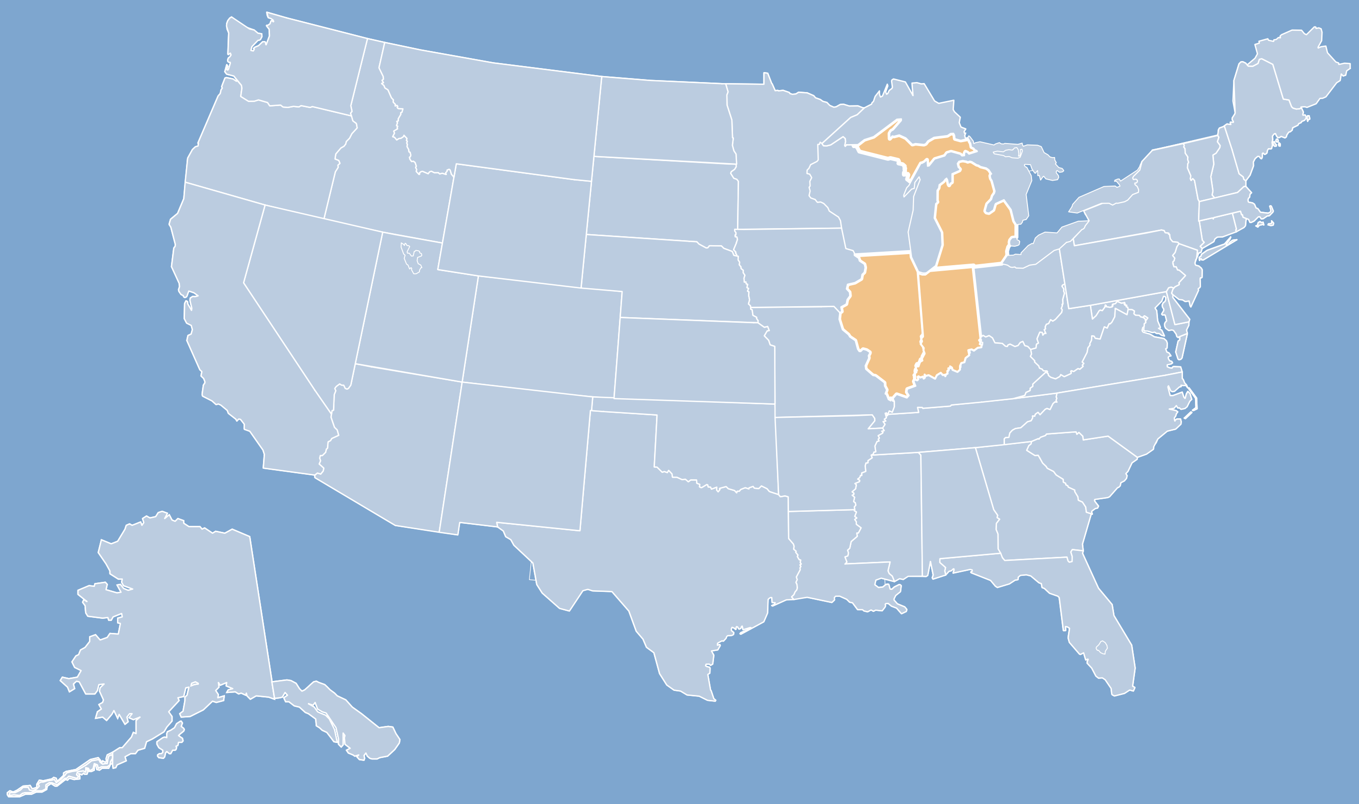
BASIN ORIENTED STRATEGIES FOR CO_2 ENHANCED OIL RECOVERY:

ILLINOIS & MICHIGAN BASINS



Prepared for

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Office of Fossil Energy – Office of Oil and Natural Gas

Prepared by

Advanced Resources International

February 2006

BASIN ORIENTED STRATEGIES FOR CO_2 ENHANCED OIL RECOVERY: ILLINOIS AND MICHIGAN BASIN OF ILLINOIS, INDIANA, KENTUCKY AND MICHIGAN

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1. SUMMARY OF FINDINGS

***1.1 INTRODUCTION**. The Illinois and Michigan Basin oil and gas producing region of Illinois, Indiana, Kentucky and Michigan has an original oil endowment of 17.8 billion barrels. Of this, 6.3 billion barrels (36%) has been produced or proven. As such, nearly 11.5 billion barrels of oil will be left in the ground, or "stranded", following the use of traditional oil recovery practices. A major portion of this "stranded oil" is in reservoirs technically and economically amenable to enhanced oil recovery (EOR) using carbon dioxide (CO_2) injection.*

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

***1.2 ALTERNATIVE OIL RECOVERY STRATEGIES AND SCENARIOS.** The report sets forth four scenarios for using CO_2-EOR to recover "stranded oil" in the Illinois and Michigan Basin 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 Illinois and Michigan Basin. In addition, this scenario assumes that a comprehensive program of research, pilot tests and field demonstrations help lower the risks inherent in applying new technology to Illinois and Michigan Basin 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 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 impact of aggregating low-cost, "EOR-ready" CO_2 supplies from various industrial and

natural sources. These CO_2 supply sources 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 from refineries and electric power plants. Capture of industrial CO_2 emissions could also be part of a national effort for reducing greenhouse gas emissions.

1.3 OVERVIEW OF FINDINGS*. Twelve major findings emerge from the study of "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Illinois and Michigan Basin of Illinois, Indiana, Kentucky and Michigan".*

1. Today's oil recovery practices will leave behind a large resource of "stranded oil" in the Illinois and Michigan Basin. The original oil resource in the Illinois and Michigan Basin reservoirs was 17.8 billion barrels. To date, 6.3 billion barrels of this original oil in-place (OOIP) has been recovered or proved. Thus, without further efforts, 11.5 billion barrels of Illinois and Michigan Basin's oil resource will become "stranded", Table 1.

Table 1. Size and Distribution of the Illinois and Michigan Basin's Oil Reservoirs Data Base

Region	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/Reserves* (Billion Bbls)	ROIP (Billion Bbls)
A. Major Oil Reservoirs				
Illinois*	82	6.9	2.7	4.2
Indiana**	17	0.7	0.2	0.5
Kentucky***	35	1.7	0.4	1.3
Michigan****	20	1.4	0.5	0.9
Data Base Total	154	10.6	3.9	6.8
*B. Regional Total**	n/a	17.8	6.3	11.5

Estimated from state data on cumulative oil recovery and proved reserves
** as of the end of 2001*
*** as of the end of 2002*
**** as of the end of 1994/1995*
***** as of the end of 2004*

2. The great bulk of the "stranded oil" resource in the large oil reservoirs of the Illinois and Michigan Basin is amenable to CO_2 enhanced oil recovery. To address the "stranded oil" issue, Advanced Resources assembled a data base that contains 154 major Illinois and Michigan Basin oil reservoirs, accounting for 61% of the region's estimated ultimate oil production. Of these, 72 reservoirs, with 4.5 billion barrels of OOIP and 3.7 billion barrels of "stranded oil" (ROIP)), were found to be favorable for CO_2-EOR, as shown below by region, Table 2.

Table 2. The Illinois and Michigan Basin's "Stranded Oil" Amenable to CO_2-EOR

Region	No. of Reservoirs	OOIP (Million Bbls)	Cumulative Recovery/ Reserves (Million Bbls)	ROIP (Million Bbls)
Illinois	46	3,120	490	2,630
Indiana	7	240	50	190
Kentucky	8	210	40	170
Michigan	11	970	230	740
TOTAL	72	4,540	810	3,730

3. Application of miscible CO_2-EOR would enable a significant portion of the Illinois and Michigan Basin's "stranded oil" to be recovered. Of the 72 large Illinois and Michigan Basin oil reservoirs favorable for CO_2-EOR, 24 reservoirs (with 2.2 billion barrels OOIP) screen as being favorable for miscible CO_2-EOR. The remaining 48 oil reservoirs (with 2.3 billion barrels OOIP) screen as being favorable for immiscible CO_2-EOR. The total technically recoverable resource from applying CO_2-EOR in these 72 large oil reservoirs, ranges from 220 million barrels to 810 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

Region	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
Illinois	16	130	300	30	-	190
Indiana	0	-	-	7	-	50
Kentucky	0	-	-	8	-	40
Michigan	8	90	210	3	-	20
TOTAL	24	220	510	48	-	300

4. Under "Traditional Practices" CO_2 flooding technology, high CO_2 costs and high risks, pursuing Illinois and Michigan Basin's "stranded oil" is not economically feasible. Traditional application of miscible CO_2-EOR technology to the 72 large reservoirs in the data base would enable 220 million barrels of "stranded oil" to become technically recoverable from the Illinois and Michigan Basin. However, with the assumed high costs for CO_2 in the Illinois and Michigan Basin (equal to $1.50 per Mcf at $30 Bbl), uncertainties about future oil prices and the performance of CO_2-EOR technology, none of this "stranded oil" would become economically recoverable at oil prices of $30 per barrel as adjusted for gravity and location, Table 4.

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

Region	No. of Reservoirs	OOIP	Economically* Recoverable	
		(MMBbls)	(# Reservoirs)	(MMBbls)
Illinois	16	1,360	-	-
Indiana	-	-	-	-
Kentucky	-	-	-	-
Michigan	8	790	-	-
TOTAL	24	2,150	0	0

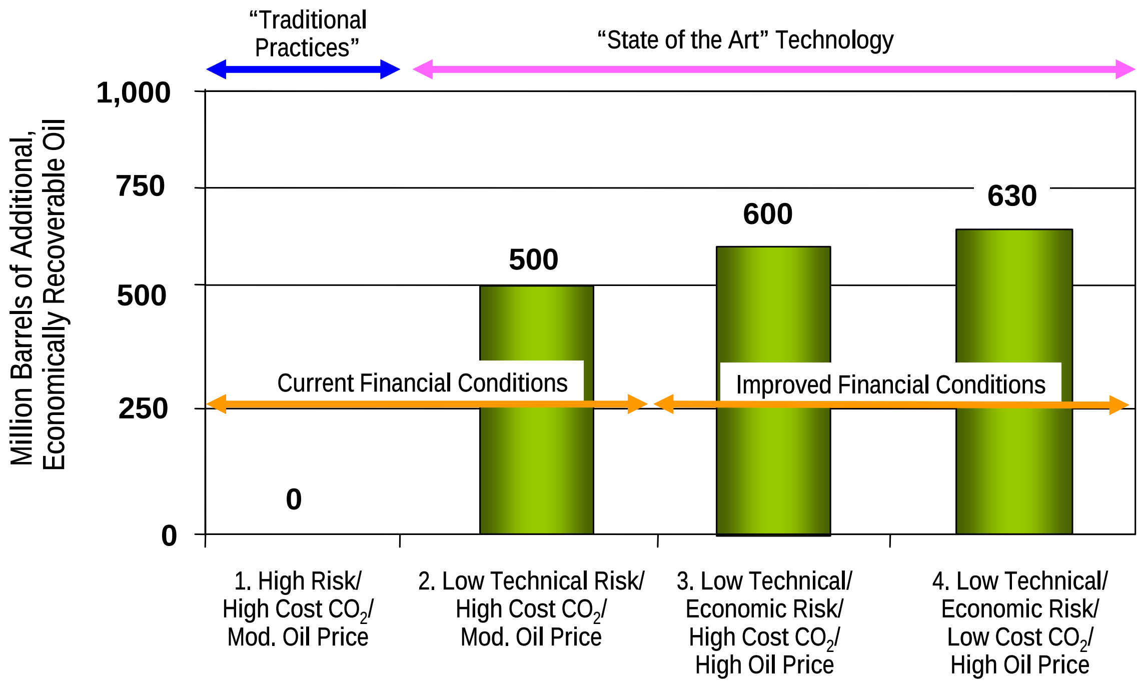
**This case assumes an oil price of $30 per barrel, a CO_2 cost of $1.50 per Mcf, and a ROR hurdle rate of 25% (before tax).*

5. Introduction of "State-of-the-art" CO_2-EOR technology, risk mitigation incentives and lower CO_2 costs would enable 0.6 billion barrels of additional oil to become economically recoverable from the Illinois and Michigan Basin. With "State-of-the-art" CO_2-EOR technology and its higher oil recovery efficiency (but at oil prices of $30 a barrel and high cost CO_2) 500 million barrels of the oil remaining in Illinois and Michigan Basin's reservoirs becomes economically recoverable.

Risk mitigation actions and/or higher oil prices, providing an oil price equal to $40 per barrel, would enable 600 million barrels of oil to become economically recoverable from Illinois and Michigan Basin's large oil reservoirs.

Lower cost CO_2 supplies, equal to $0.80 per Mcf at $40 a barrel and assuming a large-scale CO_2 transportation system and incentives for CO_2 emissions capture, would enable the economic potential to increase to 630 million barrels, Figure 1 and Table 5.

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



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

Table 5. Economically Recoverable Resources - Alternative Scenarios

Region	Scenario #2: "State-of-the-art" (Moderate Oil Price/ High CO_2 Cost)		Scenario #3: "Risk Mitigation" (High Oil Price/ High CO_2 Cost)		Scenario #4: "Ample Supplies of CO_2" (High Oil Price/ Low CO_2 Cost)	
	(# Reservoirs)	(MMBbls)	(# Reservoirs)	(MMBbls)	(# Reservoirs)	(MMBbls)
Illinois	23	380	36	450	37	460
Indiana	0	0	2	30	5	50
Kentucky	8	40	8	40	8	40
Michigan	1	80	1	80	1	80
TOTAL	32	500	47	600	51	630

6. Once the results from the study's large oil reservoirs data base are extrapolated to the region as a whole, the technically recoverable CO_2-EOR potential for the Illinois and Michigan Basin is estimated at nearly 1.5 billion barrels. The large Illinois and Michigan Basin oil reservoirs examined by the study account for 61% of the region's oil resource. Extrapolating the 810 million barrels of technically recoverable EOR potential in these oil reservoirs to the total Illinois and Michigan Basin oil resource provides an estimate of 1,460 million barrels of technical CO_2-EOR potential. (However, no extrapolation of economic potential has been estimated, as the development costs of the large Illinois and Michigan Basin oil fields may not reflect the development costs for the smaller oil reservoirs in the region.)

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

8. A small portion of this CO_2-EOR potential is already being pursued by operators in the Illinois and Michigan Basin. *Three EOR projects are currently underway in small oil fields in Michigan. Together, these three EOR projects have produced or proven over one 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 Illinois and Michigan Basin to achieve the CO_2-EOR potential defined by this study. The overall market for purchased CO_2 could be over 2.3 Tcf, plus another 4.6 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 Illinois and Michigan Basin's oil reservoirs would enable over 115 million metric tonnes of CO_2 emissions to be stored, greatly reducing greenhouse gas emissions. Advanced CO_2-EOR flooding and CO_2 storage concepts (plus incentives for storing CO_2) would significantly increase this amount.

Table 6. Potential CO_2 Supply Requirements in the Illinois and Michigan Basin: Scenario #4 ("Ample Supplies of CO_2")

Region	No. of Reservoirs	Economically Recoverable (MMBbls)	Market for Purchased CO_2 (Tcf)	Market for Recycled CO_2 (Tcf)
Illinois	37	460	1.7	3.4
Indiana	5	50	0.2	0.4
Kentucky	8	40	0.1	0.2
Michigan	1	80	0.3	0.6
TOTAL	51	630	2.3	4.6

10. Significant supplies of industrial CO_2 emissions exist in the Illinois and Michigan Basin, sufficient to meet the CO_2 needs for EOR. The natural CO_2 deposits in the Rocky mountains and Mississippi that supply CO_2 to the Permian Basin and Mississippi CO_2-EOR fields are absent in the Midwest. However, CO_2 emissions, from gas processing plants and hydrogen plants could provide 13 Bcf per year of high concentration (relatively low cost) CO_2, equal to 0.3 Tcf of CO_2 supply in 20 years. Finally, almost unlimited supplies of low concentration CO_2 emissions (equal to over 130 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 Illinois and Michigan Basin'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 Illinois and Michigan Basin's oil fields, and the considerable market and oil price risks — all argue that a partnership involving the oil production industry, potential CO_2 suppliers and transporters, the Illinois and Michigan Basin states and the federal government will be needed to overcome these barriers.

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

1.4 ACKNOWLEDGEMENTS. Advanced Resources would like to acknowledge the most valuable assistance provided to the study by a series of individuals and organizations in Illinois, Indiana, Kentucky and Michigan.

In Illinois, we would like to thank the Illinois Geologic Survey, Oil and Gas Division, particularly Ms. Beverly Seyler, Mr. Scott Frailey and Mr. Brian Huff, for providing detailed historical oil production and well data for the oil producing fields within the state as well as allowing ARI advanced access to the Oil and Gas Division's waterflood data base. This information was instrumental in allowing ARI to determine the breakout of producing to injecting wells for each oil reservoir within the state.

In Kentucky, we would like to thank the Kentucky Geological Survey, particularly Brian Nuttall, for providing historical oil production for Kentucky.

2. INTRODUCTION

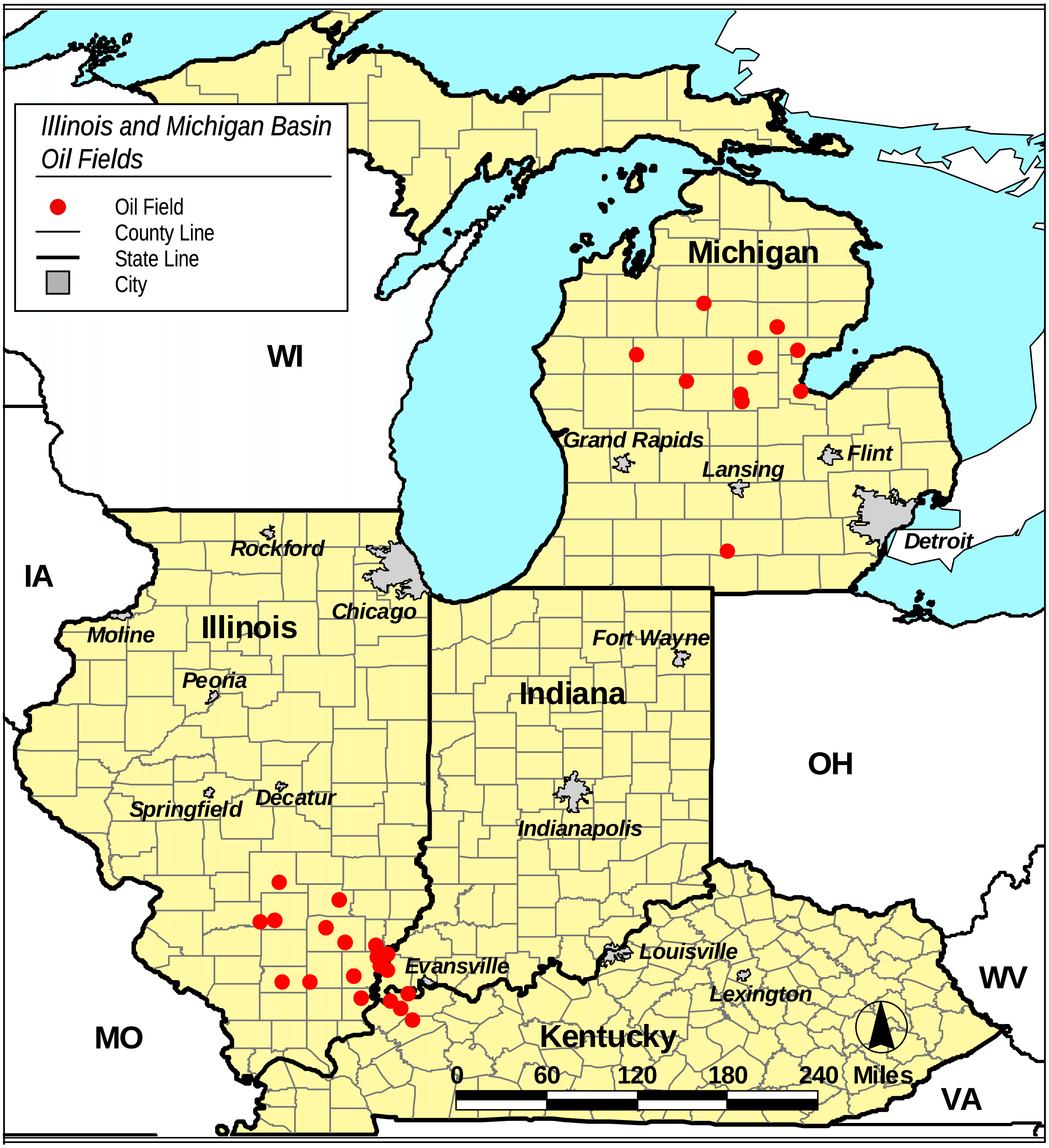
2.1 CURRENT SITUATION. *The Illinois and Michigan Basin oil producing region addressed in the report is mature and in decline. Stemming the decline in oil production will be a major challenge, requiring a coordinated set of actions by numerous parties who have a stake in this problem — Illinois and Michigan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

The main purpose of this report is to provide information to these "stakeholders" on the potential for pursuing CO_2 enhanced oil recovery (CO_2-EOR) as one option for slowing and potentially stopping the decline in the Illinois and Michigan Basin's oil production.

This report, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Illinois and Michigan Basin of Illinois, Indiana, Kentucky and Michigan," provides information on the size of the technical and economic potential for CO_2-EOR in the Illinois and Michigan Basin oil producing regions. It also identifies the many barriers — insufficient and costly CO_2 supplies, high market and economic risks, and concerns over technology performance — that currently impede the cost-effective application of CO_2-EOR in the Illinois and Michigan Basin oil producing region.

2.2 BACKGROUND. The Illinois and Michigan Basin of Illinois, Indiana, Kentucky and Michigan currently produce 51 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). The Illinois and Michigan Basin oil producing region and the location of its major oil fields amenable to CO_2-EOR are shown in Figure 2.

Figure 2. Location of Major Illinois and Michigan Basins Large Oil Fields Amenable to CO_2-EOR.

