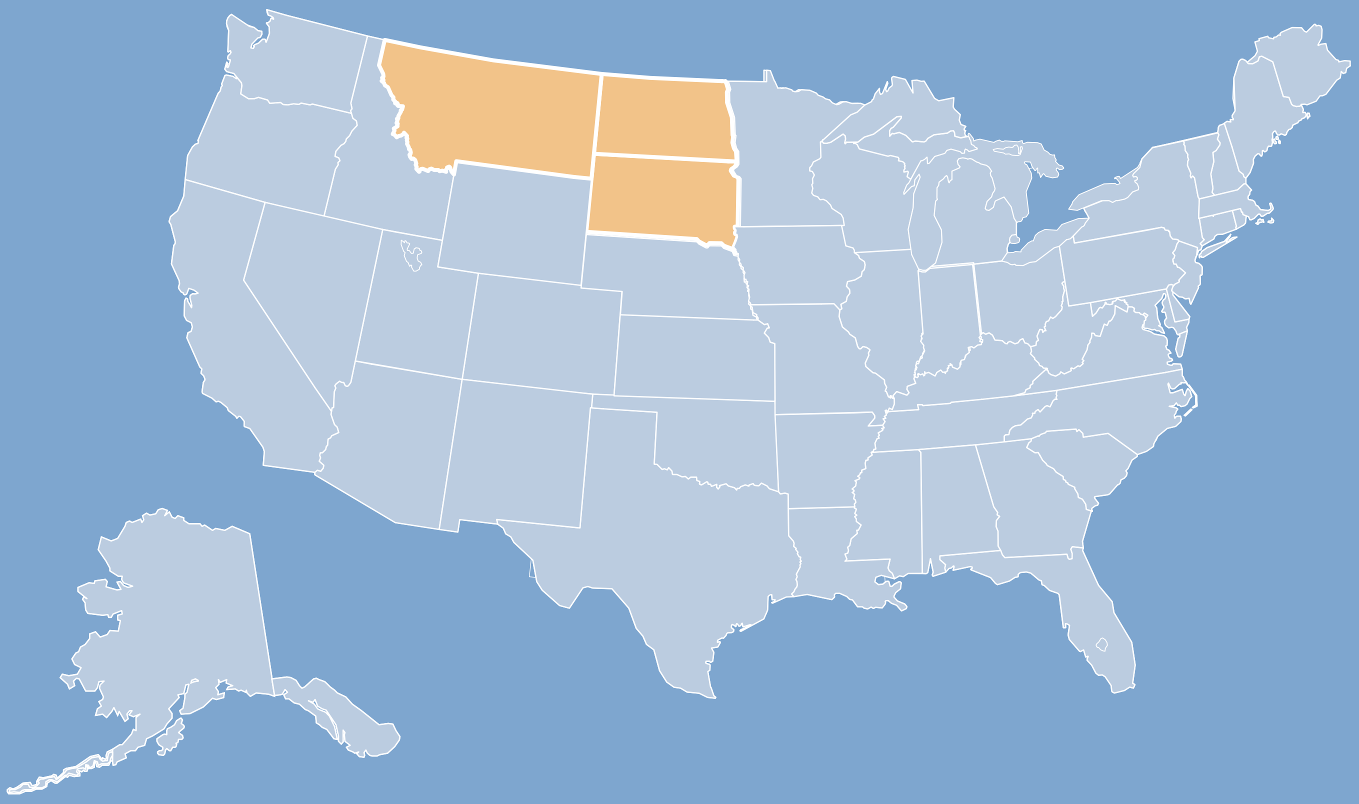
BASIN ORIENTED STRATEGIES FOR CO_2 ENHANCED OIL RECOVERY:

WILLISTON BASIN



Prepared for
U.S. Department of Energy
Office of Fossil Energy – Office of Oil and Natural Gas

Prepared by
Advanced Resources International

February 2006

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BASIN ORIENTED STRATEGIES FOR CO_2 ENHANCED OIL RECOVERY: WILLISTON BASIN OF NORTH DAKOTA, SOUTH DAKOTA, AND MONTANA

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1. SUMMARY OF FINDINGS

1.1 INTRODUCTION. The Williston Basin oil and gas producing region of North Dakota, South Dakota and Montana has an original oil endowment of 13 billion barrels. Of this, 4 billion barrels or 29% will be recovered with primary and secondary (waterflooding) oil recovery. As such, over 9 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.

