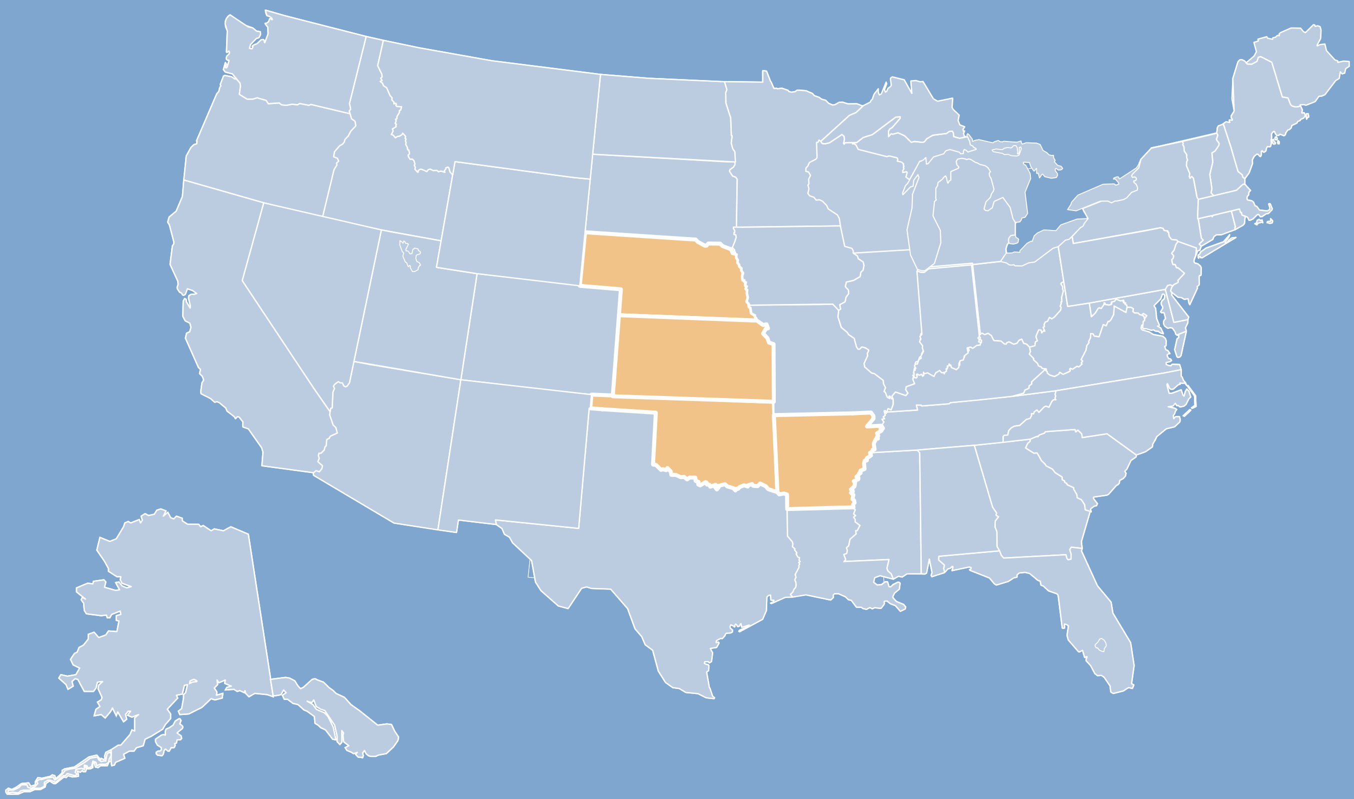
Basin Oriented Strategies for CO_2 Enhanced Oil Recovery:

MID-CONTINENT REGION



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Prepared by

Advanced Resources International

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BASIN ORIENTED STRATEGIES FOR CO_2 ENHANCED OIL RECOVERY: MID-CONTINENT REGION OF ARKANSAS, NEBRASKA, KANSAS AND OKLAHOMA

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1. SUMMARY OF FINDINGS

1.1 INTRODUCTION. The Mid-Continent oil and gas producing region has 66 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 mature reservoirs that appear to be 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 Mid-Continent Region and the barriers that stand in the way of realizing this potential. The report then discusses how a concerted set of "basin oriented strategies" could help the Mid-Continent Region's oil production industry overcome these barriers and capture the large "stranded oil" prize.

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 Mid-Continent producing region.

- The first scenario captures how CO_2-EOR technology has been applied and has performed in the past. This low technology, high-risk scenario is called "Traditional Practices".
- The second scenario, entitled "State-of-the-art", assumes that the technology progress in CO_2-EOR, achieved in recent years and in other areas, is successfully applied in the Mid-Continent region. In addition, this scenario assumes that a comprehensive program of research, pilot tests and field demonstrations help lower the technical risks inherent in applying new technology to these Mid-Continent region oil reservoirs.
- The third scenario, entitled "Risk Mitigation," examines how the economic potential of CO_2-EOR could be increased through a strategy involving state production tax reductions, federal investment tax credits, royalty relief and/or higher world oil prices that together would add an equivalent $10 per barrel to

the oil price that the producer uses for making capital investment decisions for CO_2-EOR.

- The final scenario, entitled "Ample Supplies of CO_2," examines the case when low-cost, "EOR-ready" CO_2 supplies are aggregated from various industrial and natural sources. These include industrial high-concentration CO_2 emissions from hydrogen facilities, gas processing plants, chemical plants and other sources in the region. These would be augmented, in the longer-term, from low concentration CO_2 emissions captured from refineries and electric power plants. Capture of industrial CO_2 emissions could be part of a national effort for reducing greenhouse gas emissions.

The CO_2-EOR potential of the Mid-Continent region is examined using these four bounding scenarios.

1.3 OVERVIEW OF FINDINGS. Twelve major findings emerge from the study of "Basin Oriented Strategies for CO2 Enhanced Oil Recovery: the Mid-Continent Region of Arkansas, Nebraska, Kansas and Oklahoma."

1. Today's oil recovery practices will leave behind a large resource of "stranded oil" in the Mid-Continent region. The original oil resource in the Mid-Continent region reservoirs is 90 billion barrels. To date, 24 billion barrels of this original oil in place (OOIP) has been recovered or proved. Thus, without further efforts, 66 billion barrels of the Mid-Continent region's oil resource will become "stranded", Table 1.

Table 1. Mid-Continent Region's Oil Resource and Reservoirs

State	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
A. Major Oil Reservoirs				
Arkansas*	23	4.0	1.2	2.8
Nebraska**	34	0.8	0.3	0.5
Kansas*	60	11.3	3.4	7.9
Oklahoma***	105	36.8	9.3	27.5
Data Base Total	222	52.9	14.2	38.7
*B. Regional Total**	n/a	89.6	24.0	65.6

Estimated from state data on cumulative oil recovery and proved reserves
** as of the end of 2003*
*** as of the end of 2004*
**** as of the end of 2002*

2. A major portion of the "stranded oil" resource in the large oil reservoirs of the Mid-Continent region is amenable to CO_2 enhanced oil recovery. To address the "stranded oil" issue, Advanced Resources assembled a data base that contains 222 major Mid-Continent oil reservoirs, accounting for 59% of the region's estimated ultimate oil production. Of these, 97 reservoirs, with 29.9 billion barrels of OOIP and 21.6 billion barrels of "stranded oil" (ROIP), were found to be favorable for CO_2-EOR, Table 2.

Table 2. Mid-Continent Region's "Stranded Oil" Resources Amenable to CO_2-EOR

State	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
Arkansas	6	1.0	0.4	0.6
Nebraska	3	0.3	0.2	0.1
Kansas	25	5.2	1.8	3.4
Oklahoma	63	23.4	5.9	17.5
TOTAL	97	29.9	8.3	21.6

3. Application of miscible CO_2-EOR would enable a significant portion of the Mid-Continent region's "stranded oil" to be recovered. Of the 97 large Mid-Continent region oil reservoirs favorable for CO_2-EOR, 96 reservoirs (with 29.9 billion barrels OOIP) screen as being favorable for miscible CO_2-EOR. The remaining oil reservoir screens as being favorable for immiscible CO_2-EOR. The total technically recoverable resource from applying CO_2-EOR in these 97 large oil reservoirs, ranges from 3,280 million barrels to 6,990 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

State	Miscible			Immiscible		
	No. of Reservoirs	Technically Recoverable* (MMBbls)		No. of Reservoirs	Technically Recoverable (MMBbls)	
		Traditional Practices**	State of the Art**		Traditional Practices	State of the Art
Arkansas	6	100	230	0	-	-
Nebraska	2	20	40	1	-	10
Kansas	25	570	1,270	0	-	-
Oklahoma	63	2,590	5,440	0	-	-
TOTAL	96	3,280	6,980	1	-	10

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

*** Nearly 80 MMBbls has already been proven/recovered with tertiary EOR.*

4. A portion of the Mid-Continent region's "stranded oil" is economically recoverable using "Traditional Practices" of CO_2 flooding technology. As shown above, traditional application of miscible CO_2-EOR technology (involving a relatively modest volume of CO_2 injection) to the 96 large reservoirs in the data base would enable 3,280 million barrels of "stranded oil" to become technically recoverable in the Mid-Continent region. With current costs for CO_2 in the Mid-Continent region (assumed to equal to $1.50 per Mcf at $30 Bbl) and a substantial technical risk premium because of uncertainties about future oil prices and the performance of CO_2-EOR technology, about 1,270 million barrels of this "stranded oil" could become economically recoverable at oil prices of $30 per barrel, as adjusted for gravity and location, Table 4. A portion of the 1,270 million barrels is mobile oil that becomes recoverable with the closer well spacings and improved well completions used in CO_2-EOR.

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

State	No. of Reservoirs	OOIP (MMBbls)	Economically* Recoverable	
			(# Fields)	(MMBbls)
Arkansas	6	1,020	2	10
Nebraska	2	250	0	0
Kansas	25	5,150	8	320
Oklahoma	63	23,380	21	940
TOTAL	96	29,800	31	1,270

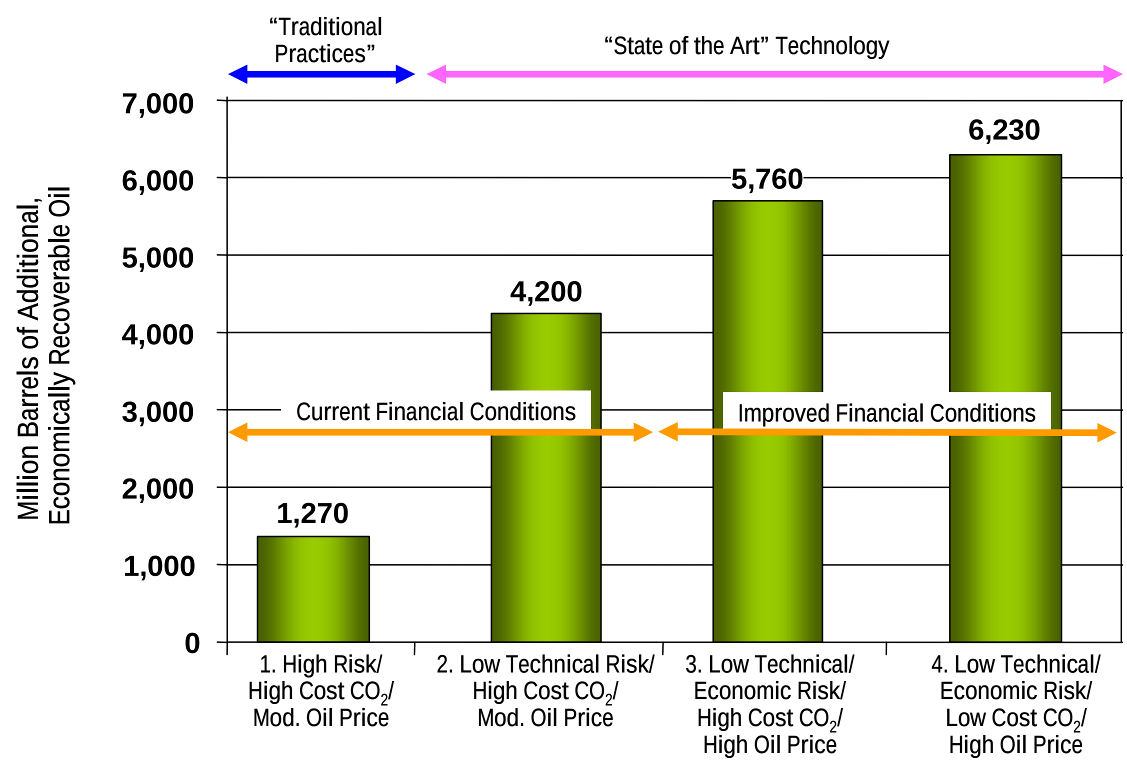
**This case assumes an oil price of $30 per barrel, a CO_2 cost of $1.50 per Mcf, and a ROR hurdle rate of 25% (before tax).*

5. Introduction of "State-of-the-art" CO_2-EOR technology, risk mitigation incentives and lower cost CO_2 costs would enable 6 billion barrels of additional oil to become economically recoverable from the Mid-Continent region. With "State-of-the-art" CO_2-EOR technology and lower technical risk (oil prices of $30 per barrel and CO_2 costs of $2 per Mcf) 4,200 million barrels of the oil remaining in Mid-Continent region's reservoirs becomes economically recoverable — Scenario #2.

Risk mitigation actions and/or higher oil prices, providing an oil price equal to $40 per barrel ($CO_2$ costs of $2 per Mcf) would enable 5,760 million barrels of oil to become economically recoverable from Mid-Continent region's large oil reservoirs — Scenario #3.

Lower cost CO_2 supplies, equal to $0.80 per Mcf (assuming the installation of a large-scale CO_2 transportation system and incentives for CO_2 emissions capture) and oil prices of $40 per barrel, would enable the economic potential to increase to 6,230 million barrels — Scenario #4, Figure 1 and Table 5.

Figure 1. Impact of Advanced Technology and Improved Financial Conditions on Economically Recoverable Oil from Mid-Continent Region's Major Reservoirs Using CO_2-EOR (Million Barrels)



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

Table 5. Economically Recoverable Resources - Alternative Scenarios

State	Scenario #2: "State-of-the-art" (Moderate Oil Price/ High CO_2 Cost)		Scenario #3: "Risk Mitigation" (High Oil Price/ High CO_2 Cost)		Scenario #4: "Ample Supplies of CO_2" (High Oil Price/ Low CO_2 Cost)	
	(# Fields)	(MMBbls)	(# Fields)	(MMBbls)	(# Fields)	(MMBbls)
Arkansas	6	230	6	230	6	230
Nebraska	3	40	3	40	3	40
Kansas	19	1,040	21	1,210	22	1,220
Oklahoma	32	2,890	43	4,280	48	4,740
TOTAL	60	4,200	73	5,760	79	6,230

6. Once the results from the study's large oil reservoirs data base are extrapolated to the state as a whole, the technically recoverable CO_2-EOR potential for the Mid-Continent region is estimated at nearly 12 billion barrels. The large Mid-Continent region oil reservoirs examined by the study account for 59% of the region's oil resource. Extrapolating the 7.0 million barrels of technically recoverable EOR potential in these 97 oil reservoirs to the total Mid-Continent region oil resource provides an estimate of 11.8 billion barrels of technical CO_2-EOR potential. (However, no extrapolation of economic potential has been estimated, as the development costs for the smaller Mid-Continent region oil fields may not reflect the development costs of the larger oil reservoirs in the region.)

7. The ultimate additional oil recovery potential from applying CO2-EOR in the Mid-Continent region 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, 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 "next generation" CO_2-EOR technology on the Mid-Continent region oil reservoirs may be examined in a subsequent study.

8. A portion of this CO2-EOR potential is already being pursued by operators in the Mid-Continent region. Significant EOR Field projects have been completed in the Lick Creek field (AR) and are underway in the Postle, Northeast Purdy, Bradley Unit, Sho-Vel-Tum, and Camrick fields in Oklahoma. Together, these 6 EOR projects have produced and proven about 80 million barrels of the CO_2-EOR potential set forth in this study.

9. Large volumes of CO_2 supplies will be required in the Mid-Continent region to achieve the CO_2-EOR potential defined by this study. The overall market for purchased CO_2 could be up to 19.3 Tcf, plus another 58.4 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 Mid-Continent region's oil reservoirs would enable 1,000 million metric tons of CO_2 emissions to be economically stored, greatly reducing greenhouse gas emissions. Advanced CO_2-EOR flooding and CO_2 storage concepts (plus incentives for storing CO_2) would significantly increase this amount.

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

Region	No. of Reservoirs	Economically Recoverable (MMBbls)	Market for Purchased CO_2 (Bcf)	Market for Recycled CO_2 (Bcf)
Arkansas	6	230	910	1,810
Nebraska	3	40	160	450
Kansas	22	1,220	4,410	8,560
Oklahoma	48	4,740	13,850	47,620
TOTAL	79	6,230	19,330	58,440

10. Significant supplies of industrial CO_2 emissions exist in the Mid-Continent region, sufficient to meet the CO_2 needs for EOR. CO_2 emissions, from gas processing plants and hydrogen plants could provide 8 Bcf per year of high concentration (relatively low cost) CO_2, equal to 160 Bcf of CO_2 supply in 20 years. Almost unlimited supplies of low concentration CO_2 emissions (equal to over 30 Tcf of CO_2 supply in 20 years) would be available from the large power plants and refineries in the region, assuming affordable cost CO_2 capture technology is developed.

11. A public-private partnership will be required to overcome the many barriers facing large scale application of CO_2-EOR in the Mid-Continent 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 Mid-Continent region's old and 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 states of the Mid-Continent region and the federal government will be needed to overcome these barriers.

12. Many entities will share in the benefits of increased CO_2-EOR based oil production in the Mid-Continent region. Successful introduction and wide-scale use of CO_2-EOR in the Mid-Continent region 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 Arkansas, Kansas, Nebraska and Oklahoma.

In Arkansas we would like to thank Gary Looney for providing up-to-date state oil production data. We would particularly like to thank the Oklahoma Geological Survey, namely Charles Mankin and Dan T. Boyd, for providing valuable insights, data on reservoir properties, and historical information on Oklahoma oil and gas fields. We would also like to thank W. Lynn Watney, Kansas Geological Survey Executive Directory, for Kansas oil field data and guidance for this report. Finally, we would like to thank Stan Balieu of the Nebraska Oil and Gas Conservation Commission for information on state waterflooding activities.

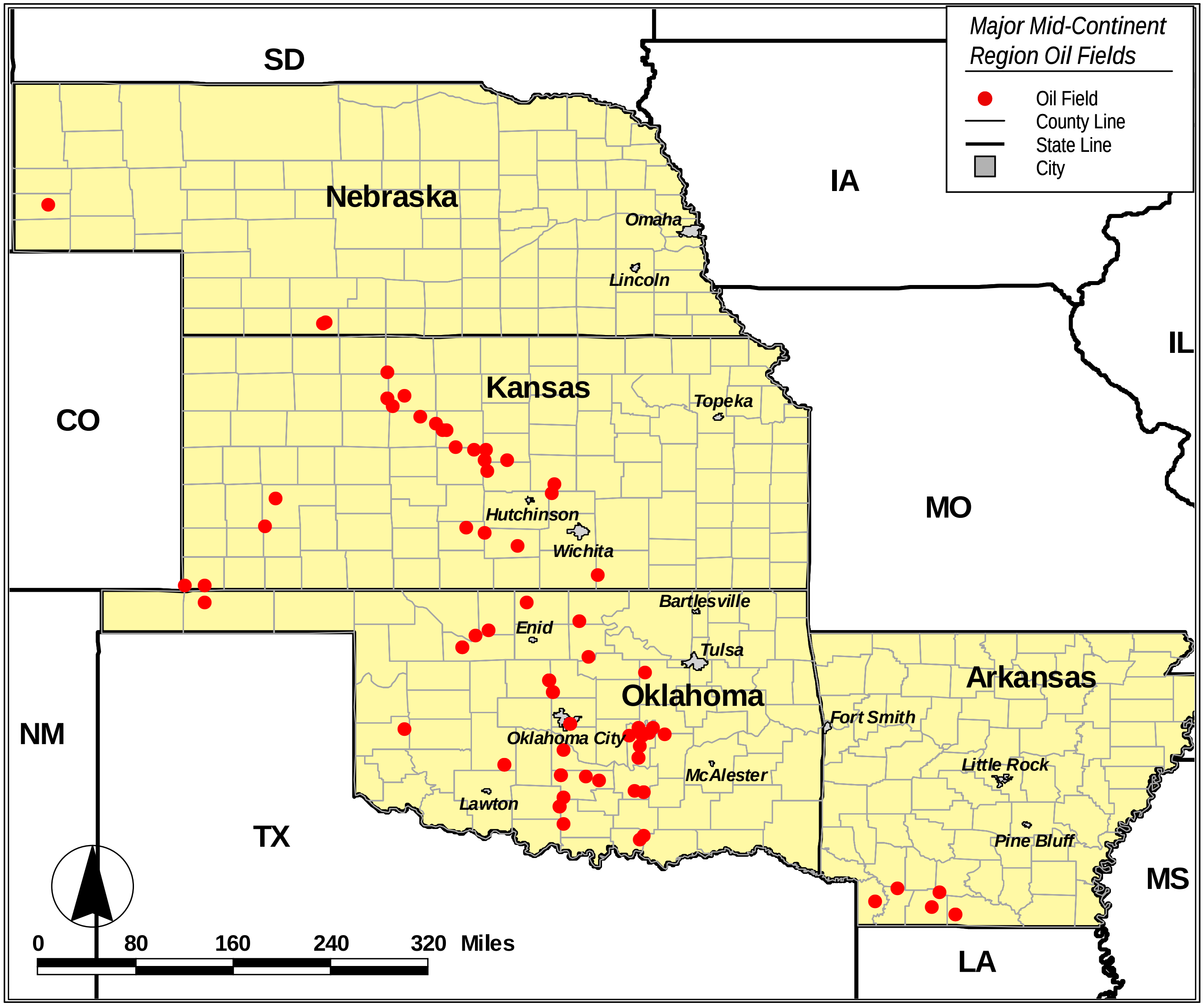
2. INTRODUCTION

2.1 CURRENT SITUATION. The Mid-Continent region contains numerous abandoned oil fields, and those that are still active are considered mature and in decline. Stemming the decline in oil production will be a major challenge, requiring the application of more advanced oil recovery methods and technology, particularly CO2 enhanced oil recovery (CO2-EOR). The main purpose of this report is to provide information on the potential for pursuing CO2-EOR as one option for slowing or potentially stopping the decline in the Mid-Continent region's oil production.

This report, "Basin Oriented Strategies for CO2 Enhanced Oil Recovery: Mid-Continent region of Arkansas, Nebraska, Kansas and Oklahoma," provides information on the size of the technical and economic potential for CO2-EOR in the Mid-Continent oil producing regions. It also identifies the many barriers — insufficient and costly CO2 supplies, high technical and economic risks, and concerns over technology performance — that currently impede the cost-effective application of CO2-EOR in the Mid-Continent region.

2.2 BACKGROUND. Although the Mid-Continent region still contains one of the largest oil producing states (Oklahoma), the region has experienced significant declines in oil production over the past 20 years. The region currently produces 293 thousand barrels of oil per day (in 2004). However, the deep, light oil reservoirs of this region are ideal candidates for miscible carbon-dioxide based enhanced oil recovery (CO_2-EOR). Some of the major oil fields of the Mid-Continent region, which may be amenable to CO_2-EOR, are shown below in Figure 2.