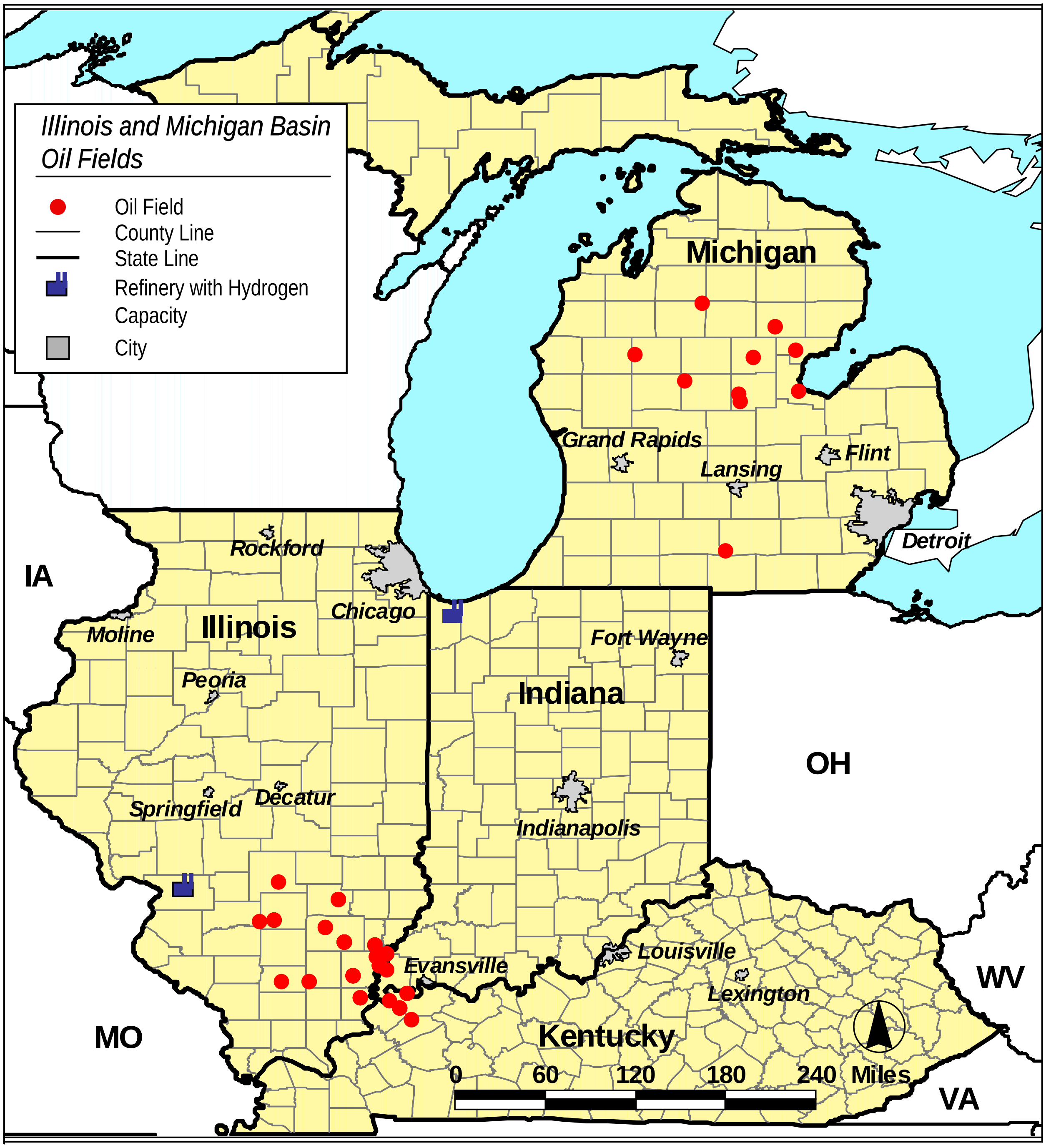


2.3 PURPOSE. This report, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Illinois and Michigan Basin of Illinois, Indiana, Kentucky and Michigan" is part of a larger effort to examine the enhanced oil recovery and CO_2 storage potential in key U.S. oil basins. The work involves establishing 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 Department of Energy/Fossil Energy (DOE/FE) itself to formulate policies and research programs that would support increased recovery of domestic oil resources. As such, this desktop model complements, but does not duplicate, the more extensive TORIS modeling system maintained by DOE/FE's National Energy Technology Laboratory.

2.4 KEY ASSUMPTIONS. *For purposes of this study, it is assumed that sufficient supplies of CO_2 will become available, by pipeline from industrial sources such as the hydrogen plants and refineries in Whiting, Indiana; and Wood River, Illinois, which produce 35 million cubic feet of CO_2 per day, Figure 3. In addition, gas processing and chemical plants in the region and particularly the electric power plants in these four states could provide a billion cubic feet of CO_2 per day. The study assumes that this CO_2 will become available in the near future, before the oil fields in the region are abandoned.*

Figure 3. Location of Refineries with Hydrogen Capacity Relative to Large Illinois and Michigan Basin Oil Fields.



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

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

2. *"State-of-the-art" Technology*. This involves bringing to the Illinois and Michigan Basin 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 hydrocarbon components into the CO_2 phase and solution of CO_2 in the oil phase) with the oil remaining in the reservoir. Typically, reservoirs at depths greater than 3,000 feet and with oil gravities greater than 25 ºAPI would be selected for miscible CO_2-EOR. Major Illinois and Michigan Basin light oil fields such as Clay City Consolidated (IL) and Albion-Scipio (MI) fit into this category. The great bulk of past CO_2-EOR floods have been conducted in these types of "favorable reservoirs".
2. *Challenging Reservoirs Involving Immiscible Application of CO_2-EOR*. These are the moderately heavy oil reservoirs (as well as shallower light oil reservoirs) that do not meet the stringent requirements for miscibility. This reservoir set includes the large Illinois and Michigan Basin oil fields, such as Griffin Consolidated (IN) and New Harmony Consolidated (IL), which still hold a significant portion of their original oil. Illinois and Michigan Basin reservoirs at depths greater than 2,000 feet with oil gravities between 17.5° and 25 °API (or higher) would generally be included in this category.

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

Table 7. Matching of CO_2-EOR Technology With the Illinois and Michigan Basin's Oil Reservoirs

CO_2-EOR Technology Selection	Oil Reservoir Selection
"Traditional Practices" Miscible CO_2-EOR	▪ 24 Deep, Light Oil Reservoirs
"State-of-the-art" Miscible and Immiscible CO_2-EOR	▪ 24 Deep, Light Oil Reservoirs ▪ 48 Deep, Moderately Heavy Oil Reservoirs

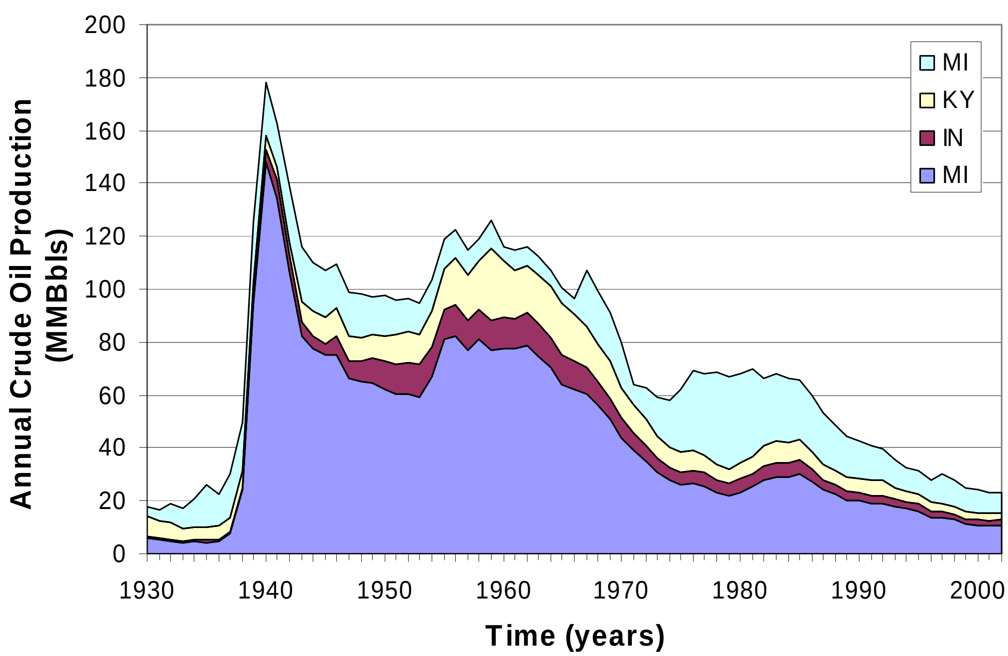
2.6 OTHER ISSUES. This study draws on a series of sources for basic data on the reservoir properties and the expected technical and economic performance of CO_2-EOR in the Illinois and Michigan Basin's major oil reservoirs. Because of confidentiality and proprietary issues, the results of the study have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

3. OVERVIEW OF ILLINOIS AND MICHIGAN BASINOIL PRODUCTION

3.1 HISTORY OF OIL PRODUCTION. Oil production for the Illinois and Michigan Basin of United States — encompassing Illinois, Indiana, Kentucky and Michigan — has declined in the past 60 years, Figure 4. Since reaching a peak in the 1940's, when oil production was over 480 thousand barrels per day, oil production reached a recent low of 18.5 million barrels (51 thousand barrels per day) in 2004.

- Illinois, the largest oil producing state in the region with 9.1 million barrels of oil produced in 2004, has seen a slide in oil production for nearly 60 years.
- Indiana, with 1.9 million barrels of oil produced in 2004, has seen a slide in oil production for nearly 40 years.
- Kentucky, with 2.5 million barrels of oil produced in 2004, has also seen a slide in oil production for nearly 40 years.
- Michigan, with 5.0 million barrels of oil produced in 2004, has seen a slide in production in the past 25 years.

Figure 4. Illinois and Michigan Basin Historical Oil Production since 1930



However, the Illinois and Michigan Basin still holds a rich resource of oil in the ground. With 17.8 billion barrels of original oil in-place (OOIP) and approximately 6.3 billion barrels expected to be recovered, 11.5 billion barrels of oil will be "stranded" due to lack of technology, lack of sufficient, affordable CO_2 supplies and high economic and technical risks.

Table 8 presents the status and annual oil production for the ten largest Illinois and Michigan Basin oil fields (based on OOIP) that account for about 28% of the oil production in this region. The table shows that for nine of the largest oil fields production is stable or in decline. Increasing the Illinois and Michigan Basin's oil production could be attained by applying enhanced oil recovery technology, particularly CO_2-EOR.

Table 8. Crude Oil Annual Production, Ten Largest Illinois and Michigan Basin Oil Fields, 2002-2004 (Million Barrels per Year)

Major Oil Fields	2002	2003	2004	Production Status
Lawrence County Division (IL)	1.3	1.2	1.0	Declining
Clay City Consolidated (IL)	1.1	1.2	1.2	Stable
Main Consolidated (IL)	1.0	1.0	0.9	Stable
Salem Consolidated (IL)	0.6	0.6	0.7	Stable
New Harmony Consolidated (IL)	0.4	0.6	0.6	Increasing
Louden (IL)	0.5	0.5	0.5	Stable
Sailor Springs (IL)	0.3	0.3	0.3	Stable
Dale City (IL)	0.1	0.1	0.1	Stable
Roland (IL)	0.1	0.1	0.1	Stable
Albion/Scipio (MI)	low*	low*	low*	Stable

** field production <10 MBbls/yr.*

3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY. Illinois and Michigan Basin oil producers are familiar with using technology for improving oil recovery. For example, producers have used waterflooding in the Illinois basin since the 1950's to improve oil recovery. More recently, two small CO_2-EOR projects have been ongoing for nearly 10 years in Michigan Additional discussion of the experience with CO_2-EOR in the Illinois and Michigan Basin is provided in Chapter 6.

3.3 THE "STRANDED OIL" PRIZE. *Even though the Illinois and Michigan Basin's oil production is declining, this does not mean that the resource base is depleted. The four producing regions in the Illinois and Michigan Basin – Illinois, Indiana, Kentucky and Michigan, still contain 65% of their OOIP after primary and secondary oil recovery. This large volume of remaining oil in-place (ROIP) is the "prize" for CO_2-EOR.*

Table 9 provides information on the maturity and oil production history of 8 large Illinois and Michigan Basin oil fields, each with estimated ultimate recovery of 100 million barrels or more.

Table 9. Selected Major Oil Fields of the Illinois and Michigan Basin

	Field/State	Year Discovered	Cumulative Production (MMBbl)	Estimated Reserves (MMBbl)	Remaining Oil In-Place (MMBbl)
1	Lawrence, IL	1906	428	13.2	631
2	Louden, IL	1937	394	4.4	549
3	Salem Consol., IL	1938	399	6.9	529
4	Main Consol., IL	1906	241	7.9	567
5	New Harmony, IL	1939	133	4.0	176
6	Albion/Scipio, MI	1957	125	0.1	165
7	Dale Consol., IL	1940	96	0.6	170
8	Griffin Consol., IN	1938	80	2.3	154

3.4 REVIEW OF PRIOR STUDIES. CO_2-EOR is beginning to gain attention in the Illinois and Michigan Basins. A recent study by the Illinois State Geological Survey and Illinois State University screened the Illinois Basin reservoirs for the potential for CO_2-miscible EOR.

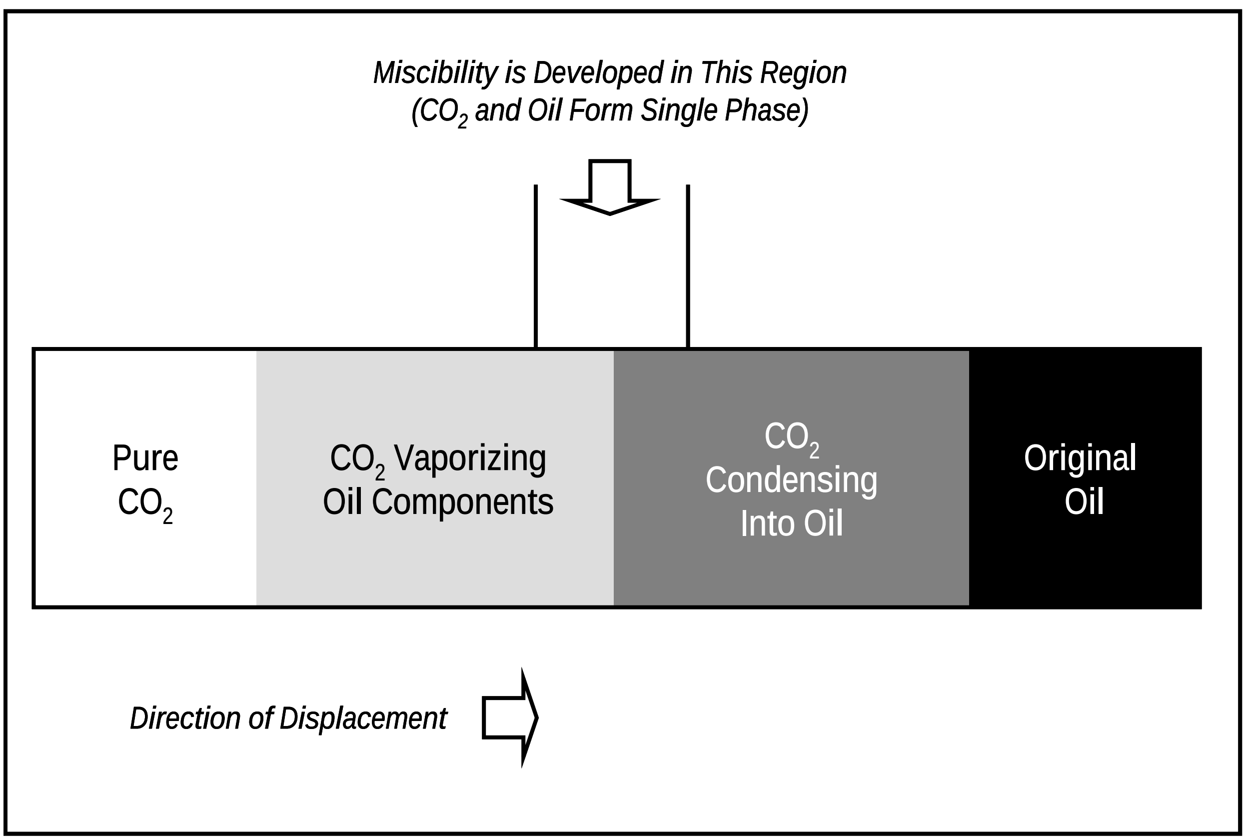
- *"CO_2 Sequestration and Enhanced Oil Recovery Potential in Illinois Basin Oil Reservoirs" by the Illinois State Geological Survey and Illinois State University in 2004.* The study classified Illinois Basin reservoirs on the basis of CO_2 miscibility. Of the 14.6 billion barrels of OOIP in the basin, 46% of the OOIP screened miscible or near-miscible. Geological and reservoir modeling was then conducted on several candidate fields to test the potential for EOR through CO_2-miscible injection. Based on this, the study estimated that an additional 10-12% of the fields' OOIP was recoverable through EOR. Extrapolating this result basin wide, they estimate that 0.7-1.6 billion barrels of oil could be produced through CO_2-EOR.

4. MECHANISMS OF CO2-EOR

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

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

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



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

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

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

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

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

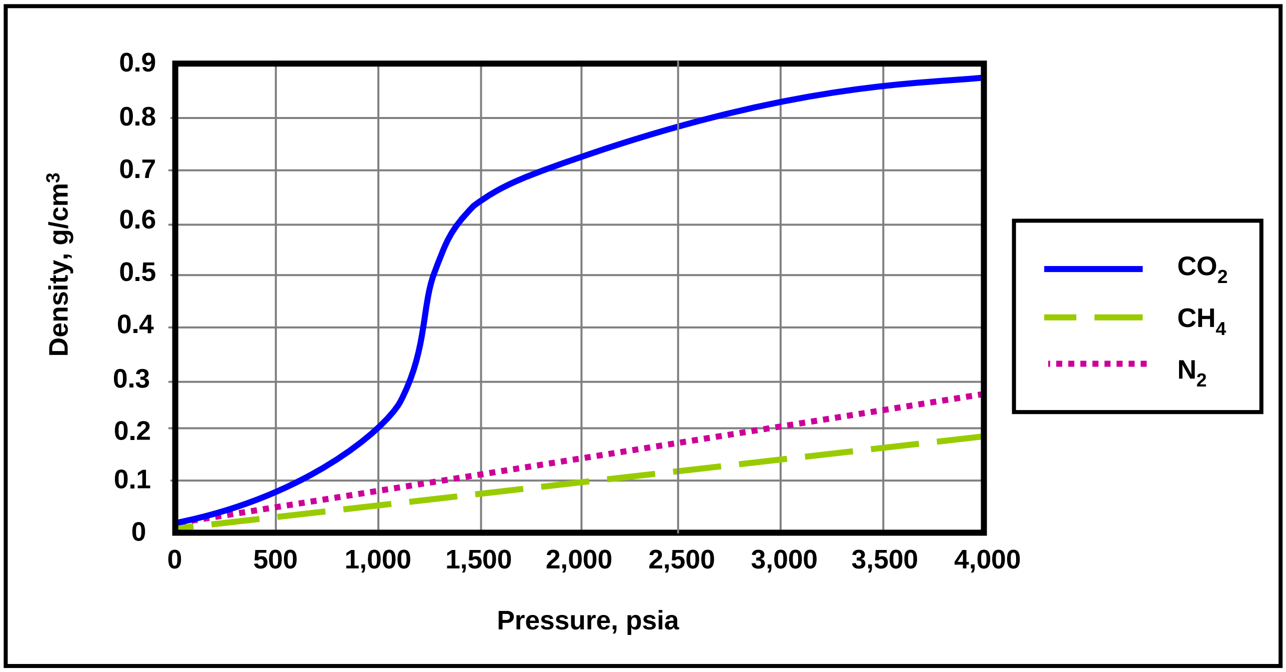


Figure 6B. Carbon Dioxide, CH_4 and N_2 viscosities at 105^0F. At high pressures, the viscosity of CO_2 is also greater then that of methane or nitrogen, although it remains low in comparison to that of liquids. Viscosities were calculated with an EOS.

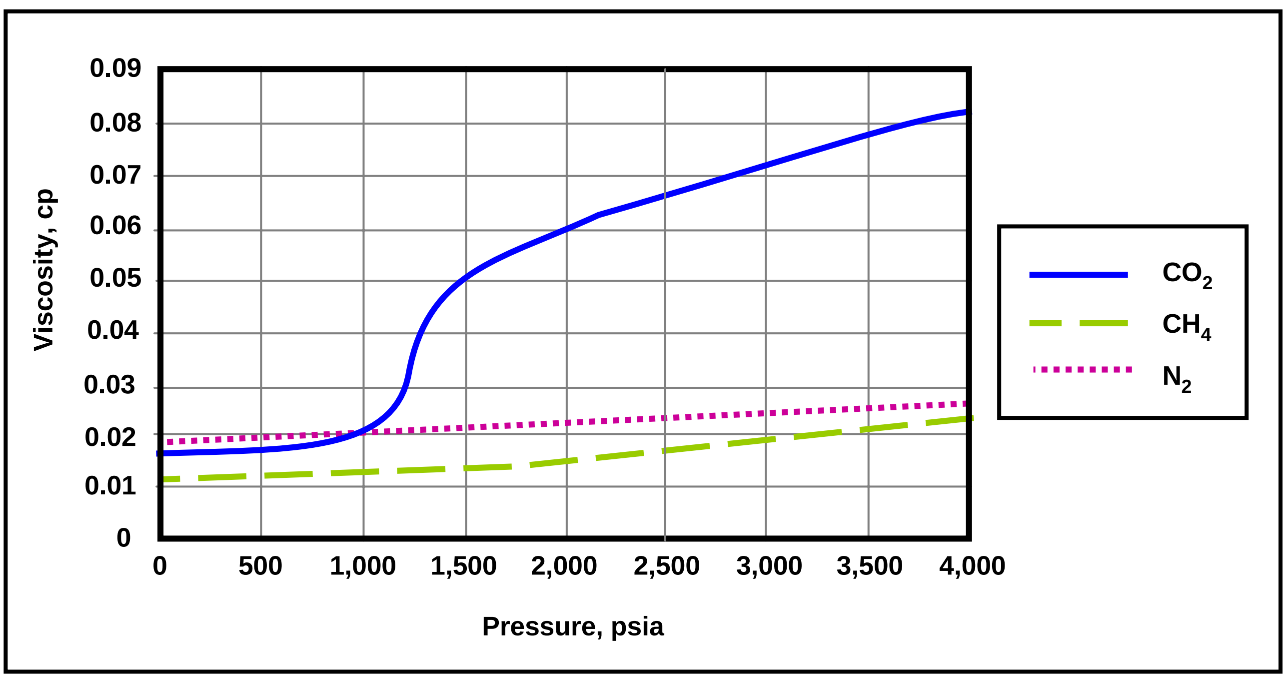


Figure 7A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid (Holm and Josendal).