The thirteen billion barrels of oil in-place set forth in this report for the Williston Basin includes only a modest portion of the larger unconventional oil resource potential that may exist in the Bakken Shale. This is because this report only addresses the potential for applying "state-of-the-art" CO_2-EOR technology to already discovered fields. Prior studies suggest that 100 to 150 billion barrels (perhaps more) of resource in-place may exist in the Bakken Shale of North Dakota, with additional in-place Bakken Shale oil resources in Montana. The feasibility of converting this large unconventional in-place resource into economic reserves using "next generation" CO_2-EOR technology may be examined in a subsequent study.

This report evaluates the future CO_2-EOR oil recovery potential from the large oil fields of the Williston Basin region, highlighting the barriers that stand in the way of achieving this potential. The report then discusses how a concerted set of "basin oriented strategies" could help Williston 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 Williston 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 Williston 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 these Williston Basin oil reservoirs.
- The third scenario, entitled “Risk Mitigation,” examines how the economic potential of CO_2-EOR could be increased through a comprehensive strategy involving state production tax reductions, federal investment tax credits, royalty relief and/or higher world oil prices that together would add an equivalent $10 per barrel to the price that the uses for making capital investment decisions for CO_2-EOR.
- The final scenario, entitled “Ample Supplies of CO_2”, assumes that large volumes of low-cost, “EOR-ready” CO_2 supplies are aggregated from various industrial and natural sources. These sources include industrial high-concentration CO_2 emissions from hydrogen facilities, gas processing plants, chemical plants and other sources in the region. These CO_2 sources would be augmented, in the longer-term, from low concentration CO_2 emissions from refineries and electric power plants. Capture of industrial CO_2 emissions could also be part of a national effort for reducing greenhouse gas emissions.

1.3 OVERVIEW OF FINDINGS. Twelve major findings emerge from the study of “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Williston Basin of North Dakota, South Dakota and Montana.”

1. Today’s oil recovery practices will leave behind a large resource of “stranded oil” in the Williston Basin region. The original oil resource in Williston Basin reservoirs is 13 billion barrels. To date, 4 billion barrels of this original oil in-place (OOIP) has been recovered or proved. Thus, without further efforts, 9 billion barrels of Williston Basin’s oil resource will become “stranded”, Table 1.

Table 1. Size and Distribution of Williston 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				
North Dakota	49	4.1	1.1	3.0
South Dakota	1	0.1	**	**
Montana	43	5.1	1.5	3.6
Data Base Total	93	9.3	2.6	6.6
*B. Regional Total**	n/a	13.2	3.8	9.4

**Estimated from state data on cumulative oil recovery and proved reserves, as of the end of 2004*
***Less than 0.05 billion barrels*

2. The great bulk of the "stranded oil" resource in the large oil reservoirs of the Williston Basin is amenable to CO_2 enhanced oil recovery. To further address the "stranded oil" issue, Advanced Resources assembled a data base that contains 93 major Williston Basin oil reservoirs, accounting for about 72% of the region's estimated ultimate oil production. Of these, 54 reservoirs, with 7.3 billion barrels of OOIP and 5.1 billion barrels of "stranded oil" (ROIP)), were found to be favorable for CO_2-EOR, as shown below by state, Table 2.

Table 2. The Williston Basin Region's "Stranded Oil" Amenable to CO_2-EOR

Region	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
North Dakota	34	3.7	1.0	2.7
South Dakota	1	0.1	*	*
Montana	19	3.5	1.1	2.4
TOTAL	54	7.3	2.1	5.1

**Less than 0.05 billion barrels*

3. Application of miscible CO_2-EOR would enable a significant portion of the Williston Basin's "stranded oil" to be recovered. 53 large Williston Basin oil reservoirs screen as being favorable for miscible CO_2-EOR. One field screens for immiscible CO_2-EOR. The total technically recoverable resource from applying CO_2-EOR in these 54 large oil reservoirs, ranges from 810 million barrels to 1,840 million barrels, depending on the type of CO_2-EOR technology that is applied — "Traditional Practices" or "State-of-the-art", Table 3.

