil price is reduced; if the oil gravity is greater than 40 ^{o}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

Texas Railroad District 3 CO_2-EOR Cost Model

March 2005

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:

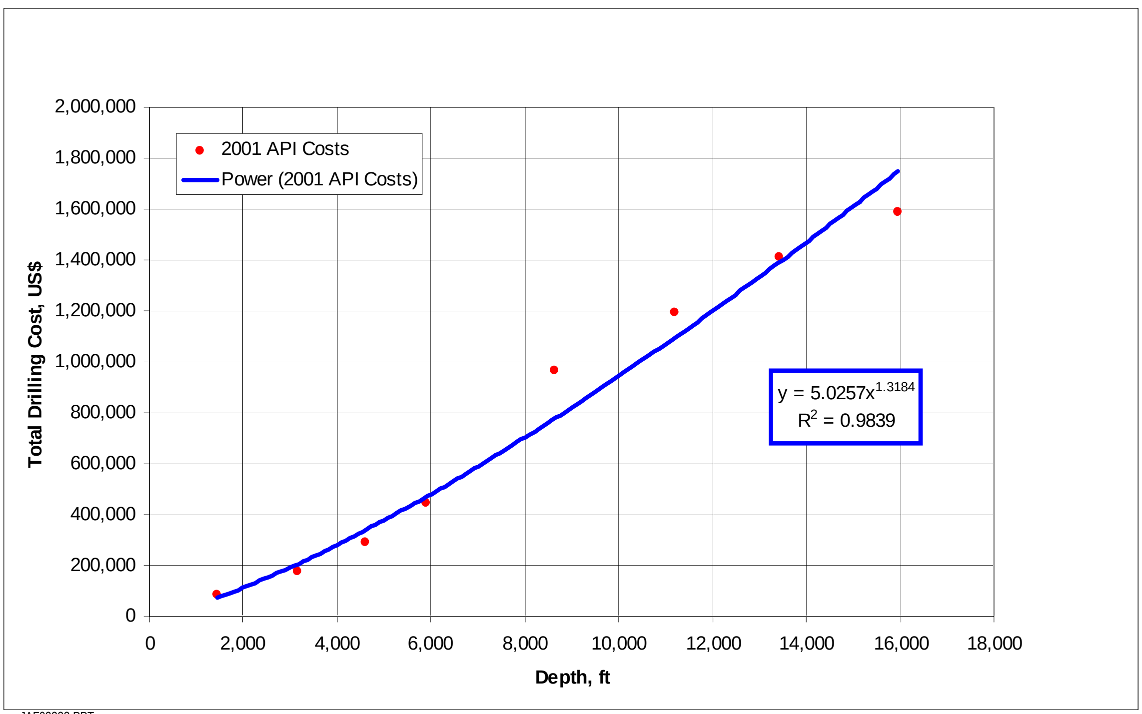
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for Texas Railroad District 3.

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_0D^{a1}
Where: a_0 is 5.0257
a_1 is 1.3184
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 Mississippi.

Figure D-1 – Oil Well D&C Costs for Texas Railroad District 3



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2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2002 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 = $c_0 + c_1D$