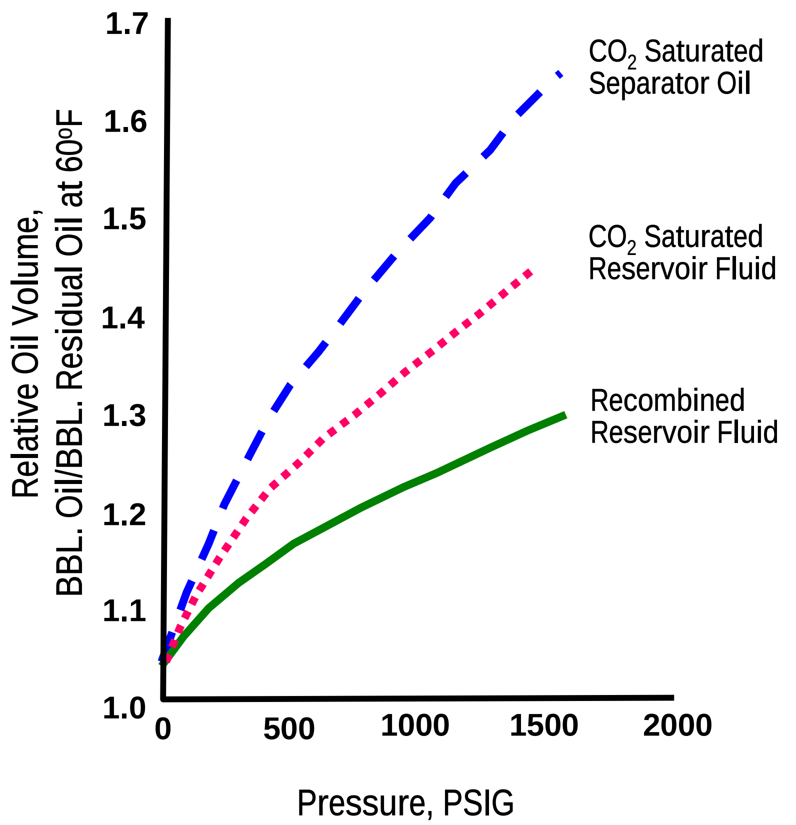


Figure 7B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

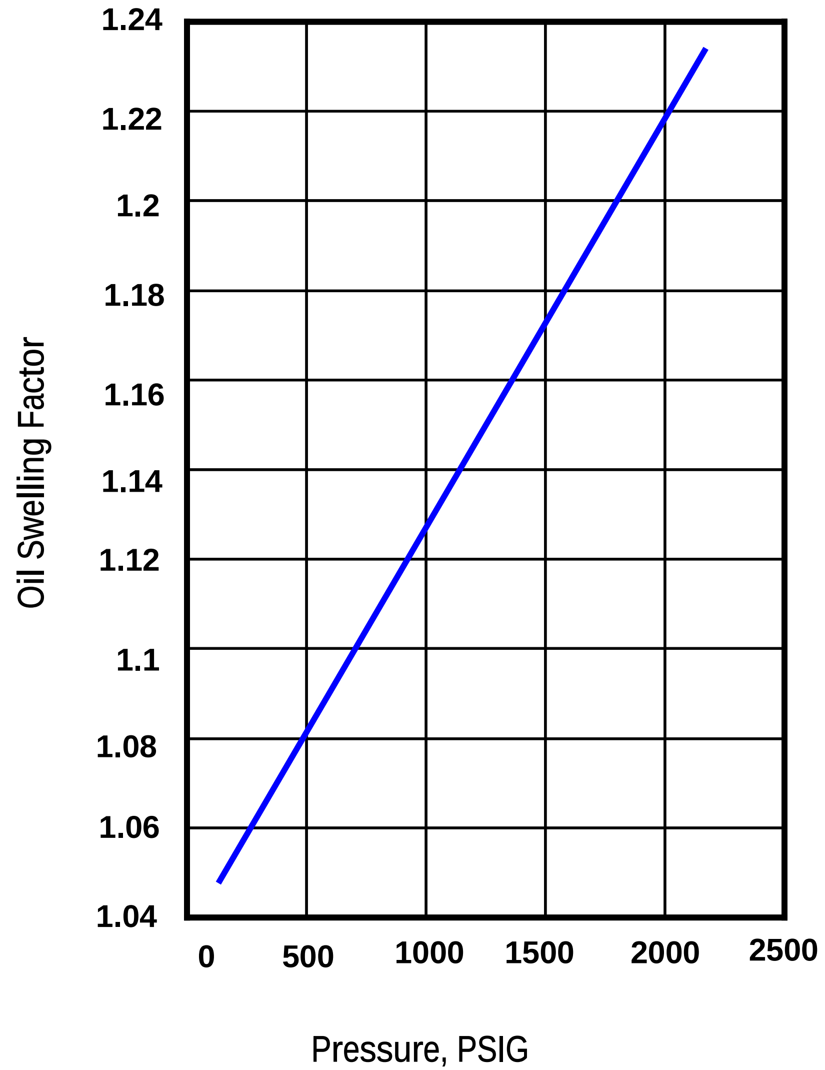
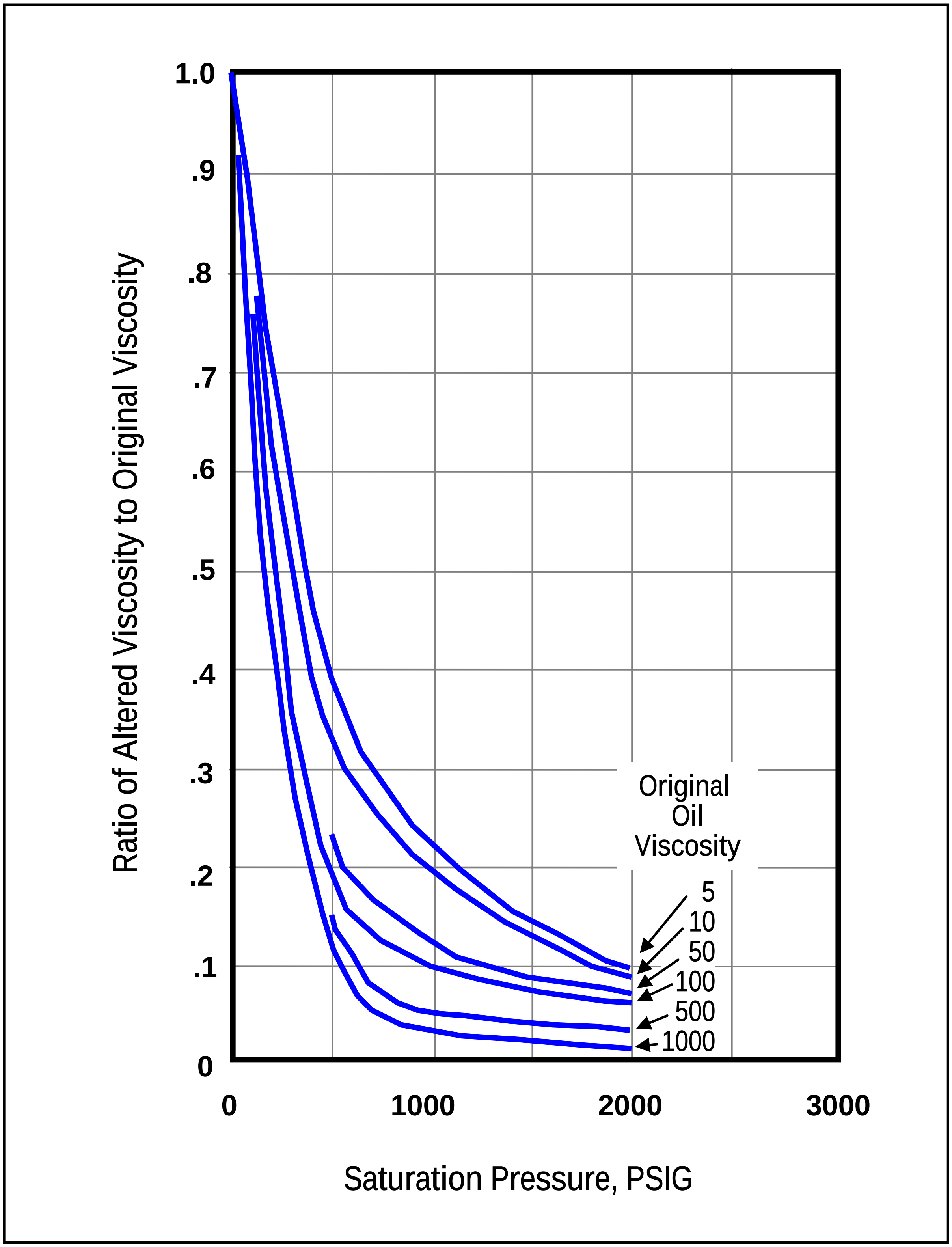


Figure 8. Viscosity Reduction Versus Saturation Pressure (Simon and Graue).



5. STUDY METHODOLOGY

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

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

5.2 ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE. The study started with the National Petroleum Council (NPC) Public Data Base, maintained by DOE Fossil Energy. The study updated and modified this publicly accessible data base to develop the Illinois and Michigan Basin Major Oil Reservoirs Data Base for Illinois, Indiana, Kentucky and Michigan.

Table 10 illustrates the oil reservoir data recording format developed by the study. The data format readily integrates with the input data required by the CO_2-EOR screening and oil recovery models, discussed below. Overall, the Illinois and Michigan Basin Major Oil Reservoirs Data Base contains 154 reservoirs, accounting for 61% of the oil expected to be ultimately produced in Illinois and Michigan Basin by primary and secondary oil recovery processes.

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

Basin Name	
Field Name	
Reservoir	

Reservoir Parameters:

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

Oil Production

	TORIS	ARI
Producing Wells (active)		
Producing Wells (shut-in)		
2002 Production (Mbbl)		
Daily Prod - Field (Bbl/d)		
Cum Oil Production (MMbbl)		
EOY 2002 Oil Reserves (MMbbl)		
Water Cut		

Water Production

	TORIS	ARI
2002 Water Production (Mbbl)		
Daily Water (Mbbl/d)		

Injection

	TORIS	ARI
Injection Wells (active)		
Injection Wells (shut-in)		
2002 Water Injection (MMbbl)		
Daily Injection - Field (Mbbl/d)		
Cum Injection (MMbbl)		
Daily Inj per Well (Bbl/d)		

EOR

EOR Type	
2002 EOR Production (MMbbl)	
Cum EOR Production (MMbbl)	
EOR 2002 Reserves (MMbbl)	
Ultimate Recovery (MMbbl)	

Volumes

	TORIS	ARI
OOIP (MMbl)		
Cum P/S Oil (MMbl)		
2002 P/S Reserves (MMbl)		
Ult P/S Recovery (MMbl)		
Remaining (MMbbl)		
P/S Recovery Efficiency (%)		

OOIP Volume Check

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

SROIP Volume Check

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

ROIP Volume Check

	TORIS	ARI
ROIP Check (MMbl)		

Considerable effort was required to construct an up-to-date, volumetrically consistent data base that contained all of the essential data, formats and interfaces to enable the study to: (1) develop an accurate estimate of the size of the original and remaining oil in-place in the Illinois and Michigan Basin; (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, and 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° API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection. Table 11 tabulates the oil reservoirs that passed the preliminary screening step. Because of data limitations, this screening study combined the sands into a single reservoir.

Table 11. Illinois and Michigan Basin Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
A. Illinois		
Illinois	ALBION	AUX VASES
Illinois	ALBION	MCCLOSKEY
Illinois	ALBION	BETHEL
Illinois	ALBION	BIEHL
Illinois	ALBION	CYPRESS
Illinois	BENTON	TAR SPRINGS
Illinois	CENTRALIA	DEVONIAN
Illinois	CLAY CITY CONSOLIDATED	OHARA
Illinois	CLAY CITY CONSOLIDATED	SPAR MOUNTAIN
Illinois	CLAY CITY CONSOLIDATED	MCCLOSKEY
Illinois	CLAY CITY CONSOLIDATED	ST LOUIS
Illinois	CLAY CITY CONSOLIDATED	SALEM
Illinois	CLAY CITY CONSOLIDATED	AUX VASES
Illinois	CLAY CITY CONSOLIDATED	CYPRESS
Illinois	DALE CITY	AUX VASES
Illinois	DALE CITY	BETHEL
Illinois	INMAN EAST AND WEST	AUX VASES
Illinois	INMAN EAST AND WEST	CYPRESS
Illinois	INMAN EAST AND WEST	TAR SPRINGS
Illinois	JOHNSONVILLE CONSOLIDATED	AUX VASES
Illinois	JOHNSONVILLE CONSOLIDATED	MCCLOSKEY
Illinois	JOHNSONVILLE CONSOLIDATED	SALEM
Illinois	NEW HARMONY CONSOLIDATED	AUX VASES
Illinois	NEW HARMONY CONSOLIDATED	BETHEL
Illinois	NEW HARMONY CONSOLIDATED	CYPRESS
Illinois	NEW HARMONY CONSOLIDATED	MCCLOSKEY
Illinois	PHILLIPSTOWN CONSOLIDATED	MCCLOSKEY
Illinois	PHILLIPSTOWN CONSOLIDATED	AUX VASES
Illinois	PHILLIPSTOWN CONSOLIDATED	BETHEL
Illinois	PHILLIPSTOWN CONSOLIDATED	TAR SPRINGS
Illinois	ROLAND CONSOLIDATED	MCCLOSKEY
Illinois	ROLAND CONSOLIDATED	AUX VASES
Illinois	ROLAND CONSOLIDATED	BETHEL
Illinois	ROLAND CONSOLIDATED	CYPRESS
Illinois	ROLAND CONSOLIDATED	HARDINSBURG
Illinois	ROLAND CONSOLIDATED	WALTERSBURG
Illinois	SAILOR SPRINGS	AUX VASES
Illinois	SAILOR SPRINGS	CYPRESS
Illinois	SAILOR SPRINGS	MCCLOSKEY
Illinois	SAILOR SPRINGS	SPAR MOUNTAIN

Table 11. Illinois and Michigan Basin Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Illinois	SALEM CONSOLIDATED	DEVONIAN
Illinois	SALEM CONSOLIDATED	TRENTON
Illinois	SALEM CONSOLIDATED	MCCLOSKEY
Illinois	SALEM CONSOLIDATED	SALEM
Illinois	SALEM CONSOLIDATED	SPAR MOUNTAIN
Illinois	ST JAMES	CARPER
B. Indiana		
Indiana	GRIFFIN CONSOLIDATED	BETHEL
Indiana	GRIFFIN CONSOLIDATED	CYPRESS
Indiana	GRIFFIN CONSOLIDATED	PAOLI
Indiana	GRIFFIN CONSOLIDATED	STE GENEVIEVE
Indiana	GRIFFIN CONSOLIDATED	TAR SPRINGS
Indiana	GRIFFIN CONSOLIDATED	WALTERSBURG
Indiana	SPRINGFIELD CONSOL.	WALTERSBURG
C. Kentucky		
Kentucky	HITESVILLE CONS	STE GENEVIEVE
Kentucky	HITESVILLE CONS	AUX VASES & WALTERSBURG
Kentucky	HITESVILLE CONS	CHESTER SS
Kentucky	POOLE CONS	CHESTER SS
Kentucky	POOLE CONS	STE GENEVIEVE
Kentucky	SMITH MILLS CONS - SMITH MILLS NORTH	STE GENEVIEVE
Kentucky	SMITH MILLS CONS - SMITH MILLS NORTH	CHESTER SS
Kentucky	UNIONTOWN CONS	CHESTER SS
D. Michigan		
Michigan	ALBION/SCIPIO	TRENTON - BLACK RIVER
Michigan	BUCKEYE NORTH	DUNDEE
Michigan	COLDWATER	DUNDEE
Michigan	DEEP RIVER	DUNDEE
Michigan	KAWKAWLIN	DUNDEE
Michigan	MT PLEASANT	DUNDEE
Michigan	NORWICH EAST	RICHFIELD
Michigan	PORTER	DUNDEE
Michigan	REED CITY	DUNDEE
Michigan	WEST BRANCH	DETROIT RIVER
Michigan	WEST BRANCH	DUNDEE
Michigan	ALBION/SCIPIO	TRENTON - BLACK RIVER

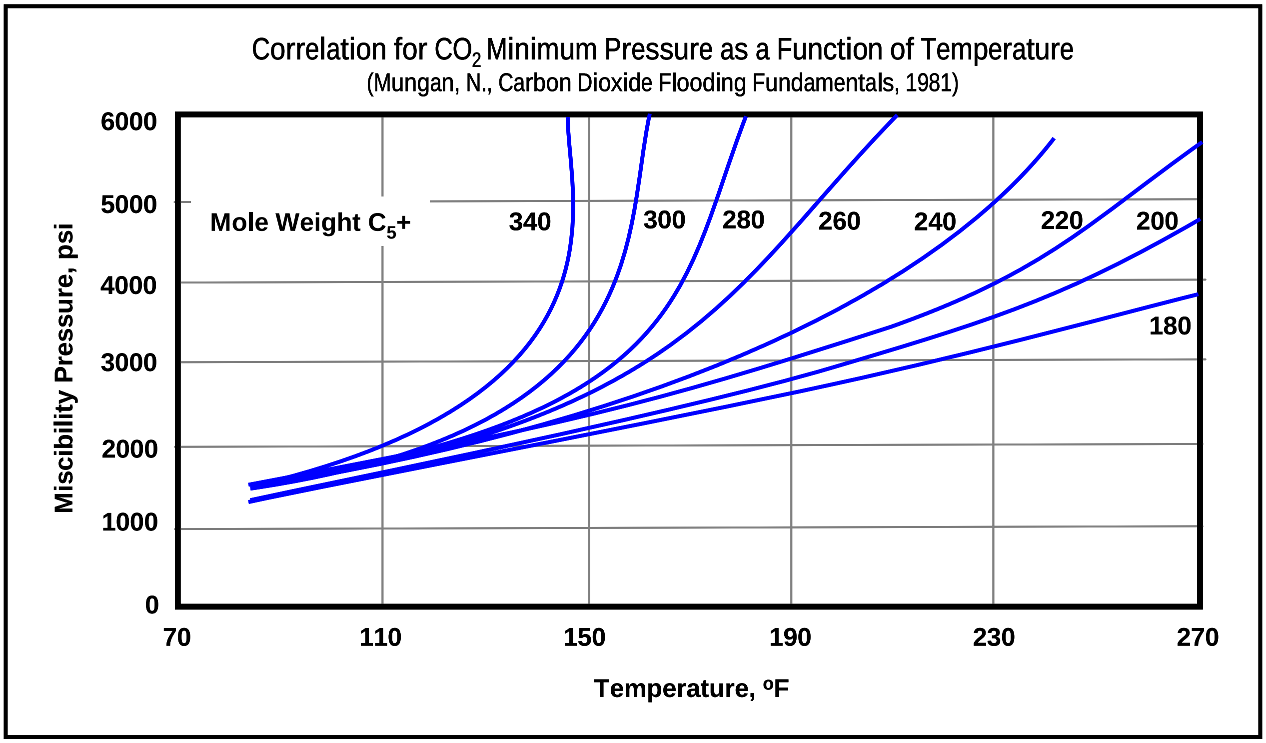
5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and 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 9 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 Illinois and Michigan Basin 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.

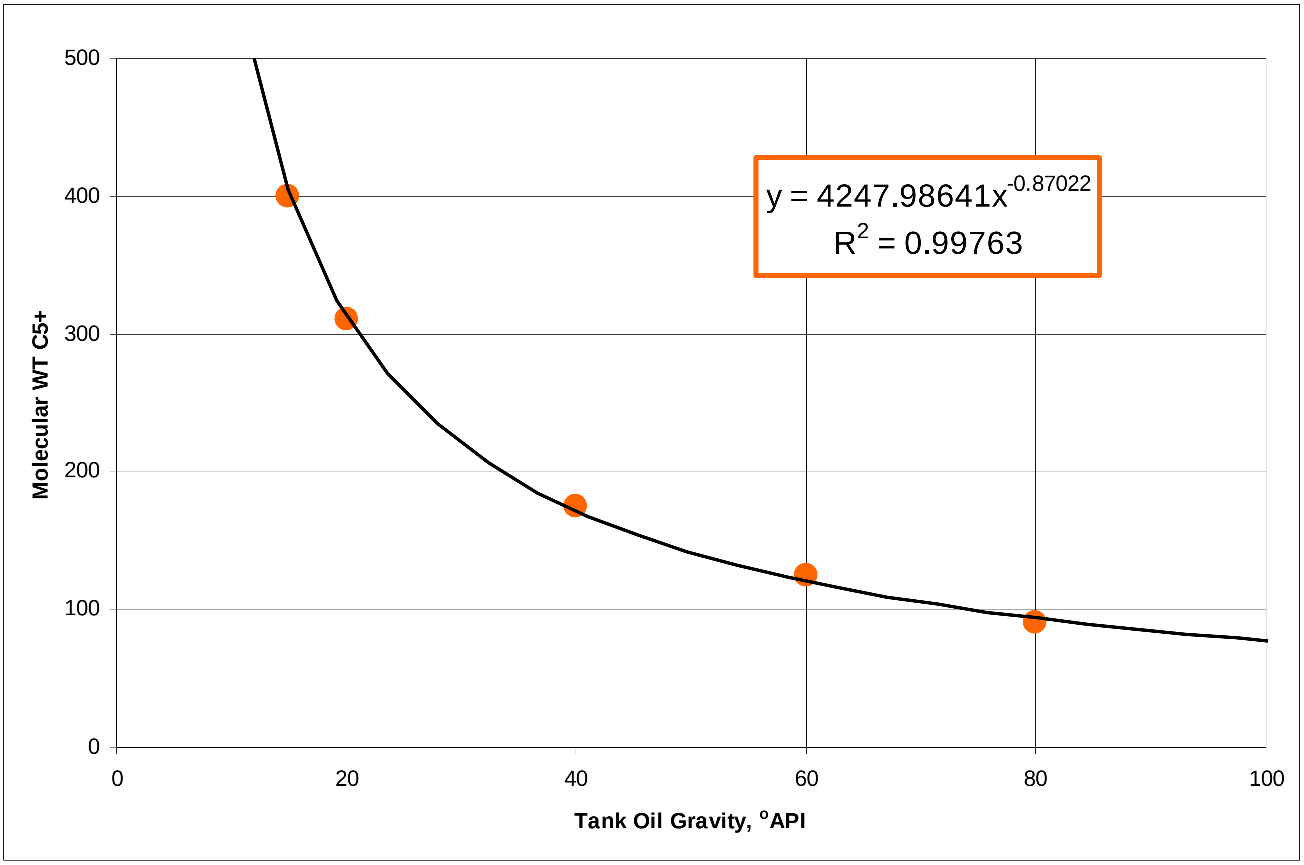
Figure 9. Estimating CO_2 Minimum Miscibility Pressure



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 10.