Table 3. Applicability of Miscible and Immiscible CO_2-EOR

	Miscible			Immiscible		
Region	No. of Reservoirs	Technically Recoverable (MMBbls)		No. of Reservoirs	Technically Recoverable (MMBbls)	
		Traditional Practices	State of the Art		Traditional Practices	State of the Art
North Dakota	33	470	1,050	1	-	10
South Dakota	1	10	20	0	-	-
Montana	19	340	760	0	-	-
TOTAL	53	810	1,830	1	-	10

4. With "Traditional Practices" CO_2 flooding technology, high CO_2 costs and high risks, very little of Williston Basin's "stranded oil" will become economically recoverable. Traditional application of miscible CO_2-EOR technology to the 53 large reservoirs in the data base would enable 810 million barrels of "stranded oil" to become technically recoverable from the Williston Basin region. However, with the current high costs for CO_2 in the Williston Basin region (assumed at $1.50 per Mcf), risks surrounding future oil prices, and uncertainties as to the performance of CO_2-EOR technology, very little of this "stranded oil" would become economically recoverable at oil prices of $30 per barrel (as adjusted for gravity and location), Table 4.

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

Region	No. of Reservoirs	OOIP	Economically Recoverable*	
		(MMBbls)	(# Reservoirs)	(MMBbls)
North Dakota	33	3,560	1	10
South Dakota	1	90	0	-
Montana	19	3,450	0	-
TOTAL	53	7,100	1	10

**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).*

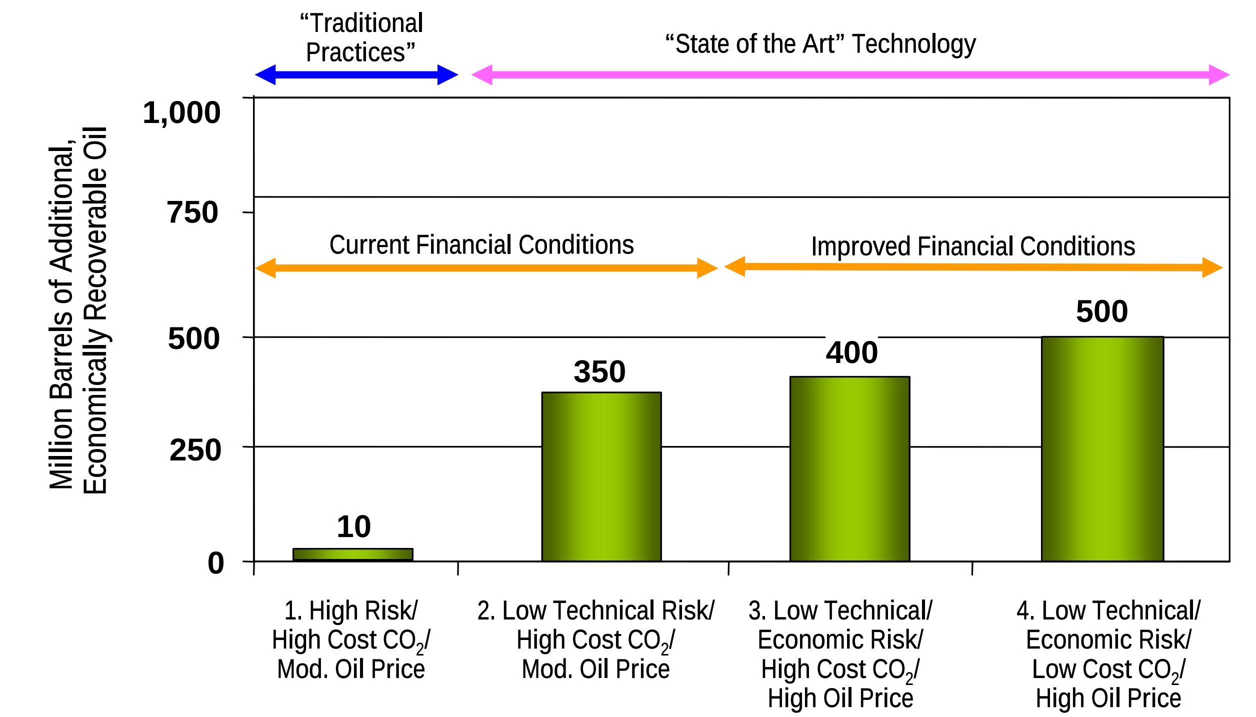
5. Introduction of "State-of-the-art" CO_2-EOR technology, risk mitigation incentives and lower CO_2 costs would enable 510 million barrels of additional oil to become economically recoverable from the Williston Basin region. With "State-of-the-art" CO_2-EOR technology and its higher oil recovery efficiency (plus oil prices of $30/B and CO_2 costs of $1.50 Mcf), 350 million barrels of the oil remaining in Williston Basin's large oil reservoirs becomes economically recoverable – Scenario #2.