Figure 2. Large Mid-Continent Region Oil Fields Amenable to CO_2-EOR



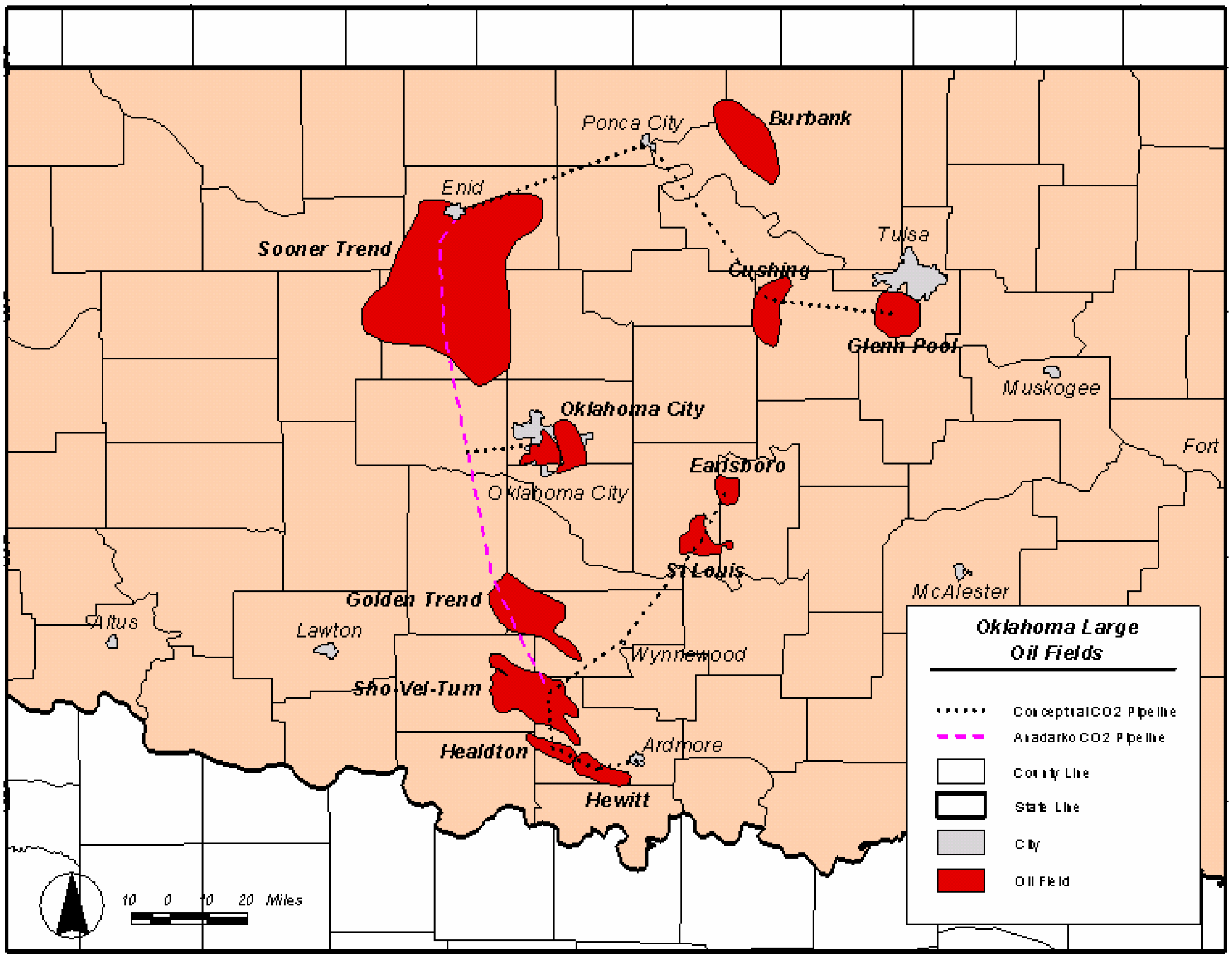
2.3 PURPOSE. This report, “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Mid-Continent region of Arkansas, Nebraska, Kansas and Oklahoma” is part of a larger effort to examine the enhanced oil recovery and CO_2 storage potential in key U.S. oil basins. The work involves establishing the geological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

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

2.4 KEY ASSUMPTIONS. For purposes of this study, it is assumed that sufficient supplies of CO_2 will become available, either by pipeline from natural sources such as the Bravo Dome of New Mexico, or from the hydrogen plants at the refineries in Ardmore, OK (capacity of 10 MMcf/d), Ponca City, OK (estimated CO_2 capacity of 4 MMcf/d), and Wynnewood, OK (capacity of 4 MMcf/d). The timing of this availability assumes that this CO_{2v} will be delivered in the near future before the major oil fields are plugged and abandoned.

Figure 3 provides a conceptual illustration of a CO_2 pipeline system that would transport captured CO_2 emissions from Ponca City, Ardmore, and Wynnewood refineries to some of the large oil fields of Oklahoma. It makes no warranties as to the availability of pipeline right-of-ways due to environmental and/or landowner constraints.

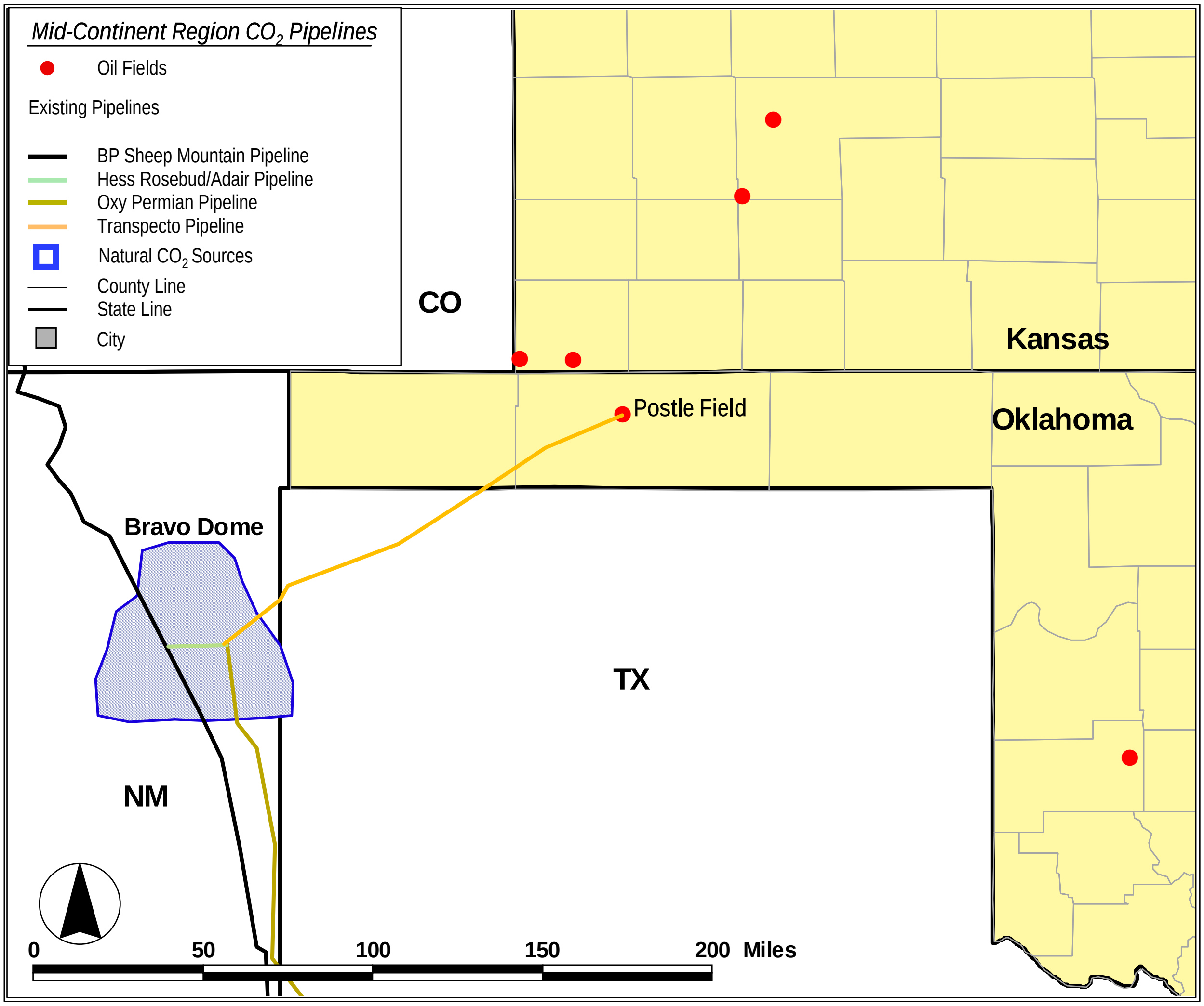
Figure 3. Conceptual CO_2 Pipeline System Connecting CO_2 Sources With Oklahoma Oil Fields



Currently, a 120-mile CO_2 pipeline transports CO_2 from Enid in northern Oklahoma to the Northeast Purdy and the Bradley Unit of the composite Golden Trend Field and to the Sko-Vel-Tum Field, both south of Oklahoma City (also shown in Figure 3). This pipeline could also provide CO_2 to other CO_2-EOR candidate fields, including Sooner Trend, Oklahoma City, Healdton, and Hewitt.

A second pipeline brings CO_2 from the Bravo Dome to the Postle and Camrick fields in the Oklahoma Panhandle near Guyman, OK through Transpetco's CO_2 Pipeline. Constructed in 1996, the 120-mile Transpetco/Bravo Pipeline has a capacity of 175 MMcf/d, Figure 4.

Figure 4. CO_2 Pipeline to the Postle Field



Given the limited oil reservoir data in Oklahoma, many reservoirs within a field were lumped together in our analysis of CO_2-EOR potential. A more detailed breakout of the reservoir properties and oil production of the many reservoirs within each field is beyond the scope of our initial assessment.

It should also be noted that there are thousands of orphaned oil and gas wells in Oklahoma without records, API numbers, or locations. These old, abandoned wells, often left unplugged, would need to be located and plugged prior to initiation of a CO_2 flood. Finding and plugging these old wells presents one of the biggest challenges to the success of CO_2-EOR in Oklahoma oil reservoirs.

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 Mid-Continent region oil reservoirs, under two technology options:

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

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

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

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

1. *Favorable Light Oil Reservoirs Meeting Stringent CO_2 Miscible Flooding Criteria*. These are the moderately deep, higher gravity oil reservoirs where CO_2 becomes miscible (after extraction of 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 Mid-Continent region light oil fields such as Magnolia (AR), Sleepy Hollow (NE), Chase-Silica (KS), and Sho-Vel-Tum (OK), 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 (shallower than 3,000 ft or having oil gravities between 17.5^o and 25 ^{o}API). In this study, there is one Mid-Continent region oil reservoir that is considered for immiscible flooding, Sleepy Hollow, NE.

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

Table 7. Matching of CO_2-EOR Technology With Mid-Continent Region's Oil Reservoirs

CO_2-EOR Technology Selection	Oil Reservoir Selection
"Traditional Practices"; Miscible CO_2-EOR	▪ 96 Deep, Light Oil Reservoirs
"State-of-the-art"; Miscible and Immiscible CO_2-EOR	▪ 96 Deep, Light Oil Reservoirs ▪ 1 Deep, Moderately Heavy Oil Reservoirs

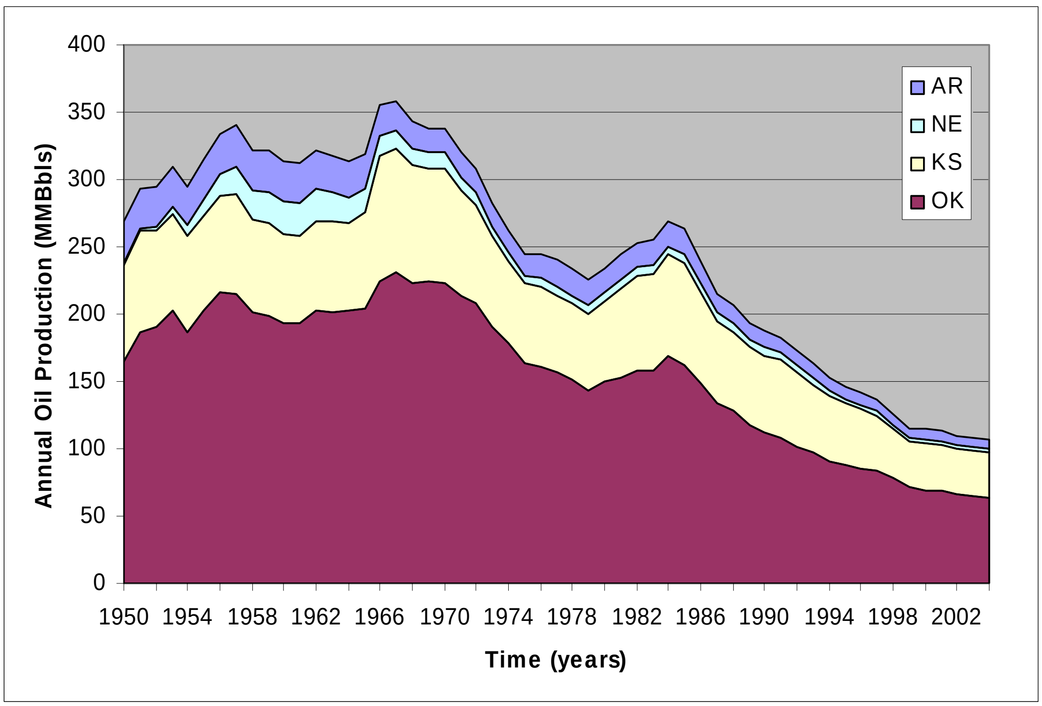
2.6 OTHER ISSUES. This study draws on a series of sources for basic data on the reservoir properties and the expected technical and economic performance of CO_2-EOR in the Mid-Continent region's major oil reservoirs. Because of confidentiality and proprietary issues, reservoir-level data and results 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 results reported in this study.

3. OVERVIEW OF MID-CONTINENT REGION OIL PRODUCTION

3.1 HISTORY OF OIL PRODUCTION. Oil production in the Mid-Continent region began before 1900, reaching its latest peak in 1967, Figure 5. Since then oil production has declined, despite secondary recovery attempts and waterflooding applications in many of the large and aging oil fields. Oil production in 2004 dropped to 107 million barrels (293,000 barrels per day), down from the region's peak in 1967 of 358 million barrels.

- Arkansas, with 6.7 million barrels of oil produced in 2004, has seen oil production decline in the last 30 years.
- Nebraska, with 2.5 million barrels of oil produced in 2004, has also seen a decline in oil production after reaching a peak in the mid-1960's.
- Kansas, with 33.9 million barrels of oil produced in 2004, has seen a decline in oil production after reaching a second production peak in the 1980's.
- Oklahoma, with 63.8 million barrels of oil produced in 2004, has seen a decline in its oil production since the 1960's.

Figure 5. Mid-Continent Historical Oil Production since 1950



However, the Mid-Continent region still holds a rich resource of oil in the ground. With more than 90 billion barrels of original oil in place (OOIP) and approximately 24 billion barrels expected to be recovered, 66 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 8 presents the status and latest annual oil production for the ten largest the Mid-Continent region oil fields that account for 22% of the oil production in this region. Restoring the level of oil production in the large Mid-continent region's oil field could be attained by applying enhanced oil recovery technology, particularly CO_2-EOR.

Table 8. Crude Oil Annual Production, Ten Largest Mid-Continent Region Oil Fields, 2001-2003 (Million Barrels per Year)

Major Oil Fields	2001	2002	2003	Production Status
Sho-Vel-Tum (OK)	7.8	7.8	7.9	Stable
Oklahoma City (OK)	0.6	0.6	0.6	Stable
Sooner Trend (OK)	2.2	1.7	1.6	Declining
Smackover (AR)	1.7	1.7	1.7	Stable
Glenn Pool (OK)	0.4	0.4	0.4	Stable
Golden Trend (OK)	2.4	2.2	2.0	Declining
Cushing (OK)	1.0	1.1	1.1	Stable
Earlsboro (OK)	0.1	0.1	0.1	Stable
El Dorado (KS)	0.6	0.6	0.6	Stable
Fitts (OK)	1.6	1.6	1.7	Stable

3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY. The Mid-Continent region's oil producers are familiar with using technology for improving oil recovery. For example, a large number of oil fields have undergone or are currently under waterflood recovery. Also, significant efforts are underway in several Mid-Continent region oil fields, such as Lick Creek (AR), Hall-Gurney (KS), Postle (OK), Northeast Purdy (OK) and Bradley Unit (OK) in applying CO_2 for enhanced oil recovery. Additional discussion of the experience with CO_2-EOR in the Mid-Continent region is provided in Chapter 6.

3.3 THE "STRANDED OIL" PRIZE. Even though the Mid-Continent region's oil production is declining, this does not mean that the resource base is depleted. The oil producing regions of the Mid-Continent region will still over 70% 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 9 provides information on the oil production history and remaining oil in place of 9 large the Mid-Continent region oil fields, each with estimated ultimate recovery of 300 million barrels or more. Of particular note are the giant light oil fields that may be attractive for miscible CO2-EOR, including: Sho-Vel-Tum with 2,749 million barrels of ROIP, Oklahoma City with 1,843 million barrels of ROIP, Golden Trend with 1,402 million barrels of ROIP, Cushing with 1,113 million barrels of ROIP, Healdton with 682 million barrels of ROIP and Sooner Trend with 1,687 million barrels of ROIP.

Table 9. Selected Major Oil Fields of the Mid-Continent Region

	Field	Year Discovered	Cumulative Production** (MMBbl)	Estimated Reserves** (MMBbl)	Remaining Oil In-Place** (MMBbl)
1	SHO-VEL-TUM (OK)	1905	1,417	63	2,749
2	OKLAHOMA CITY (OK)	1928	754	4	1,843
3	SMACKOVER (AR)	1922	580	12	1,382
4	GOLDEN TREND (OK)	1945	489	23	1,402
5	CUSHING (OK)	1912	458	7	1,113
6	GLENN POOL (OK)no	1905	388	4	1,570
7	HEALDTON (OK)	1913	345	7	682
8	SOONER TREND (OK)	1938	317	12	1,687
9	EL DORADO (KS)	1915	305	4	1,085

**Cumulative oil production and reserves do not include CO_2-EOR.*
*** Arkansas and Kansas as of 2003, Oklahoma data as of 2002.*

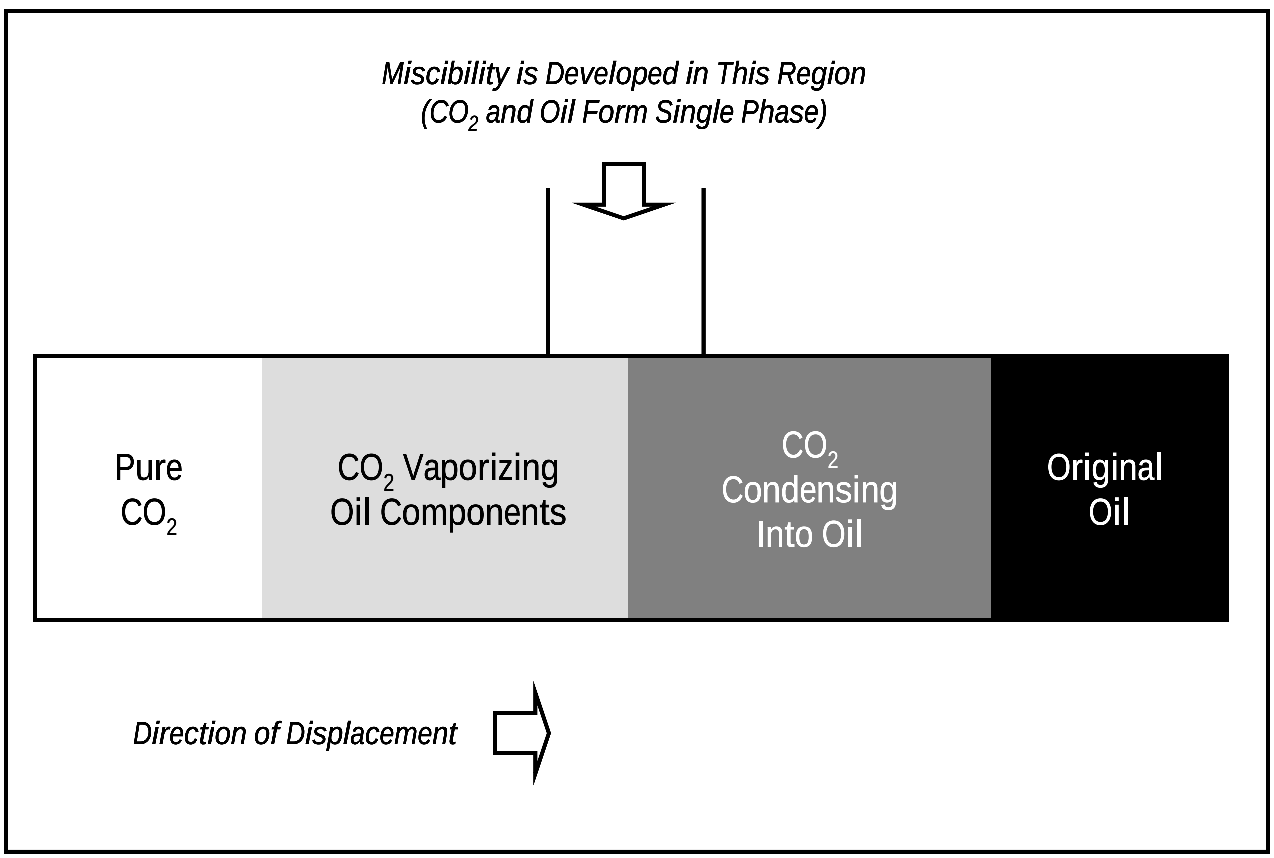
3.4 REVIEW OF PRIOR STUDIES. No recent studies of the potential for CO2 enhanced oil recovery in the Mid-Continent region oil reservoirs have been conducted since the National Petroleum Council's efforts in 1984 and 1976. These studies were conducted for the United States as a whole and do not contain results by state.

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



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 residual oil mobilization) that occurs from: (1) CO_2 injection into a West Texas light reservoir oil; and, (2) CO_2 injection into a very heavy (12 ^{o}API) oil reservoir in Turkey. Laboratory work on the Bradford Field (Pennsylvania) oil reservoir showed that the injection of CO_2, at 800 psig, increased the volume of the reservoir's oil by 50%. Similar laboratory work on Mannville "D" Pool (Canada) reservoir oil showed that the injection of 872 scf of CO_2 per barrel of oil (at 1,450 psig) increased the oil volume by 28%, for crude oil already saturated with methane.

Viscosity reduction is a second important oil recovery mechanism, particularly for immiscible CO_2-EOR. Figure 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).

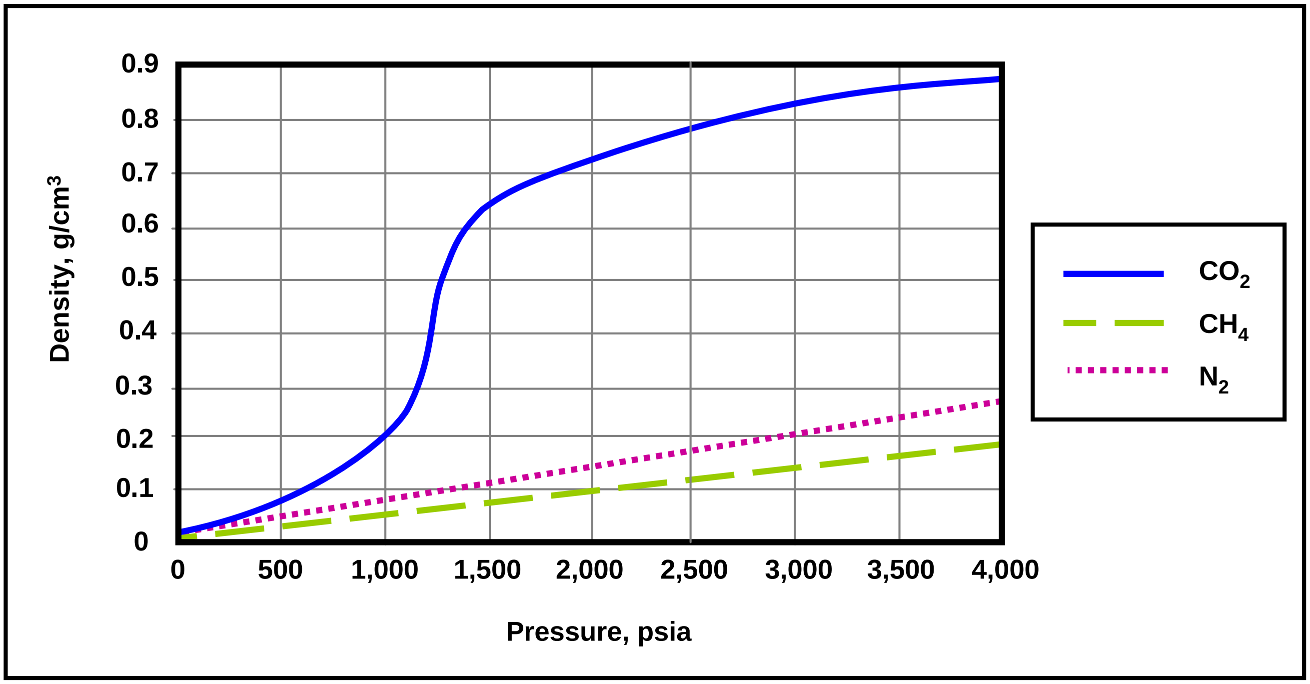


Figure 7B. Carbon Dioxide, CH_4 and N_2 viscosities at 105^0F. At high pressures, the viscosity of CO_2 is also greater then that of methane or nitrogen, although it remains low in comparison to that of liquids. Viscosities were calculated with an EOS.

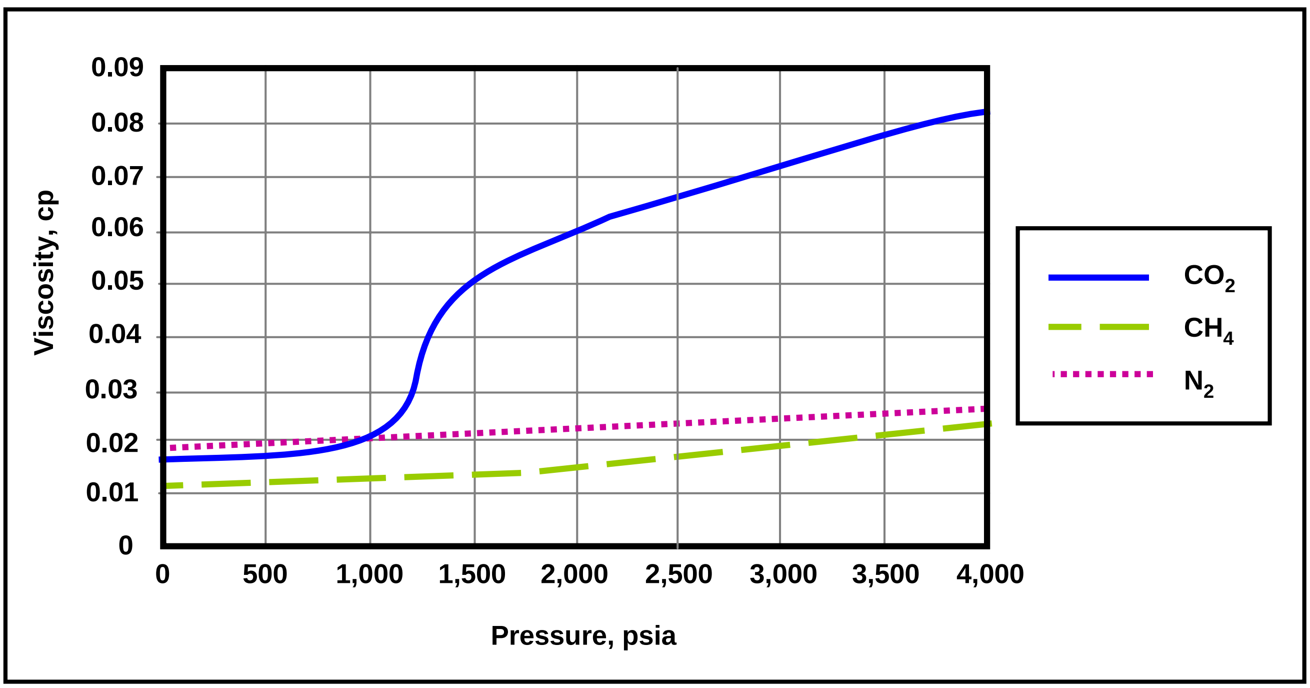


Figure 8A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid (Holm and Josendal).