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 10. Correlation of MW C5+ to Tank Oil Gravity



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 12. Economic Model Established by the Study

Pattern-Level Cashflow Model		**Advanced**											
State				New Injectors	0.39								
Field				Existing Injectors	0.00			5					
Formation				Converted Producers	0.61								
Depth				New Producers	0.0								
Distance from Trunkline (mi)				Existing Producers	1.34								
# of Patterns				Disposal Wells	0.00								
Miscibility:	**Immiscible**												
	Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
CO_2 Injection (MMcf)			285	285	285	285	285	285	242	190	190	190	190
H_2O Injection (Mbw)			143	143	143	143	143	143	164	190	190	190	190
Oil Production (Mbbl)			9	25	34	24	9	16	17	13	13	8	11
H_2O Production (MBw)			246	224	176	164	169	160	156	168	184	190	188
CO_2 Production (MMcf)			-	13	108	169	195	200	220	214	172	169	166
CO_2 Purchased (MMcf)			285	272	177	116	90	85	22	-	18	21	24
CO_2 Recycled (MMcf)			-	13	108	169	195	200	220	190	172	169	166
Oil Price ($/Bbl)	**$ 40.00**		$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Gravity Adjustment	**38**	Deg	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50
Gross Revenues ($M)			$ 327	$ 978	$ 1,324	$ 916	$ 358	$ 601	$ 643	$ 497	$ 481	$ 323	$ 431
Royalty ($M)	**-12.5%**		$ (41)	$ (122)	$ (166)	$ (115)	$ (45)	$ (75)	$ (80)	$ (62)	$ (60)	$ (40)	$ (54)
Severance Taxes ($M)	**-1.0%**		$ (3)	$ (9)	$ (12)	$ (8)	$ (3)	$ (5)	$ (6)	$ (4)	$ (4)	$ (3)	$ (4)
Ad Valorum ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 283	$ 847	$ 1,147	$ 794	$ 310	$ 520	$ 557	$ 430	$ 417	$ 280	$ 374
Capital Costs ($M)													
New Well - D&C		$ (138)											
Reworks - Producers to Producers		$ (61)											
Reworks - Producers to Injectors		$ (16)											
Reworks - Injectors to Injectors		$ -											
Surface Equipment (new wells only)		$ (19)											
CO_2 Recycling Plant		$ -	$ (384)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (34)											
Total Capital Costs		$ (268)	$ (384)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	**0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO_2 Costs ($M)													
Total CO_2 Cost ($M)			$ (228)	$ (223)	$ (185)	$ (161)	$ (150)	$ (148)	$ (105)	$ (76)	$ (83)	$ (84)	$ (86)
O&M Costs													
Operating & Maintenance ($M)			$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)
Lifting Costs ($/bbl)	**$ 0.25**		$ (64)	$ (62)	$ (53)	$ (47)	$ (44)	$ (44)	$ (43)	$ (45)	$ (49)	$ (50)	$ (50)
G&A	**20%**		(25)	(24)	(23)	(21)	(21)	(21)	(21)	(21)	(22)	(22)	(22)
Total O&M Costs			$ (148)	$ (147)	$ (135)	$ (128)	$ (125)	$ (124)	$ (123)	$ (126)	$ (131)	$ (131)	$ (132)
Net Cash Flow ($M)		$ (268)	$ (476)	$ 478	$ 828	$ 505	$ 35	$ 248	$ 328	$ 228	$ 203	$ 65	$ 156
Cum. Cash Flow		$ (268)	$ (745)	$ (267)	$ 561	$ 1,066	$ 1,101	$ 1,349	$ 1,677	$ 1,905	$ 2,108	$ 2,173	$ 2,329
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		$ (268)	$ (381)	$ 306	$ 424	$ 207	$ 12	$ 65	$ 69	$ 38	$ 27	$ 7	$ 13
Disc. Cum Cash Flow		$ (268)	$ (649)	$ (343)	$ 80	$ 287	$ 299	$ 364	$ 432	$ 471	$ 498	$ 505	$ 518
NPV (BTx)	25%	$526											
NPV (BTx)	20%	$ 720											
NPV (BTx)	15%	$ 988											
NPV (BTx)	10%	$ 1,390											
IRR (BTx)		53.27%											

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

Depth															
Distance from Trunkline (mi)															
# of Patterns															
Miscibility:	**Immiscible**														
	Year	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
CO2 Injection (MMcf)		190	190	190	190	190	69	-	-	-	-	-	-	-	-
H2O Injection (Mbw)		190	190	190	190	190	251	285	285	285	285	285	285	285	285
Oil Production (Mbbl)		10	6	4	3	4	5	7	9	11	11	9	8	8	8
H2O Production (MBw)		189	192	193	194	193	201	221	247	255	262	266	270	271	272
CO2 Production (MMcf)		168	169	172	174	173	181	146	74	46	30	24	19	14	13
CO2 Purchased (MMcf)		22	21	18	16	17	-	-	-	-	-	-	-	-	-
CO2 Recycled (MMcf)		168	169	172	174	173	69	-	-	-	-	-	-	-	-
Oil Price ($/Bbl)	**$ 40.00**	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Gravity Adjustment	38	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50
Gross Revenues ($M)		$ 366	$ 231	$ 139	$ 116	$ 158	$ 204	$ 254	$ 343	$ 435	$ 431	$ 350	$ 308	$ 312	$ 308
Royalty ($M)	**-12.5%**	$ (46)	$ (29)	$ (17)	$ (14)	$ (20)	$ (26)	$ (32)	$ (43)	$ (54)	$ (54)	$ (44)	$ (39)	$ (39)	$ (39)
Severance Taxes ($M)	**-1.0%**	$ (3)	$ (2)	$ (1)	$ (1)	$ (1)	$ (2)	$ (2)	$ (3)	$ (4)	$ (4)	$ (3)	$ (3)	$ (3)	$ (3)
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 317	$ 200	$ 120	$ 100	$ 137	$ 177	$ 220	$ 297	$ 377	$ 374	$ 303	$ 267	$ 270	$ 267
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)		$ (85)	$ (85)	$ (83)	$ (82)	$ (83)	$ (27)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M Costs															
Operating & Maintenance ($M)		$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)
Lifting Costs ($/bbl)	**$ 0.25**	$ (50)	$ (50)	$ (49)	$ (49)	$ (49)	$ (52)	$ (57)	$ (64)	$ (67)	$ (68)	$ (69)	$ (69)	$ (76)	$ (76)
G&A	**20%**	(22)	(22)	(22)	(22)	(22)	(22)	(23)	(25)	(25)	(26)	(26)	(26)	(27)	(27)
Total O&M Costs		$ (131)	$ (131)	$ (131)	$ (131)	$ (131)	$ (134)	$ (140)	$ (149)	$ (152)	$ (154)	$ (154)	$ (155)	$ (163)	$ (163)
Net Cash Flow ($M)		$ 101	$ (16)	$ (94)	$ (113)	$ (77)	$ 16	$ 80	$ 148	$ 225	$ 220	$ 149	$ 112	$ 107	$ 104
Cum. Cash Flow		$ 2,430	$ 2,414	$ 2,320	$ 2,207	$ 2,130	$ 2,146	$ 2,226	$ 2,374	$ 2,599	$ 2,819	$ 2,968	$ 3,080	$ 3,187	$ 3,291
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
Disc. Net Cash Flow		$ 7	$ (1)	$ (4)	$ (4)	$ (2)	$ 0	$ 1	$ 2	$ 3	$ 2	$ 1	$ 1	$ 1	$ 0
Disc. Cum Cash Flow		$ 525	$ 524	$ 520	$ 516	$ 514	$ 514	$ 516	$ 518	$ 521	$ 523	$ 524	$ 524	$ 525	$ 525
NPV (BTx)	25%														
NPV (BTx)	20%														
NPV (BTx)	15%														
NPV (BTx)	10%														
IRR (BTx)															

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

Depth												
Distance from Trunkline (mi)												
# of Patterns												
Miscibility:	**Immiscible**											
	Year	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**
CO2 Injection (MMcf)		-	-	-	-	-	-	-	-	-	-	-
H2O Injection (Mbw)		285	285	285	285	75	-	-	-	-	-	-
Oil Production (Mbbl)		7	7	6	6	1	-	-	-	-	-	-
H2O Production (MBw)		274	275	276	277	73	-	-	-	-	-	-
CO2 Production (MMcf)		10	9	7	7	2	-	-	-	-	-	-
CO2 Purchased (MMcf)		-	-	-	-	-	-	-	-	-	-	-
CO2 Recycled (MMcf)		-	-	-	-	-	-	-	-	-	-	-
Oil Price ($/Bbl)	**$ 40.00**	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ 40.00	$ -	$ -	$ -	$ -	$ -	$ -
Gravity Adjustment	**38**	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ 38.50	$ (1.50)	$ (1.50)	$ (1.50)	$ (1.50)	$ (1.50)	$ (1.50)
Gross Revenues ($M)		$ 266	$ 250	$ 243	$ 223	$ 54	$ -	$ -	$ -	$ -	$ -	$ -
Royalty ($M)	**-12.5%**	$ (33)	$ (31)	$ (30)	$ (28)	$ (7)	$ -	$ -	$ -	$ -	$ -	$ -
Severance Taxes ($M)	**-1.0%**	$ (2)	$ (2)	$ (2)	$ (2)	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 230	$ 217	$ 210	$ 193	$ 47	$ -	$ -	$ -	$ -	$ -	$ -
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)		$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($/bbl)	**$ 0.25**	$ (75)	$ (75)	$ (75)	$ (75)	$ (20)	$ -	$ -	$ -	$ -	$ -	$ -
G&A	**20%**	(27)	(27)	(27)	(27)	(16)	-	-	-	-	-	-
Total O&M Costs		$ (162)	$ (162)	$ (162)	$ (162)	$ (95)	$ -	$ -	$ -	$ -	$ -	$ -
Net Cash Flow ($M)		$ 68	$ 55	$ 48	$ 32	$ (49)	$ -	$ -	$ -	$ -	$ -	$ -
Cum. Cash Flow		$ 3,358	$ 3,413	$ 3,461	$ 3,493	$ 3,444	$ 3,444	$ 3,444	$ 3,444	$ 3,444	$ 3,444	$ 3,444
Discount Factor	**25%**	0.00	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	$ 0	$ 0	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -
Disc. Cum Cash Flow		$ 526	$ 526	$ 526	$ 526	$ 526	$ 526	$ 526	$ 526	$ 526	$ 526	$ 526
NPV (BTx)	25%											
NPV (BTx)	20%											
NPV (BTx)	15%											
NPV (BTx)	10%											
IRR (BTx)												

6. RESULTS BY STATE

6.1 ILLINOIS. Illinois is a major oil producing state with a rich history of oil and gas development. Crude oil production began in 1904, and has reached a cumulative recovery of 3.6 billion barrels through 2004. In 2004, Illinois ranked 14th in oil production in the onshore U.S., providing 9.1 MMBbls of oil (25 MBbls/day). It has about 16,737 producing oil wells and oil reserves of 92 MMBbls. Illinois has seen a steady drop in production in recent years, (Table 13).

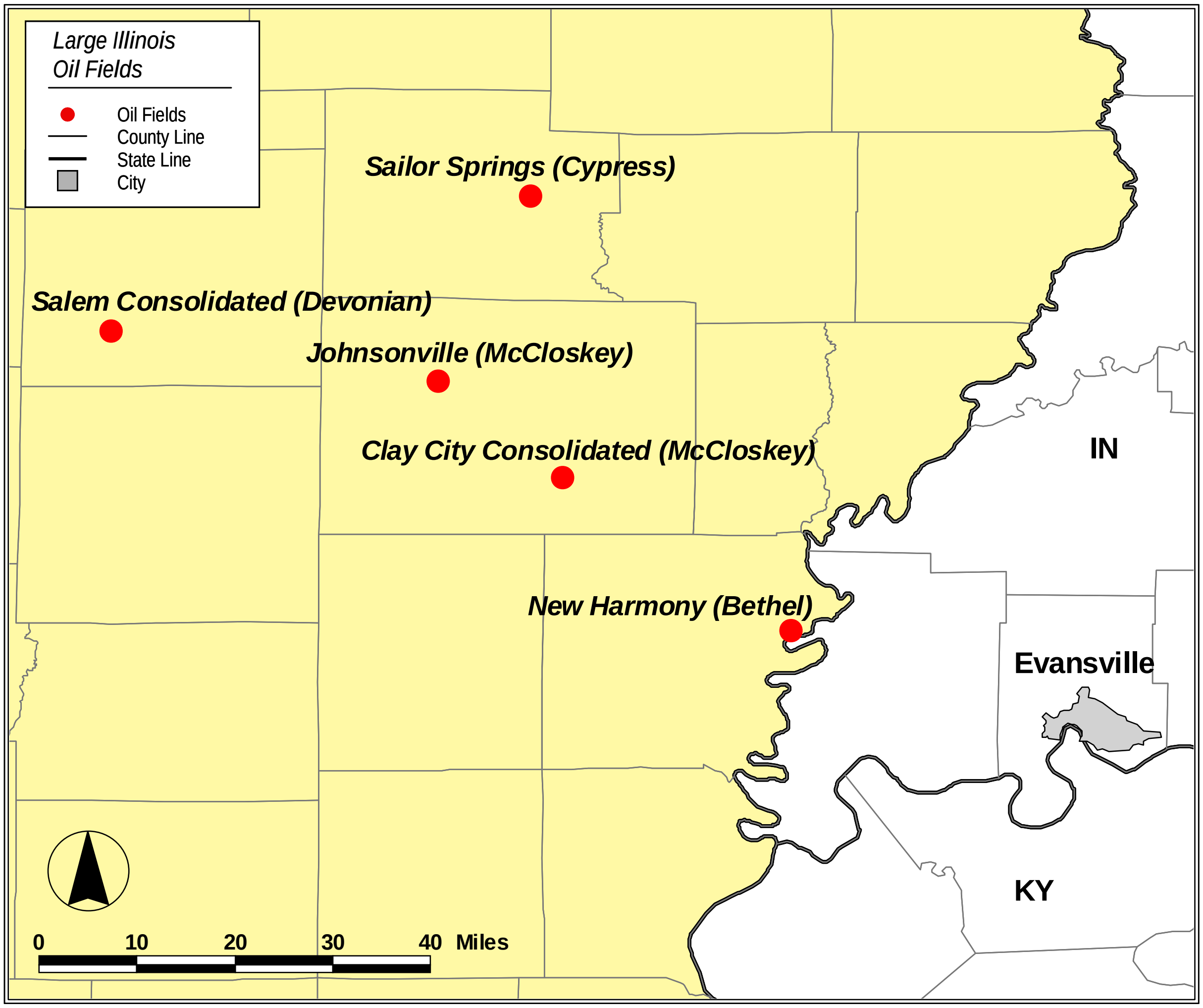
Table 13. Recent History of Illinois Oil Production

	Annual Oil Production	
	(MMBbls/year)	(MBbls/day)
2000	10.8	30
2001	10.4	28
2002	10.9	30
2003	9.1	25
2004	9.1	25

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

- Clay City Consolidated (McCloskey Reservoir)
- Salem Consolidated (Devonian Reservoir)
- Johnsonville Consolidated (McCloskey Reservoir)
- New Harmony Consolidated (Bethel Reservoir)
- Sailor Springs (Cypress Reservoir)

Figure 11. Large Illinois Oil Fields



These five fields, distributed across Illinois, could serve as the “anchor” sites for 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 5 large light oil fields are set forth in Table 14.

Table 14. Status of Large Oil Illinois Fields/Reservoirs (as of 2000)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Clay City Consolidated (McCloskey)	404	116	4	284
2	Salem Consolidated (Devonian)	174	75	1	98
3	Johnsonville Consolidated (Mccloskey)	89	36	1	52
4	New Harmony Consolidated (Behel)	105	41	1	63
5	Sailor Springs (Cypress)	92	31	1	60

These five large "anchor" fields, each with over 60 million barrels of ROIP, may be favorable for miscible or immiscible CO_2 -EOR, based on their reservoir properties, Table 15. Illinois Basin fields often produce from several reservoirs at varying depths. Deeper reservoirs in the Salem Consolidated, Johnsonville Consolidated, and Clay City Consolidated fields screen miscible, while the shallower reservoirs in the Salem Consolidated and Clay City Consolidated, as well as all of the New Harmony and Sailor Springs reservoirs screen immiscible

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

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Clay City Consolidated (McCloskey)	3,050	39.0	Undergoing Waterflood
2	Salem Consolidated (Devonian)	3,440	40.0	Undergoing Waterflood
3	Johnsonville Consolidated (McCloskey)	3,170	38.0	Undergoing Waterflood
4	New Harmony Consolidated (Behel)	2,700	37.0	Undergoing Waterflood
5	Sailor Springs (Cypress)	2,550	37.2	Undergoing Waterflood

Past CO_2-EOR Projects. Illinois oil producers have had limited experiences with CO_2 injection. A small pilot was initiated in the Forsyth field, utilizing CO_2 from the Archer-Daniels-Midland Ethanol Processing Facility in Decatur, IL and results from this project have been published. In the early 1990s, a single-well "huff-and-puff" CO_2 pilot project began in the Mattoon field. The well was drilled to a depth of 1,800 feet in the Cypress reservoir, and CO_2 was again supplied from ADM's ethanol plant in Decatur, IL. After several months of operation, the pilot was shutdown due to high CO_2 costs compared to the oil recovery rate. Currently, there is considerable work underway by the Illinois Geological Survey on locating and characterizing reservoirs suitable for CO_2-EOR.

Future CO_2-EOR Potential. Illinois contains 16 reservoirs that are candidates for miscible CO_2-EOR and 30 reservoirs that are candidates for immiscible CO_2-EOR. Under "Traditional Practices" (and Base Case financial conditions, defined above), however, none of these fields are economically attractive for miscible CO_2 flooding. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection) and establishing lower risk financial conditions, the number of economically favorable for CO_2-EOR oil reservoirs in Illinois is 23, providing 380 million barrels of additional oil recovery, Table 16.

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

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential* (No. of Reservoirs)	Economic Potential* (MMBbls)
"Traditional Practices"	16	1,357	133	0	0
"State-of-the-art" Technology	46	3,115	494	23	380

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

Combining “State-of-the-art” technologies with risk mitigation incentives and/or higher oil prices and lower cost CO_2 supplies would enable CO_2-EOR in Illinois to recover 460 million barrels of CO_2-EOR oil from 37 major reservoirs, Table 17.

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

More Favorable Financial Conditions	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
Plus: Risk Mitigation Incentives*	494	36	450
Plus: Low Cost CO_2 Supplies**	494	37	460

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

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

6.2 INDIANA AND KENTUCKY. Indiana is the 23rd largest onshore oil producing state. Crude oil production in the state began in the 1883, reaching a cumulative recovery of 550 million barrels through 2004. In 2004, the state’s production was 1.9 MMBbls (5.2 MBbls/day). Indiana has about 5,000 producing oil wells and oil reserves of 11 MMBbls. Indiana oil production has been low, but steady in resent years, Table 18.

Table 18. Recent History of Indiana Oil Production

	Annual Oil Production	
	(MMBbls/year)	(MBbls/day)
2000	2.0	5
2001	2.0	5
2002	2.0	5
2003	1.9	5
2004	1.9	5

Kentucky is the 20th largest onshore oil producing state and produced 2.5 MMBbls (7 MBbls/day) of oil (in 2004), from about 18,000 producing wells and 27 MMBbls of crude oil reserves. Oil production began in 1883 in Kentucky and cumulative production has reached 780 MMBbls. The state's oil production has been in slight decline in recent years, Table 19.

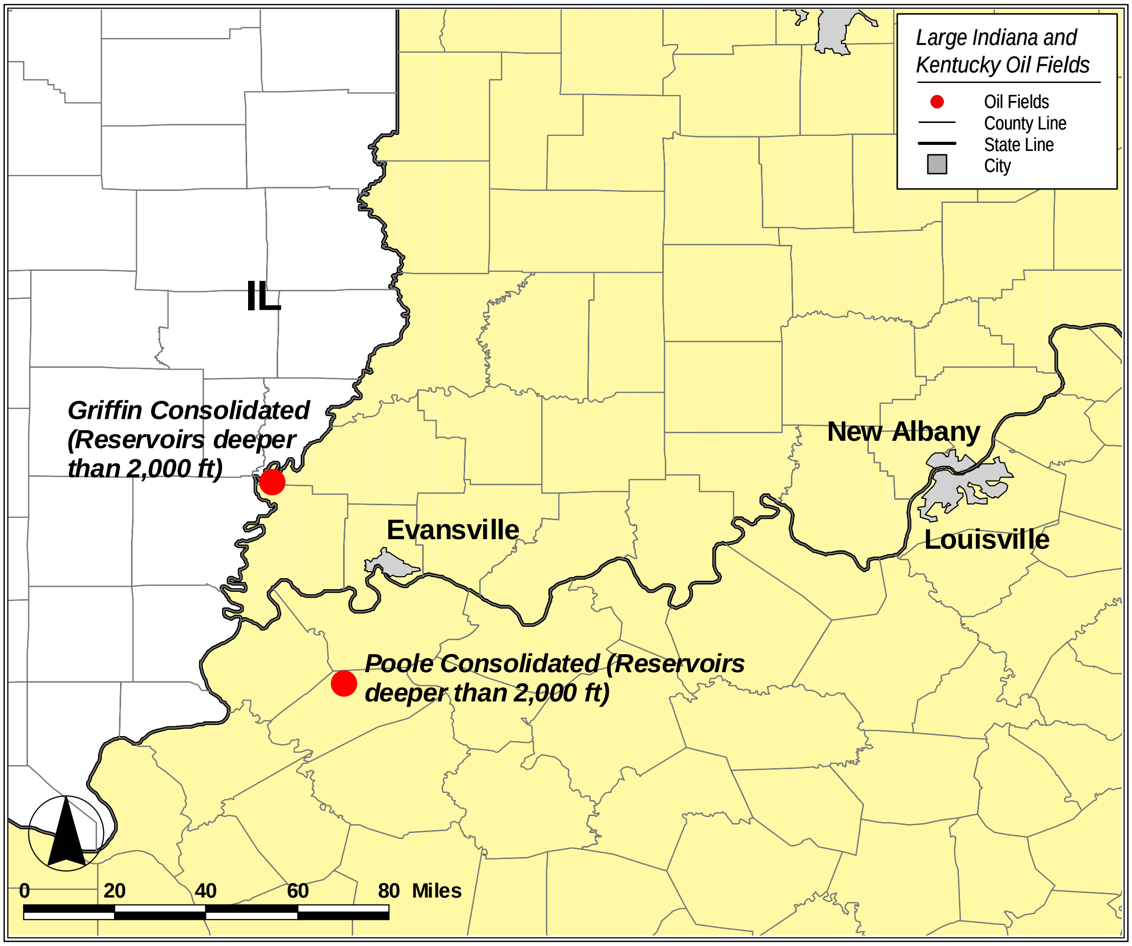
Table 19. Recent History of Kentucky Oil Production

	Annual Oil Production	
	(MMBbls/year)	(MBbls/day)
2000	2.9	8
2001	2.8	8
2002	2.7	7
2003	2.5	7
2004	2.5	7

Indiana and Kentucky Oil Fields*.* The light oil fields of the Illinois Basin of Indiana and Kentucky are too shallow for miscible CO_2-EOR, making them amenable to immiscible CO_2-EOR. To better understand the potential of using CO_2-EOR in Indiana and Kentucky's light oil fields, this section examines, in more depth, two large oil fields, shown in Figure 12.