Risk mitigation incentives and/or higher oil prices, providing an oil price equal to $40 per barrel, would enable 400 million barrels of oil to become economically recoverable from Williston Basin's large oil reservoirs – Scenario #3.

With lower cost CO_2 supplies (equal to $0.80 per Mcf, assuming a large-scale CO_2 collection and transportation system) and incentives for capture of CO_2 emissions, the economic potential increases to 500 million barrels – Scenario #4.

Figure 1 and Table 5 provide further details on the economic oil potential under these three scenarios.

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



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

Table 5. Economically Recoverable Resources - Alternative Scenarios

Basin	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)
North Dakota	10	240	12	290	14	390
South Dakota	-	-	-	-	-	-
Montana	5	110	5	110	5	110
TOTAL	15	350	16	400	19	500

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 Williston Basin is estimated at 2,500 million barrels. The large Williston Basin oil reservoirs examined by the study account for 72% of the region's "stranded oil" resource. Extrapolating the 1,840 million barrels of technically recoverable EOR potential in these oil reservoirs to the total Williston Basin oil resource provides an estimate of 2,700 million barrels of technical CO_2-EOR potential. (However, no extrapolation of economic potential has been estimated, as the development costs of the large Williston 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 Williston 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 Williston Basin oil reservoirs are being examined in a separate study.

8. A portion of this CO_2-EOR potential has been examined, in the past, by operators in the Williston Basin. No full scale CO_2-EOR projects are currently active in the Williston Basin. However two pilot studies in Little Knife Field, North Dakota and South Pine Field, Montana showed promising results. These pilot studies are discussed in more detail in Chapter 6.

9. Significant volumes of CO_2 supplies will be required in the Williston Basin to achieve the CO_2-EOR potential defined by this study. The overall market for purchased CO_2 could be nearly 2 Tcf, plus another nearly 4 Tcf of recycled CO_2, Table 6. Assuming that the volume of CO_2 stored equals the volume of CO_2 purchased and that the bulk of purchased CO_2 is from industrial sources, applying CO_2-EOR to the Williston Basin's oil reservoirs would enable over 100 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 these volumes.

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

Region	No. of Reservoirs	Economically Recoverable (MMBbls)	Market for Purchased CO_2 (Bcf)	Market for Recycled CO_2 (Bcf)
North Dakota	14	390	1,510	2,830
South Dakota	-	-	-	-
Montana	5	110	470	1,150
TOTAL	19	500	1,980	3,980

10. Given the large unconventional oil resource judged to exist in the Bakken Shale, further evaluation of converting this in-place resource into economic reserves seems warranted. It could be valuable to examine, in depth, the potential of injecting CO_2 for enhancing the recovery of oil from the Bakken Shale. Use of this alternative oil recovery methodology could help overcome two of the critical barriers limiting oil recovery from this unconventional resource, namely: lack of sufficient reservoir drive and the detrimental effects of introducing water into this low permeability, oil-wet petroleum system. In addition, examination of the application of advanced horizontal well and stimulation technology, such as being used to productively produce gas shales, could also be warranted.

11. A public-private partnership will be required to overcome the many barriers facing large scale application of CO_2-EOR in the Williston Basin Region's oil fields. The challenging nature of the current barriers — lack of sufficient, low-cost CO_2 supplies, uncertainties as to how the technology will perform in the Williston Basin's complex oil fields, and the considerable market and oil price risks — all argue that a partnership involving the oil production industry, potential CO_2 suppliers and transporters, the Williston 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 Williston Basin. Successful introduction and wide-scale use of CO_2-EOR in the Williston 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 organizations in North Dakota, South Dakota and Montana.