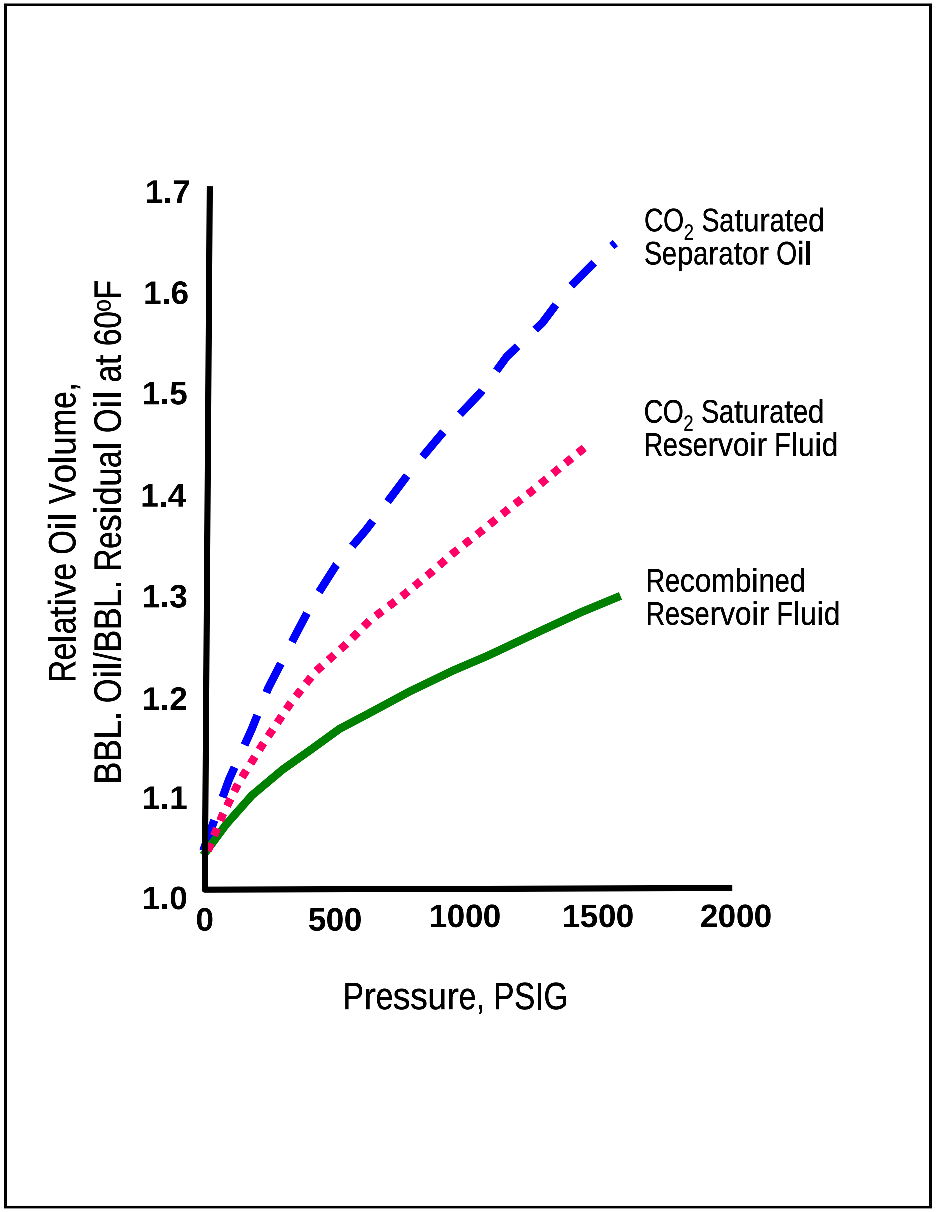


Figure 8B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

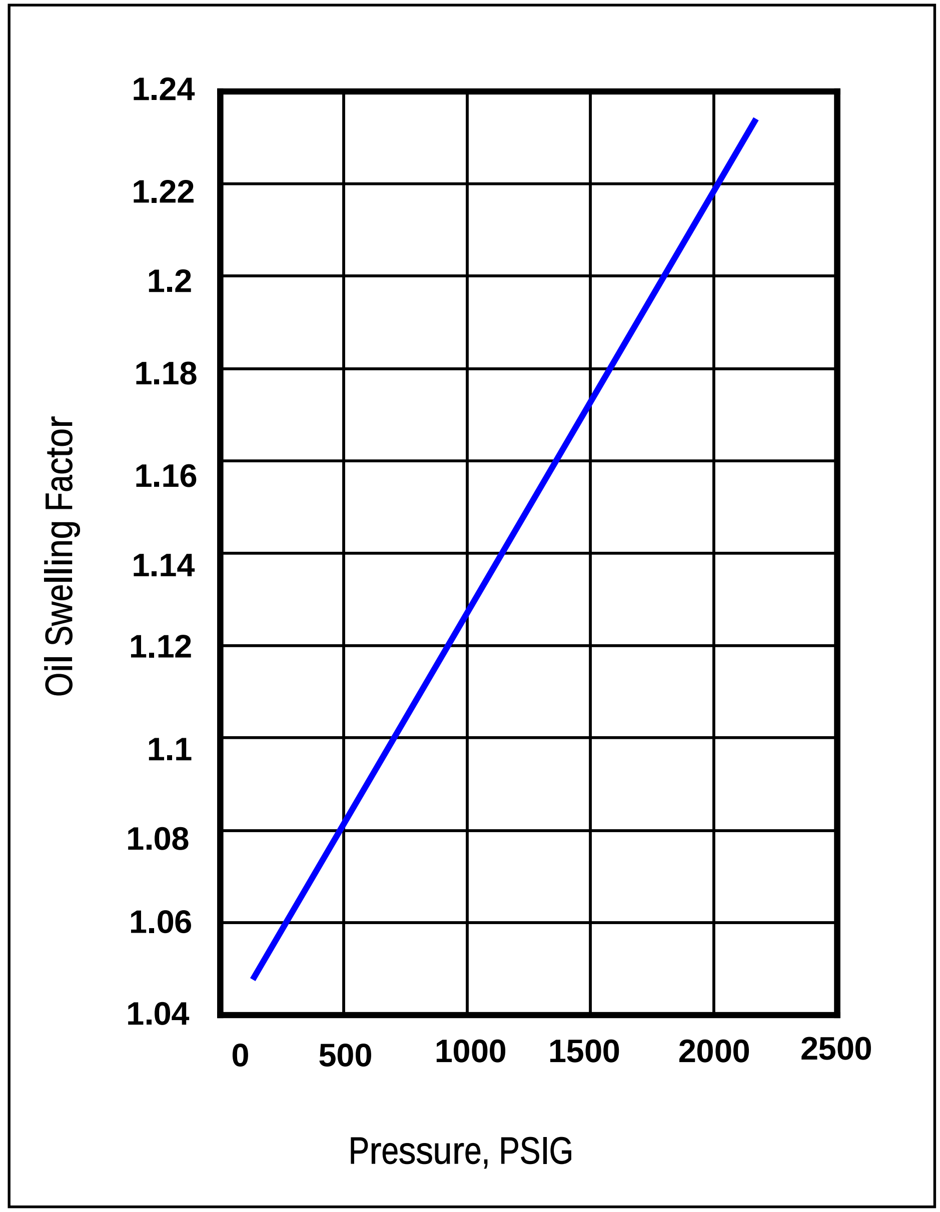
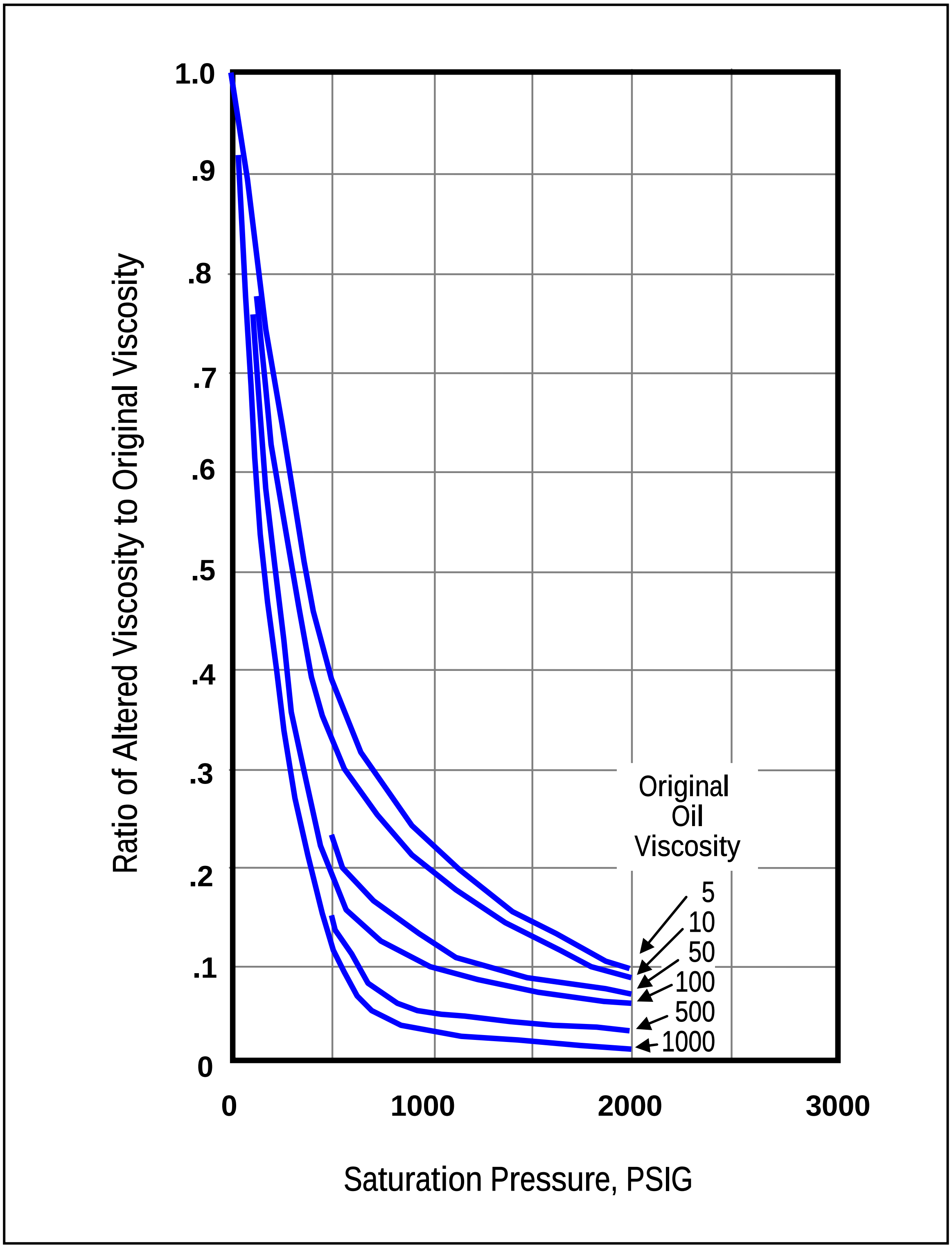


Figure 9. Viscosity Reduction Versus Saturation Pressure. (Simon and Graue).



5. STUDY METHODOLOGY

5.1 OVERVIEW. A six part methodology was used to assess the CO_2-EOR potential of the Mid-Continent region's oil reservoirs. The seven steps were: (1) assembling the Mid-Continent Region 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; and, (6) performing economic and 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 Mid-Continent Region Oil Reservoirs Data Base.

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 Mid-Continent Region Major Oil Reservoirs Data Base contains 222 reservoirs, accounting for 59% of the oil expected to be ultimately produced in Oklahoma by primary and secondary oil recovery processes.

Table 10. 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	

JAF2004005.XLS

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 Mid-Continent region; (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 ^oAPI was used to ensure the reservoir's oil had sufficient mobility. 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 11. Mid-Continent Region Oil Reservoirs Screened Acceptable for CO_2-EOR

State	Field	Formation
A. Arkansas		
Arkansas	FOUKE	PALUXY - TUSCALOOSA
Arkansas	MAGNOLIA	SMACKOVER
Arkansas	MIDWAY	SMACKOVER
Arkansas	SCHULER	COTTON VALLEY
Arkansas	SCHULER	JONES
Arkansas	WESSON	HOGG
B. Nebraska		
Nebraska	HARRISBURG	D-J SAND
Nebraska	SLEEPY HOLLOW	B PENNSYLVANIAN SAND - LANSING KANSAS CITY- G SAND
Nebraska	SLEEPY HOLLOW	REAGAN
C. Kansas		
Kansas	BARRY	ARBUCKLE
Kansas	BEMIS-SHUTTS	ARBUCKLE AND OTHERS
Kansas	BLOOMER	ARBUCKLE LANSING K C
Kansas	CHASE-SILICA	ARBUCKLE
Kansas	CUNNINGHAM	LANSING-KANSAS CITY
Kansas	DAMME	PENNSYLVANIAN AND MISSISSIPIAN
Kansas	FAIRPORT	ARBUCKLE
Kansas	GENESEO	ARBUCKLE
Kansas	GORHAM	ARBUCKLE
Kansas	HOLLOW-NIKKEL	HUNTON
Kansas	INTERSTATE	UPPER MORROW-PURDY
Kansas	IUKA-CARMI	SIMPSON
Kansas	KRAFT-PRUSA	ARBUCKLE ETC
Kansas	MARCOTTE	ARBUCKLE
Kansas	MOREL	ARBUCKLE
Kansas	MOREL	LANSING KANSAS CITY AND CONG
Kansas	PLEASANT PRAIRIE	MISSISSIPPI
Kansas	RAINBOW BEND	BURGESS
Kansas	RAY	REAGAN
Kansas	RUSSELL	ARBUCKLE AND LANS KC
Kansas	SPIVEY-GRABS-BASIL	OSAGE CHERT
Kansas	STOLTENBERG	ARBUCKLE
Kansas	TRAPP	ARBUCKLE
Kansas	VOSHELL	ARBUCKLE
Kansas	WILBURTON	MORROWAN
D. Oklahoma		
Oklahoma	ALLEN DISTRICT	CROMWELL, HUNTON, BROMIDE

Table 11. Mid-Continent Region Oil Reservoirs Screened Acceptable for CO_2-EOR

State	Field	Formation
Oklahoma	ANTIOCH,SOUTHWEST	DEESE
Oklahoma	APACHE	BROMIDE
Oklahoma	AYLESWORTH	MISENER AND OTHERS
Oklahoma	BINGER	NOVEMBERAND
Oklahoma	BOWLEGS	ALL
Oklahoma	CAMRICK DISTRICT	MORROW
Oklahoma	CARTHAGE DISTRICT	MORROW
Oklahoma	CEMENT	HOXBAR
Oklahoma	CEMENT	PERMIAN & HOXBAR
Oklahoma	CHEROKITA TREND	CHEROKEE
Oklahoma	CHEYENNE VALLEY	CV CHEROKEE
Oklahoma	CHEYENNE VALLEY	RED FORK
Oklahoma	CHICKASHA	NOVEMBERAND
Oklahoma	CHICKASHA	NOBLE-OLSON
Oklahoma	CROMWELL	VARIOUS PENNSYLVANIAN
Oklahoma	CUMBERLAND	MCLISH-BROMIDE
Oklahoma	CUSHING	OTHER SANDS
Oklahoma	EARLSBORO	EARLSBORO
Oklahoma	EDMOND WEST	HUNTON
Oklahoma	EDMOND WEST	PENN SANDS
Oklahoma	EDMOND WEST	SIMPSON AND WILCOX 2
Oklahoma	ELK CITY	HOXBAR
Oklahoma	EOLA ROBBERSON	SIMPSON
Oklahoma	FITTS	HUNTON
Oklahoma	FITTS	SIMPSON & VIOLA
Oklahoma	FITTS WEST	VIOLA
Oklahoma	GOLDEN TREND	BROMIDE AND DEEP SS
Oklahoma	GOLDEN TREND	DEESE AND PENN SS
Oklahoma	GOLDEN TREND	HUNTON-VIOLA
Oklahoma	HEALDTON	ARBUCKLE
Oklahoma	KEOKUK	MISENER-HUNTON
Oklahoma	KNOX	PONTOTOC-HOXBAR-DEESE
Oklahoma	LITTLE RIVER	CROMWELL
Oklahoma	LITTLE RIVER	WILCOX
Oklahoma	MAUD	HUNTON
Oklahoma	MISSION	HUNTON
Oklahoma	MUSTANG NORTH	HUNTON BOIS D'ARC
Oklahoma	OAKDALE	RED FORK
Oklahoma	OKLAHOMA CITY	LOWER SIMPSON
Oklahoma	OKLAHOMA CITY	PENNSYLVANIAN
Oklahoma	OKLAHOMA CITY	WILCOX

Table 11. Mid-Continent Region Oil Reservoirs Screened Acceptable for CO_2-EOR

State	Field	Formation
Oklahoma	PAPOOSE	CROMWELL
Oklahoma	PAULS VALLEY	BASAL PENNSYLVANIAN
Oklahoma	PAULS VALLEY, EAST	BURNS-BRUNDIDGE
Oklahoma	POSTLE	MORROW
Oklahoma	PUTNAM	OSWEGO
Oklahoma	RINGWOOD	MANNING
Oklahoma	SEMINOLE	WILCOX & OTHER SANDS
Oklahoma	SHO-VEL-TUM	DEESE
Oklahoma	SHO-VEL-TUM	DORNICK-SPRINGER
Oklahoma	SHO-VEL-TUM	SYCAMORE
Oklahoma	SOONER TREND	HUNTON
Oklahoma	SOONER TREND	LAYTON AND OTHERS
Oklahoma	SOONER TREND	MANNING AND CHESTER
Oklahoma	SOONER TREND	MERAMEC
Oklahoma	SOUTH LONE ELM	CLEVELAND SAND
Oklahoma	ST LOUIS	ALL
Oklahoma	TONKAWA	WILCOX
Oklahoma	WASHINGTON	OSBORNE
Oklahoma	WATONGA TREND	MORROW
Oklahoma	WEST SEMINOLE	WILCOX
Oklahoma	WEWOKA DISTRICT	CROMWELL

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.

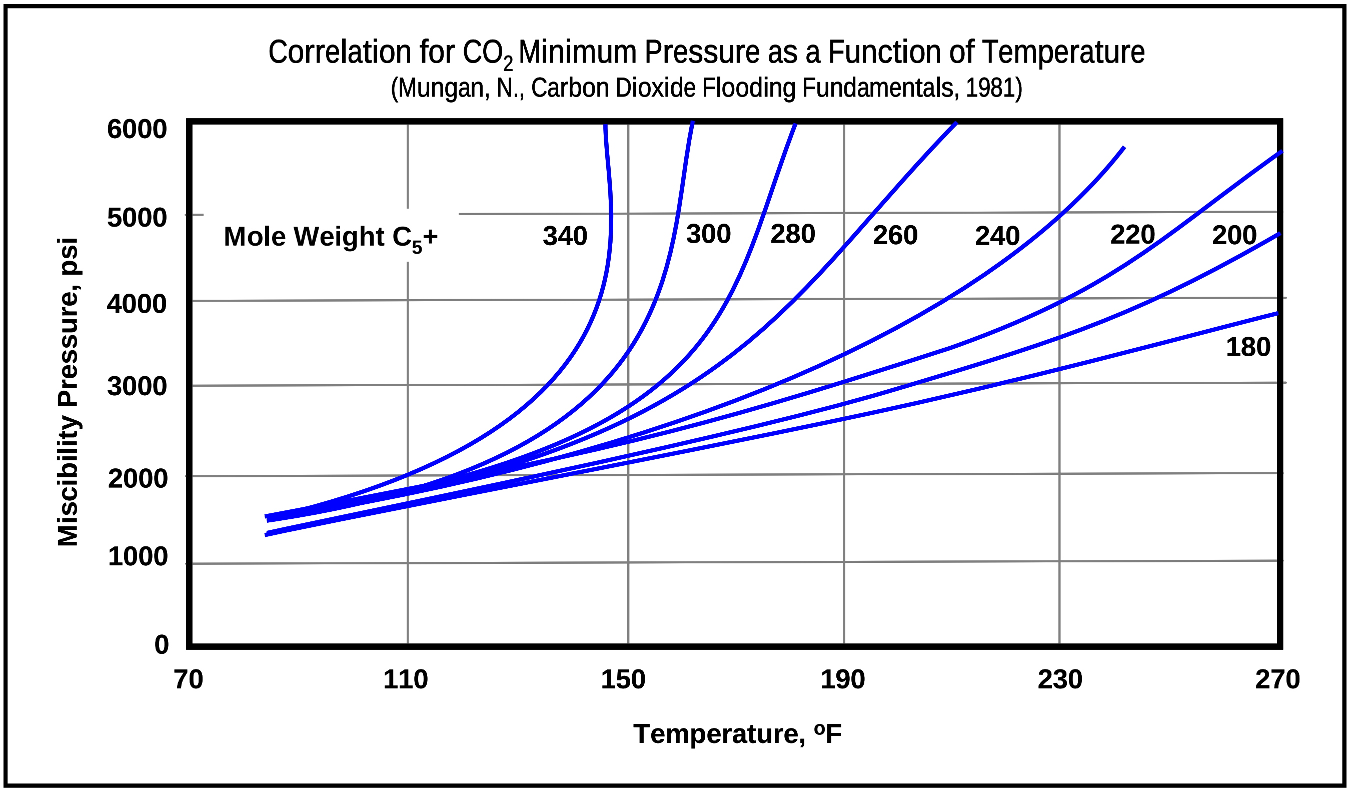
To determine the minimum miscibility pressure (MMP) for any given reservoir, the study used the Cronquist correlation, Figure 10. This formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, without considering the mole percent of methane.

(Most Mid-Continent region 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 °F, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

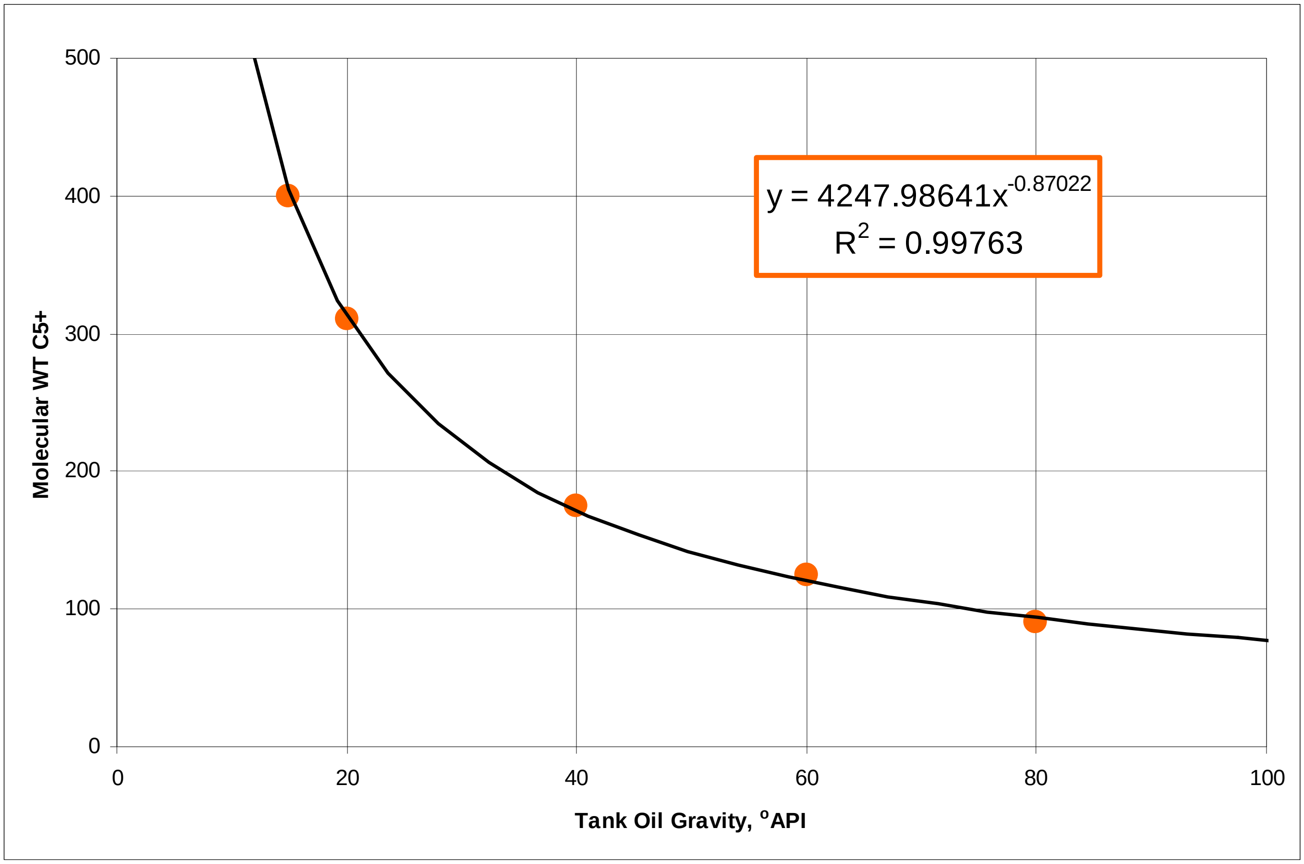
Figure 10. Estimating CO_2 Minimum Miscibility Pressure



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
(modified from: Mungan, N., Carbon Dioxide Fundamentals, 1981)



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

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

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

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

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

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

5.7 CONSTRUCTING AN ECONOMICS MODEL. The economic model used by the study is an industry standard cash flow model that can be run on either a pattern or a field-wide basis. The economic model accounts for royalties, severance and ad valorem taxes, as well as any oil gravity and market location discounts (or premiums) from the “marker” oil price. A variety of oil prices are available to the model user. Table 11 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 Mid-Continent region’s 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 CO_2-EOR options — “Traditional Practices” and “State-of-the-art” Technology.