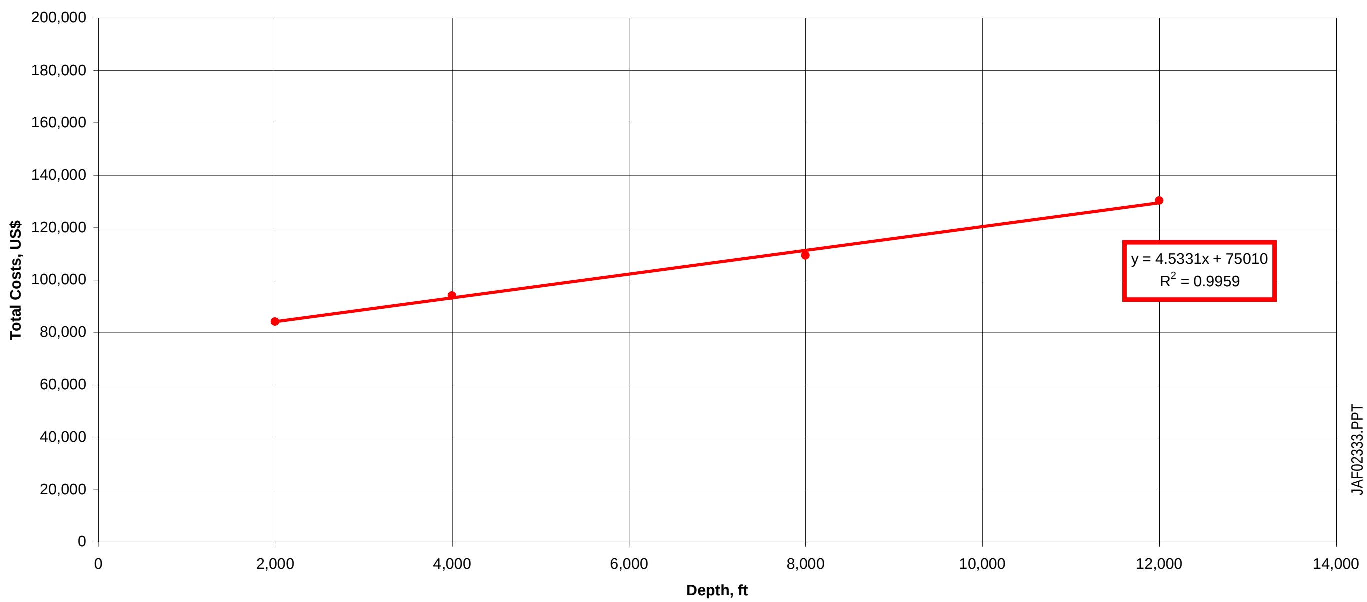
Where: c_o = \$75,010 (fixed)

c_1 = \$4.53 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 South Texas vs. Depth



3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in Texas Railroad District 3 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 Texas Railroad District 3 is:

Injection Well Equipping Costs = $c_0 + c_1D$

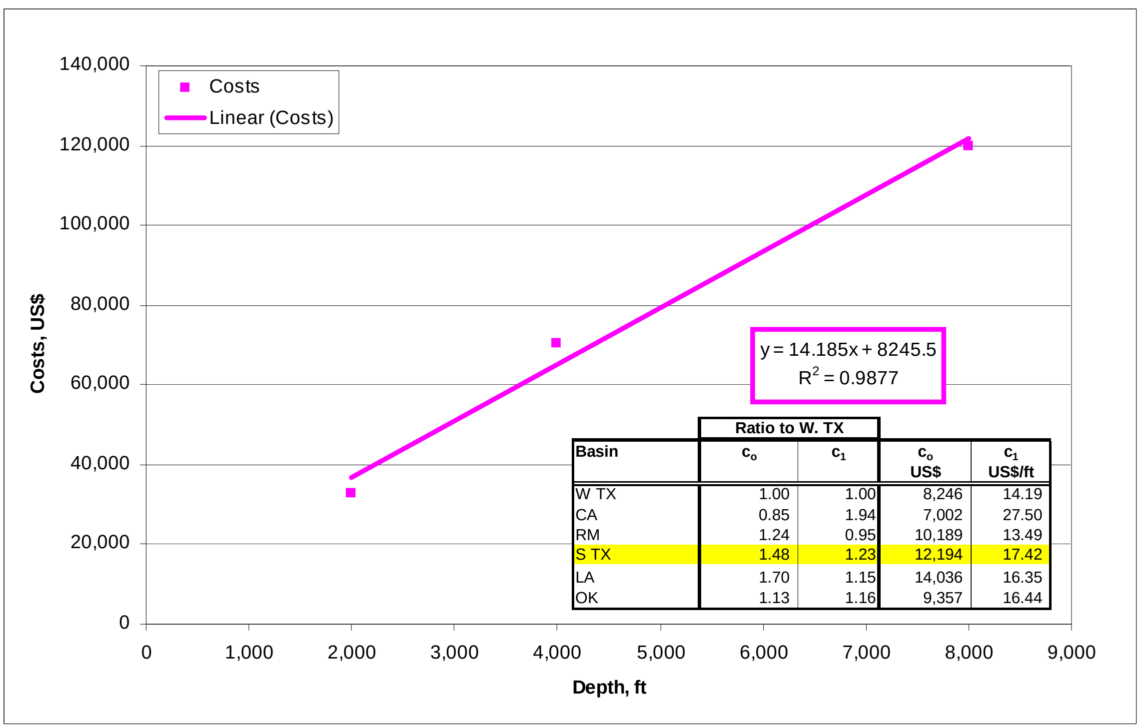
Where: c_o = \$12,194 (fixed)