In North Dakota, we would like to thank the North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division for their field-level production and well data and state-level annual production data. In South Dakota, we would like to thank the Department of Environmental and Natural Resources, Minerals and Mining Program, Oil and Gas Section for detailed field production and well data and historical annual production data. In Montana, we would like to thank the Board of Oil and Gas Conservation for detailed field production and well data and the Department of Environmental Quality for historical annual production data and in particular Mr. George Hudak for data on injection wells. Finally, we thank Dr. David J. Bardin for providing valuable background information on the unconventional resource potential in the Bakken Shale of the Williston Basin.

2. INTRODUCTION

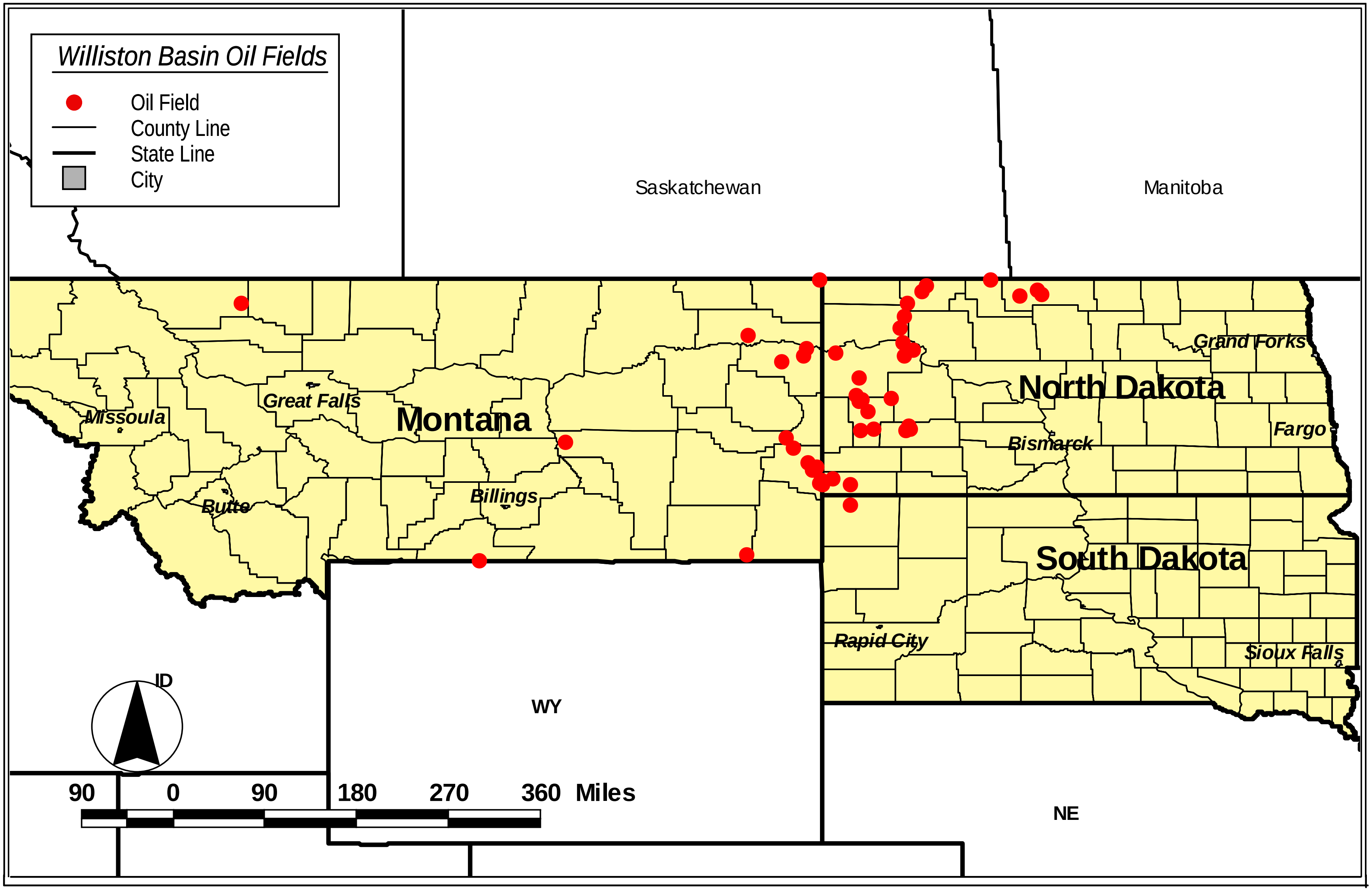
2.1 CURRENT SITUATION. The Williston Basin oil producing region had been in a slow decline up until 2004 when application of horizontal drilling technologies and discovery of new fields led to an increase in oil production. Sustaining and further increasing this production growth will be a challenge, requiring a coordinated set of actions by numerous parties who have a stake in this problem — Williston Basin state revenue and economic development officials; private, state and federal royalty owners; the Williston 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 further increasing Williston Basin’s oil production.