- Griffin Consolidated Field, IN (Reservoirs >2,000 feet)
- Poole Consolidated Field, KY (Reservoirs >2,000 feet)

Figure 12. Illinois and Kentucky Anchor Fields



These major oil fields could serve as anchor sites for CO_2 projects that could later extend to small fields in the states. The cumulative oil production, proved reserves and remaining oil in-place (ROIP) for the oil reservoirs in this field are set forth in Table 20.

Table 20. Status of Large Indiana and Kentucky 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	Griffin Consolidated (All>2,000 Feet*)	236	84	2	150
2	Poole Consolidated (All>2,000 Feet**)	70	27	2	41

**including Waltersburg, Tar Springs, Paoli, Cypress, Bethel, and Ste. Genevieve reservoirs.*
*** including Ste. Genevieve and Chester s.s. reservoirs*

These large oil fields each contain several individual light oil reservoirs amenable to immiscible CO_2-EOR due to their shallow depth. Table 21 provides the reservoir and oil properties these fields and their current secondary oil recovery activities.

Table 21. Reservoir Properties and Improved Oil Recovery Activity,
Large Indiana Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Griffin Consolidated (All >2,000 Feet)	2,050-2,850	38	Undergoing Waterflood
2	Poole Consolidated (>2,000 Feet	2,030-2,560	36	Undergoing Waterflood

**including Waltersburg, Tar Springs, Paoli, Cypress, Bethel, and Ste. Genevieve reservoirs.*
*** including Ste. Genevieve and Chester s.s. reservoirs*

Past and Current CO_2-EOR Projects. To date, there have been no CO_2-EOR projects in Indiana or Kentucky. However, due to the similarity in reservoir characteristics to those in Illinois, projects in that state may serve as a guide for Indiana/Kentucky EOR projects.

Future CO2-EOR Potential. Indiana and Kentucky contains no oil reservoirs that are candidates for miscible CO_2-EOR due to their shallow depths. Therefore, there is no potential for applying "Traditional Practices" EOR in these states. However, when applying "State-of-the-art Technology" (involving higher volume CO_2 injection, immiscible EOR, and lower risk), 15 immiscible EOR oil reservoirs become technically feasible and 8 reservoirs are economically feasible, Table 22.

Table 22. Economic Oil Recovery Potential Under Two Technologic Conditions, Indiana and Kentucky

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential* (No. of Reservoirs)	Economic Potential* (MMBbls)
"Traditional Practices"	0	0	0	0	0
"State-of-the-art" Technology	15	446	86	8	40

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

Combining "State-of-the-art" technology with risk mitigation incentives and/or higher oil prices plus lower cost CO_2 supplies, would enable an additional 80 million barrels of CO_2-EOR Indiana and Kentucky from 5 major oil reservoirs, Table 23.

Table 23. Economic Oil Recovery Potential with More Favorable Financial Conditions, Indiana and Kentucky

More Favorable Financial Conditions	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
Plus: Risk Mitigation Incentives*	86	10	60
Plus: Low Cost CO_2 Supplies**	86	13	80

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

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

6.3 MICHIGAN. Michigan is the 17th largest domestic oil producing state, providing 5 MMBbls (14 MBbls/day) of oil in 2004, from almost 4,000 producing wells. Oil production in the state of Michigan began in 1925. Cumulative oil recovery in the state is 1.25 billion barrels with 53 million barrels of reserves. In recent years, oil production in Michigan has been in decline, Table 24.

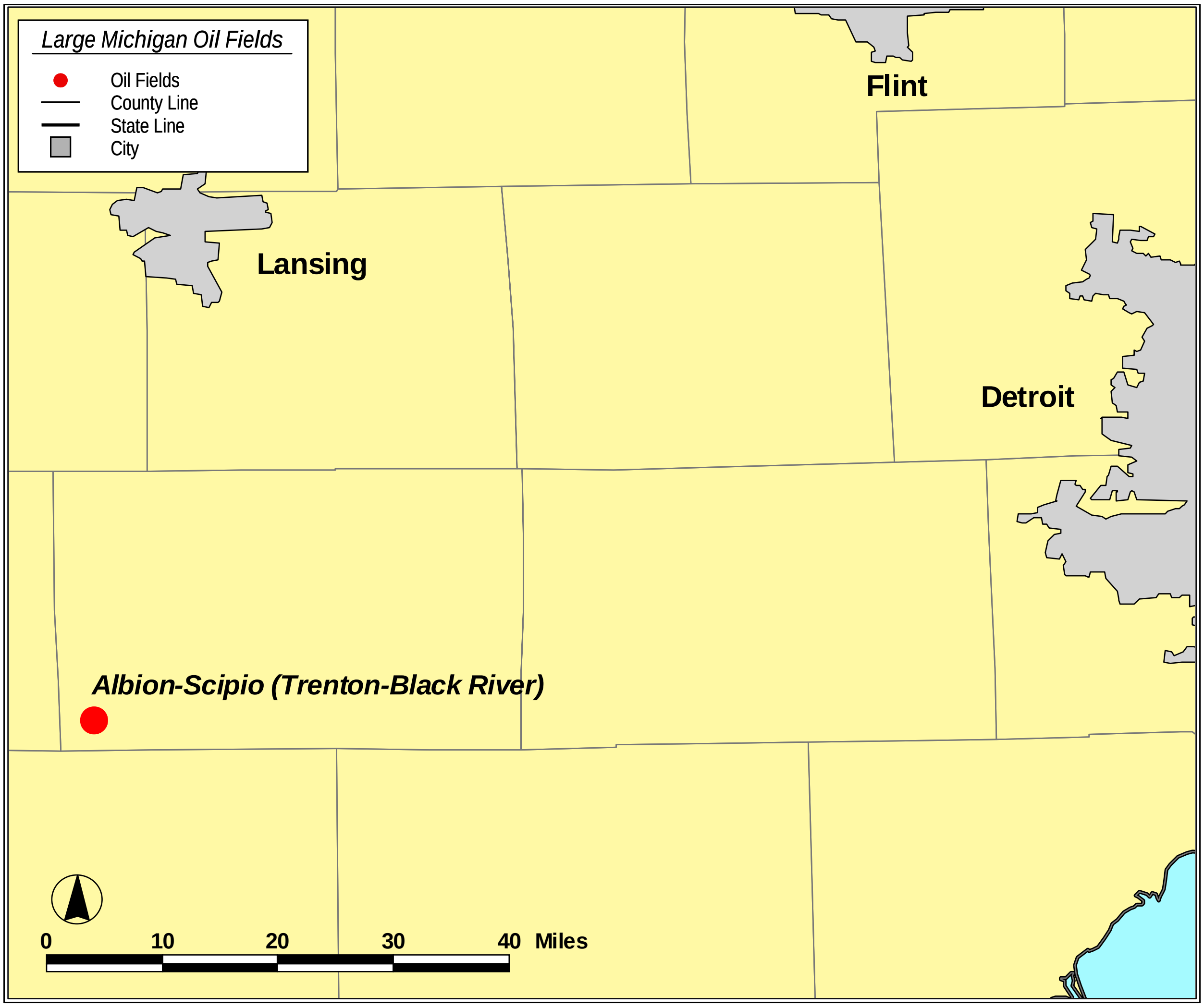
Table 24. Recent History of Michigan Oil Production

	Annual Oil Production	
	(MMBbls/year)	(MBbls/day)
1999	8.6	24
2000	8.4	23
2001	8.1	22
2002	7.5	21
2003	6.7	18
2004	5.0	14

Michigan Fields. Michigan contains 8 large oil fields that may be amenable to miscible CO_2-EOR, Figure 13. To better understand the potential of using CO_2-EOR in Michigan's light oil fields, this section examines, in more depth, the state's largest miscible EOR field:

- Albion/Scipio Field (Trenton-Black River Reservoir)

Figure 13. Albion/Scipio Oil Field, Michigan



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

Table 25. Status of Large Michigan Oil Fields/Reservoirs (as of 2003)

Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
Albion/Scipio (Trenton-Black River)	312	125	low	187

This large oil reservoir, with over 180 million barrels of ROIP, is technically amenable for miscible CO_2-EOR. Table 26 provides the reservoir and oil properties for these reservoirs and their current oil recovery activities.

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

Fields/Reservoir	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
Albion/Scipio (Trenton-Black River)	3,900	41.3	none

Past and Current CO_2-EOR Projects. Two small miscible CO_2-EOR floods have been ongoing in Michigan for the past 10 years using CO_2 from an Antrim shale gas processing plant. In 1996, Core Energy, LLC, began CO_2 miscible flood projects on two Niagran pinnacle reef field reservoirs at 5200 feet depth, Dover 33 and Dover 36, with OOIP's of 4.1 and 3.7 MMBbls, respectively. Dover 36 is expected to ultimately produce an estimated 31% of its OOIP through primary production. Injection of 5.4 Bcf of CO_2 has increased production by an additional 5% of the field OOIP. Dover 33 is expected to perform better, with primary production netting 33% of the OOIP. CO_2 EOR is expected to produce an additional 18% OOIP after 21 Bcf of CO_2 injection. The field operator attributes the low recovery efficiency at Dover 36 to the highly heterogeneous nature of the reservoir. The more optimized well patterns for CO_2 injection in Dover 33 account for the higher expected recovery efficiency.

A third CO_2 EOR project is being conducted by a joint venture between Michigan Technical University, Western Michigan University and Jordan Development Company, LLC on the Dover 35 field. This Niagran pinnacle reef field is similar in size and reservoir characteristics to the Dover 33 and 36 fields. CO_2 injection began in 2004 and the operators expect to produce an additional 10-25% of the field's 2.2 MMBbls of OOIP in addition to an expected ultimate primary recovery of 44% OOIP.

Future CO2-EOR Potential. Michigan contains 11 large oil reservoirs that are candidates for miscible or immiscible CO_2-EOR technology. The potential for economically developing these oil reservoirs is examined first under Base Case financial criteria that combine an oil price of $30 per barrel, CO_2 supply costs ($1.50/Mcf), and a high risk rate of return (ROR) hurdle (25% before tax).

Under "Traditional Practices" (involving a small volume of high cost CO_2 injection and high risk financial conditions), miscible CO_2 flooding would not be economically attractive in the large Michigan oil fields. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection, immiscible EOR, and lower risk), one large oil reservoir in Michigan becomes economically feasible, providing 80 million barrels of additional oil recovery, Table 27.

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

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"	8	793	94	0	0
"State-of-the-art" Technology	11	971	230	1	80

* Oil price of $30 per barrel.

Combining "State-of-the-art" technologies with risk mitigation incentives and/or higher oil prices plus lower cost CO_2 supplies does not enable any additional large oil fields in Michigan to become economic, Table 28.

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

More Favorable Conditions	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
Plus: Risk Mitigation*	230	1	80
Plus: Low Cost CO_2**	230	1	80

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

Input Data Requirements

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

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

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

Calibrating CO_2-PROPHET

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

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

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

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

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

Comparison of *CO_2-PROPHET* and *CO_2PM*

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

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

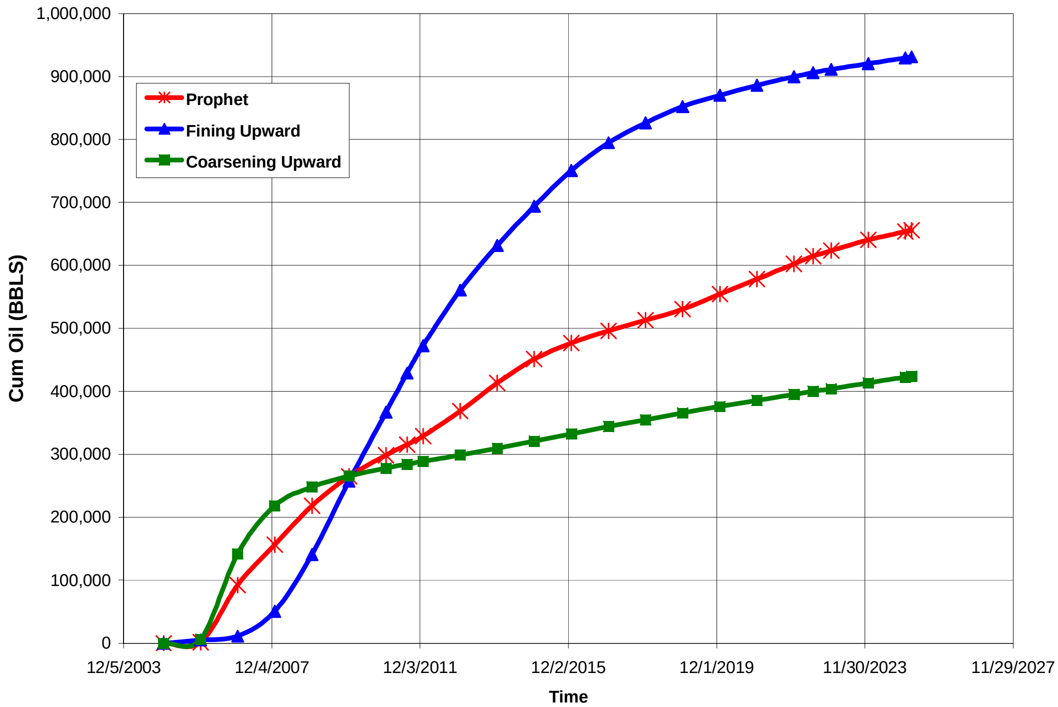
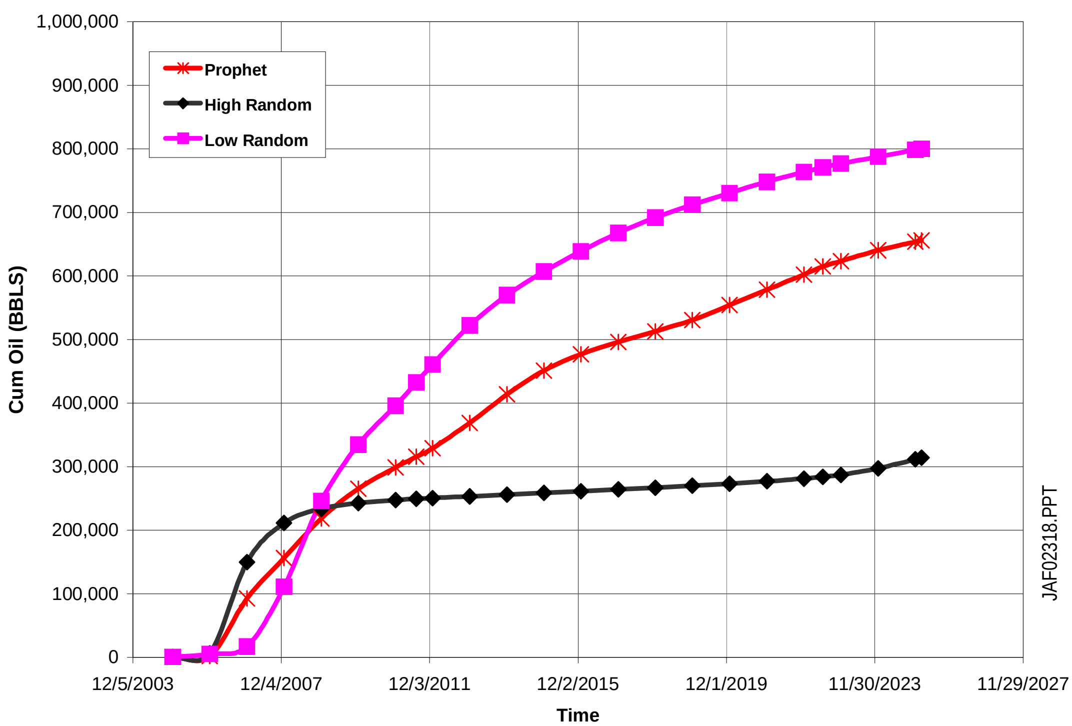


Figure A-2. CO_2-*PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



- *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

Illinois 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:

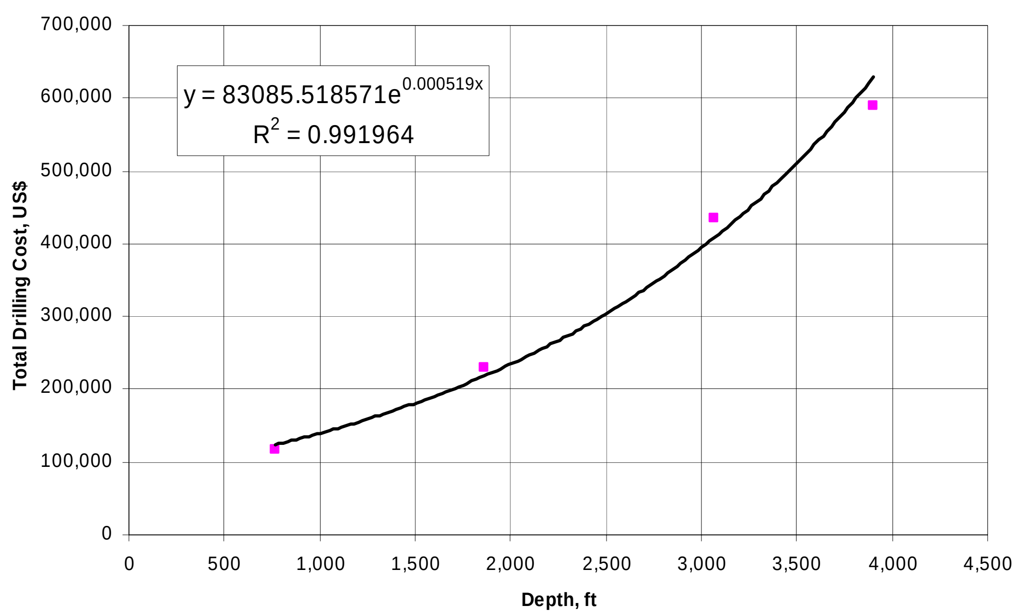
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for Illinois.

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 with depth. The total equation is:

Well D&C Costs = $a_0 \, e^{a_1 D}$
Where: a_0 is 83085
a_1 is 0.00052
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 Illinois.

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



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 Illinois D&C cost calculations to reflect this increase in 2004 drilling costs.