c_1 = \$17.42 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 Texas Railroad District 3 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	8,246	14.19
CA	0.85	1.94	7,002	27.50
RM	1.24	0.95	10,189	13.49
S TX	1.48	1.23	12,194	17.42
LA	1.70	1.15	14,036	16.35
OK	1.13	1.16	9,357	16.44

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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 Texas Railroad District 3 is:

Well Conversion Costs = $c_0 + c_1D$

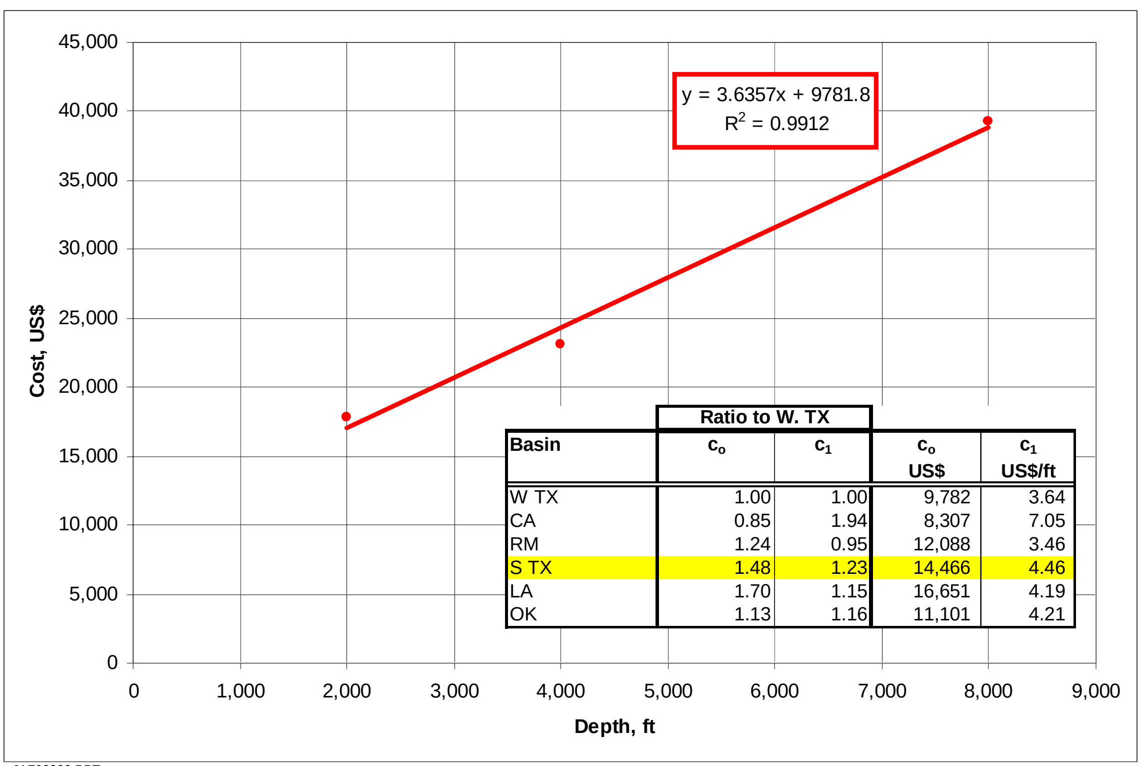
Where: c_o = \$14,466 (fixed)