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

- <u>Two CO_2 supply costs were considered.</u> The high CO_2 cost was set at 5% of the oil price ($1.50 per Mcf at $30 per barrel) to represent the costs of a new transportation system bringing natural CO_2 to the Mid-Continent region’s oil fields. A lower CO_2 supply cost equal to 2% of the oil price ($0.60 per Mcf at $30 per barrel) was included to represent the potential future availability of low-cost CO_2 from industrial and power plants as part of CO_2 storage.

- <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, CO_2 supply cost, and rate of return hurdles were combined into four scenarios, as set forth below:

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

Table 12. Economic Model Established by the Study

Pattern-Level Cashflow Model		**Advanced Technology**											
State				New Injectors	0.90								
Field				Existing Injectors	0.10			1					
Formation				Converted Producers	0.00								
Depth				New Producers	1.1								
Distance from Trunkline (mi)				Existing Producers	0.12								
# of Patterns				Disposal Wells	0.00								
Miscibility:	**Miscible**												
	Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
CO_2 Injection (MMcf)			-	731	731	731	731	731	731	731	731	728	656
H_2O Injection (Mbw)			548	183	183	183	183	183	183	183	183	184	220
Oil Production (Mbbl)			-	135	175	101	64	11	12	12	15	25	39
H_2O Production (MBw)			-	360	128	127	148	174	203	204	203	197	202
CO_2 Production (MMcf)			-	1	439	618	657	723	656	652	648	638	602
CO_2 Purchased (MMcf)			-	730	292	112	74	8	75	78	83	90	54
CO_2 Recycled (MMcf)			-	1	439	618	657	723	656	652	648	638	602
Oil Price ($/Bbl)	**$ 30.00**		$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Gravity Adjustment	**35**	Deg	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75
Gross Revenues ($M)			$ -	$ 3,873	$ 5,023	$ 2,889	$ 1,849	$ 328	$ 333	$ 351	$ 434	$ 713	$ 1,127
Royalty ($M)	**-12.5%**		$ -	$ (484)	$ (628)	$ (361)	$ (231)	$ (41)	$ (42)	$ (44)	$ (54)	$ (89)	$ (141)
Severance Taxes ($M)	**-7.0%**		$ -	$ (237)	$ (308)	$ (177)	$ (113)	$ (20)	$ (20)	$ (21)	$ (27)	$ (44)	$ (69)
Ad Valorum ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ -	$ 3,151	$ 4,087	$ 2,351	$ 1,504	$ 267	$ 271	$ 285	$ 353	$ 580	$ 917
Capital Costs ($M)													
New Well - D&C		$ (456)											
Reworks - Producers to Producers		$ (7)											
Reworks - Producers to Injectors		$ -											
Reworks - Injectors to Injectors		$ (6)											
Surface Equipment (new wells only)		$ (157)											
CO_2 Recycling Plant		$ -	$ (1,279)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (21)											
Total Capital Costs		$ (646)	$ (1,279)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	**0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO_2 Costs ($M)													
Total CO_2 Cost ($M)			$ -	$ (1,095)	$ (569)	$ (354)	$ (308)	$ (229)	$ (309)	$ (313)	$ (319)	$ (327)	$ (262)
O&M Costs													
Operating & Maintenance ($M)			$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)
Lifting Costs ($/bbl)	**$ 0.25**		$ -	$ (124)	$ (76)	$ (57)	$ (53)	$ (46)	$ (54)	$ (54)	$ (54)	$ (56)	$ (60)
G&A	**20%**		(12)	(37)	(27)	(23)	(23)	(21)	(23)	(23)	(23)	(23)	(24)
Total O&M Costs			$ (73)	$ (221)	$ (163)	$ (141)	$ (136)	$ (128)	$ (137)	$ (138)	$ (138)	$ (139)	$ (145)
Net Cash Flow ($M)		$ (646)	$ (1,352)	$ 1,835	$ 3,354	$ 1,857	$ 1,060	$ (90)	$ (174)	$ (165)	$ (103)	$ 114	$ 510
Cum. Cash Flow		$ (646)	$ (1,998)	$ (163)	$ 3,191	$ 5,048	$ 6,108	$ 6,018	$ 5,844	$ 5,679	$ 5,575	$ 5,689	$ 6,200
Discount Factor	**25%**	1.00	0.80	0.64	0.51	0.41	0.33	0.26	0.21	0.17	0.13	0.11	0.09
Disc. Net Cash Flow		$ (646)	$ (1,082)	$ 1,175	$ 1,717	$ 760	$ 347	$ (24)	$ (37)	$ (28)	$ (14)	$ 12	$ 44
Disc. Cum Cash Flow		$ (646)	$ (1,728)	$ (553)	$ 1,164	$ 1,925	$ 2,272	$ 2,248	$ 2,212	$ 2,184	$ 2,170	$ 2,182	$ 2,226
NPV (BTx)	25%	$2,336											
NPV (BTx)	20%	$ 2,905											
NPV (BTx)	15%	$ 3,654											
NPV (BTx)	10%	$ 4,686											
IRR (BTx)		78.37%											

Table 12. 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**	**26**
CO2 Injection (MMcf)		656	656	656	656	656	656	656	656	656	656	656	656	656	626	-
H2O Injection (Mbw)		220	220	220	220	220	220	220	220	220	220	220	220	220	235	548
Oil Production (Mbbl)		44	38	33	30	25	24	23	21	18	18	19	18	15	11	8
H2O Production (MBw)		211	208	205	203	208	211	211	209	214	213	212	211	217	218	312
CO2 Production (MMcf)		571	592	610	623	624	620	622	632	627	629	628	632	627	637	523
CO2 Purchased (MMcf)		85	64	46	34	32	37	34	25	29	27	29	25	29	-	-
CO2 Recycled (MMcf)		571	592	610	623	624	620	622	632	627	629	628	632	627	626	-
Oil Price ($/Bbl)	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Gravity Adjustment	35	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75	$ 28.75
Gross Revenues ($M)		$ 1,271	$ 1,090	$ 954	$ 863	$ 725	$ 690	$ 667	$ 592	$ 518	$ 509	$ 546	$ 529	$ 437	$ 319	$ 241
Royalty ($M)	-12.5%	$ (159)	$ (136)	$ (119)	$ (108)	$ (91)	$ (86)	$ (83)	$ (74)	$ (65)	$ (64)	$ (68)	$ (66)	$ (55)	$ (40)	$ (30)
Severance Taxes ($M)	-7.0%	$ (78)	$ (67)	$ (58)	$ (53)	$ (44)	$ (42)	$ (41)	$ (36)	$ (32)	$ (31)	$ (33)	$ (32)	$ (27)	$ (20)	$ (15)
Ad Valorum ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 1,034	$ 887	$ 777	$ 702	$ 590	$ 561	$ 543	$ 482	$ 421	$ 414	$ 445	$ 430	$ 356	$ 260	$ 197
Capital Costs ($M)																
New Well - D&C																
Reworks - Producers to Producers																
Reworks - Producers to Injectors																
Reworks - Injectors to Injectors																
Surface Equipment (new wells only)																
CO2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction																
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)																
Total CO2 Cost ($M)		$ (299)	$ (274)	$ (252)	$ (237)	$ (235)	$ (241)	$ (238)	$ (226)	$ (231)	$ (229)	$ (231)	$ (226)	$ (231)	$ (188)	$ -
O&M Costs																
Operating & Maintenance ($M)		$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)	$ (61)
Lifting Costs ($/bbl)	$ 0.25	$ (64)	$ (62)	$ (60)	$ (58)	$ (58)	$ (59)	$ (58)	$ (57)	$ (58)	$ (58)	$ (58)	$ (57)	$ (69)	$ (66)	$ (86)
G&A	20%	(25)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(26)	(25)	(29)
Total O&M Costs		$ (149)	$ (146)	$ (144)	$ (143)	$ (142)	$ (143)	$ (143)	$ (142)	$ (142)	$ (142)	$ (142)	$ (142)	$ (156)	$ (151)	$ (176)
Net Cash Flow ($M)		$ 586	$ 467	$ 381	$ 322	$ 212	$ 178	$ 162	$ 114	$ 48	$ 43	$ 71	$ 63	$ (32)	$ (80)	$ 20
Cum. Cash Flow		$ 6,786	$ 7,253	$ 7,633	$ 7,955	$ 8,167	$ 8,344	$ 8,507	$ 8,620	$ 8,668	$ 8,711	$ 8,782	$ 8,845	$ 8,813	$ 8,734	$ 8,754
Discount Factor	25%	0.07	0.05	0.04	0.04	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Disc. Net Cash Flow		$ 40	$ 26	$ 17	$ 11	$ 6	$ 4	$ 3	$ 2	$ 1	$ 0	$ 1	$ 0	$ (0)	$ (0)	$ 0
Disc. Cum Cash Flow		$ 2,267	$ 2,292	$ 2,309	$ 2,320	$ 2,326	$ 2,330	$ 2,333	$ 2,335	$ 2,335	$ 2,336	$ 2,336	$ 2,337	$ 2,337	$ 2,336	$ 2,336
NPV (BTx)	25%															
NPV (BTx)	20%															
NPV (BTx)	15%															
NPV (BTx)	10%															
IRR (BTx)																

Table 12. 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	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**
CO2 Injection (MMcf)		-	-	-	-	-	-	-	-	-	-
H2O Injection (Mbw)		548	305	-	-	-	-	-	-	-	-
Oil Production (Mbbl)		6	3	-	-	-	-	-	-	-	-
H2O Production (MBw)		458	264	-	-	-	-	-	-	-	-
CO2 Production (MMcf)		191	87	-	-	-	-	-	-	-	-
CO2 Purchased (MMcf)		-	-	-	-	-	-	-	-	-	-
CO2 Recycled (MMcf)		-	-	-	-	-	-	-	-	-	-
Oil Price ($/Bbl)	**$ 30.00**	$ 30.00	$ 30.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gravity Adjustment	**35**	$ 28.75	$ 28.75	$ (1.25)	$ (1.25)	$ (1.25)	$ (1.25)	$ (1.25)	$ (1.25)	$ (1.25)	$ (1.25)
Gross Revenues ($M)		$ 175	$ 89	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Royalty ($M)	**-12.5%**	$ (22)	$ (11)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Severance Taxes ($M)	**-7.0%**	$ (11)	$ (5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 143	$ 73	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Costs ($M)											
New Well - D&C											
Reworks - Producers to Producers											
Reworks - Producers to Injectors											
Reworks - Injectors to Injectors											
Surface Equipment (new wells only)											
CO2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction											
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	**0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)											
Total CO2 Cost ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M Costs											
Operating & Maintenance ($M)		$ (61)	$ (61)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($/bbl)	**$ 0.25**	$ (121)	$ (69)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
G&A	**20%**	(36)	(26)	-	-	-	-	-	-	-	-
Total O&M Costs		$ (217)	$ (156)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Cash Flow ($M)		$ (75)	$ (83)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cum. Cash Flow		$ 8,679	$ 8,596	$ 8,596	$ 8,596	$ 8,596	$ 8,596	$ 8,596	$ 8,596	$ 8,596	$ 8,596
Discount Factor	**25%**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Disc. Net Cash Flow		$ (0)	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Disc. Cum Cash Flow		$ 2,336	$ 2,336	$ 2,336	$ 2,336	$ 2,336	$ 2,336	$ 2,336	$ 2,336	$ 2,336	$ 2,336
NPV (BTx)	25%										
NPV (BTx)	20%										
NPV (BTx)	15%										
NPV (BTx)	10%										
IRR (BTx)											

6. RESULTS BY STATE

6.1 ARKANSAS. Crude oil production in Arkansas began in 1920, reaching a peak in 1948 of 32 MMBbls, and has provided a cumulative recovery of over 1.7 billion barrels of oil to date. In 2004, Arkansas ranked 19th in production in the onshore U.S., producing 6.7 MMBbls of oil (18 MBbls per day) from 6,660 producing wells, and 16th in reserves at 53 MMBbls, Table 13. (The state contains 2 petroleum refineries with a crude oil distillation capacity of over 70 MBbls/day.)

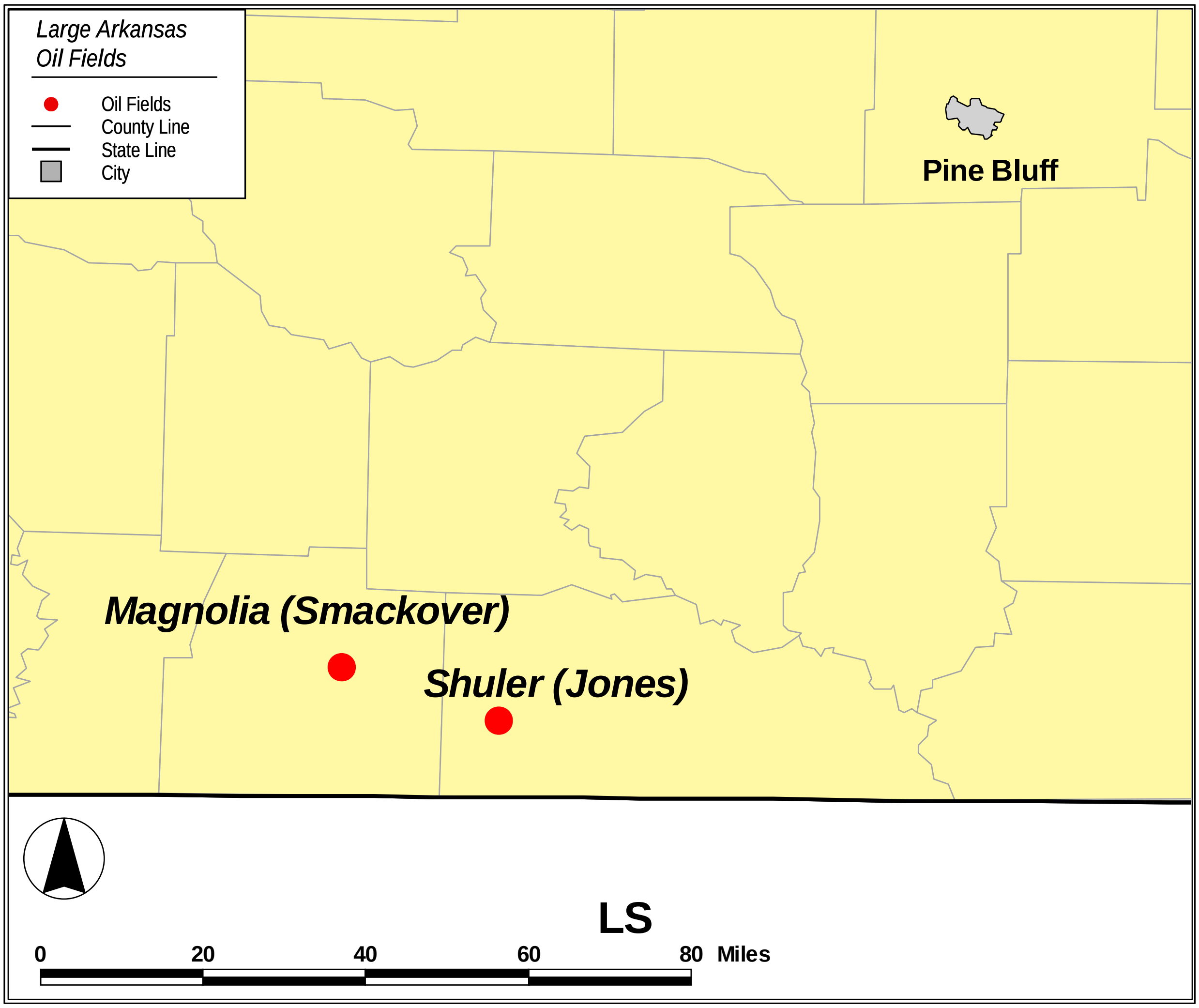
Table 13. Recent History of Arkansas Oil Production

	Annual Oil Production	
	(MMBl/Yr)	(MBbl/d)
2000	7.4	20
2001	7.6	21
2002	7.3	20
2003	7.2	20
2004	6.7	18

Arkansas Oil Fields. To better understand the potential of using CO_2-EOR in Arkansas' light oil fields, this section examines, in more depth, two large fields, shown in Figure 12. These include:

- Magnolia (Smackover Reservoir)
- Schuler (Jones Reservoir)

Figure 12. Large Arkansas Oil Fields



These two fields 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 two light oil fields are set forth in Table 14.

Table 14. Status of Large Arkansas Oil Fields/Reservoirs (as of 2003)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Magnolia (Smackover)	430	169	2	257
2	Schuler (Jones)	220	83	1	136

These two large oil fields, each with over 130 million barrels of ROIP, appear to be favorable for miscible CO_2 -EOR, based on their reservoir properties, Table 15.

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

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (^oAPI)	Active Waterflood or Gas Injection
1	Magnolia (Smackover)	7,500	38	Undergoing waterflooding
2	Schuler (Jones)	7,530	34	Undergoing waterflooding

Past and On-Going CO_2-EOR Projects. An immiscible CO_2-EOR project in Arkansas has been conducted in the Lick Creek oil field.

Lick Creek Field. In 1976, a CO_2/waterflooding project was initiated by Phillips Petroleum Co. The goal of the project was to demonstrate the viability of the immiscible CO_2/wateflood process as a secondary recovery option for thin, heavy oil sands like the Meakin Sandstone. The CO_2/waterflooding project for the Lick Creek field was conducted in four phases; (1) cycling all wells with CO_2, (2) CO_2 injection into the permanent injectors, (3) CO_2/water injection into the permanent injectors, and (4) water injection into the permanent injectors. Presently the project is in the third phase. Through 1981, 1.07 MMBbls of oil (0.755 MMBbls of which is estimated to be incremental) had been produced from the Meakin Sandstone using immiscible CO_2/waterflooding. The projected total production for the project is estimated at 3.66 MMBbls total oil with 3.09 MMBbls incremental in the 15 years of production.

Future CO_2-EOR Potential. Arkansas contains 6 reservoirs that are candidates for miscible CO_2-EOR.

Under "Traditional Practices" (and current financial conditions, defined above), there are 2 oil reservoirs economically attractive for miscible CO_2 flooding in Arkansas. 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 Arkansas increases to 6, providing 230 million barrels of additional oil recovery, Tables 16 and 17.

Table 16. Economic Oil Recovery Potential Under Current Conditions, Arkansas

CO_2-EOR Technology	No. of Reservoirs	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential	
				(No. of Reservoirs)	(MMBbls)
"Traditional Practices"*	6	1,018	100	2	10
"State of Art Technology"*	6	1,018	230	6	230

Oil price of $30 per barrel.

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

More Favorable Conditions	Technical Potential (MMBbls)	Economic Potential*	
		(No. of Reservoirs)	(MMBbls)
Plus: Risk Mitigation*	230	6	230
Plus: Low Cost CO_2**	230	6	230

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

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

6.2 NEBRASKA. The Nebraska crude oil production reached a peak in production of 25 MMBbls in 1962, and has recovered over 500 MMBbls of oil to date. In 2004, Nebraska ranked 22nd in production in the onshore U.S., producing 2.5 MMBbls of oil (7 MBbls per day) from 1,629 producing wells, and 22nd in reserves at 15 MMBbls, Table 18.

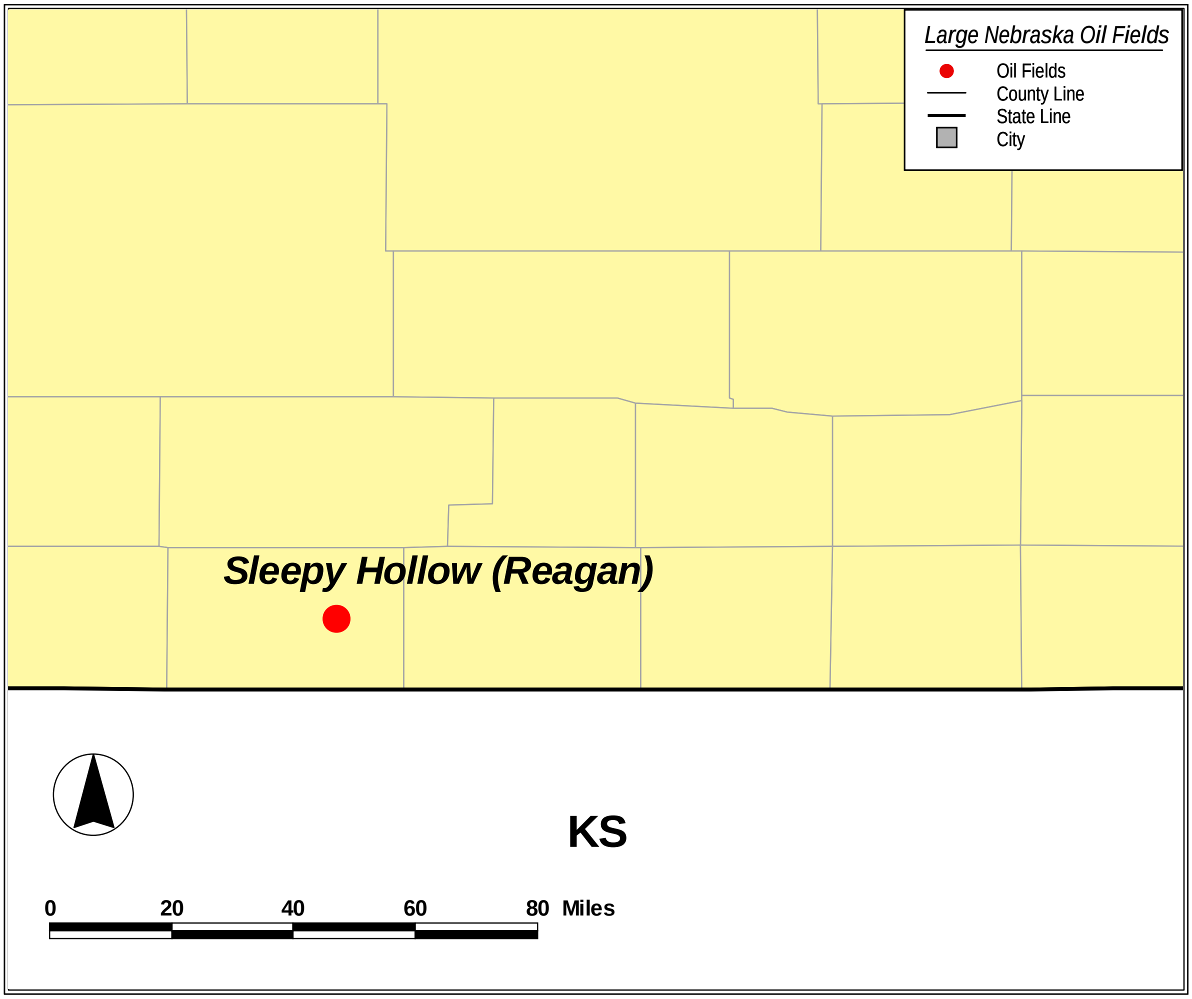
Table 18. Recent History of Nebraska Oil Production

	Annual Oil Production	
	(MMBls/Yr)	(MBbls/d)
2000	3.0	8
2001	2.9	8
2002	2.8	8
2003	2.8	8
2004	2.5	7

Nebraska Oil Fields. To better understand the potential of using CO_2-EOR in Nebraska's light oil fields, this section examines, in more depth, one large field, shown in Figure 13:

- Sleepy Hollow (Reagan Reservoirs)

Figure 13. Large Nebraska Oil Fields



This field could serve as the "anchor" site 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 this light oil field is set forth in Table 19.

Table 19. Status of Large Nebraska Oil Fields/Reservoirs (as of 2001)

Large Fields/Reservoirs		Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Sleepy Hollow (Reagan)	179	44	1	134

This large “anchor” field, with over 100 million barrels of ROIP, appears to be favorable for miscible CO_2 -EOR, based on its reservoir properties, Table 20.

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

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (^oAPI)	Active Waterflood or Gas Injection
1	Sleepy Hollow (Reagan)	10,018	31	Undergoing waterflooding

Past and On-Going CO_2-EOR Projects. There is no CO_2-EOR history in the state of Nebraska. However, due to the similarity in reservoirs, CO_2-EOR projects in Kansas may serve as a guide for future Nebraska EOR projects

Future CO_2-EOR Potential. Nebraska contains two reservoirs that are candidates for miscible CO_2-EOR and one reservoir that is a candidate for immiscible CO_2-EOR.

Under “Traditional Practices” (and current financial conditions, defined above), there are no oil reservoirs economically attractive for miscible CO2 flooding in Nebraska. Applying “State-of-the-art Technology” (involving higher volume CO2 injection) and lower risk financial conditions, the number of economically favorable oil reservoirs in Nebraska increases to three, providing 40 million barrels of additional oil recovery, Tables 21and 22.

Table 21. Economic Oil Recovery Potential Under Current Conditions, Nebraska

CO_2-EOR Technology	No. of Reservoirs	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
“Traditional Practices”*	2	247	20	0	0
“State of Art Technology”*	3	276	40	3	40

Oil price of $30 per barrel.