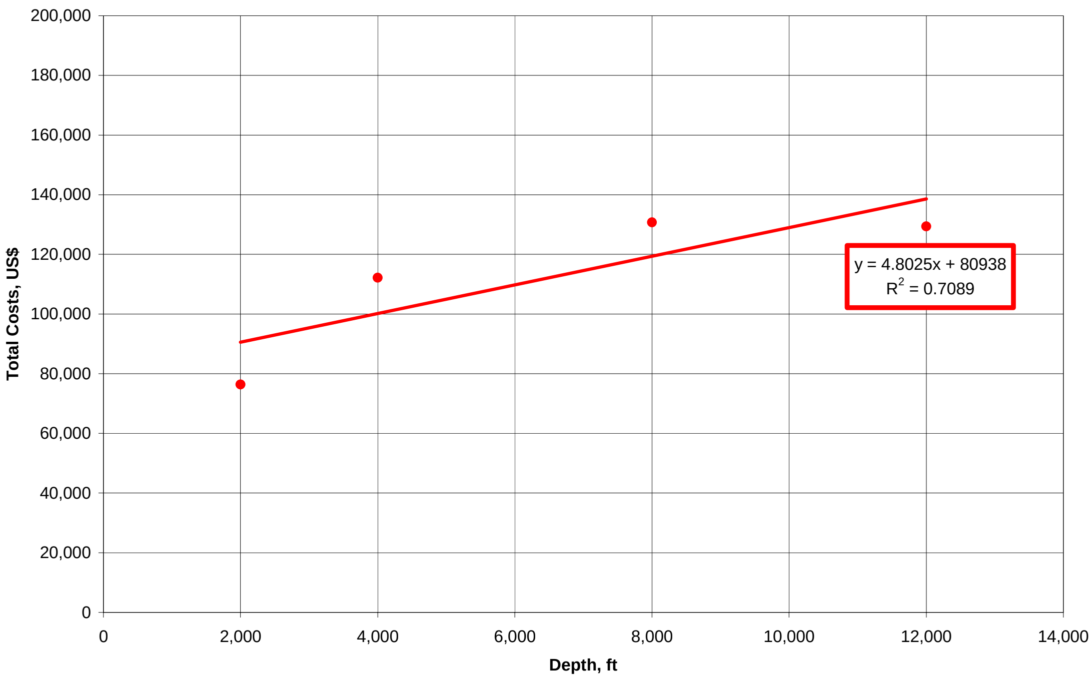
2. <u>Lease Equipment Costs for New Producing Wells.</u> The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report. This survey provides estimated lease equipment costs 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 = $4.8025 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 Illinois vs. Depth



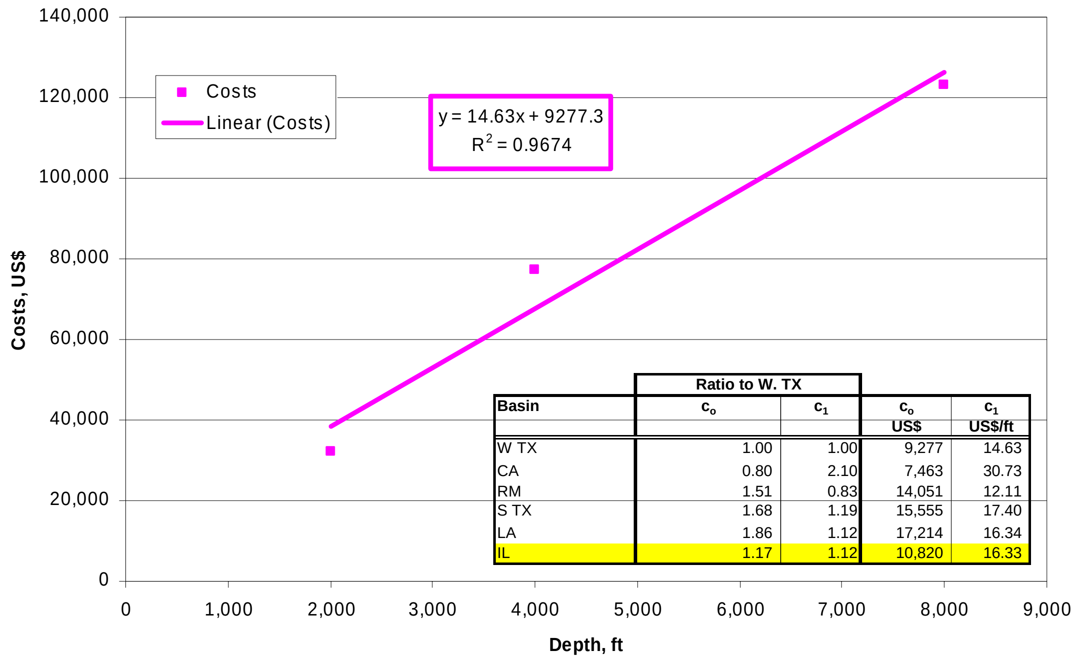
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Illinois include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation for Illinois 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 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 Illinois 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
IL	1.17	1.12	10,820	16.33

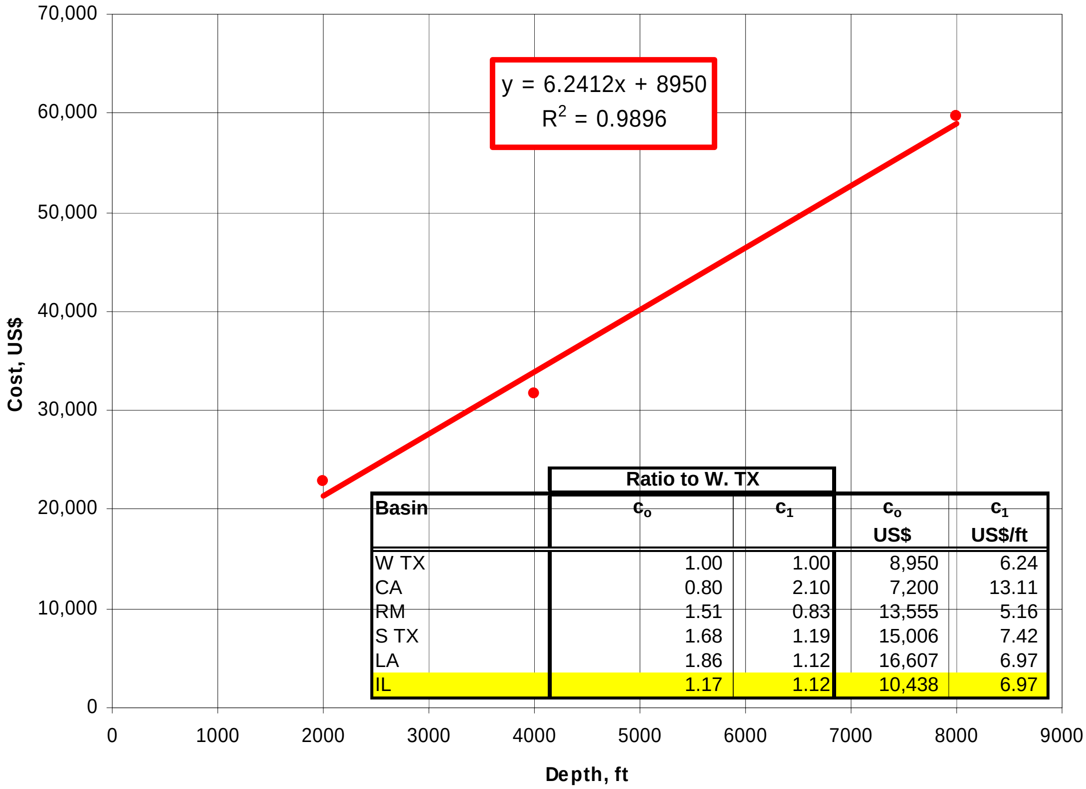
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection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

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



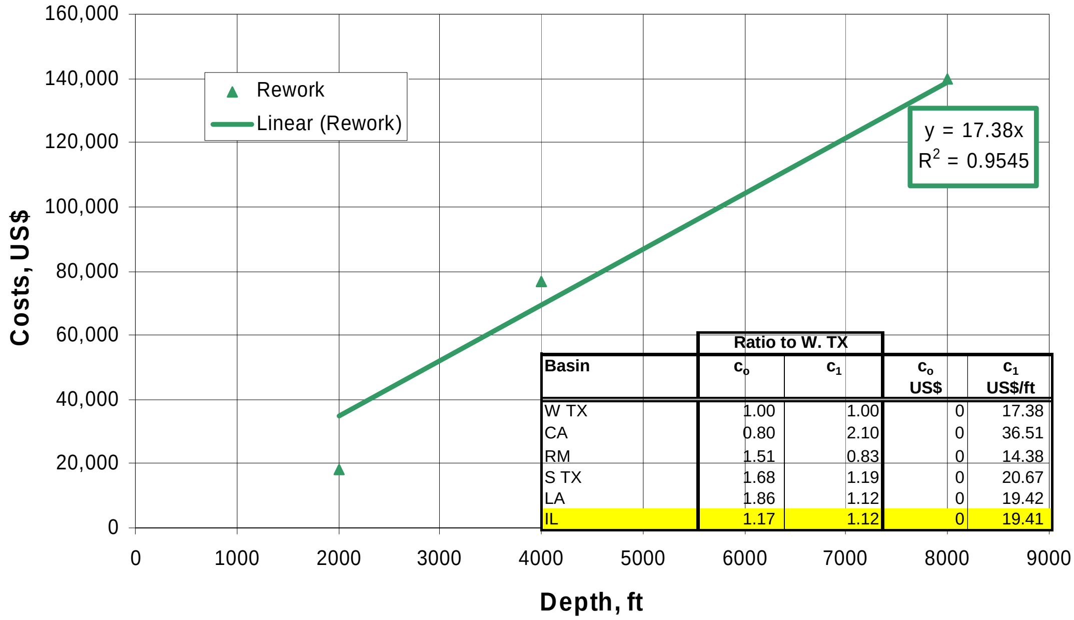
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
IL	1.17	1.12	10,438	6.97

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 Illinois is:

Well Rework Costs = $c_1 D$
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 Illinois 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
IL	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 Illinois primary oil production O&M costs (Figure B-6) are used to estimate Illinois 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

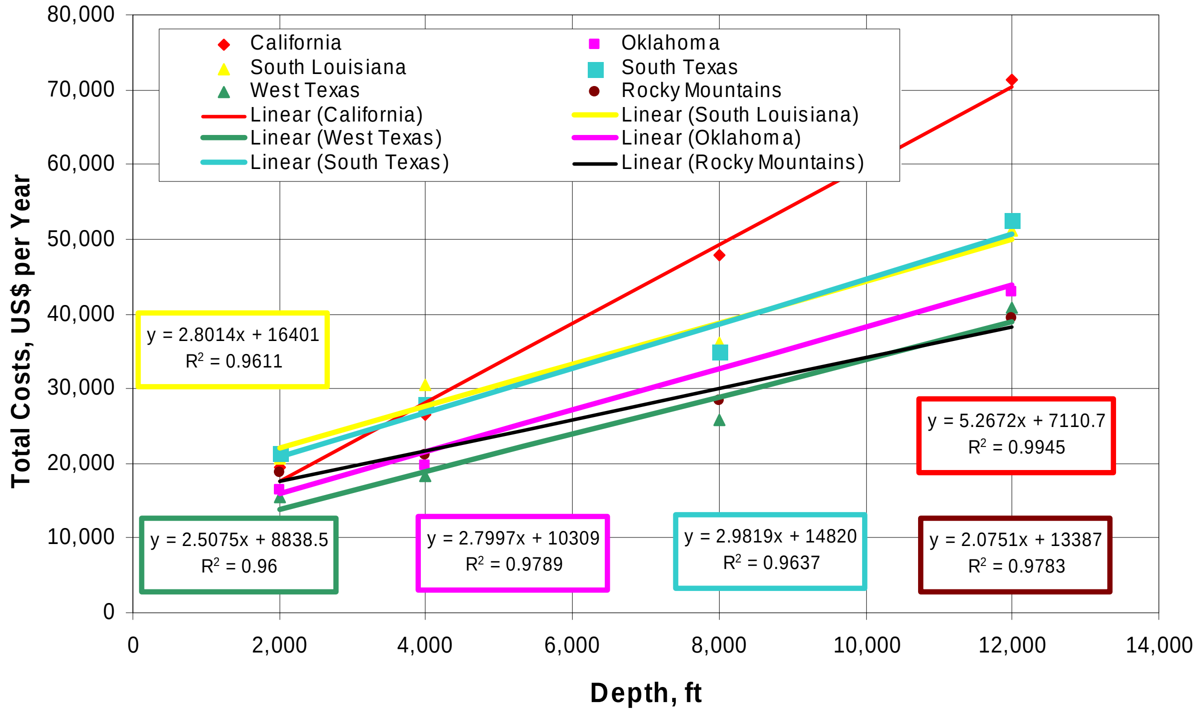


Table B-1. Regional Lease O&M Costs and Their Relationship to West Texas

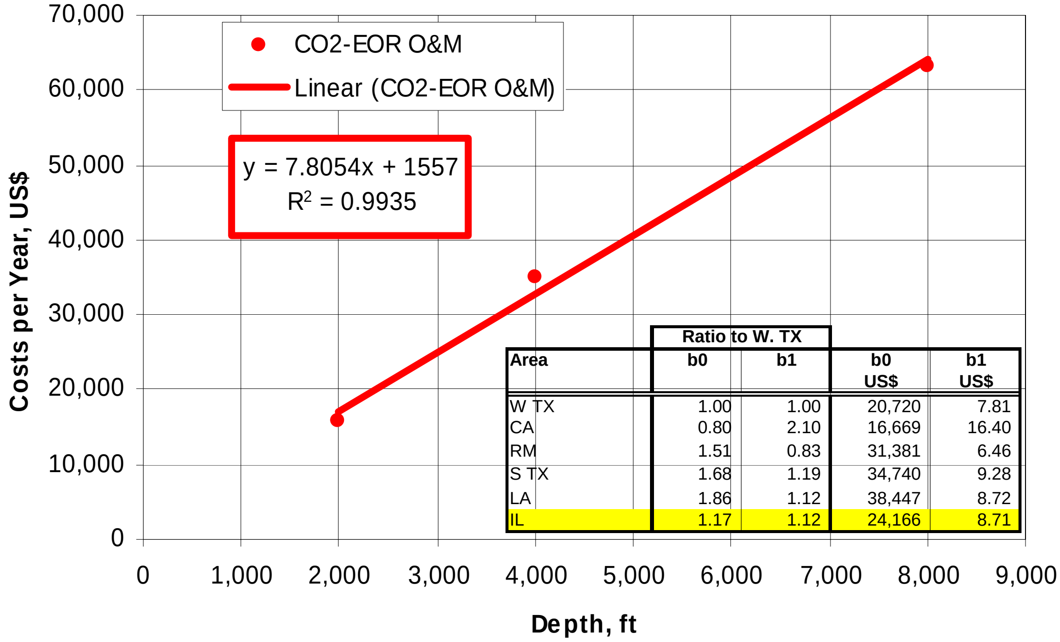
Basin	c_o US$	c_1 US$/ft	Ratio to W. TX c_o	Ratio to W. TX c_1
W TX	8,839	2.508	1.00	1.00
CA	7,111	5.267	0.80	2.10
RM	13,387	2.075	1.51	0.83
S TX	14,820	2.982	1.68	1.19
LA	16,401	2.801	1.86	1.12
IL	10,309	2.800	1.17	1.12

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 Illinois, shown in the inset of Figure B-7. The equation for Illinois 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
IL	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 recycles 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 St. Louis formation of the Clay City Consolidated field, with 16 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$10.9 million. A large project in the Aux Vases formation of the Dale City field, with 73 MMcf/d of CO_2 reinjection and 138 injectors requires a recycling plant costing \$51.4 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 15 MMcf/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, cost also depends 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 Illinois 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 both set at 0% on the oil production stream.

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 Illinois (-$1.00 per barrel) and the current gravity differential (-$0.25 per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for Illinois is:

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

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

Appendix C

Indiana 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:

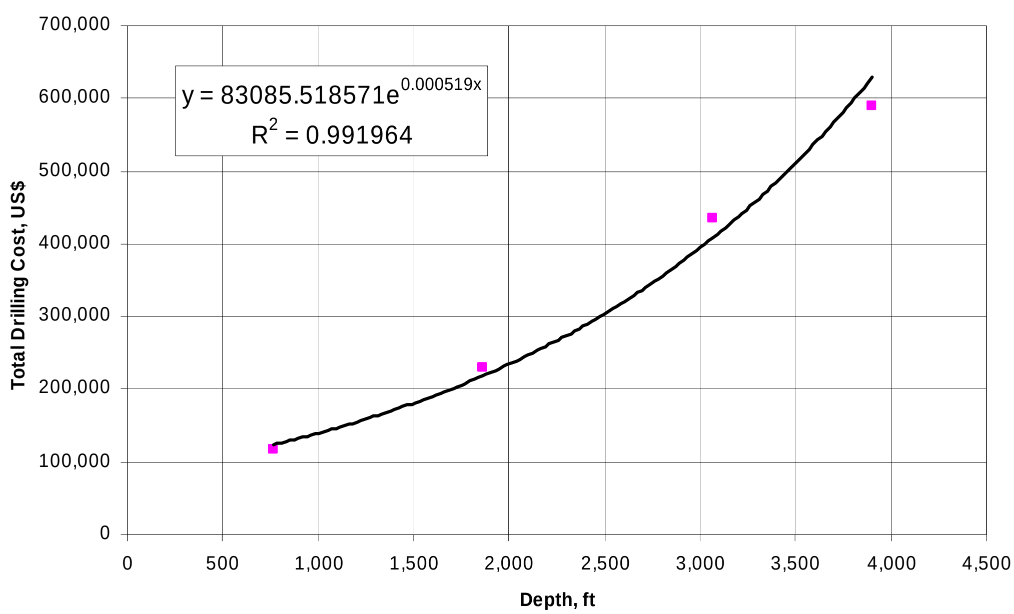
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for Indiana.

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 with depth. The total equation is:

Well D&C Costs = $a_0\, e^{a_1 D}$
Where: a_0 is 83085
a_1 is 0.00052
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 Indiana.

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



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 Indiana D&C cost calculations to reflect this increase in 2004 drilling costs.

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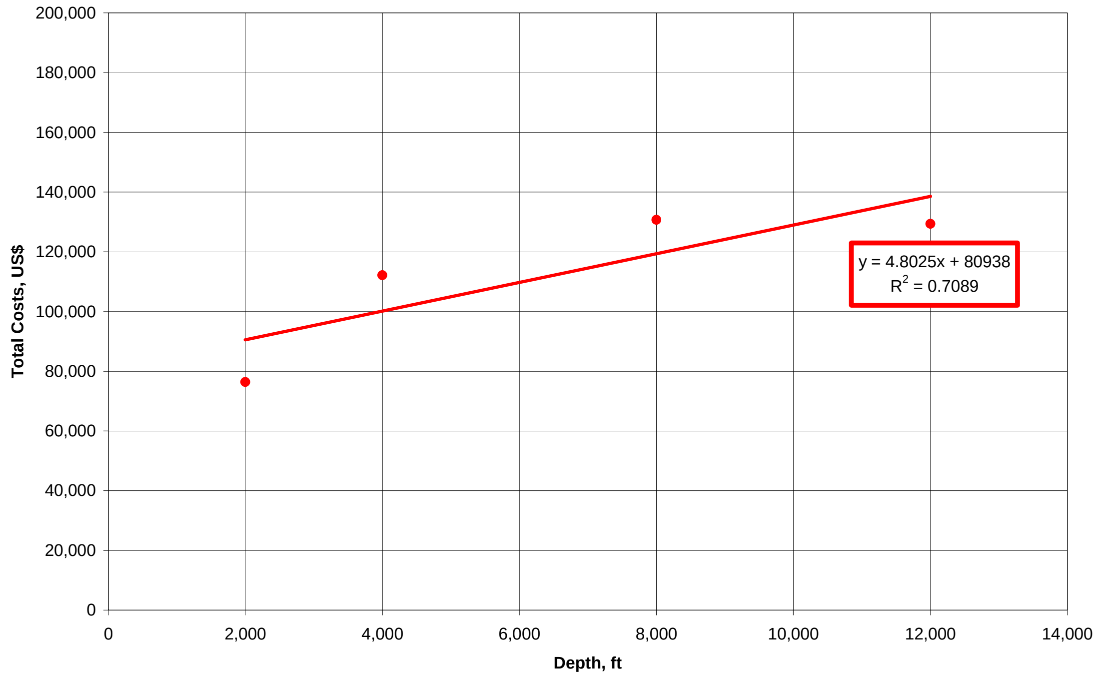
The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$80,938 (fixed)
c_1 = \$4.8025 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 Indiana vs. Depth



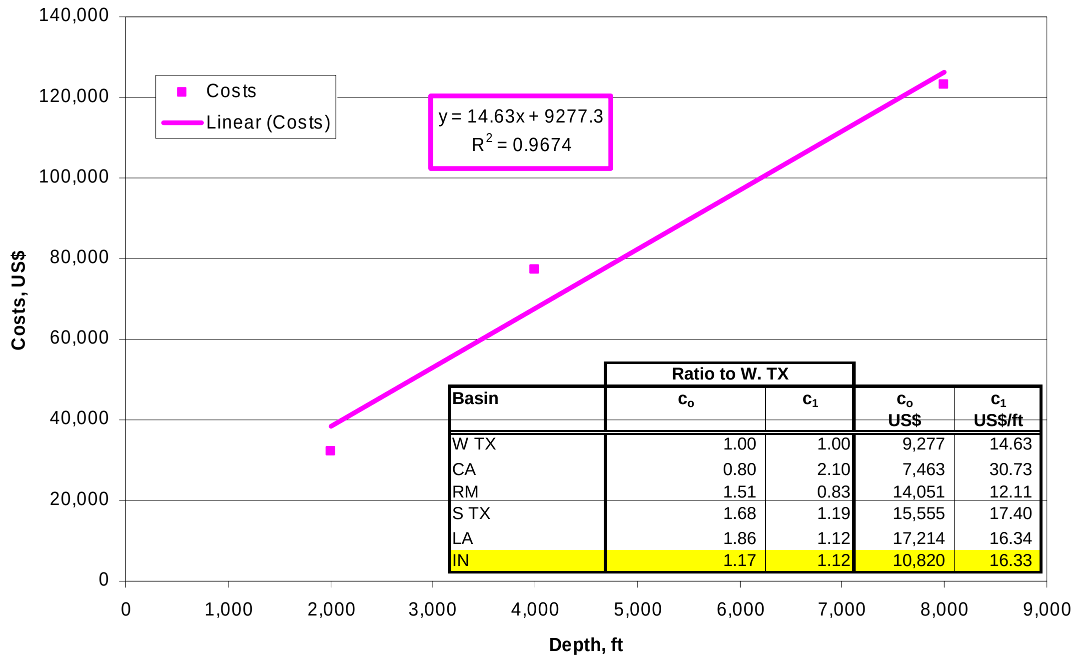
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Indiana include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation for Indiana 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 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 Indiana 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
IN	1.17	1.12	10,820	16.33

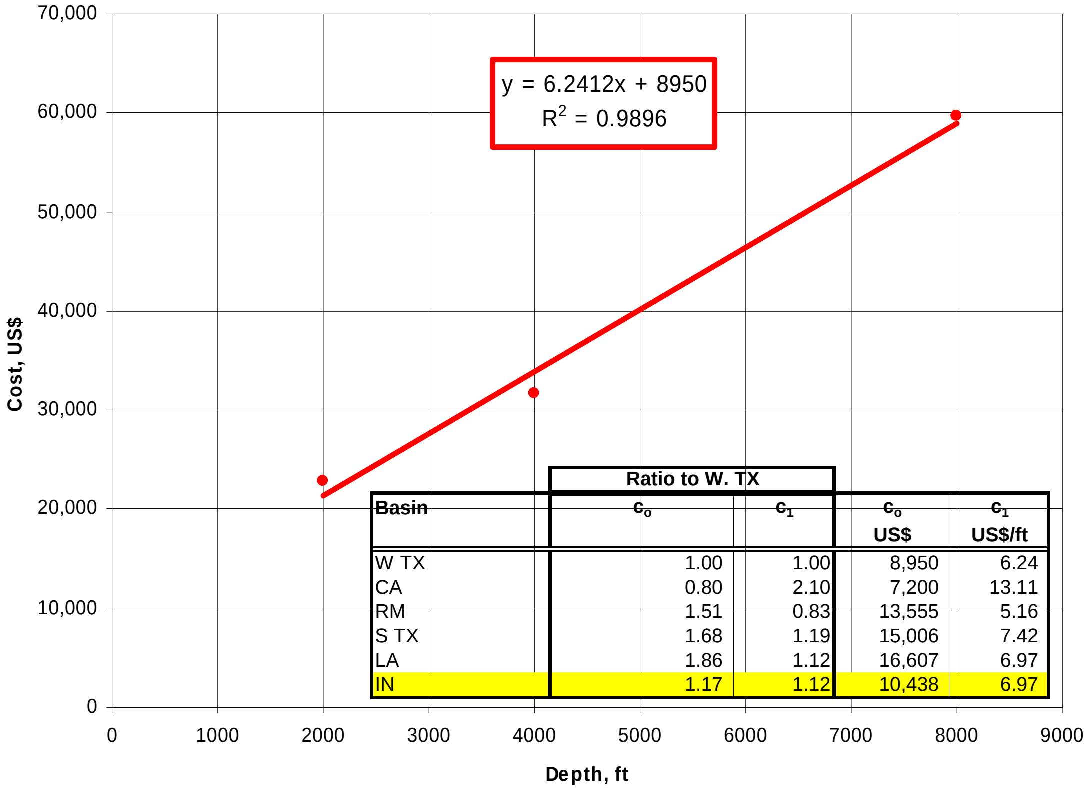
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection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