c_1 = \$4.46 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 Texas Railroad District 3 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	9,782	3.64
CA	0.85	1.94	8,307	7.05
RM	1.24	0.95	12,088	3.46
S TX	1.48	1.23	14,466	4.46
LA	1.70	1.15	16,651	4.19
OK	1.13	1.16	11,101	4.21

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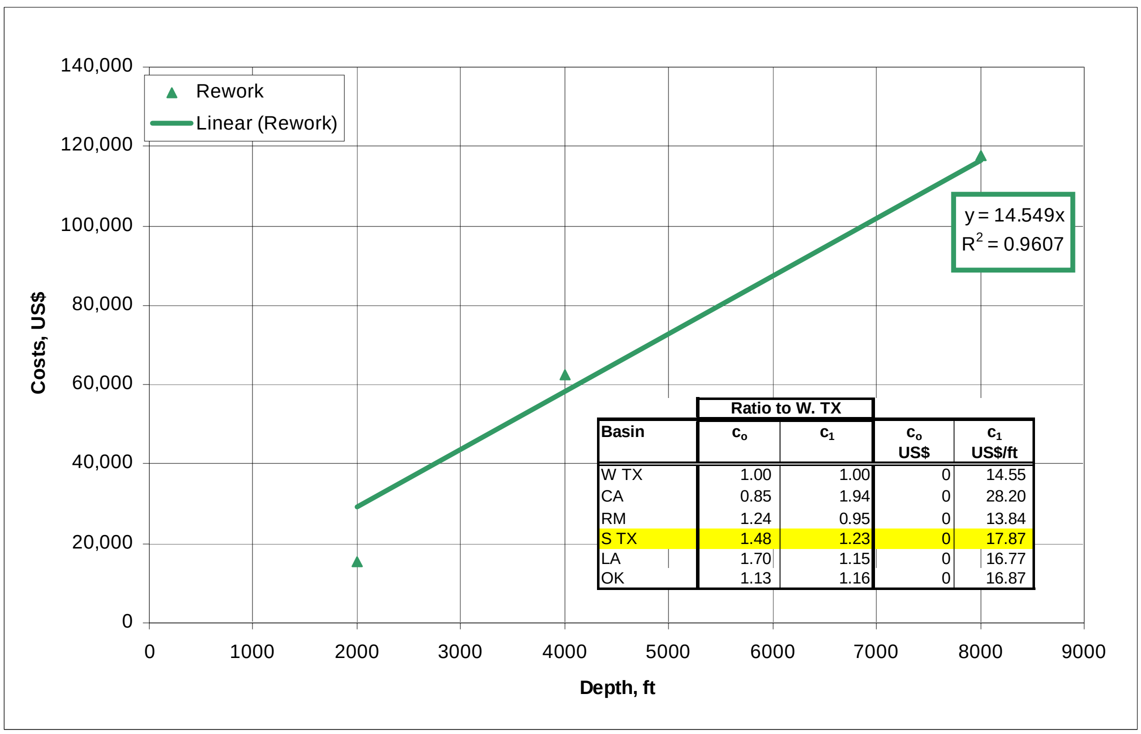
5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework). The reworking of existing oil production or CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for Texas Railroad District 3 is:

Well Rework Costs = c_1D
Where: c_1 = $17.87 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 Texas Railroad District 3 cost equation.