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

More Favorable Conditions	Technical Potential (MMBbls)	Economic Potential*	
		(No. of Reservoirs)	(MMBbls)
Plus: Risk Mitigation*	40	3	40
Plus: Low Cost CO_2**	40	3	40

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

** CO_2 supply costs, to $0.80/Mcf

6.3 KANSAS. Kansas crude oil production began in 1932, reaching a peak in production in 1966 of 93 MMBbls. The state has cumulative oil recovery of over 6.2 billion barrels of oil to date. In 2004, Kansas ranked 8th in production in the onshore U.S., producing 34 MMBbls of oil (93 MBbls per day) from 6,660 producing wells, and 11th in reserves at 53 MMBbls, Table 23 The state contains 3 petroleum refineries with a crude oil distillation capacity of over 276 MBbls/day.

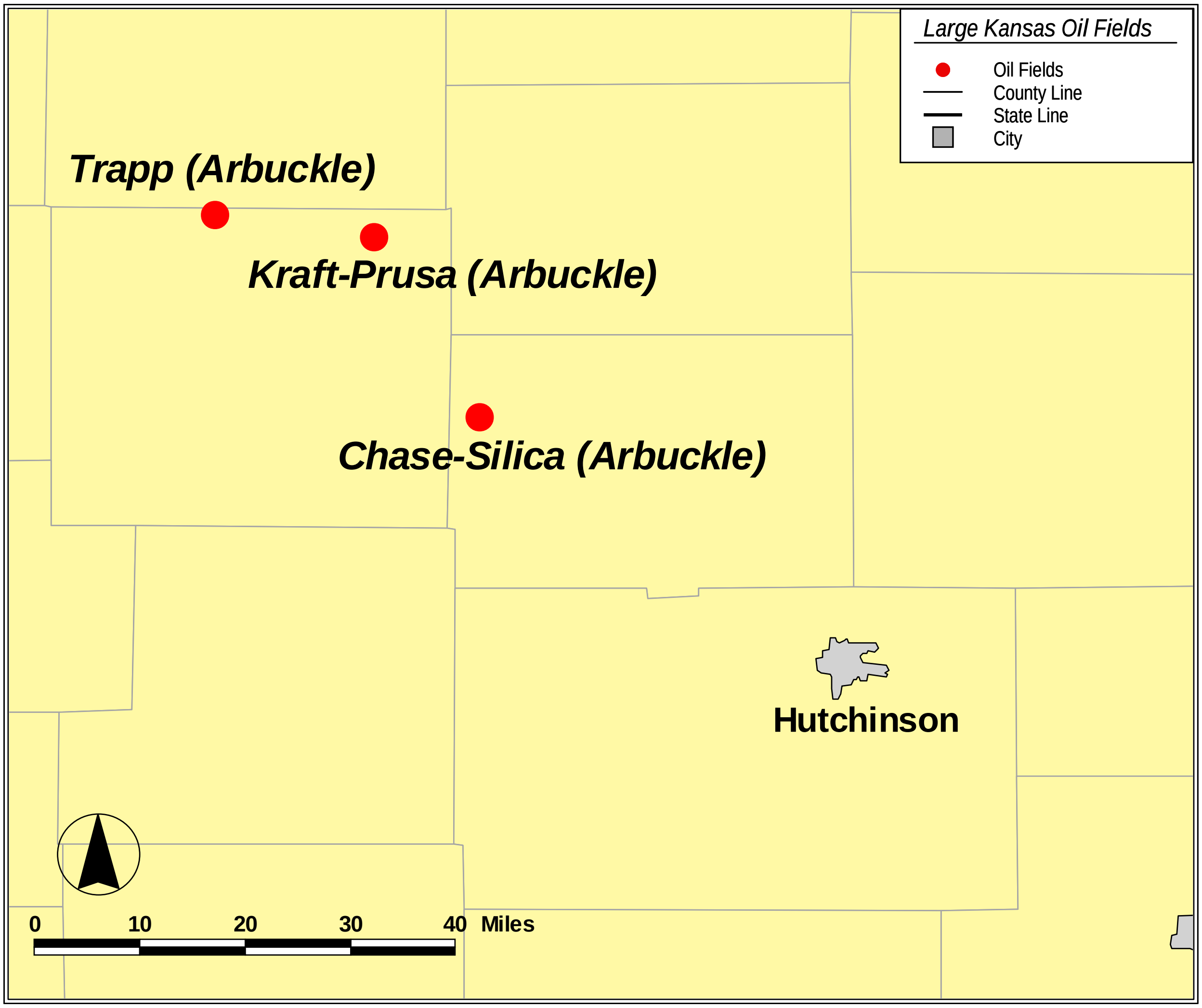
Table 23. Recent History of Kansas Oil Production

	Annual Oil Production	
	(MMBls/yr)	(MBbls/d)
2000	35.2	96
2001	34.1	93
2002	33.4	92
2003	34.0	93
2004	33.9	93

Kansas Oil Fields. To better understand the potential of using CO_2-EOR in Kansas' light oil fields, this section examines, in more depth, three large fields, shown in Figure 14. These include:

- Chase-Silica (Arbuckle Reservoir)
- Kraft-Prusa (Arbuckle etc. Reservoirs)
- Trapp (Arbuckle Reservoir)

Figure 14. Large Kansas Oil Fields



These three fields 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 three light oil fields are set forth in Table 24.

Table 24. Status of Large Kansas Oil Fields/Reservoirs (as of 2004)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Chase-Silica (Arbuckle)	814	278	4	532
2	Kraft-Prusa (Arbuckle etc)	432	135	2	295
3	Trapp (Arbuckle)	777	238	4	535

These three large oil fields, each with 300 or more million barrels of ROIP, appear to be favorable for miscible CO_2 -EOR, based on their reservoir properties, Table 25.

Table 25. Reservoir Properties and Improved Oil Recovery Activity,

Large Kansas Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Chase-Silica (Arbuckle)	3,328	48	Undergoing waterflooding
2	Kraft-Prusa (Arbuckle etc)	3,281	42	Undergoing waterflooding
3	Trapp (Arbuckle)	3,252	40	Undergoing waterflooding

Past and On-Going CO_2-EOR Projects. A CO_2-EOR project is underway at Hall-Gurney Field.

Hall-Gurney Field. A joint DOE-industry CO_2-EOR pilot demonstration is being conducted in the Hall-Gurney field in the Lansing-Kansas City formation C-zone with the goal to demonstrate the potential for EOR. The 10 acre project was initiated in 2000 using one CO_2 injector and two producing wells on a half five spot pattern, with field production beginning in 2003. To date, production has increased slightly from 0 to 3.4 barrels per day. However, a well defined oil bank has yet to arrive at the production wells. Speculation is that the slow apparent response to CO_2 may be due to CO_2 loss from the pattern to the north on the opposite side from the producer wells.

***Future CO_2-EOR Potential*.** Kansas contains 25 reservoirs that are candidates for miscible CO_2-EOR.

Under "Traditional Practices" (and current financial conditions, defined above), there are 8 economically attractive oil reservoirs for miscible CO_2 flooding in Kansas. 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 Kansas increases to 19, providing 1,040 million barrels of additional oil recovery, Table 26.

Table 26. Economic Oil Recovery Potential Under Current Conditions, Kansas

CO_2-EOR Technology	No. of Reservoirs	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
"Traditional Practices"*	25	5,149	570	8	320
"State of Art Technology"*	25	5,149	1,270	19	1,040

**Oil price of $30 per barrel.*

Lower cost CO_2 supplies and risk sharing/higher oil prices would enable CO_2-EOR in Kansas to recover up to 1,220 million barrels of oil (from 22 major reservoirs), Table 27.

Table 27. Economic Oil Recovery Potential with More Favorable Financial Conditions, Kansas

More Favorable Conditions	Technical Potential (MMBbls)	Economic Potential* (No. of Reservoirs)	Economic Potential* (MMBbls)
Plus: Risk Mitigation*	1,270	21	1,210
Plus: Low Cost CO_2**	1,270	22	1,220

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

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

6.4 OKLAHOMA. Oklahoma is still one of the largest oil producing states in the country with a rich history of oil recovery. Crude oil production began in 1897, and has reached a cumulative recovery of over 14.5 billion barrels of oil to date. In 2002, Oklahoma ranked 6th in production in the onshore U.S., producing 66 MMBbls of oil (181 MBbls/day) from 83,750 producing wells, and 5th in reserves at 598 MMBbls. The state contains 5 petroleum refineries with a crude oil distillation capacity of over 472 MBbls/day.

Despite being one of the top oil producing states, Oklahoma has seen a continuation of the decline in oil production in recent years, Table 28.

Table 28. Recent History of Oklahoma Oil Production

	Annual Oil Production	
	(MMBls/yr)	(MBbls/d)
2000	69	189
2001	69	189
2002	66	181
2003	65	177
2004	64	175

An active program of secondary oil recovery has helped maintain oil production in the state. As of 2002, over 50% of oil fields in the state of Oklahoma had been or were currently undergoing waterflooding. Most of the major waterflood projects, however, have occurred in the western half of the state in the Anadarko Basin, where thick point-bar sandstone deposits make for a more favorable waterflooding conditions.

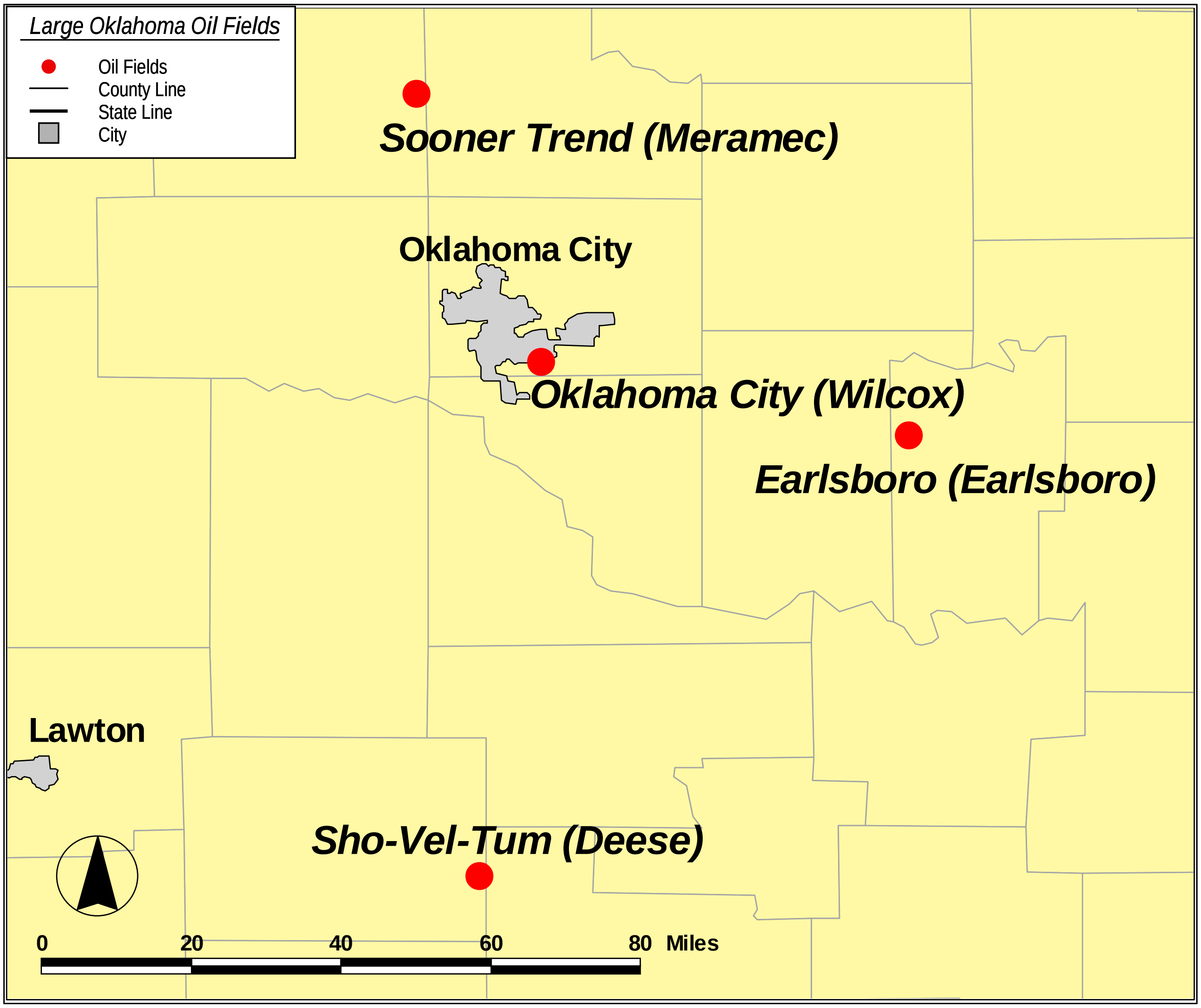
To the east, in the Cherokee Uplift, waterflooding has been unreliable. Currently, a waterflood demonstration project is taking place at the Wolco Field in Osage County, OK. The project is too new to have yielded any substantial waterflood production data, however, the project indicates that optimum performance would occur in thicker sand sections by using horizontal injection and production wells.

Overall the success of waterflooding has been minimal in the eastern portion of the state as a result of lack of detailed reservoir characterization and field-wide simulation. The waterfloods in the larger oil fields of western Oklahoma are mature, with many of the fields near their production limits, calling for alternative methods for maintaining oil production.

Oklahoma Oil Fields. To better understand the potential of using CO_2-EOR in Oklahoma's light oil fields, this section examines, in more depth, four large fields, shown in Figure 15. The stack of individual reservoirs in many of these fields has been grouped into:

- Earlsboro (Earlsboro Reservoirs)
- Oklahoma City (Wilcox Reservoirs)
- Sho-Vel-Tum (Deese Reservoirs)
- Sooner Trend (Meramec Reservoirs)

Figure 15. Large Oklahoma Oil Fields



These four fields 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 light oil fields are set forth in Table 29.

Table 29. Status of Large Oklahoma Oil Fields/Reservoirs (as of 2002)

Large Fields/Reservoirs		Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Earlsboro (Earlsboro)	1,395	208	1	1,185
2	Oklahoma City (Wilcox)	1,494	520	3	971
3	Sho-Vel-Tum (Deese)	1,438	482	22	935
4	Sooner Trend (Meramec)	1,052	152	6	894

These four large "anchor" fields, each with over a billion barrels of OOIP and 800 or more million barrels of ROIP, appear to be favorable for miscible CO_2 -EOR, based on their reservoir properties, Table 30.

Table 30. Reservoir Properties and Improved Oil Recovery Activity, Large Oklahoma Oil Fields/Reservoirs

Large Fields/Reservoirs		Depth (ft)	Oil Gravity (^oAPI)	Active Waterflood or Gas Injection
1	Earlsboro (Earlsboro)	3,500	39.0	Undergoing waterflooding
2	Oklahoma City (Wilcox)	6,000	38.7	Undergoing waterflooding
3	Sho Vel Tum (Deese)	3,050	29.0	Undergoing waterflooding
4	Sooner Trend (Meramec)	6,900	40.0	Undergoing waterflooding

Past and On-Going CO_2-EOR Projects. CO_2-EOR projects in Oklahoma are underway at Northeast Purdy, Bradley Unit, Postle, Sho-Vel-Tum, and Camrick oil fields. The largest CO_2-EOR project has been ExxonMobil's 11,000 acre Postle Field CO_2 flood, started in 1995 involving 140 production wells and 110 injection wells. The most recent CO_2-EOR project is Chaparral Energy's 2,320 acre Camrick Field CO_2 flood strarted in 2001.

Postle Field. Beginning in November of 1995, ExxonMobile began injecting CO_2 into the Postle Field of Oklahoma, applying CO_2-EOR at the end of the waterflood. Located in near the town of Guyman in the Oklahoma Panhandle, the Postle Field began waterflooding in 1967, having produced about 92 MMBbls of oil by 1995. Oil production peaked in 1970 at 22,000 Bbls/day, and had dropped to about 2,000 Bbls/day when CO_2 injection began.

At the start of the project ExxonMobil, the operator, had plans to increase production to 2,300 Bbls/day by 1996, peaking at about 10,000 Bbls/day by 2000, and incremental recovery of 10-14% of OOIP.

- CO_2 injection began on November 15, 1995 at a rate of 35 MMcf/d, after construction of a $25 million, 120-mile pipleline to carry $CO_2$from Bravo Dome, New Mexico. In 1998, ExxonMobile was injecting 90 MMcf/d of CO_2.
- Oil response to CO_2 injection occurred 6 months after CO_2 injection began. Significant response occurred after 10% pore volume of CO_2 had been injected.
- Production has risen to 6,500 Bbls/day in late 1999 and 2,000 Bbls/day in 2003 with 6,000 Bbls/day of enhanced oil production due to the CO_2 flood. Estimated ultimate oil production from CO_2-EOR in the Postle Field is 25 MMBbls. As of 2004, expansion of the project is noted as likely.

Northeast Purdy and Bradley Unit Fields. Currently Anadarko Petroleum has two CO_2 floods underway in the Northeast Purdy and Bradley Unit fields of Oklahoma. The company operates a 120-mile pipeline, transporting CO_2 from a large fertilizer complex in the town of Enid in northern Oklahoma to Lindsay, south of Oklahoma City. Enhanced oil production in the Northeast Purdy Field is 1,800 Bbls/day and in the Bradley Unit is 600 Bbls/day. The CO_2-EOR project in the Bradley Unit is expected to expand to a field-wide flood, as of 2004.

Other Projects. Chaparrel Energy is operating two CO_2-EOR projects in the Sho-Vel-Tum Field in southern Oklahoma. The miscible CO_2 flood at Sho-Vel-Tum was started in 1982 in the light oil (30 ^oAPI) Sims reservoir. This 1,100 acre project, involving 60 production and 40 injections wells is half finished and is producing an incremental 1,250 barrels per day of oil due to CO_2-EOR. The immiscible CO_2 flood at Sho-Vel-Tum was started in late 1998 in a heavier oil (19 ^{o}API) Aldridge reservoir. This 98 pilot project involving 6 production and injection wells is producing about 100 barrels of additional oil per day due to CO_2-EOR and is evaluated as being promising and profitable by the operator.

Chaparrel Energy's third CO_2-EOR project, a miscible CO_2 flood in the Camrick Field of western Oklahoma was started in 1991. This 2,320 acre project in the Morrow reservoir has 14 production and 10 injection wells. This recently started project is producing 390 additional (490 total) barrels of oil per day due to the CO_2 flood. The operator rates the project as successful and profitable and indicates plans to expand the flood.

***Future CO_2-EOR Potential*.** Oklahoma contains 63 reservoirs that are candidates for miscible CO_2-EOR.

Under "Traditional Practices" (and current financial conditions, defined above), there are 21 economically attractive oil reservoirs for miscible CO2 flooding in Oklahoma. Applying "State-of-the-art Technology" (involving higher volume CO2 injection) and lower risk financial conditions, the number of economically favorable oil reservoirs in Oklahoma increases to 32, providing 2,890 million barrels of additional oil recovery, Table 31.

Table 31. Economic Oil Recovery Potential Under Current Conditions, Oklahoma

CO_2-EOR Technology	No. of Reservoirs	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
"Traditional Practices"*	63	23,500	2,590	21	940
"State of Art Technology"*	63	23,500	5,440	32	2,890

*Oil price of $30 per barrel.

Lower cost CO_2 supplies and risk sharing/higher oil prices would enable CO_2-EOR in Oklahoma to recover up to 4,740 million barrels of oil (from 48 major reservoirs), Table 32.

Table 32. Economic Oil Recovery Potential with More Favorable Financial Conditions, Oklahoma

More Favorable Conditions	Technical Potential (MMBbls)	Economic Potential*	
		(No. of Reservoirs)	(MMBbls)
Plus: Risk Mitigation*	5,440	43	4,280
Plus: Low Cost CO_2**	5,440	48	4,740

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

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

Appendix A

Using *CO_2-PROPHET* for Estimating Oil Recovery

Model Development

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

Input Data Requirements

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

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

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

Calibrating CO_2-PROPHET

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

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

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

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

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

Comparison of *CO_2-PROPHET* and *CO_2PM*

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

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

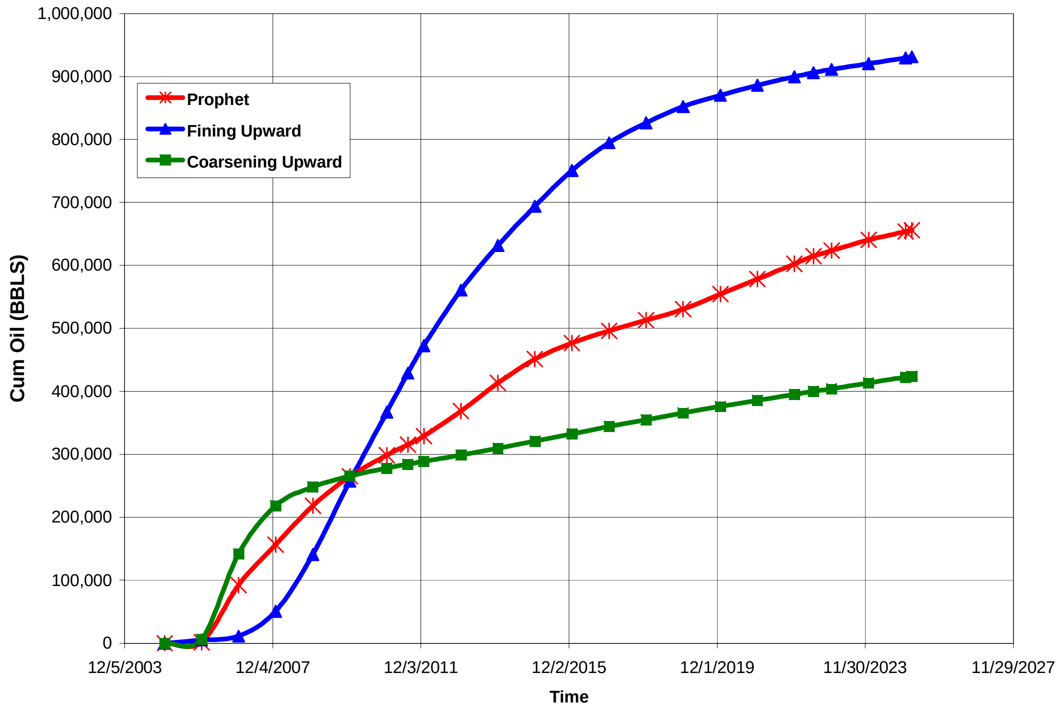
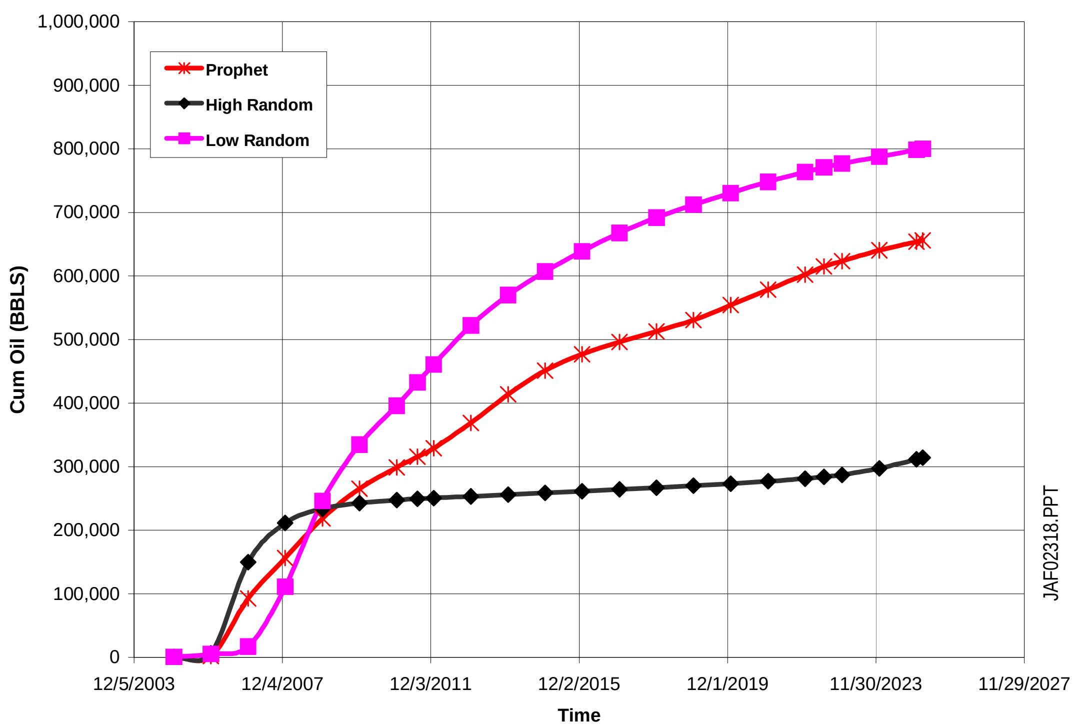


Figure A-2. *CO_2-PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



- *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

Arkansas CO_2-EOR Cost Model

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

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

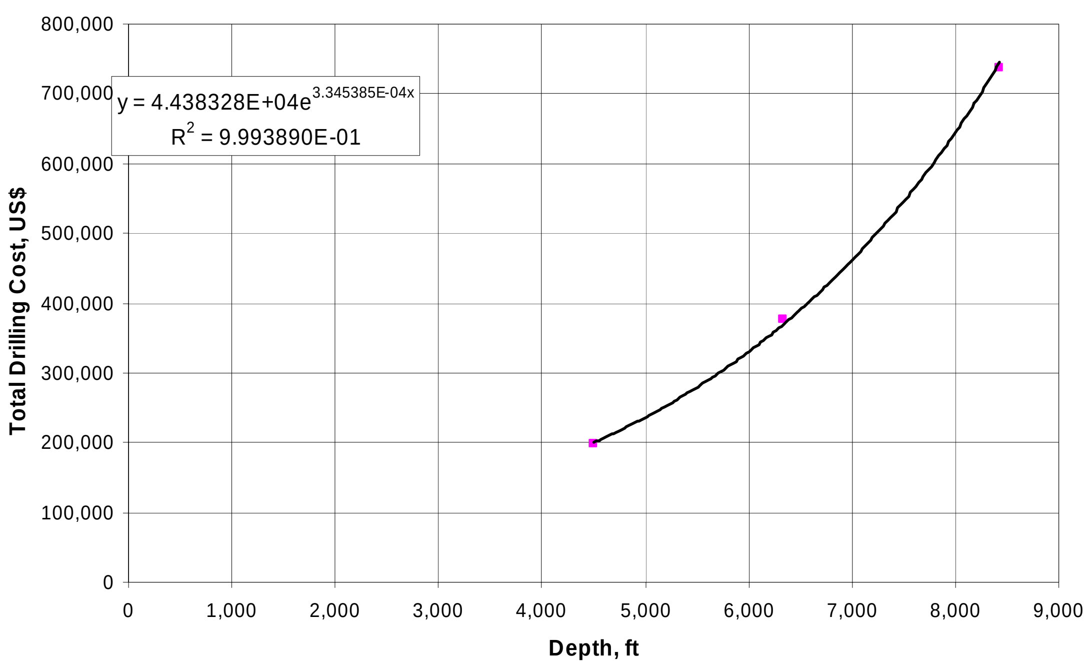
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for Arkansas.