This report, “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Williston Basin of North Dakota, South Dakota and Montana,” provides information on the size of the technical and economic potential for CO_2-EOR in the Williston Basin oil producing region. 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 Williston Basin.

2.2 BACKGROUND. The Williston Basin region of North Dakota, South Dakota and Montana currently produces 154 thousand barrels of oil per day (in 2004). The deep, light oil reservoirs of this region are ideal candidates for miscible carbon dioxide-based enhanced oil recovery (CO_2-EOR). The outline of the Williston Basin’s oil producing region and the concentration of its major oil fields that screen for CO_2-EOR are shown in Figure 2.

Figure 2. Location of Major Williston Basin Region Oil Fields that Screen for CO_2-EOR



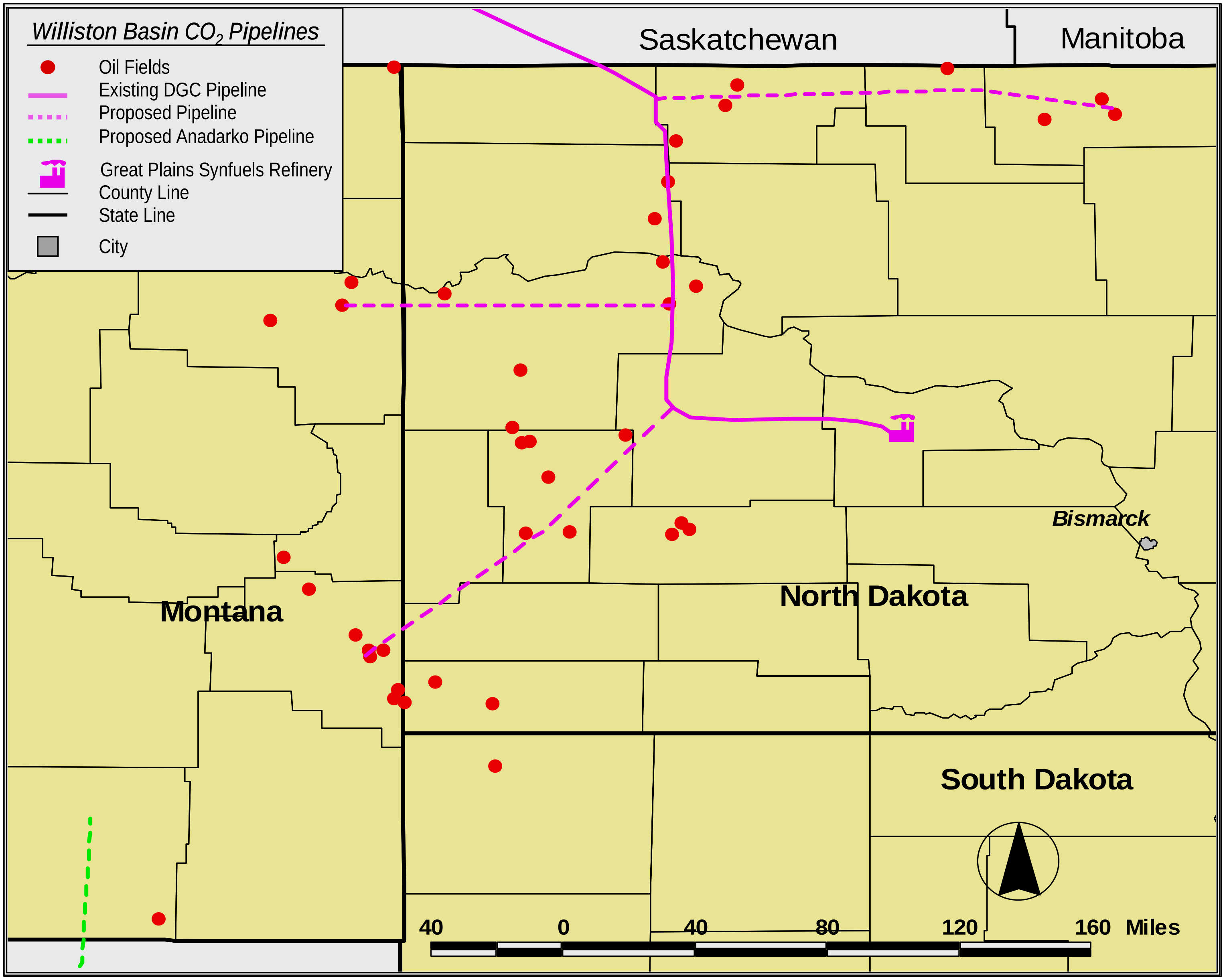
2.3 PURPOSE. This report, “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Williston Basin of North Dakota, South Dakota and Montana” is part of a larger effort to examine the enhanced oil recovery and CO_2 storage potential in key U.S. oil basins. The work involves establishing the geological 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, from natural sources in western Montana and/or from industrial sources in the region. The industrial CO_2 sources include the hydrogen plants and refineries in Mandan, North Dakota and Billings, Montana; the gas processing and chemical plants in the area; and the electric power plants in the three-state region. The Dakota Gasification Plant in Buelah, North Dakota already supplies 95 MMcf/d of relatively pure CO_2 that is transported to the Weyburn oil field in Canada for CO_2-EOR. (An expansion in the supply of CO_2 from the Dakota Gasification Plant to Canadian oil fields is currently underway.) The study assumes that sufficient CO_2 will become available in the near future, before the oil fields in the region are plugged and abandoned.