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



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6. <u>Annual O&M Costs, Including Periodic Well Workovers.</u> The EIA Cost and Indices report provides secondary operating and maintenance (O&M) costs only for West Texas. As such, West Texas and Texas Railroad District 3 primary oil production O&M costs (Figure D-6) are used to estimate Texas Railroad District 3 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

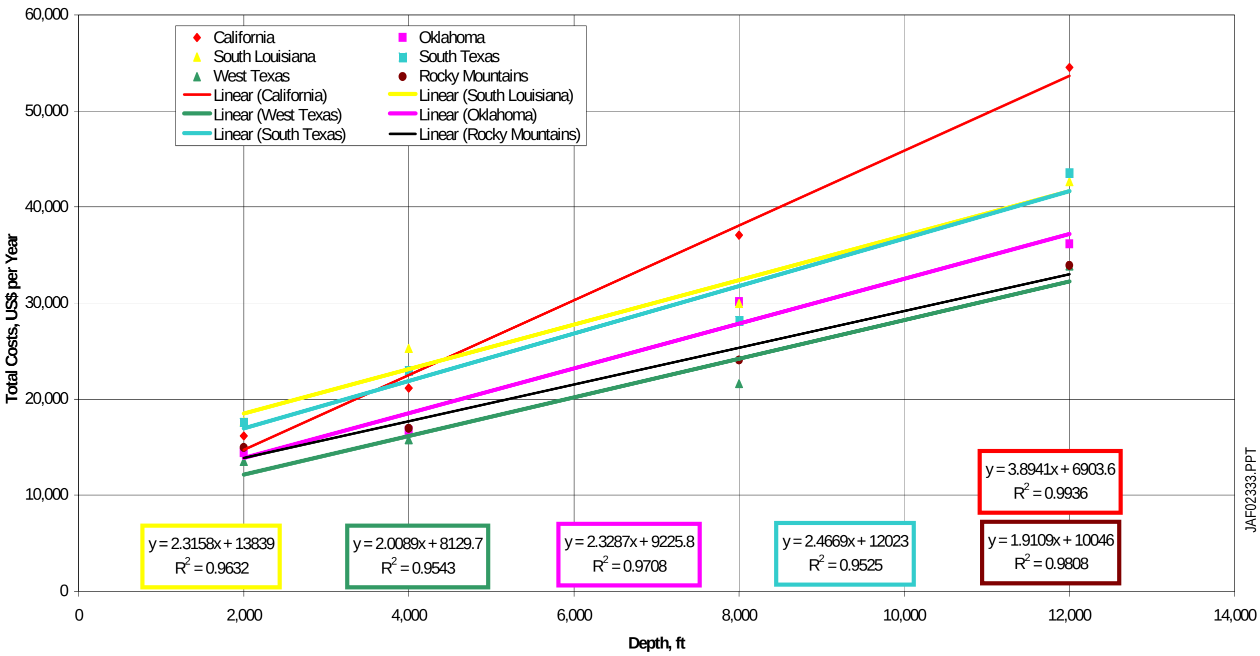

Table D-1 – Regional Lease O&M Costs and Their Relationship to West Texas

Basin	c_o US$	c_1 US$/ft	Ratio to W. TX c_o	Ratio to W. TX c_1
West Texas	8,130	2.01	1.00	1.00
California	6,904	3.89	0.85	1.94
Rocky Mountain	10,046	1.91	1.24	0.95
South Texas	12,023	2.47	1.48	1.23
Louisiana	13,839	2.32	1.70	1.15
Oklahoma	9,226	2.33	1.13	1.16