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 = $a_0 e^{a_1 D}$
Where: a_0 is 44383
a_1 is .00033
D is well depth

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

Figure B-1. Oil Well D&C Costs for Arkansas



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

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

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

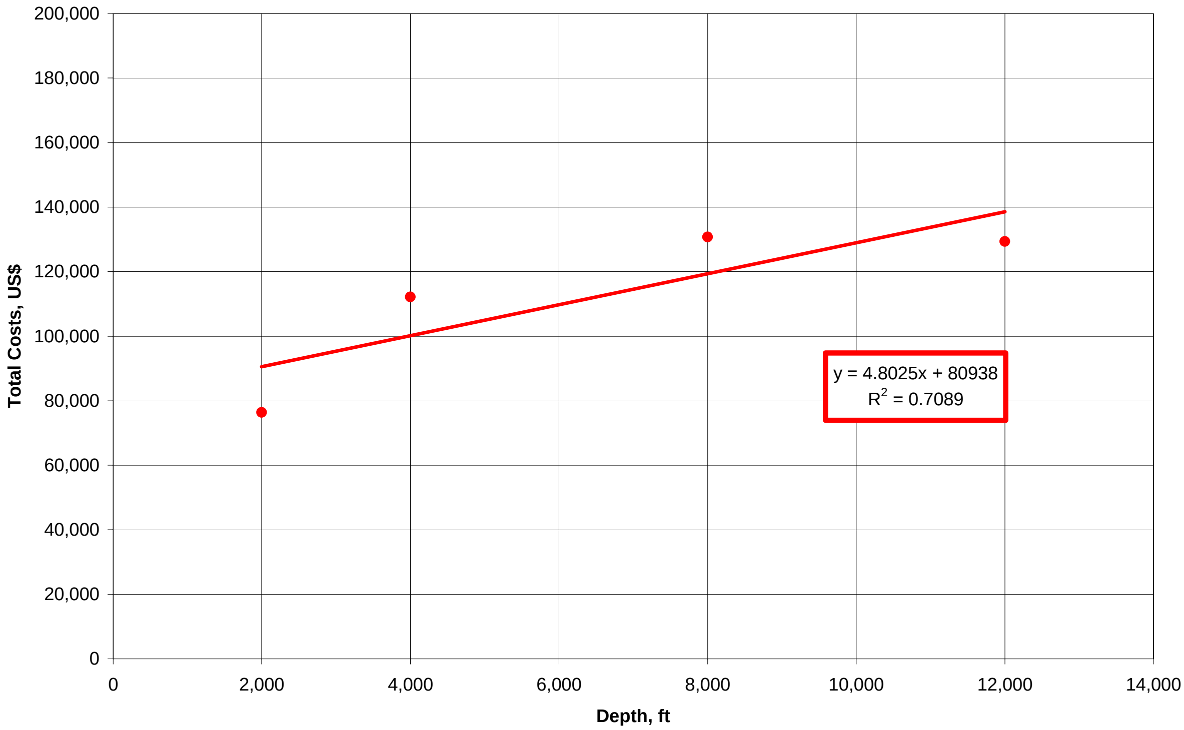
2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 EIA "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report. This survey provides estimated lease equipment costs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

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

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = $80938 (fixed)
c_1 = $4.80 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 Arkansas vs. Depth



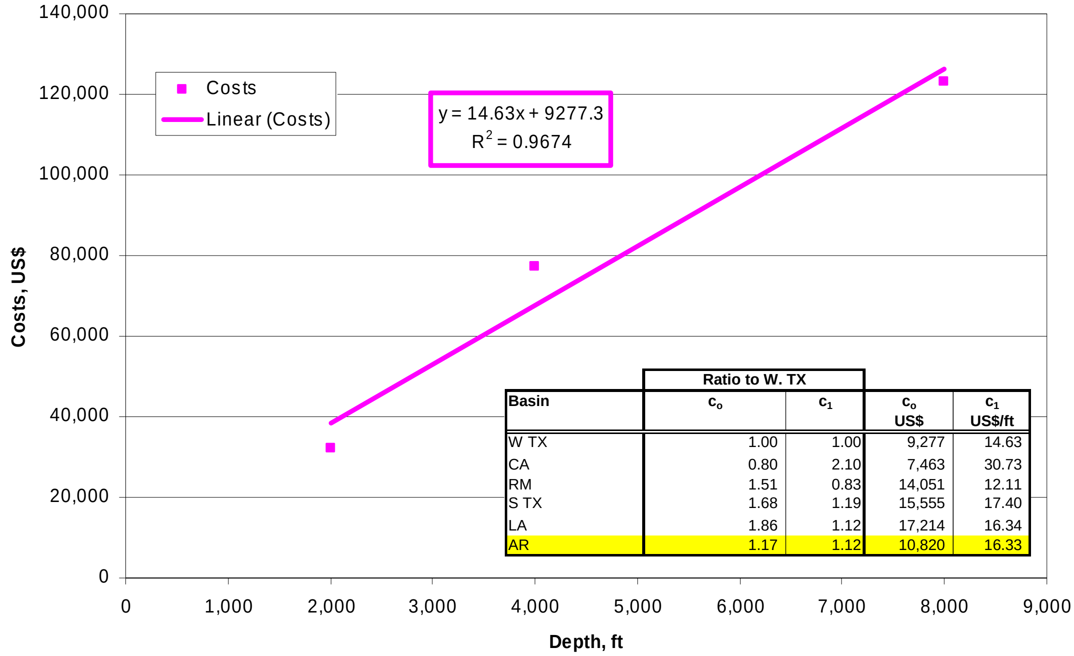
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Arkansas include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_0 = \$10,820 (fixed)
c_1 = \$16.33 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 Arkansas cost equation.

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



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

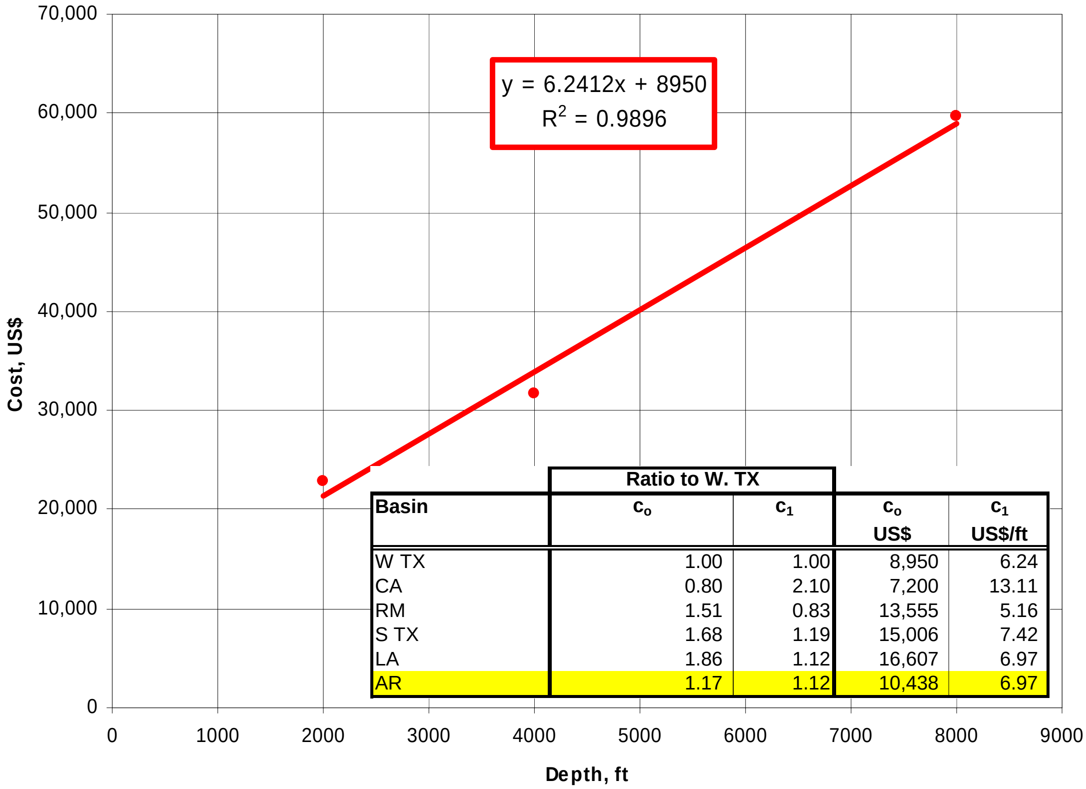
4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are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

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

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = $10,438 (fixed)
c_1 = $6.97 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 Arkansas cost equation.

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



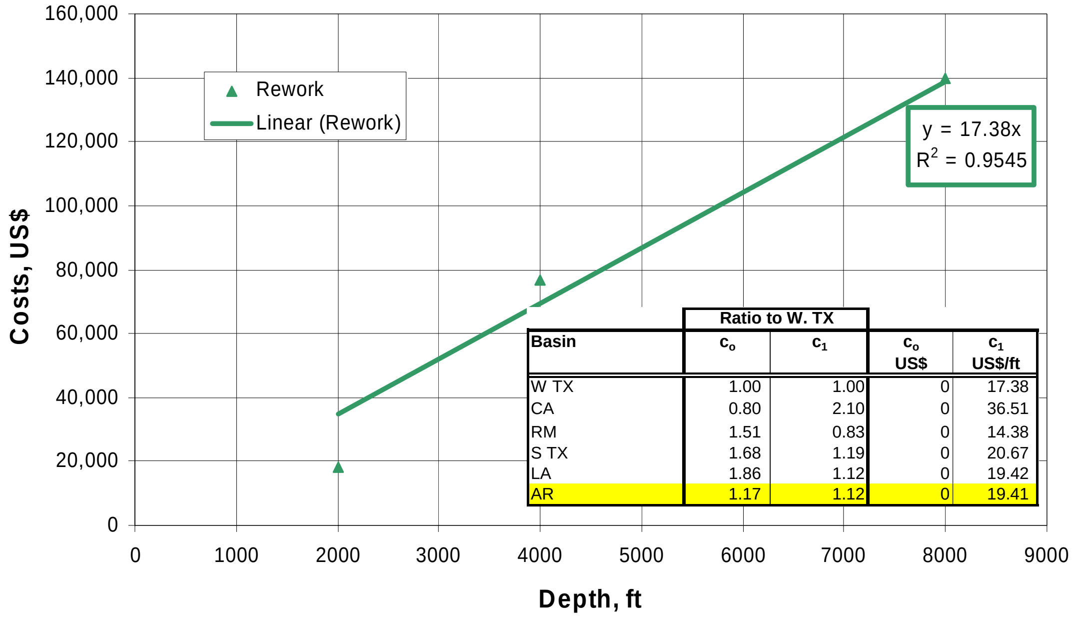
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
AR	1.17	1.12	10,438	6.97

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

Well Rework Costs = c_1D
Where: c_1 = \$19.41 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 Arkansas cost equation.

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



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

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

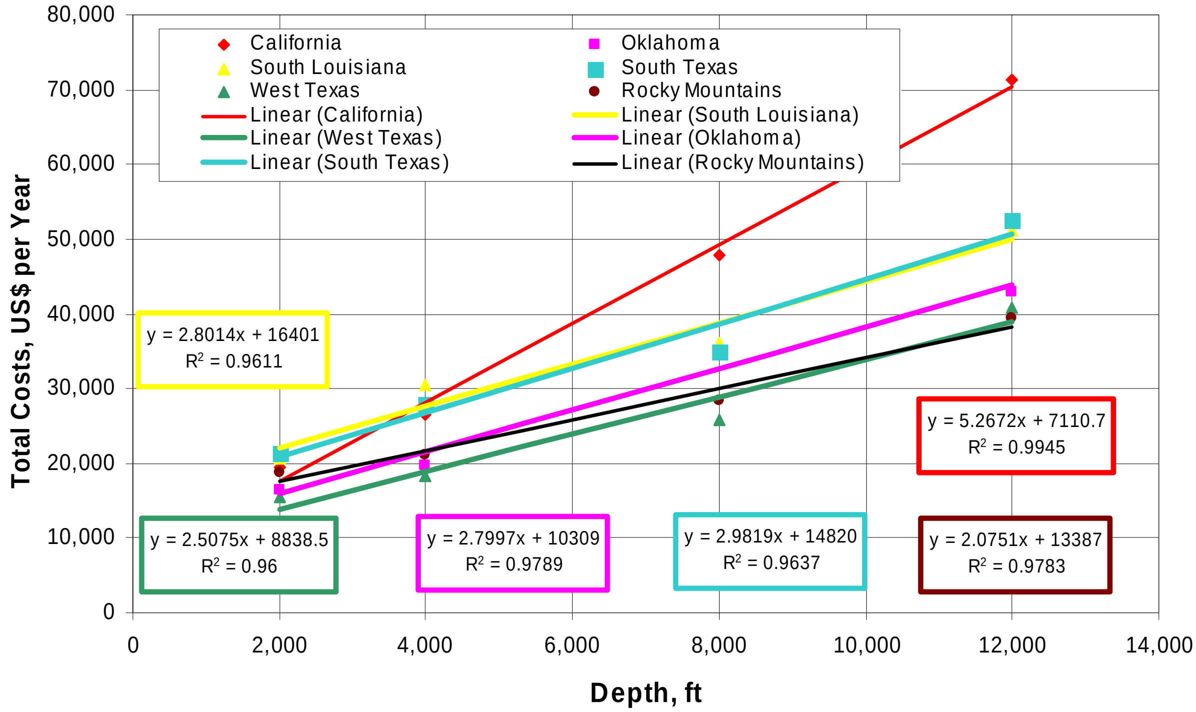


Table B-1. Regional Lease O&M Costs and their Relationship to West Texas

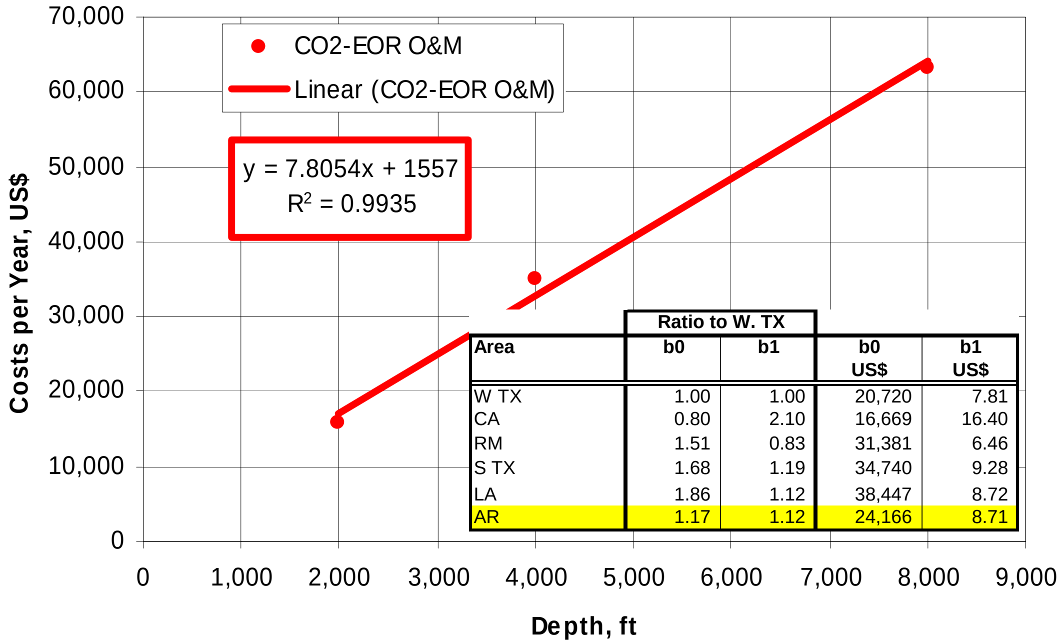
Basin	c_o US$	c_1 US$/ft	Ratio to W. TX c_o	Ratio to W. TX c_1
W TX	8,839	2.508	1.00	1.00
CA	7,111	5.267	0.80	2.10
RM	13,387	2.075	1.51	0.83
S TX	14,820	2.982	1.68	1.19
LA	16,401	2.801	1.86	1.12
AR	10,309	2.800	1.17	1.12

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

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

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$24,166 (fixed)
b_1 = \$8.71 per foot
D is well depth

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



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

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

The cost of the recycling plant is set at \$700,000 per MMcf/d of CO_2 capacity. As such, small CO_2-EOR project in the Cotton Valley formation of the Schuler field, with 25 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$17 million. A large project in the Magnolia field, with 219 MMcf/d of peak CO_2 reinjection and 42 injectors requires a recycling plant costing \$153 million.

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

8. Other COTWO Model Costs.

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

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

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

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

The CO_2 distribution cost equation for Arkansas 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% and 1%, respectively, for a total production tax of 6% 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 Arkansas (-$1.00 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 Arkansas is:

Wellhead Oil Price = Oil Price + (-$1.00) – [$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.

Appendix C

Kansas CO_2-EOR Cost Model

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

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

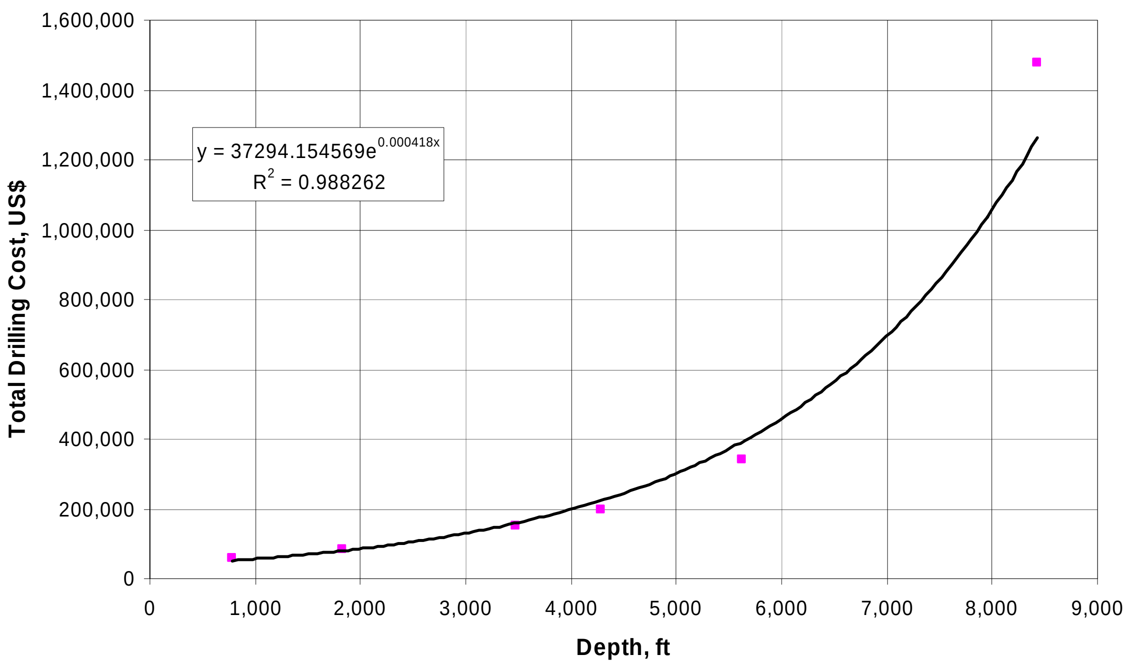
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for Kansas.

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 = $a_0 e^{a_1 D}$
Where: a_0 is 37294
a_1 is .00042
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 Kansas.

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



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

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

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

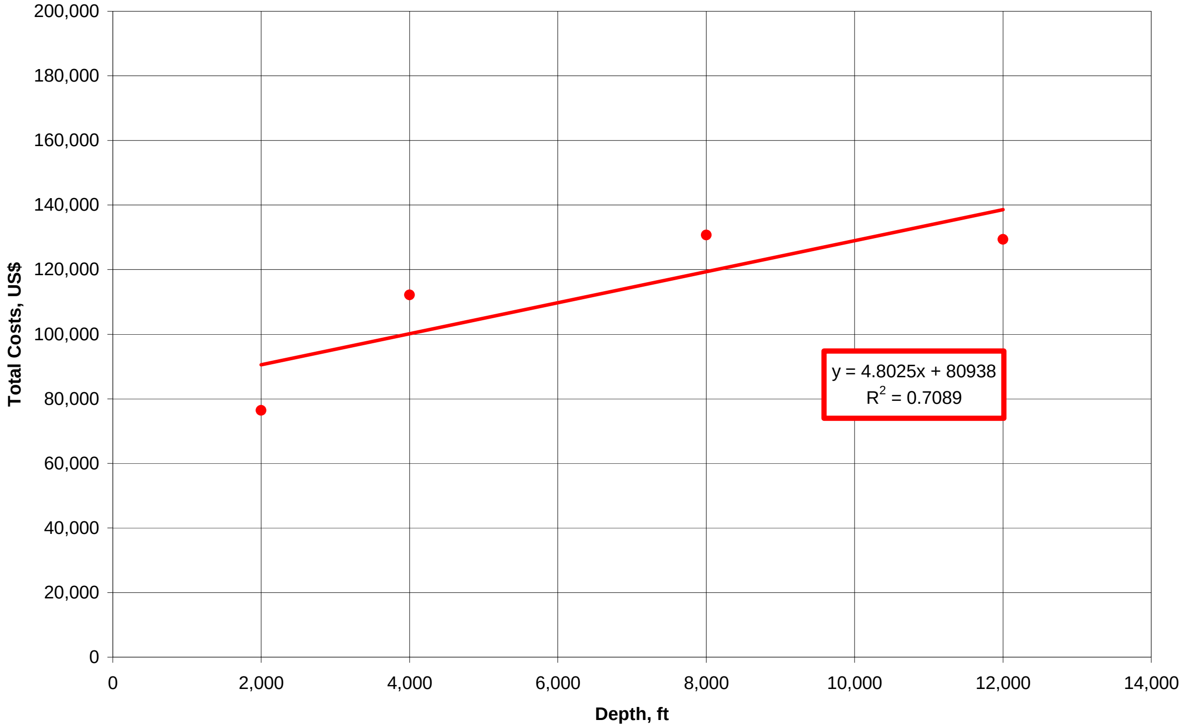
2. <u>Lease Equipment Costs for New Producing Wells.</u> The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 EIA "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report. This survey provides estimated lease equipment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

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

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$80938 (fixed)
c_1 = \$4.80 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 Kansas vs. Depth



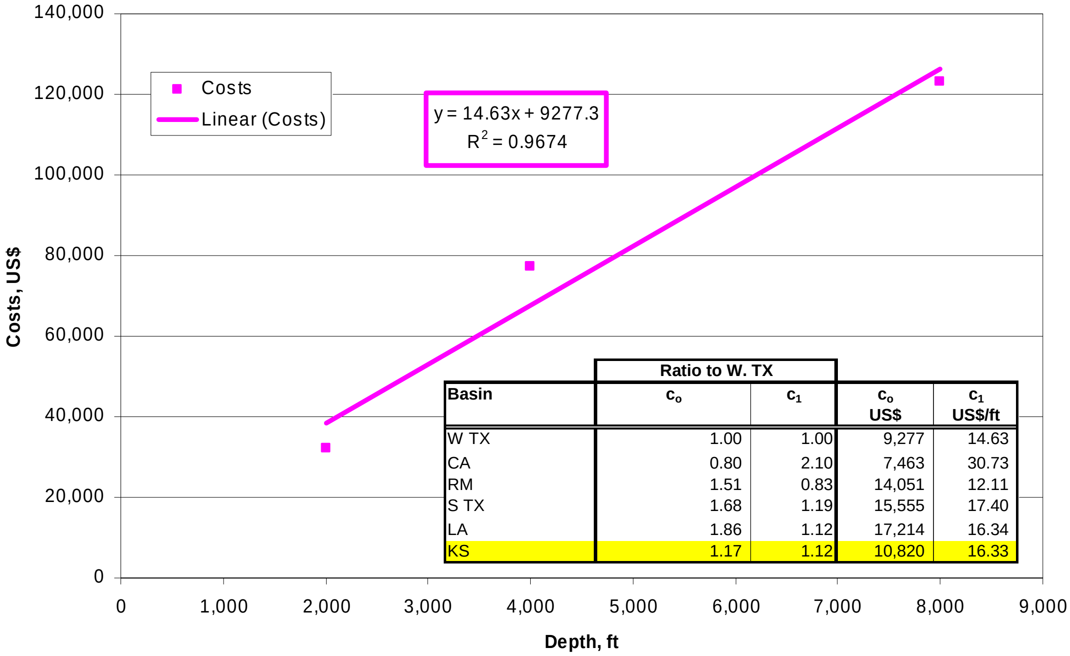
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Kansas include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_0 = \$10,820 (fixed)
c_1 = \$16.33 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 Kansas cost equation.