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



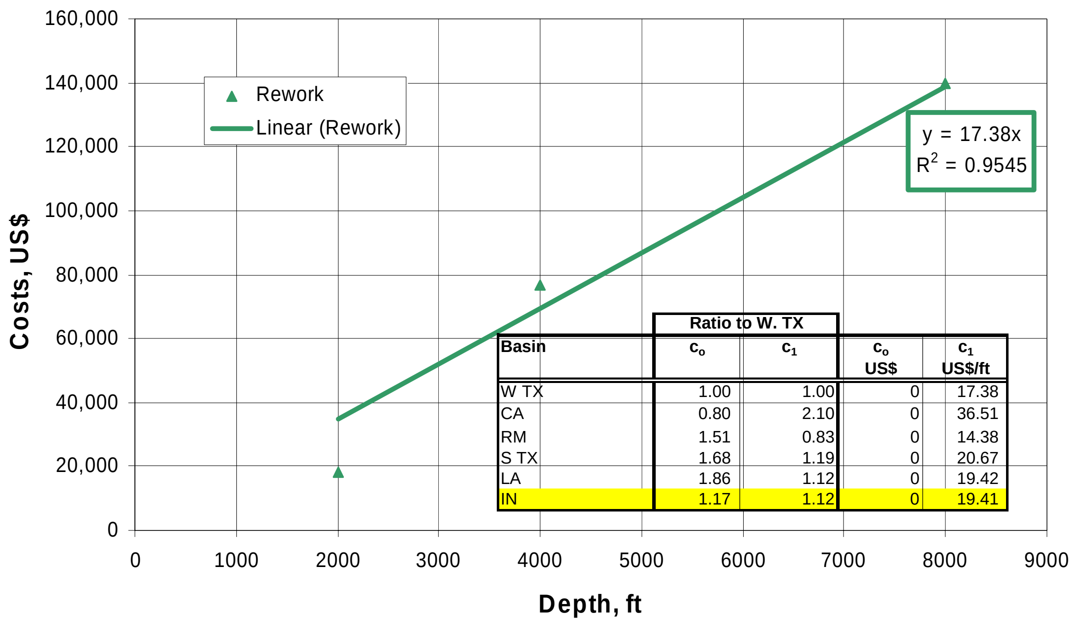
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
IN	1.17	1.12	10,438	6.97

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

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

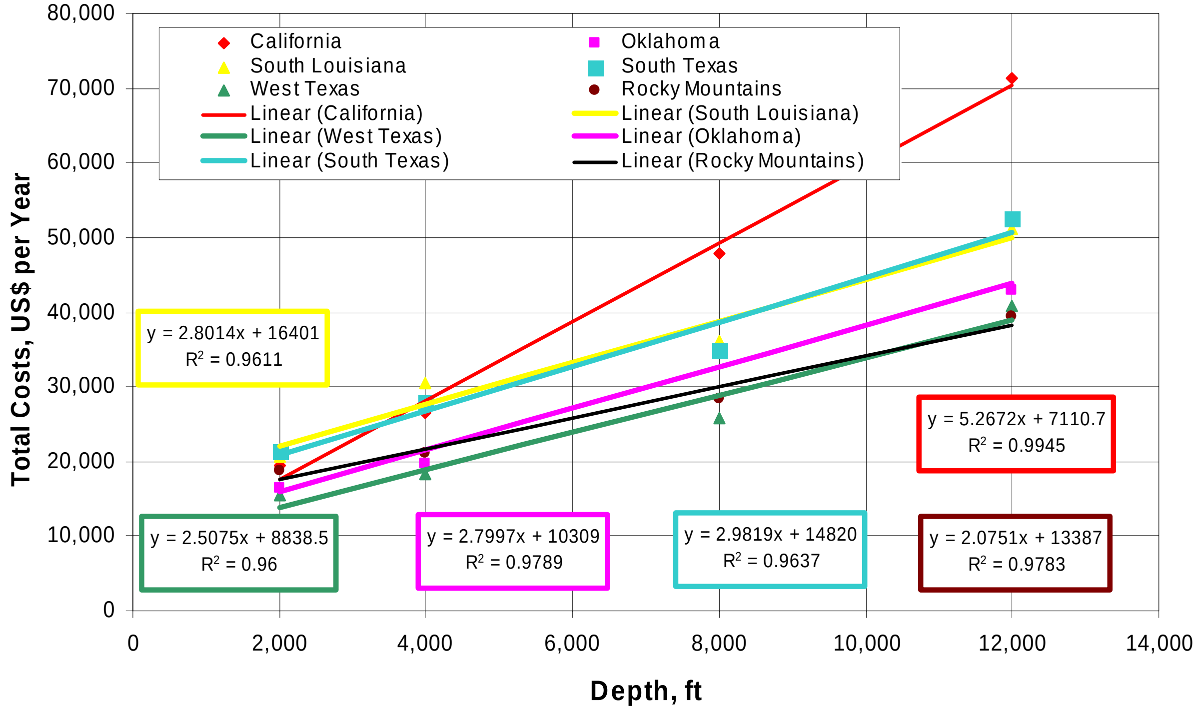


Table C-1. Regional Lease O&M Costs and Their Relationship to West Texas

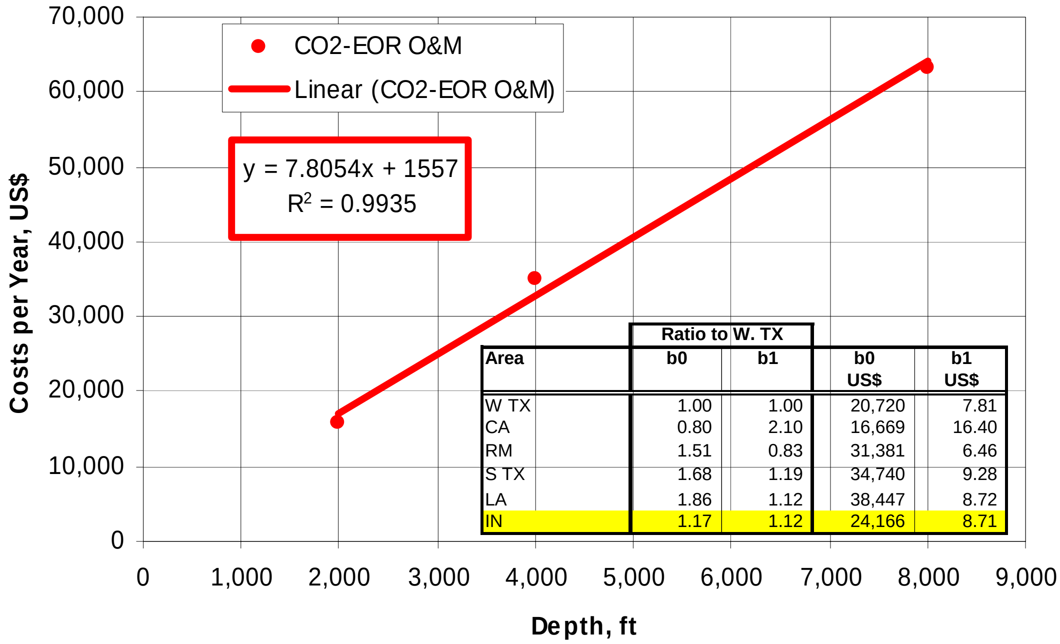
			Ratio to W. TX	
Basin	**c_o US$**	**c_1 US$/ft**	**c_o**	**c_1**
W TX	8,839	2.508	1.00	1.00
CA	7,111	5.267	0.80	2.10
RM	13,387	2.075	1.51	0.83
S TX	14,820	2.982	1.68	1.19
LA	16,401	2.801	1.86	1.12
IN	10,309	2.800	1.17	1.12

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 Indiana, shown in the inset of Figure C-7. The equation for Indiana 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



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
IN	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 recycles 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 Waltersburg formation of the Springfield Consolidated field, with 65 MMcf/d of CO_2 reinjection, will require a recycling plant costing $45 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, cost also depends 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 Indiana 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 tax is set at 1% and ad valorum tax is set at 0% on the oil production stream.

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 Indiana (-$1.00 per barrel) and the current gravity differential (-$0.25 per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for Indiana is:

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

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

Appendix D

Kentucky 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:

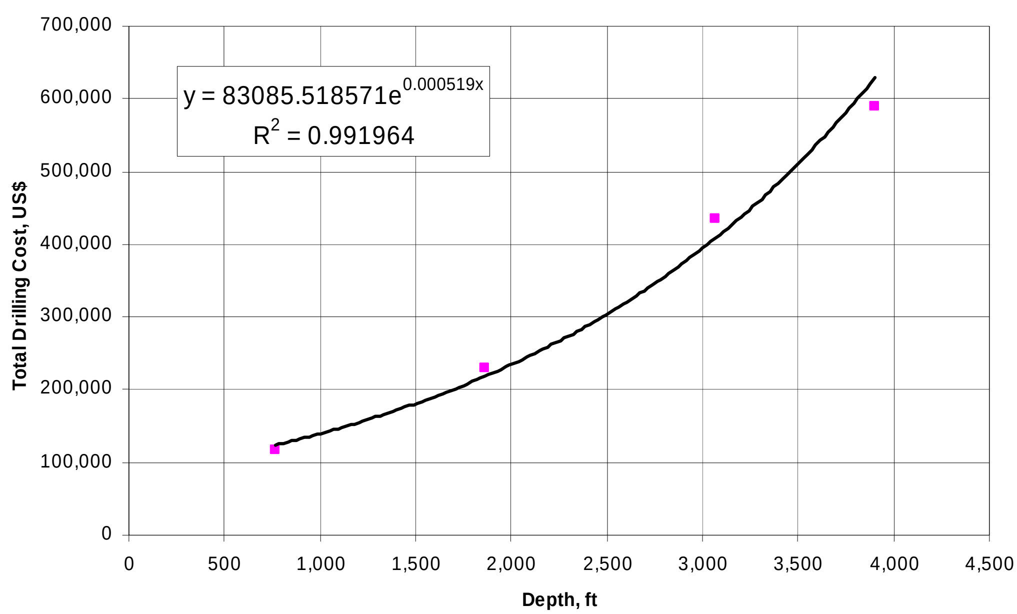
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for Kentucky.

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 with depth. The total equation is:

Well D&C Costs = $a_0 e^{a_1 D}$
Where: a_0 is 83085
a_1 is 0.00052
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 Kentucky.

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



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 Kentucky 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 “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 = $c_0 + c_1D$

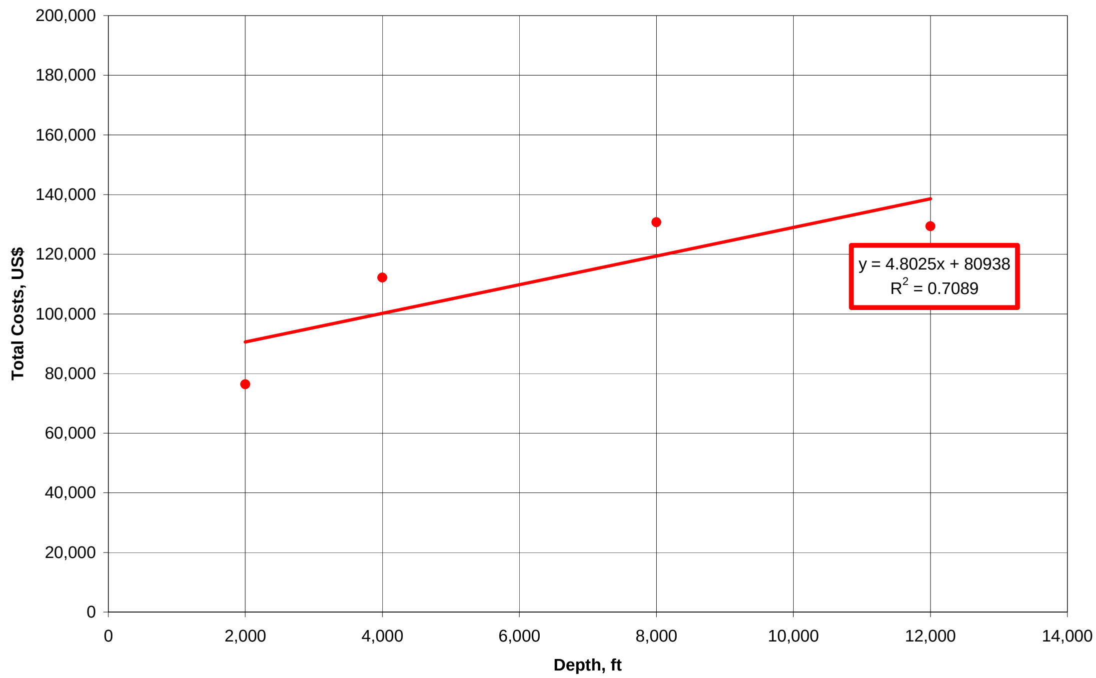
Where: c_o = \$80,938 (fixed)

c_1 = \$4.8025 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 Kentucky vs. Depth



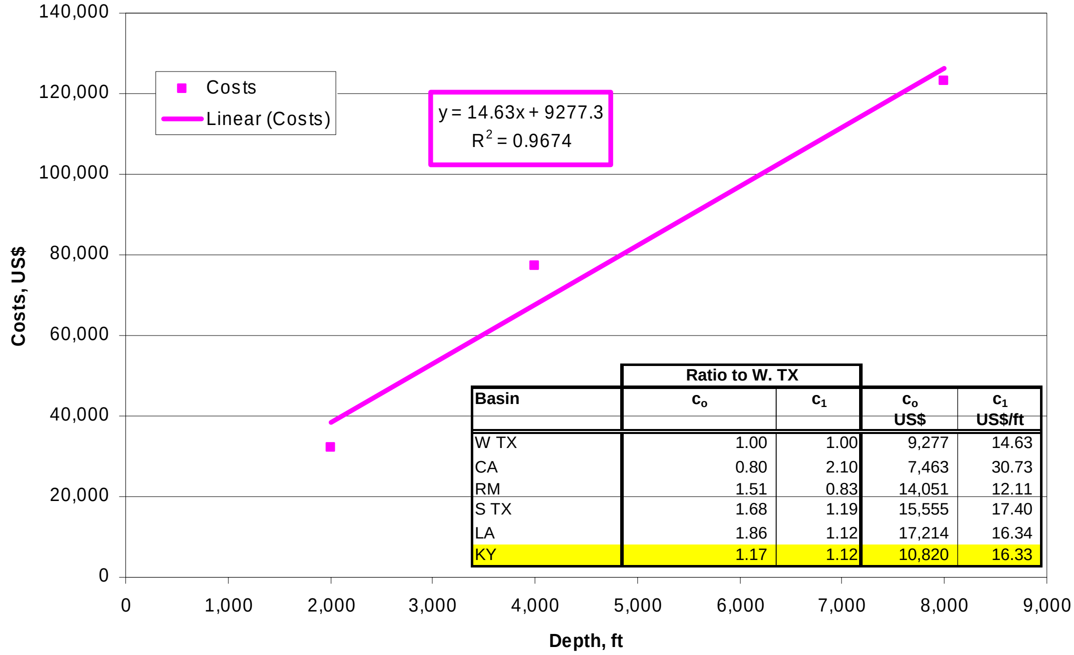
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Kentucky include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

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



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

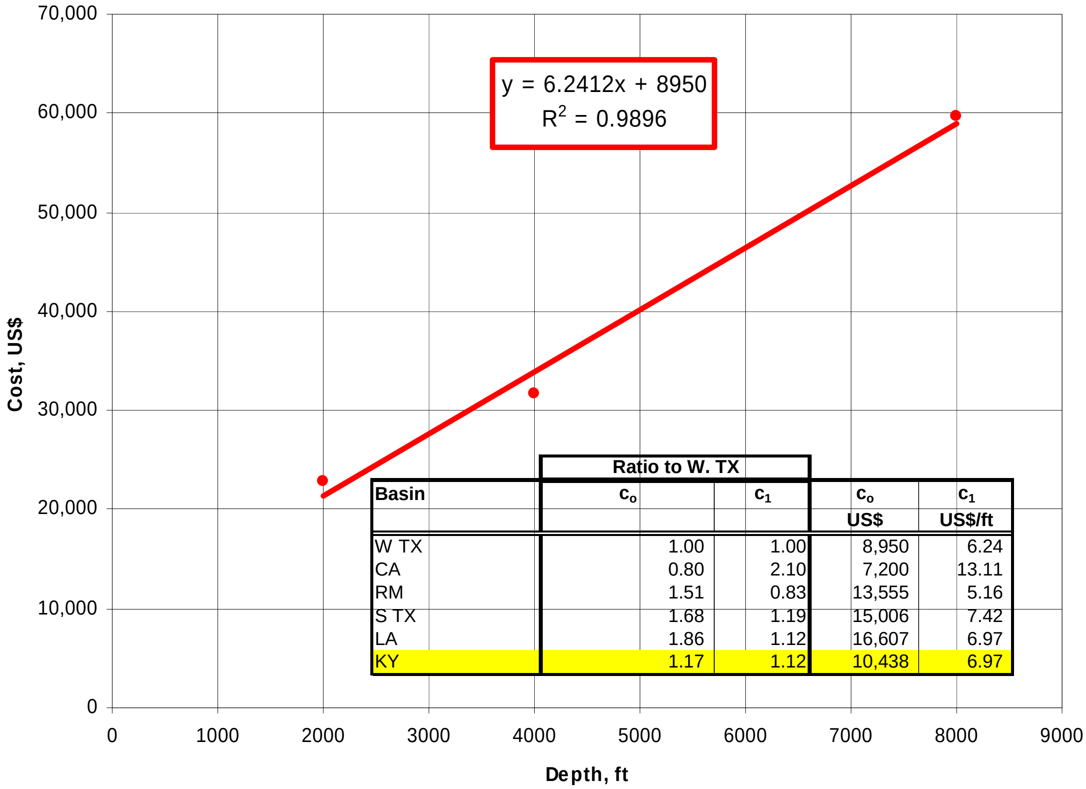
4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are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

Well Conversion Costs = $c_0 + c_1 D$
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 Kentucky cost equation.

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



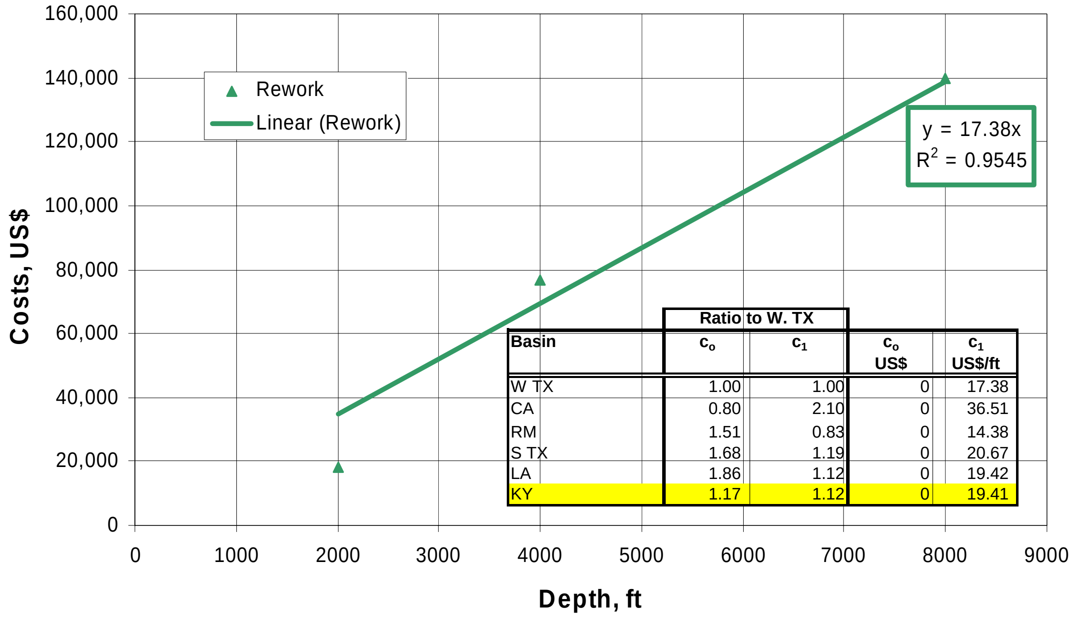
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
KY	1.17	1.12	10,438	6.97

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 Kentucky 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 Kentucky 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
KY	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 Kentucky primary oil production O&M costs (Figure D-6) are used to estimate Kentucky 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