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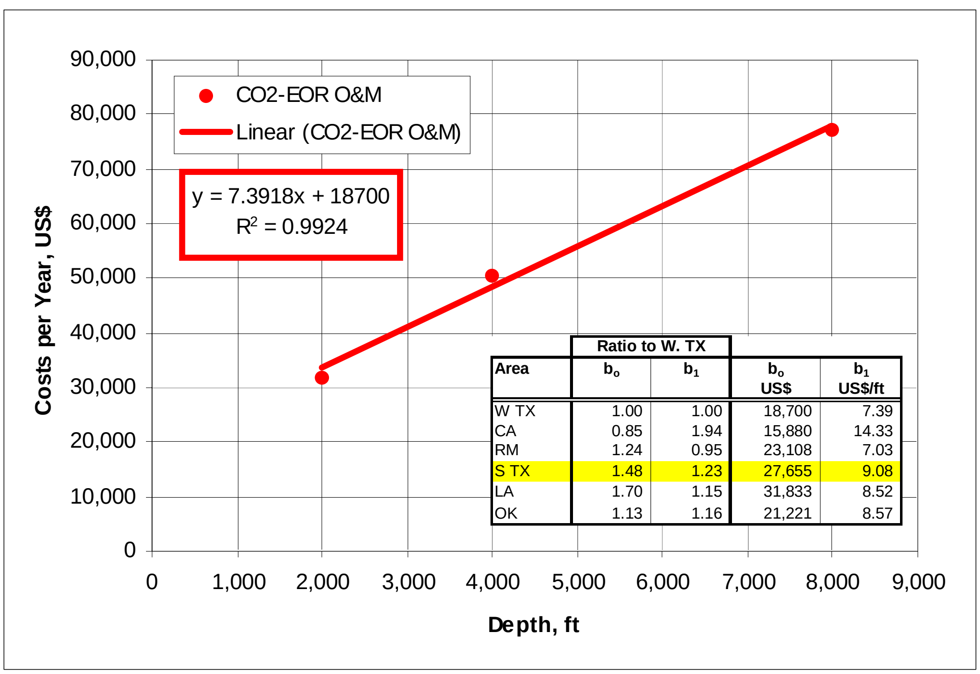
To account for the O&M cost differences between waterflooding and CO_2-EOR, two adjustments are made to the EIA's reported O&M costs for secondary recovery. Workover costs, reported as surface and subsurface maintenance, are doubled to reflect the need for more frequent remedial well work in CO_2-EOR 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 Texas Railroad District 3, shown in the inset of Figure D-7. The equation for Texas Railroad District 3 is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = $27,655 (fixed)
b_1 = $9.08 per foot
D is well depth

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



Area	Ratio to W. TX b_o	Ratio to W. TX b_1	b_o US$	b_1 US$/ft
W TX	1.00	1.00	18,700	7.39
CA	0.85	1.94	15,880	14.33
RM	1.24	0.95	23,108	7.03
S TX	1.48	1.23	27,655	9.08
LA	1.70	1.15	31,833	8.52
OK	1.13	1.16	21,221	8.57

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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 recycle requirements.

The cost of the recycling plant is set at $700,000 per MMcfd of CO_2 capacity. As such, small CO_2-EOR project in the Frio 12 formation of the Trinity Bay field, with 29 MMcfd of CO_2 reinjection, will require a recycling plant costing $20.2 million. A large project in the Thompson field, with 376 MMcfd of peak CO_2 reinjection and 241 injectors, requires a recycling plant costing $263 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. <u>Other COTWO Model Costs.</u>

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 15MMcfd), $120,000 per mile for 6" pipe (CO_2 rate of 15 to 35 MMcfd), $160,000 per mile for 8" pipe (CO_2 rate of 35 to 60 MMcfd), and $200,000 per mile for pipe greater than 8" diameter (CO_2 rate greater than 60 MMcfd). Aside from the injection volume, cost 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 South Texas 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. Severance and ad valorum taxes are set at 5.0% and 2.5%, respectively, for a total production tax of 7.5% 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 Texas Railroad District 3 ($3.60 per barrel) and the current gravity differential (-$0.25 per ^{o}API, from a basis of 40 ^{o}API) into the average wellhead oil price realized by each oil reservoir. The equation for Texas Railroad District 3 is:

Wellhead Oil Price = Oil Price + ($3.60) – [$0.25*(40 - ^{o}API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
^{o}API is oil gravity

If the oil gravity is less than 40 ^{o}API, the wellhead oil price is reduced; if the oil gravity is greater than 40 ^{o}API, the wellhead oil price is increased. In addition, some fields within Texas Railroad District 3 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.