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



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

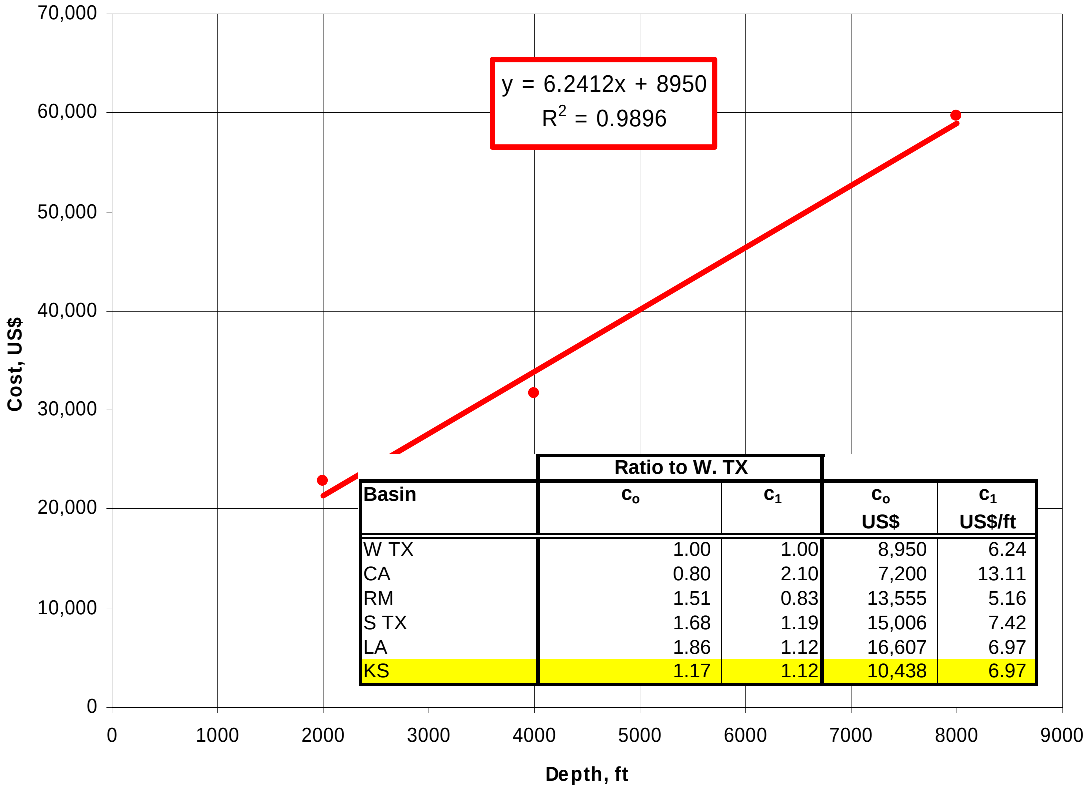
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection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

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

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$10,438 (fixed)
c_1 = \$6.97 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 Kansas cost equation.

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



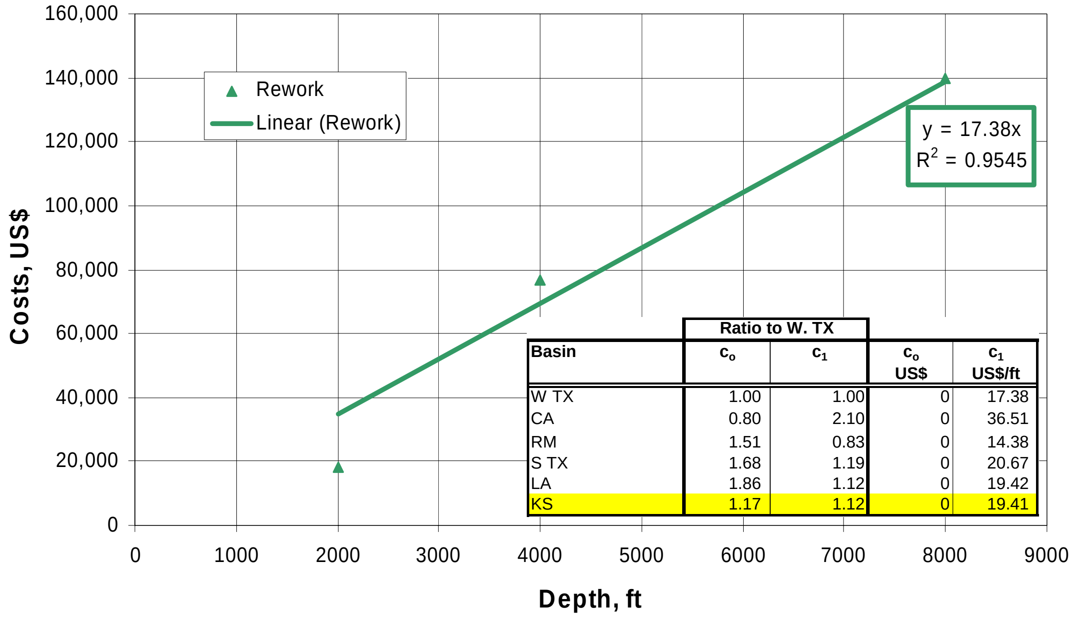
	Ratio to W. TX			
Basin	c_o	c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
KS	1.17	1.12	10,438	6.97

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

Well Rework Costs = c_1D
Where: c_1 = $19.41 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 Kansas cost equation.

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



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

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

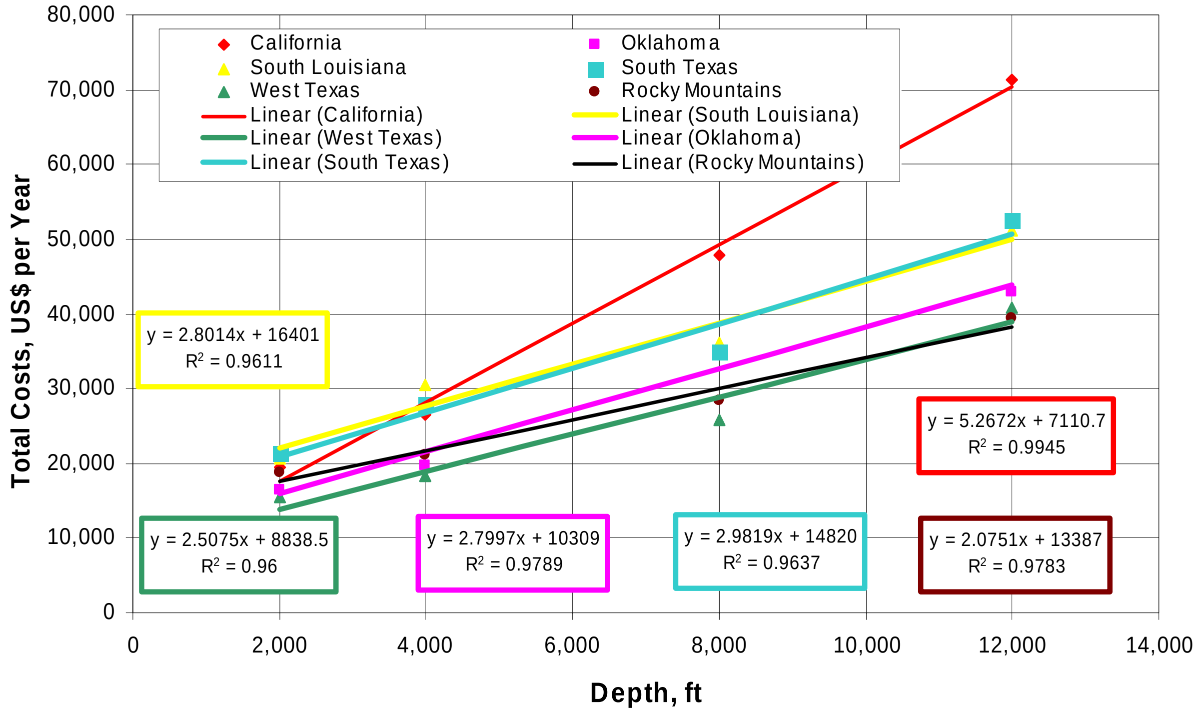


Table C-1. Regional Lease O&M Costs and their Relationship to West Texas

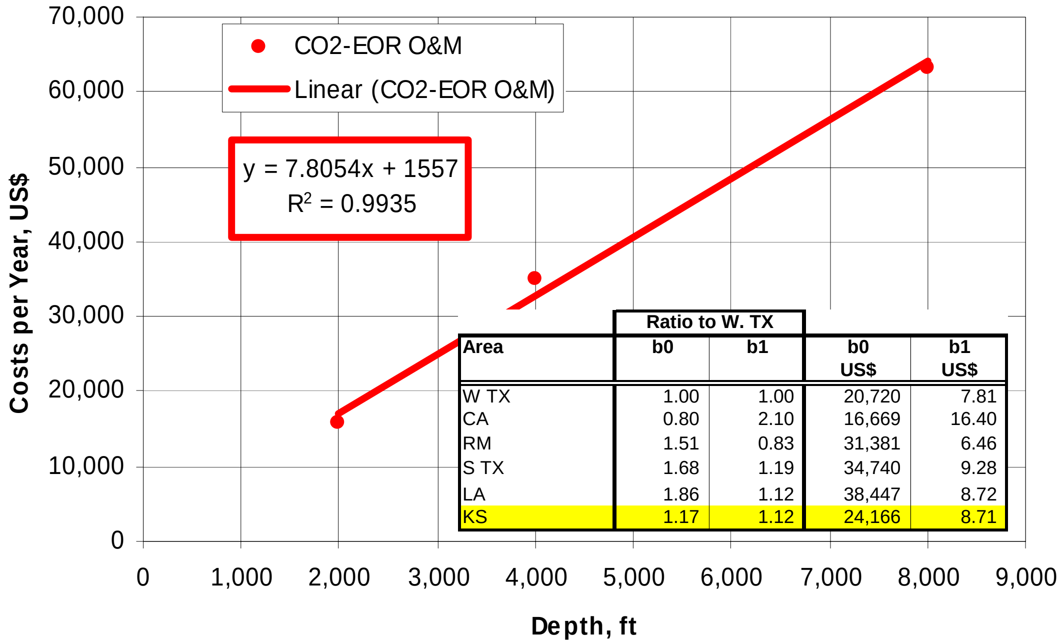
Basin	c_o US$	c_1 US$/ft	Ratio to W. TX c_o	Ratio to W. TX c_1
W TX	8,839	2.508	1.00	1.00
CA	7,111	5.267	0.80	2.10
RM	13,387	2.075	1.51	0.83
S TX	14,820	2.982	1.68	1.19
LA	16,401	2.801	1.86	1.12
KS	10,309	2.800	1.17	1.12

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

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

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$24,166 (fixed)
b_1 = \$8.71 per foot
D is well depth

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



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

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

The cost of the recycling plant is set at \$700,000 per MMcf/d of CO_2 capacity. As such, small CO_2-EOR project in the Arbuckle formation of the Geneseo field, with 52 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$36 million. A large project in the Trapp field, with 451 MMcf/d of peak CO_2 reinjection and 101 injectors requires a recycling plant costing \$315 million.

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

8. Other COTWO Model Costs.

a. CO$_2$ Recycle O&M Costs. The O&M costs of CO_2 recycling are indexed to energy costs and set at 1% of the oil price ($0.25 per Mcf @ $25 Bbl oil).

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

c. CO$_2$ Distribution Costs. The CO_2 distribution system is similar to the gathering systems used for natural gas. A distribution "hub" is constructed with smaller pipelines delivering purchased CO_2 to the project site.

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

The CO_2 distribution cost equation for Kansas 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 4.3% and 4%, respectively, for a total production tax of 8.3% 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 Kansas (-$1.00 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 Kansas is:

$$\text{Wellhead Oil Price} = \text{Oil Price} + (-\$1.00) - [\$0.25*(40 - {}^{o}\text{API})]$$

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.

Appendix D

Nebraska CO_2-EOR Cost Model

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

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

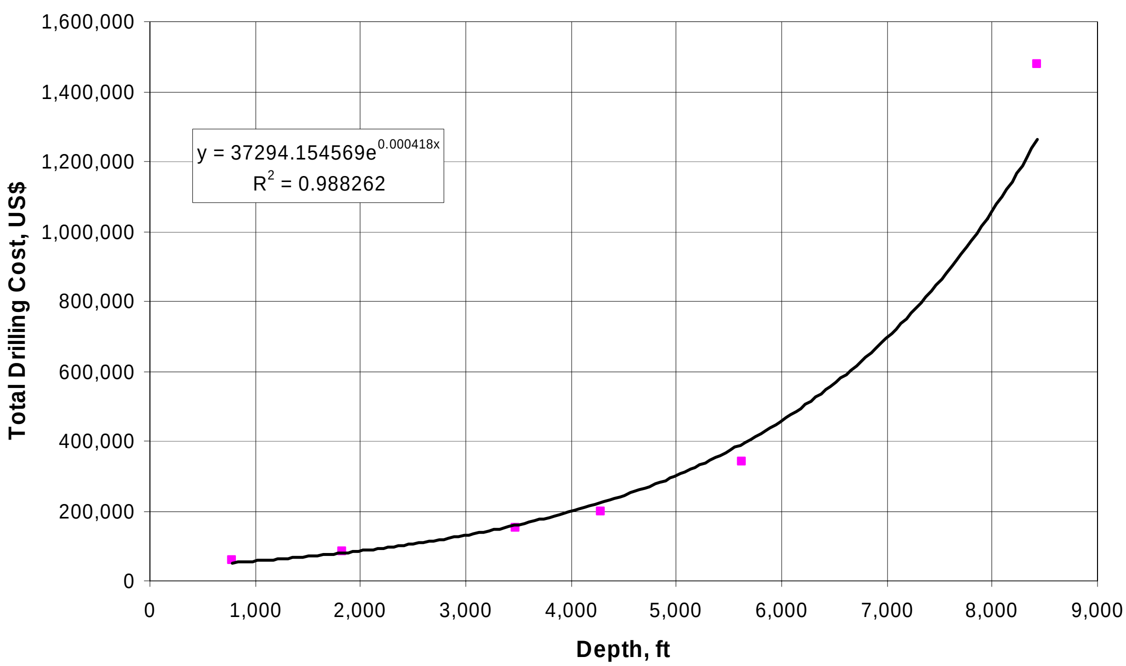
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for Nebraska.

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 = $a_0e^{a_1D}$
Where: a_0 is 37,294
a_1 is 0.00042
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 Nebraska.

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



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

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

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

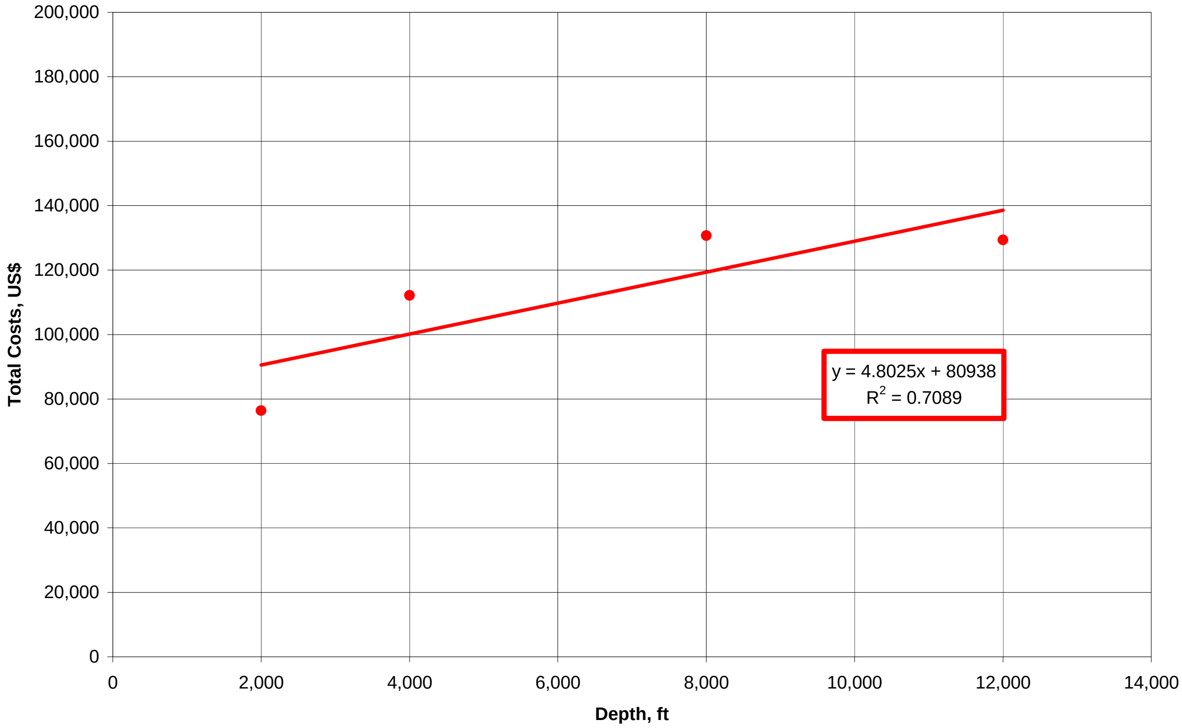
2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 EIA "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report. This survey provides estimated lease equipment costs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

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

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = $80,938 (fixed)
c_1 = $4.80 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 Nebraska vs. Depth



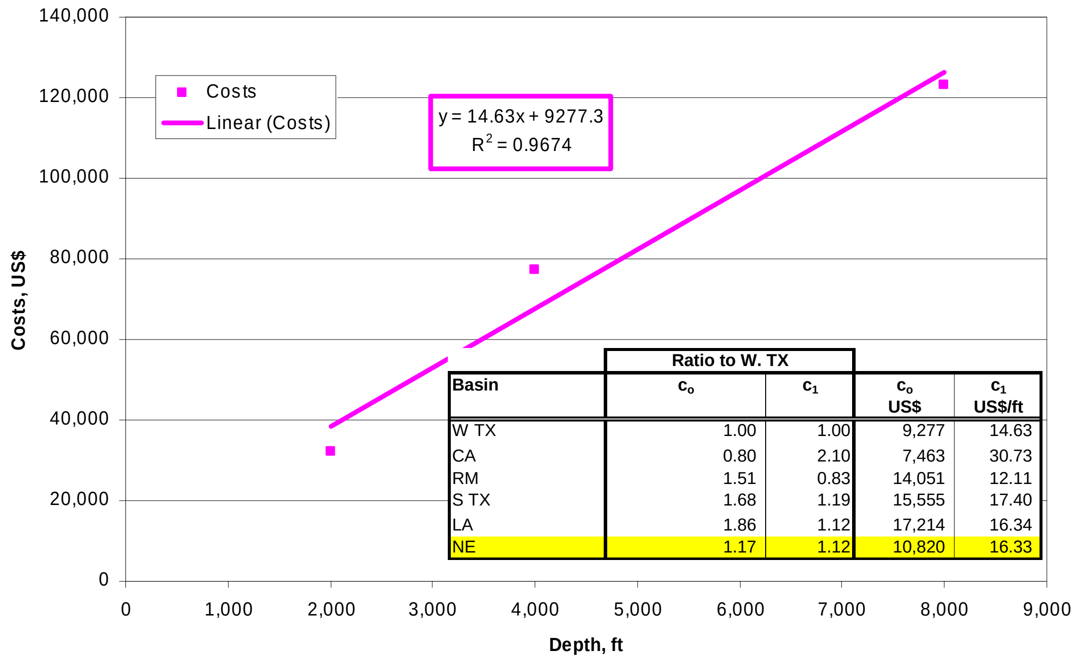
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Nebraska include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$10,820 (fixed)
c_1 = \$16.33 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 Nebraska cost equation.

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



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

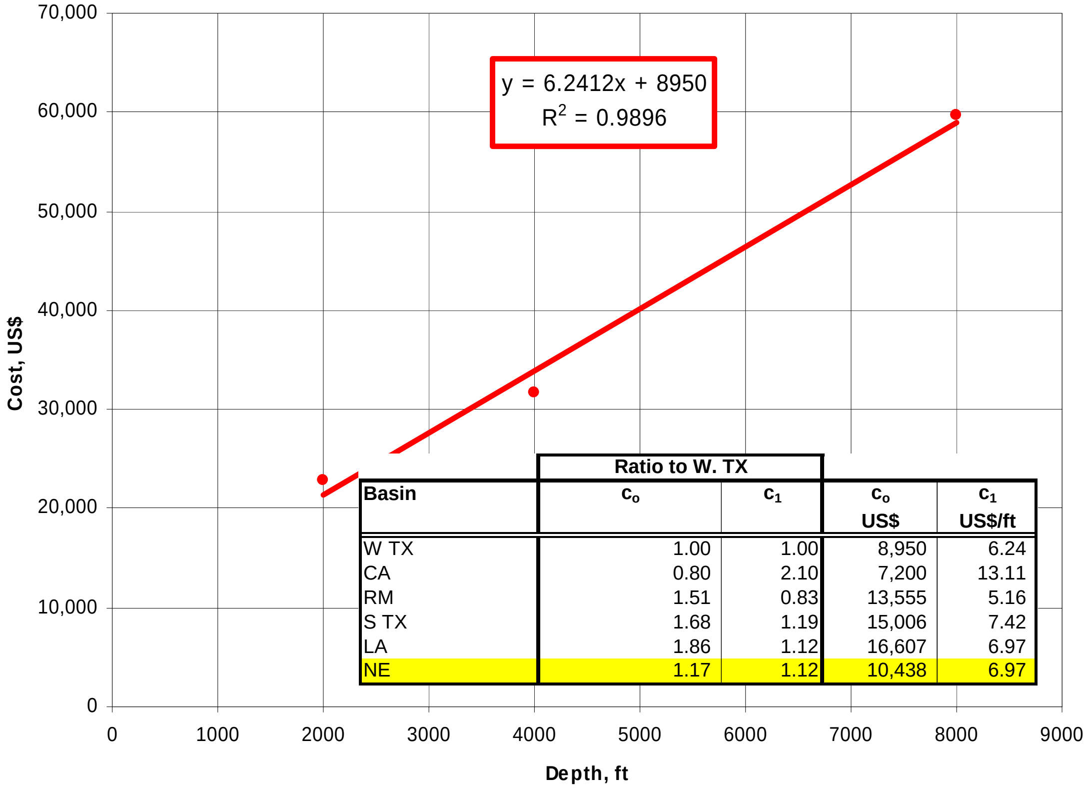
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection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

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

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$10,438 (fixed)
c_1 = \$6.97 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 Nebraska cost equation.

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



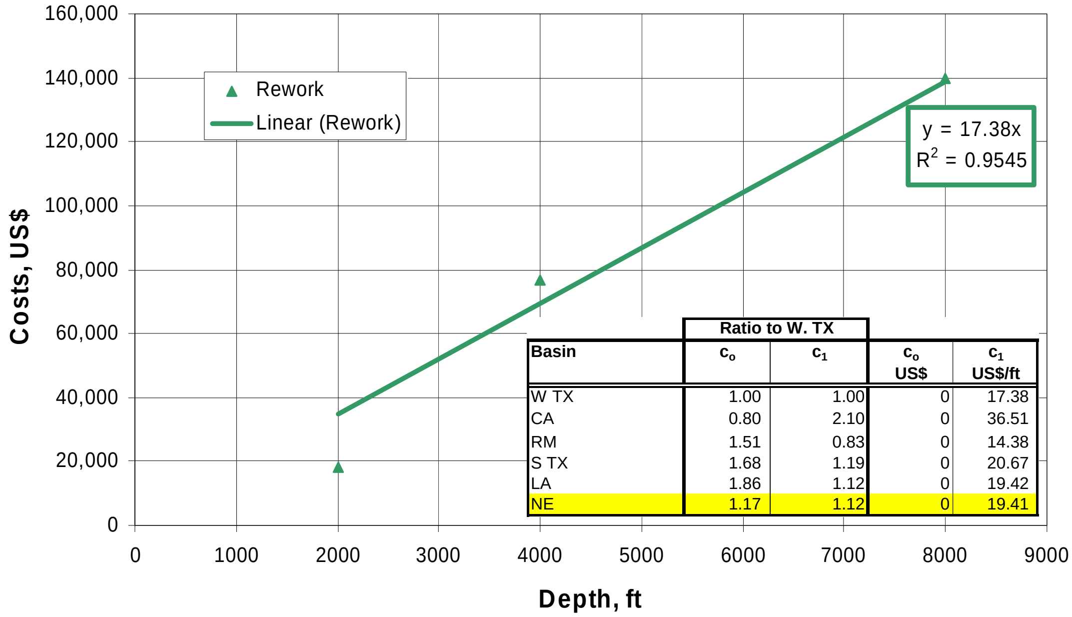
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
NE	1.17	1.12	10,438	6.97

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

Well Rework Costs = c_1D
Where: c_1 = \$19.41 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 Nebraska cost equation.