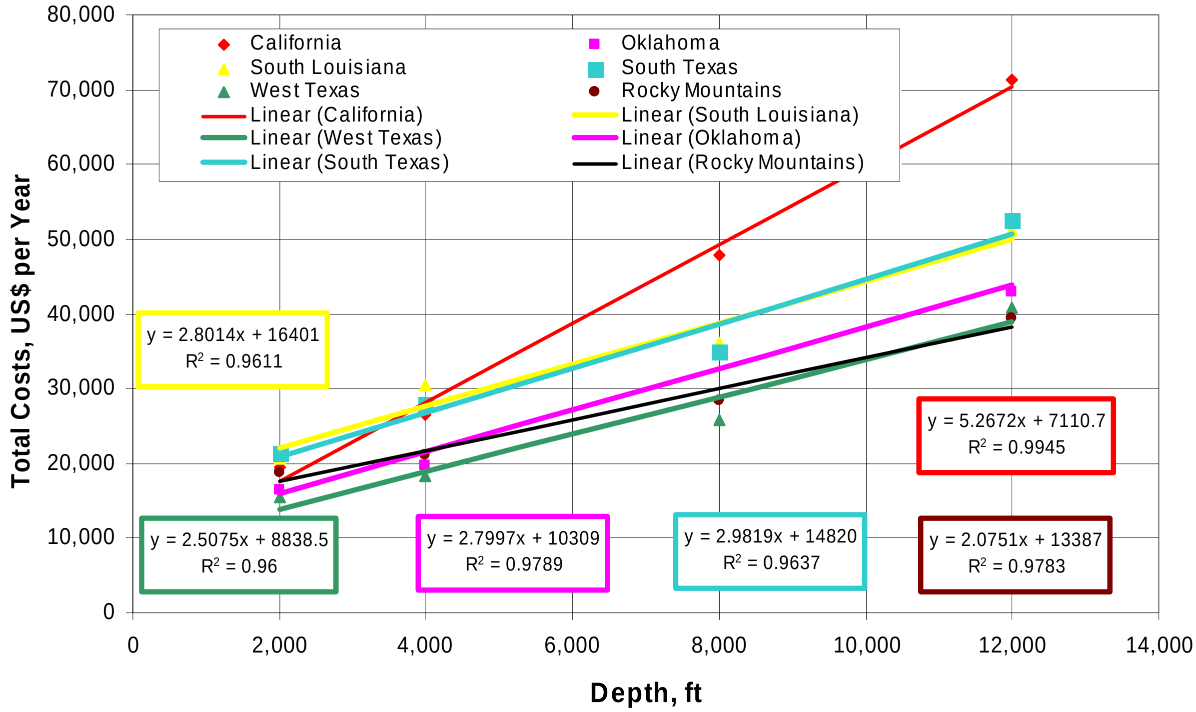


Table D-1. Regional Lease O&M Costs and Their Relationship to West Texas

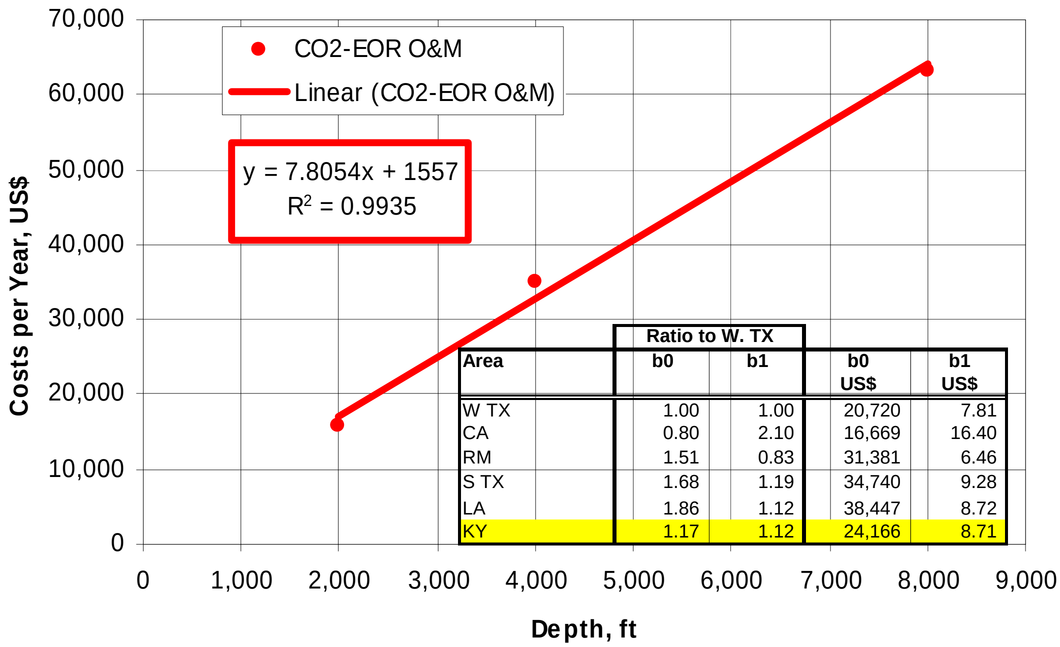
Basin	c_o US$	c_1 US$/ft	Ratio to W. TX c_o	Ratio to W. TX c_1
W TX	8,839	2.508	1.00	1.00
CA	7,111	5.267	0.80	2.10
RM	13,387	2.075	1.51	0.83
S TX	14,820	2.982	1.68	1.19
LA	16,401	2.801	1.86	1.12
KY	10,309	2.800	1.17	1.12

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 Kentucky, shown in the inset of Figure D-7. The equation for Kentucky 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



	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
KY	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 recycles 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 Chester Sandstone formation of the Poole Consolidated field, with 12 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$8 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, cost also depends 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 Kentucky 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 taxes are set at 4.5% and ad valorum taxes are both set at 1% on the oil production stream.

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 Kentucky (-$1.00 per barrel) and the current gravity differential (-$0.25 per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for Kentucky is:

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

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

Appendix E

Michigan 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:

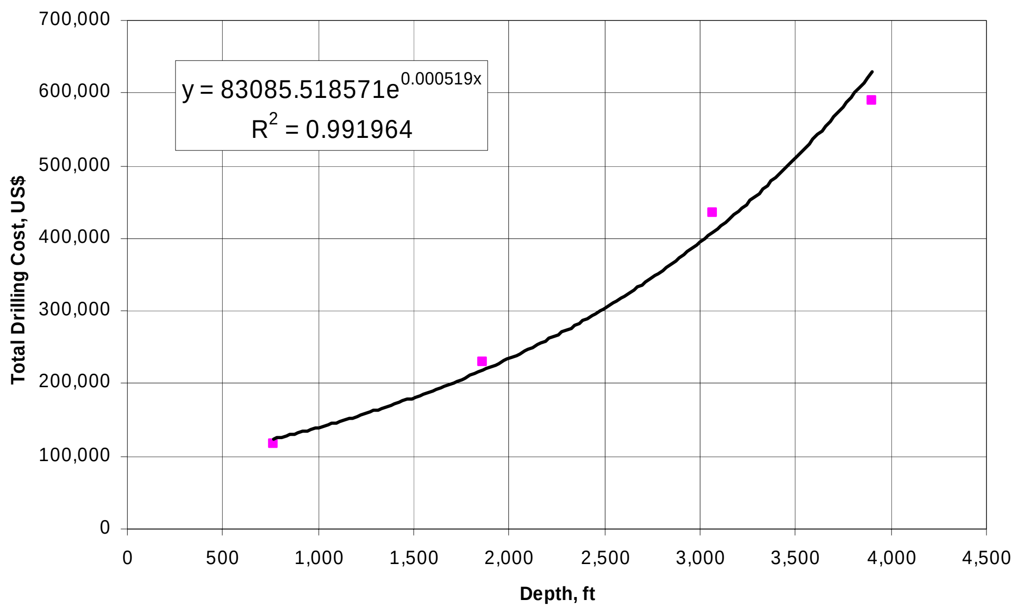
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for Michigan.

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 with depth. The total equation is:

Well D&C Costs = $a_0 e^{a_1 D}$
Where: a_0 is 83085
a_1 is 0.00052
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 Michigan.

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



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 Michigan D&C cost calculations to reflect this increase in 2004 drilling costs.

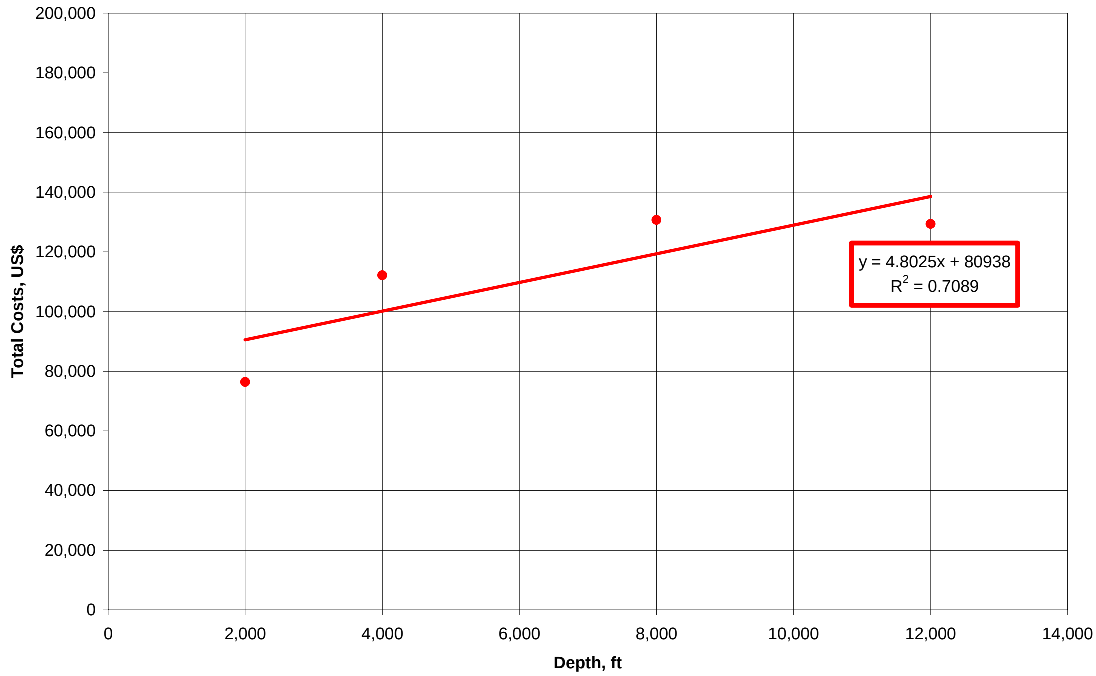
2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 “Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations” report. This survey provides estimated lease equipment costs for 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 = $4.8025 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 Michigan vs. Depth



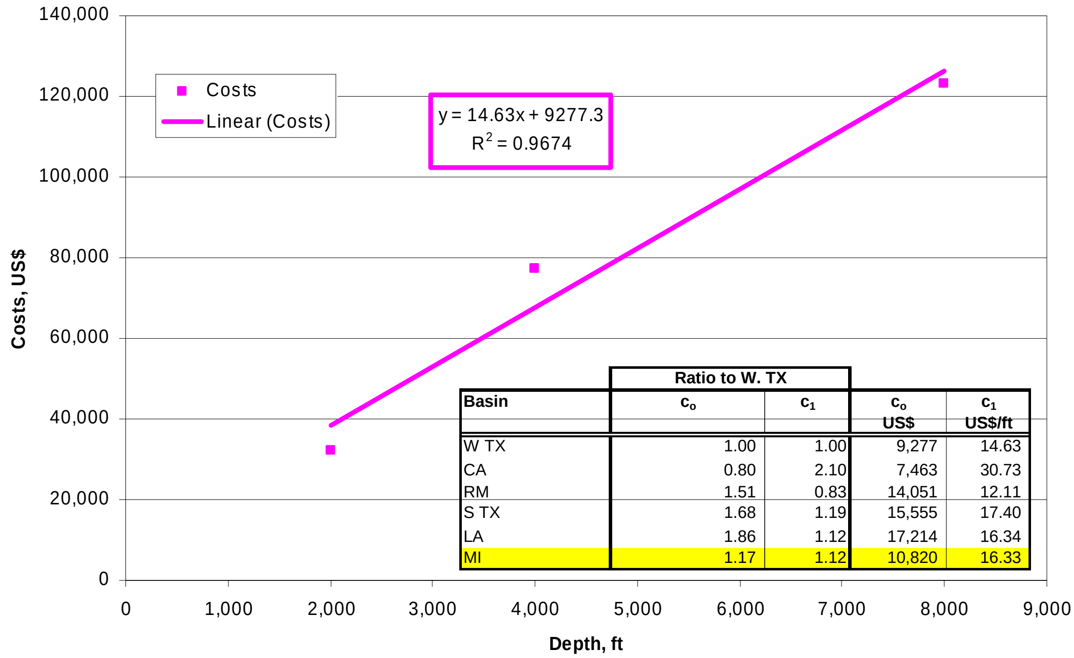
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in Michigan include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation for Michigan 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 Michigan 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
MI	1.17	1.12	10,820	16.33

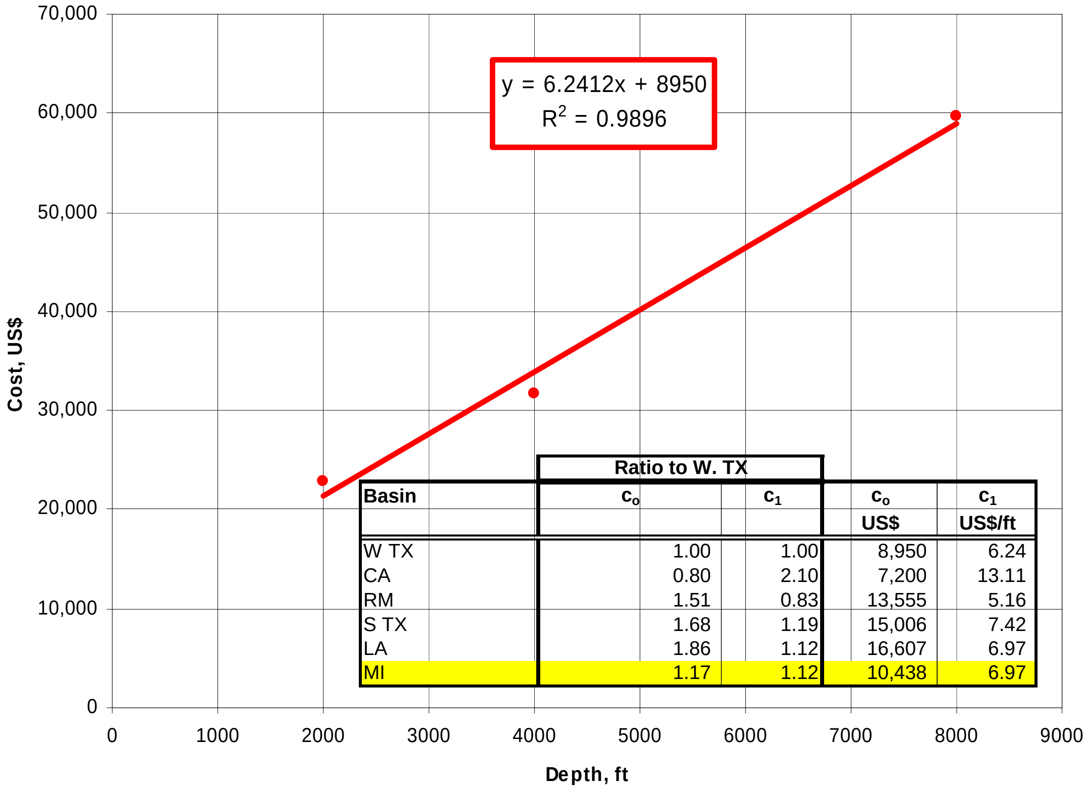
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection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

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



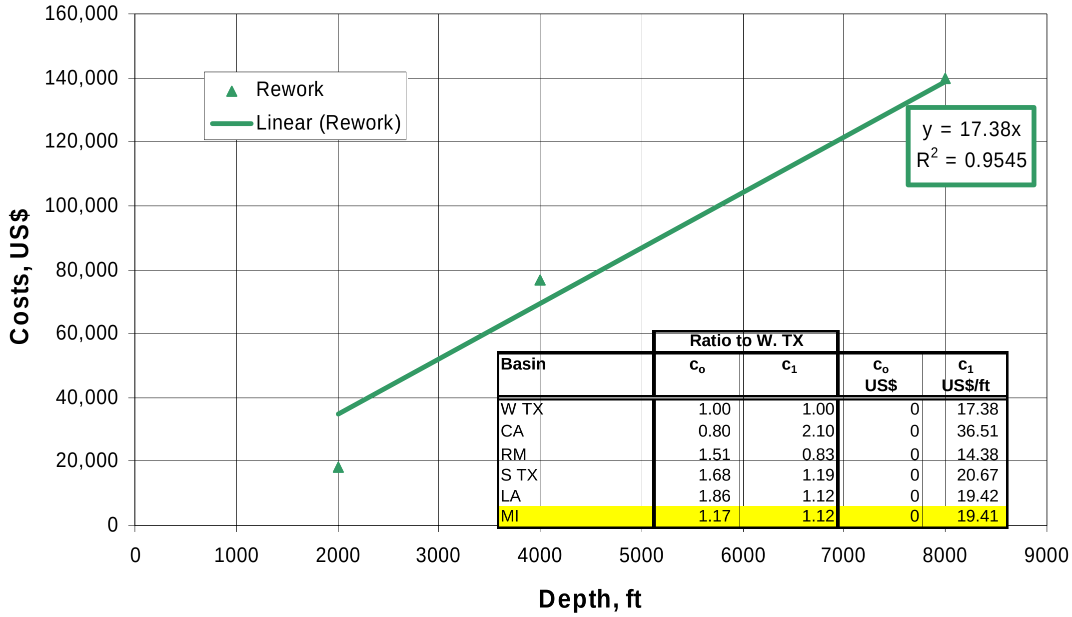
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
RM	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
MI	1.17	1.12	10,438	6.97

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 Michigan 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 Michigan 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
MI	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 Michigan primary oil production O&M costs (Figure E-6) are used to estimate Michigan 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

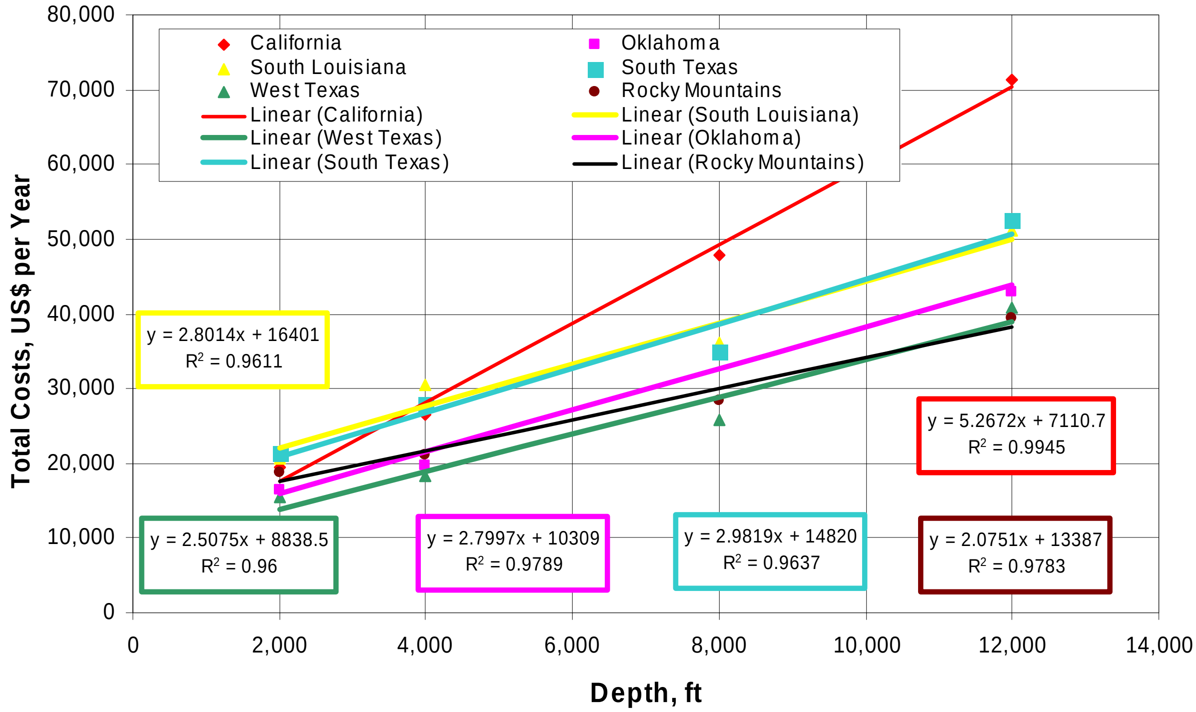


Table E-1. Regional Lease O&M Costs and Their Relationship to West Texas

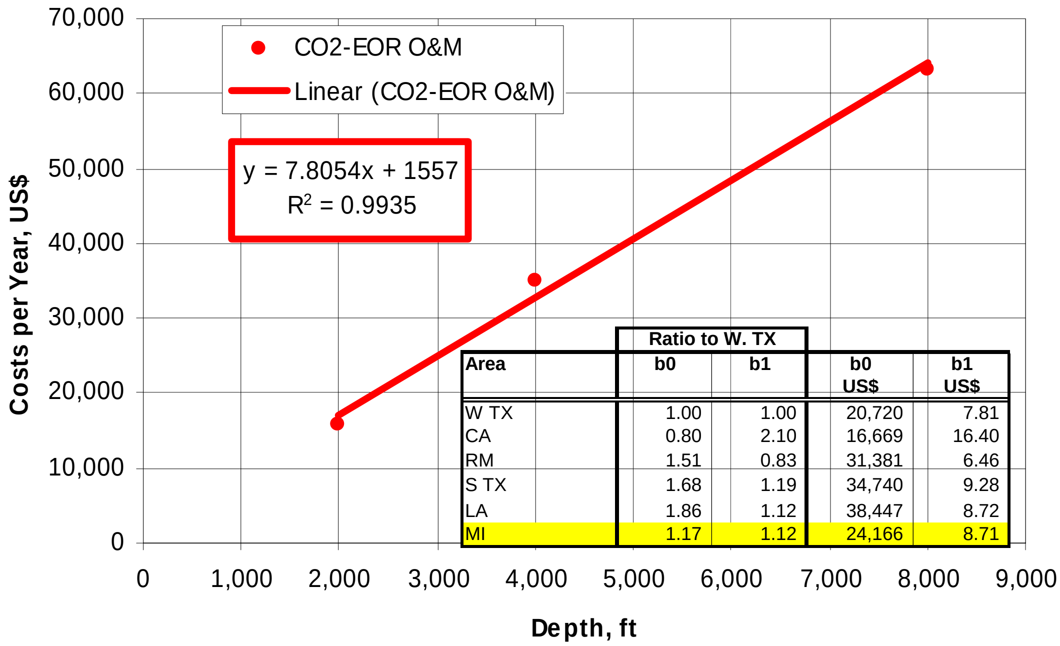
Basin	c_o US$	c_1 US$/ft	Ratio to W. TX c_o	Ratio to W. TX c_1
W TX	8,839	2.508	1.00	1.00
CA	7,111	5.267	0.80	2.10
RM	13,387	2.075	1.51	0.83
S TX	14,820	2.982	1.68	1.19
LA	16,401	2.801	1.86	1.12
MI	10,309	2.800	1.17	1.12

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 Michigan, shown in the inset of Figure E-7. The equation for Michigan 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



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
MI	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 recycles 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 Trenton-Black River formation of the Albion/Scipio field, with 72 MMcf/d of CO_2 reinjection, will require a recycling plant costing $50 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, cost also depends 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 Michigan 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 taxes are set at 4.5% and ad valorum taxes are both set at 1% on the oil production stream.

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 Michigan (-$3.92 per barrel) and the current gravity differential (-$0.25 per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for Michigan is:

Wellhead Oil Price = Oil Price + (-$3.92) – [$0.25*(40 - °API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
°API is oil gravity

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