Figure 3 shows the existing pipeline system that transports CO_2 from the Dakota Gasification Company (DGC), in Buelah, North Dakota, 200 miles north to the Weyburn oil field in Saskatchewan, Canada. Figure 3 also provides a conceptual illustration of a CO_2 pipeline system that could transport additional CO_2 from DGC to the nearby oil fields of western North Dakota and eastern Montana. In addition, discussions are underway for extending of Anadarko's CO_2 pipeline, currently supplying fields in Wyoming, to southeastern Montana.

Figure 3. Location of Existing and Potential CO_2 Supply Pipelines in North Dakota and Montana



2.5 TECHNICAL OBJECTIVES. The objectives of this study are to examine the technical and the economic potential of applying CO2-EOR in the Williston 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 Williston Basin region.

2. *"State-of-the-art" Technology*. This involves bringing to the Williston Basin the benefits of recent improvements in the performance of the CO_2-EOR process and gains in understanding of how best to customize its application to the many different types of oil reservoirs in the region. As further discussed below, moderately deep, light oil reservoirs are selected for miscible CO_2-EOR and the shallower light oil and the heavier oil reservoirs are targeted for immiscible CO_2-EOR. "State-of-the-art" technology entails injecting and managing 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 ^{o}API would be selected for miscible CO_2-EOR. Major Williston Basin light oil fields such as Cut Bank (MT), Beaver Lodge (ND) and Buffalo (SD) 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. One large, Williston Basin reservoir is currently 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 Williston Basin's reservoirs amenable to CO_2-EOR, Table 7.

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

CO_2-EOR Technology Selection	Oil Reservoir Selection
"Traditional Practices" Miscible CO_2-EOR	▪ 53 Deep, Light Oil Reservoirs
"State-of-the-art" Miscible and Immiscible CO_2-EOR	▪ 53 Deep, Light Oil Reservoirs ▪ 1 Shallow, Light Oil Reservoir ▪ No Deep, Moderately Heavy Oil Reservoirs