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



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

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

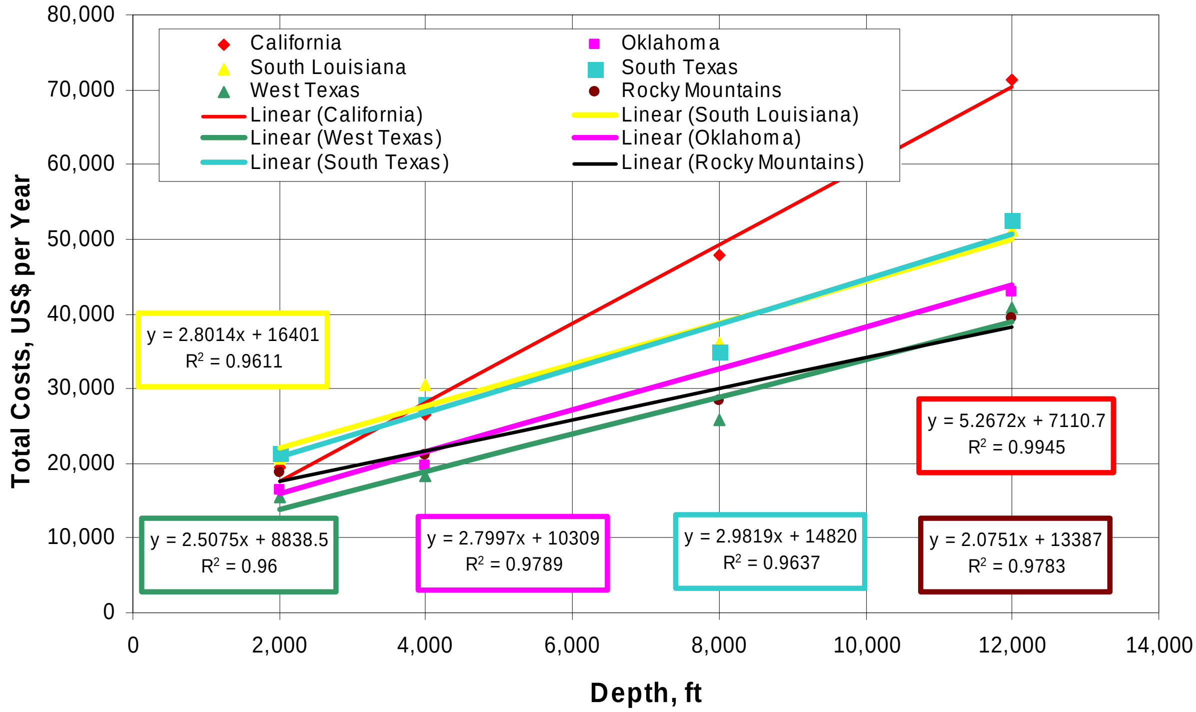


Table D-1. Regional Lease O&M Costs and their Relationship to West Texas

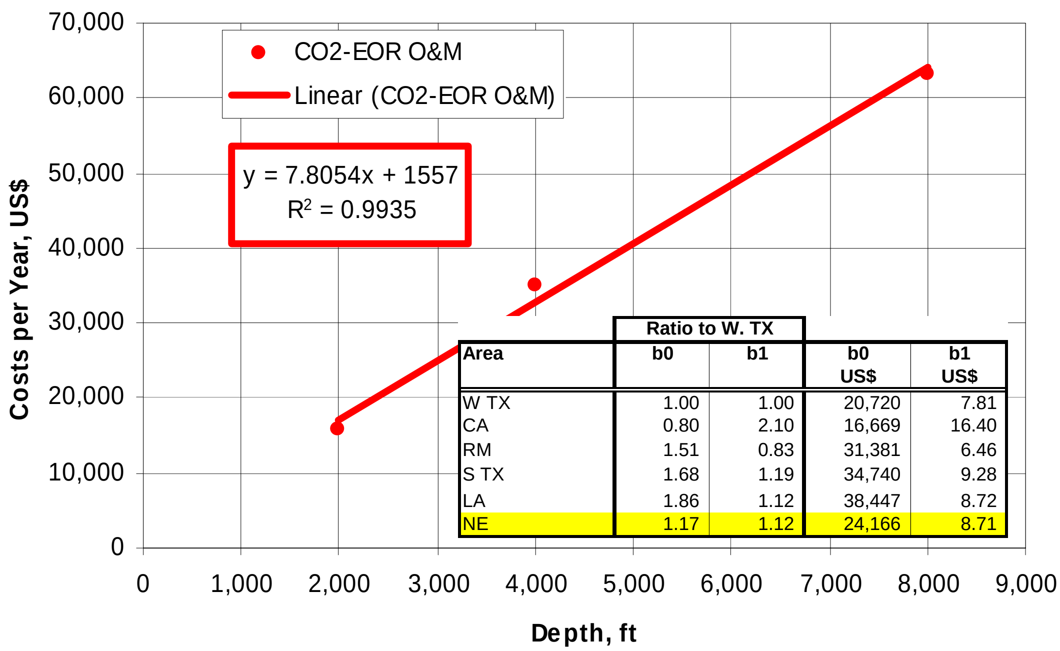
Basin	c_o US$	c_1 US$/ft	Ratio to W. TX c_o	Ratio to W. TX c_1
W TX	8,839	2.508	1.00	1.00
CA	7,111	5.267	0.80	2.10
RM	13,387	2.075	1.51	0.83
S TX	14,820	2.982	1.68	1.19
LA	16,401	2.801	1.86	1.12
NE	10,309	2.800	1.17	1.12

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

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

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$24,166 (fixed)
b_1 = \$8.71 per foot
D is well depth

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



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

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

The cost of the recycling plant is set at \$700,000 per MMcf/d of CO_2 capacity. As such, a CO_2-EOR project in the Reagan formation of the Sleepy Hollow field, with 84 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$59 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. Lifting Costs. Liquid (oil and water) lifting costs are calculated on total liquid production and costed at $0.25 per barrel. This cost includes liquid lifting, transportation and re-injection.

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

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

The CO_2 distribution cost equation for Nebraska 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 3% and 0%, respectively, for a total production tax of 3% 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 Nebraska (-$1.00 per barrel) and the current gravity differential (-$0.25 per ^oAPI, from a basis of 40 ^oAPI) into the average wellhead oil price realized by each oil reservoir. The equation for Nebraska is:

Wellhead Oil Price = Oil Price + (-$1.00) – [$0.25*(40 - ^oAPI)]
Where: Oil Price is the marker oil price (West Texas intermediate)
^oAPI is oil gravity

If the oil gravity is less than 40 ^oAPI, the wellhead oil price is reduced; if the oil gravity is greater than 40 ^oAPI, the wellhead oil price is increased.

Appendix E

Oklahoma CO_2-EOR Cost Model

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

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

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

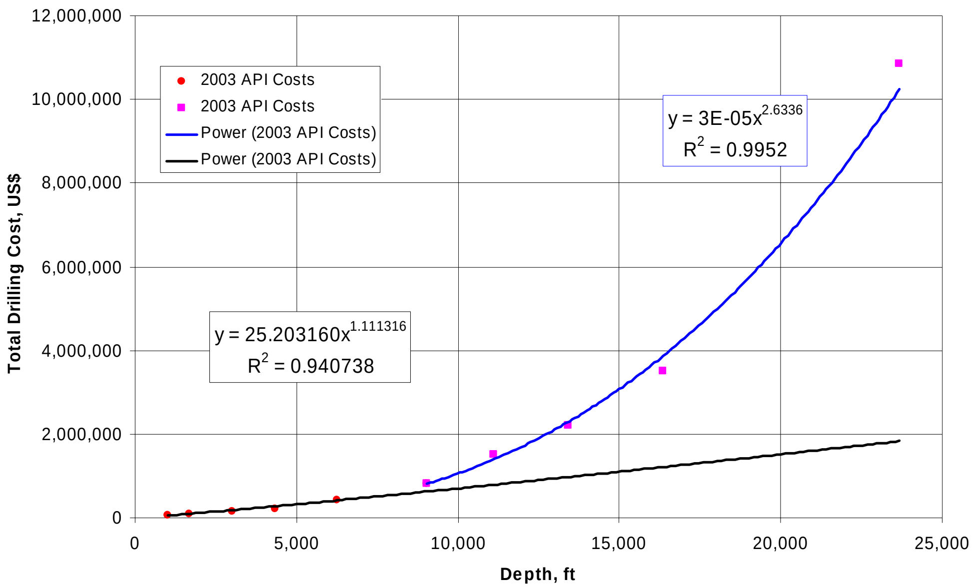
The well D&C cost equation has a fixed cost constant for site preparation and other fixed cost items and a variable cost equation that increases exponentially with depth. The total equation is:

0-9,000 feet depth
Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 25.2
a_1 is 1.11
D is well depth

>9,000 feet depth
Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 3×10^{-5}
a_1 is 2.63
D is well depth

Figure E-1 provides the details for the cost equation and illustrates the “goodness of fit” for the well D&C cost equation for Oklahoma.

Figure E-1. Oil Well D&C Costs for Oklahoma



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

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

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

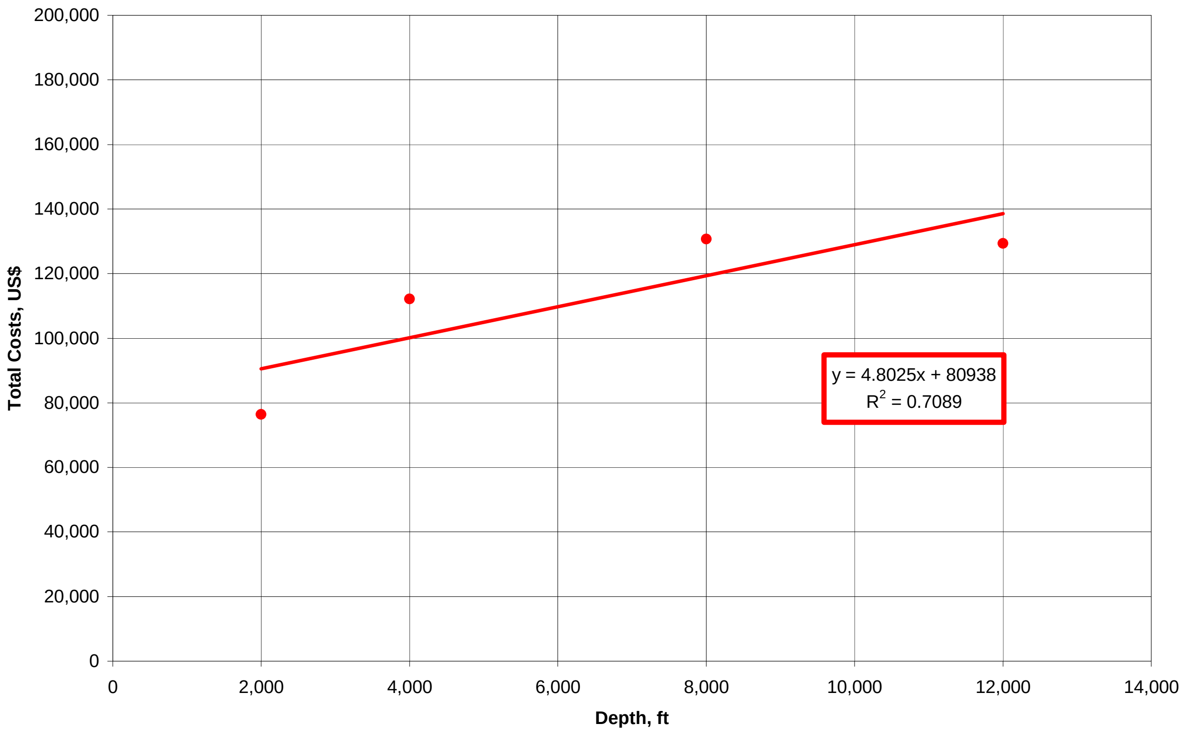
2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 EIA "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report. This survey provides estimated lease equipment costs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

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

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = $80,938 (fixed)
c_1 = $4.80 per foot
D is well depth

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

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



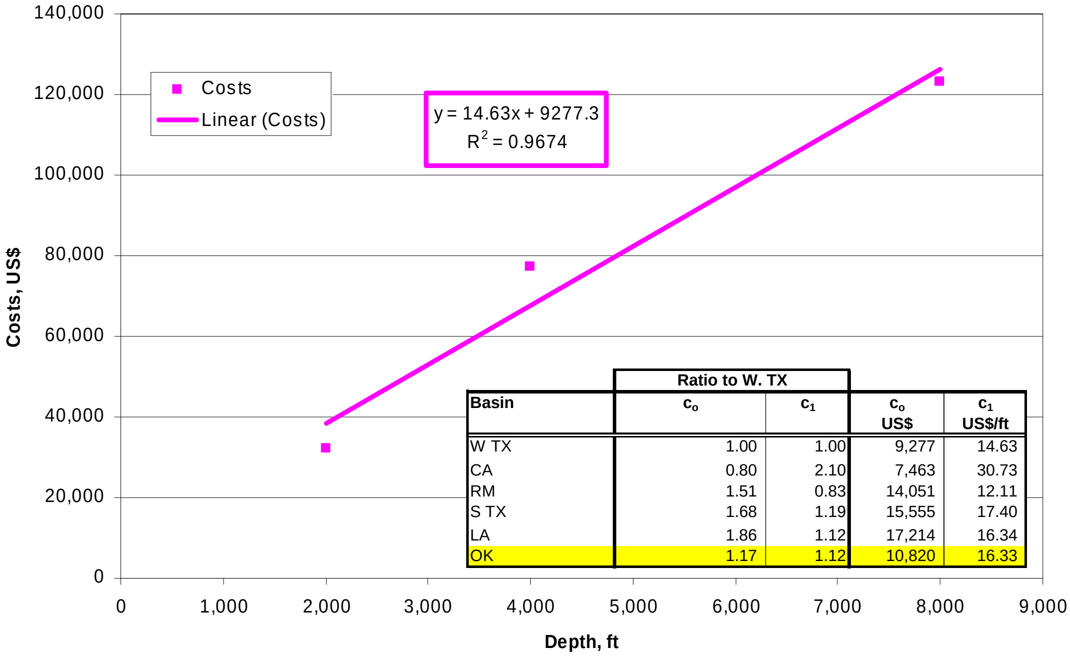
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in Oklahoma include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = $10,820 (fixed)
c_1 = $16.33 per foot
D is well depth

Figure E-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 Oklahoma cost equation.

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



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

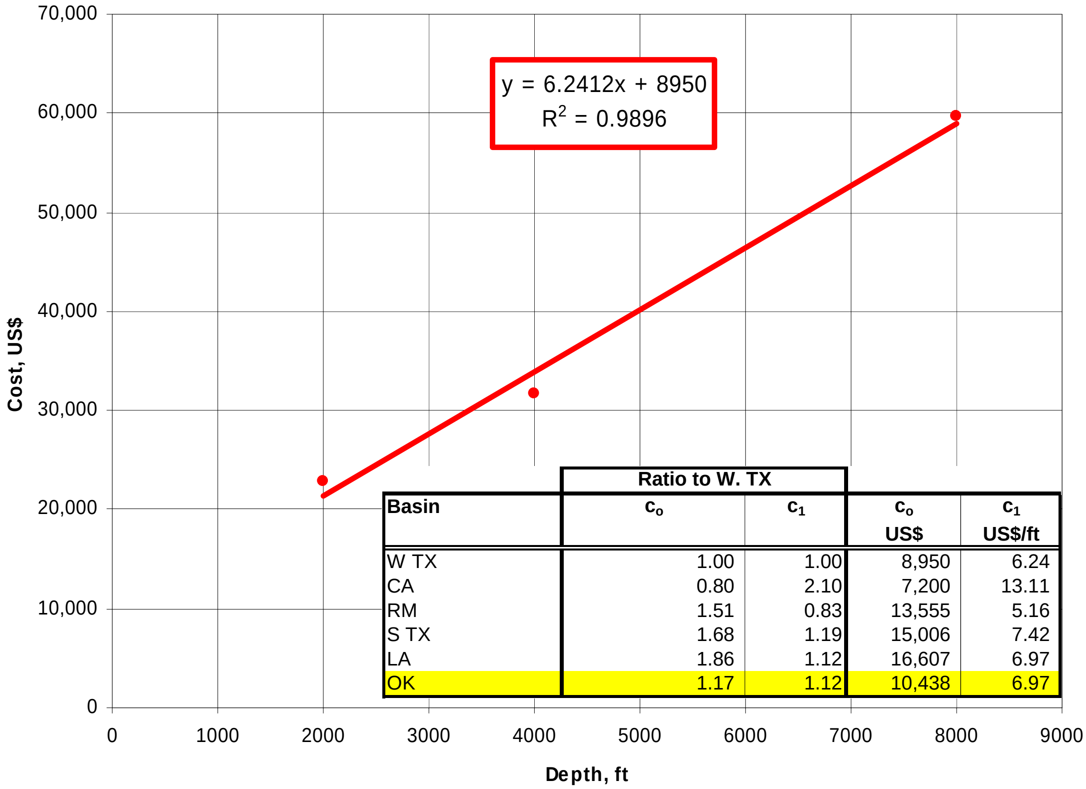
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection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

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

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$10,438 (fixed)
c_1 = \$6.97 per foot
D is well depth

Figure E-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 Oklahoma cost equation.

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



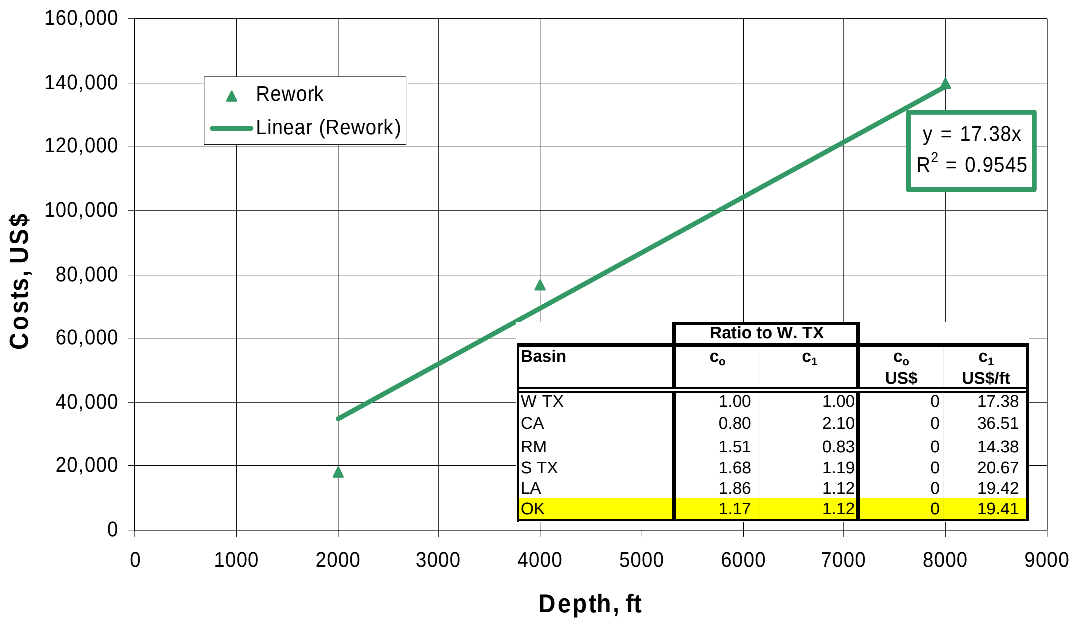
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
OK	1.17	1.12	10,438	6.97

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

Well Rework Costs = c_1D
Where: c_1 = \$19.41 per foot)
D is well depth

Figure E-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 Oklahoma cost equation.

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



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

6. <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 Oklahoma primary oil production O&M costs (Figure E-6) are used to estimate Oklahoma secondary recovery O&M costs. Linear trends are used to identify fixed cost constants and variable cost constants for each region, Table E-1.

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

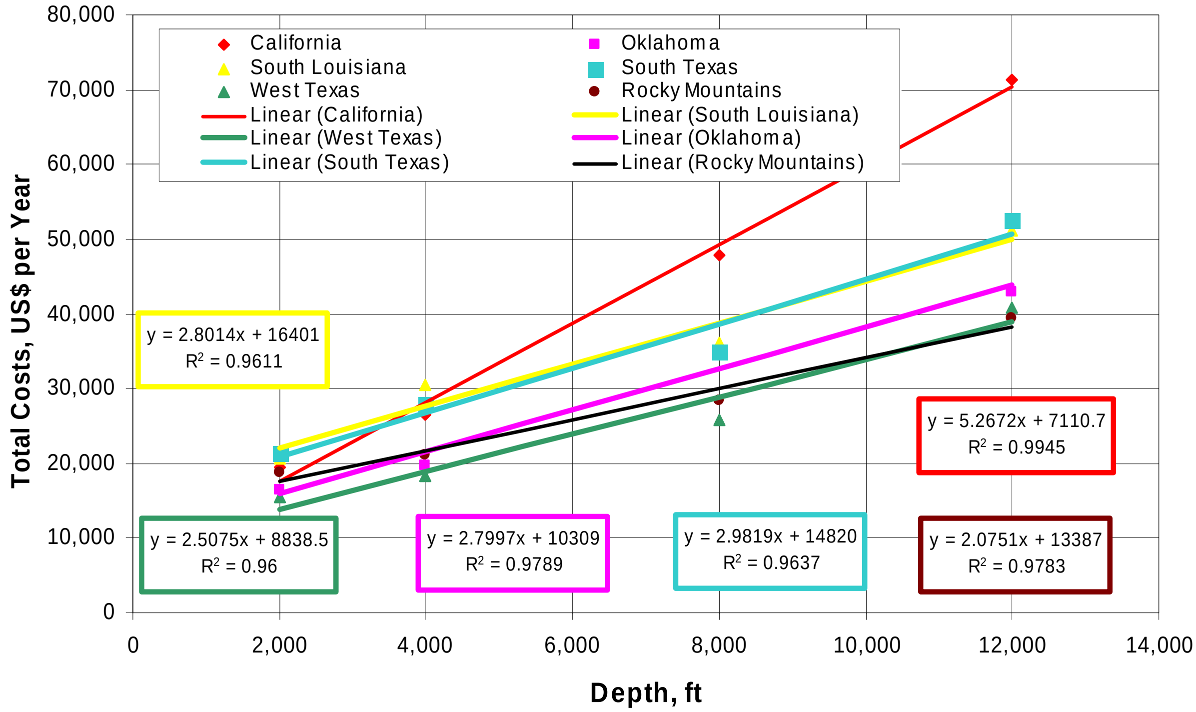


Table E-1. Regional Lease O&M Costs and their Relationship to West Texas

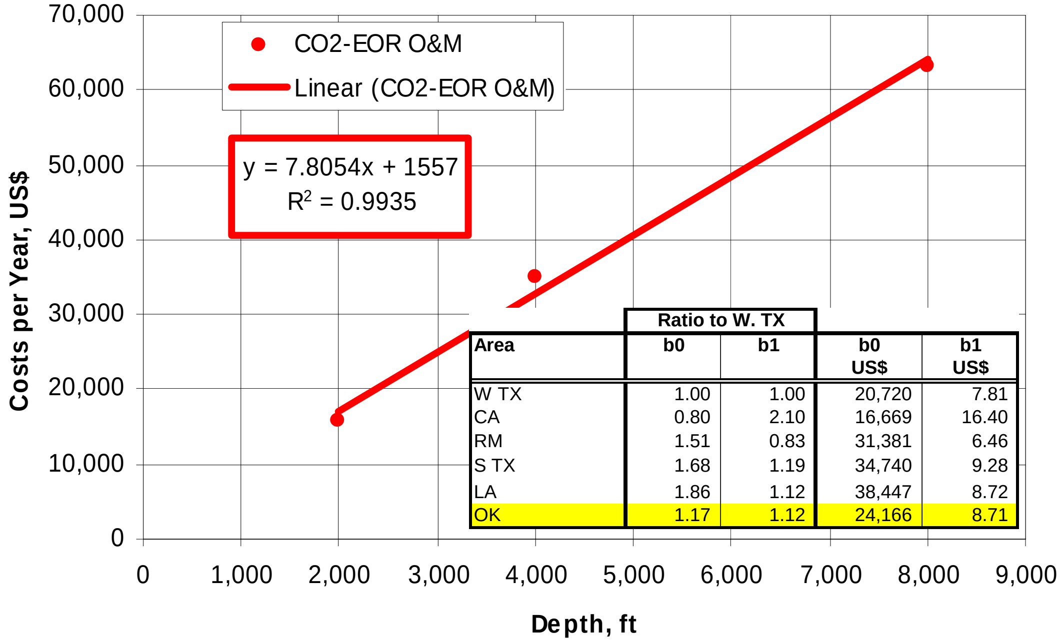
			Ratio to W. TX	
Basin	**c_o US$**	**c_1 US$/ft**	**c_o**	**c_1**
W TX	8,839	2.508	1.00	1.00
CA	7,111	5.267	0.80	2.10
RM	13,387	2.075	1.51	0.83
S TX	14,820	2.982	1.68	1.19
LA	16,401	2.801	1.86	1.12
OK	10,309	2.800	1.17	1.12

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

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

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = $24,166 (fixed)
b_1 = $8.71 per foot
D is well depth

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



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

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

The cost of the recycling plant is set at $700,000 per MMcf/d of CO_2 capacity. As such, a small CO_2-EOR project in the Misener formation of the Aylesworth field, with 18 MMcf/d of CO_2 reinjection, will require a recycling plant costing $12 million. A large scale project, such as the Earlsboro field, with 968 injectors and a CO_2 injection rate of 555 MMcf/d, would require a recycling plant costing $392 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. Lifting Costs. Liquid (oil and water) lifting costs are calculated on total liquid production and costed at $0.25 per barrel. This cost includes liquid lifting, transportation and re-injection.

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

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

The CO_2 distribution cost equation for Oklahoma 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 7% and 0%, respectively, for a total production tax of 7% 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 Oklahoma (-$1.00 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 Oklahoma is:

Wellhead Oil Price = Oil Price + (-$1.00) – [$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.