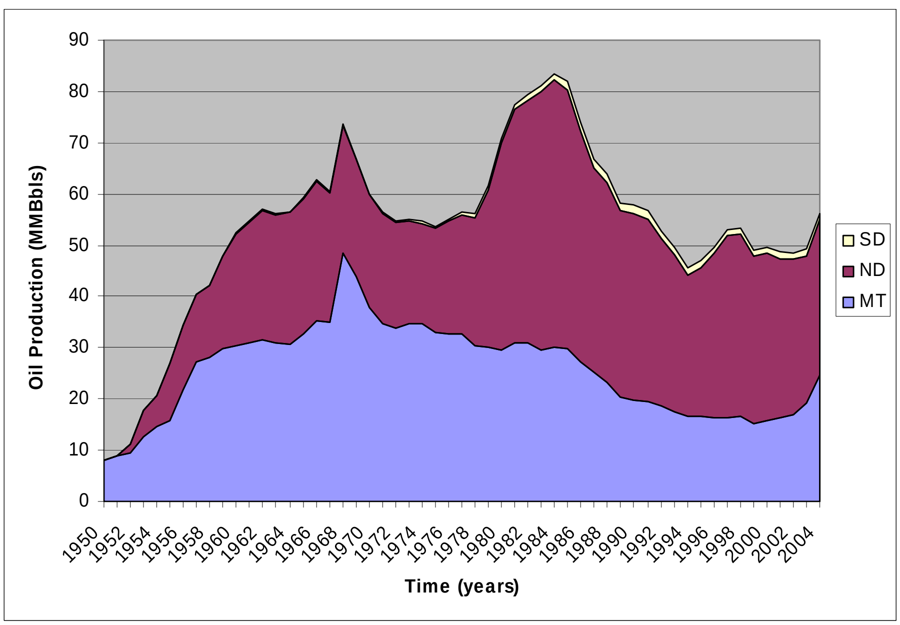
2.6 OTHER ISSUES. This study draws on a variety of sources for basic data on the reservoir properties and the expected technical and economic performance of CO_2-EOR in the Williston Basin. Because of confidentiality and proprietary issues, the results of the study have been aggregated and presented for the three states within the Williston 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 WILLISTON BASIN OIL PRODUCTION

3.1 HISTORY OF OIL PRODUCTION. Oil production for the Williston Basin region, encompassing North Dakota, South Dakota, and Montana has fluctuated considerably in the past 30 years, Figure 4. Since reaching a peak in 1985, oil production dropped sharply for the next ten years before leveling out and beginning an increase in the past few years. The recent increase in oil production is primarily due to application of horizontal drilling in Bakken Shale reservoirs in eastern Montana. Oil production reached a recent high of 56 million barrels (154,000 barrels per day) in 2004.

- North Dakota, with 30 million barrels of oil produced in 2004, has seen its crude oil proved reserves increase in recent years, due to new field discoveries, while its production has been relatively stable.
- South Dakota, with 1.4 million barrels of oil produced in 2004, has seen its production remain constant in the past ten years.
- Montana, with 25 million barrels of oil produced in 2004, has seen an increase in proved reserves and an increase in oil production starting in 2002 due to application of horizontal drilling in Bakken Shale oil reservoirs.

Figure 4. Williston Basin Production since 1950.



The Williston Basin still holds a rich resource of oil in the ground. With 13 billion barrels of original oil in place (OOIP) and approximately 4 billion barrels expected to be recovered, 9 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 Williston Basin oil fields that account for about one fifth of the oil production in this region. The table shows that one oil field is in production decline, seven oil fields are stable and two are increasing. Further oil production increases could be attained by applying enhanced oil recovery technology, particularly CO_2-EOR.

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

Major Oil Fields	2002	2003	2004	Production Status
Cedar Hill, ND	3.4	3.8	6.4	Increasing
Pennel, MT	2.2	2.4	2.4	Stable
Beaver Lodge, ND	1.6	1.6	1.6	Stable
Buffalo, SD	1.2	1.2	1.3	Stable
Cabin Creek, MT	1.2	1.1	1.1	Stable
Pine, MT	1.0	1.2	1.2	Stable
Little Knife, ND	1.0	0.9	0.9	Stable
Elm Coulee, MT	0.8	2.7	7.5	Increasing
Elk Basin, MT	0.5	0.5	0.5	Stable
Cut Bank, MT	0.4	0.4	0.3	**Declining**

3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY. Williston Basin oil producers are familiar with using technology for improving oil recovery. For example, High Pressure Air Injection (HPAI) has been successfully applied in the Buffalo Field, South Dakota and in the Medicine Pole Field, North Dakota for over 20 years. New projects have been started in Cedar Hills North, Pannel and Little Beaver oil fields in recent years.

Horizontal well drilling has also been successfully applied in the Bakken Shale of the Elm Coulee Field, Montana, accounting for its sharp increase in recent oil production. Small CO_2-EOR tests were conducted at Little Knife Field, North Dakota and South Hills Field, Montana, in the early 1980's. Additional discussion of experience with CO_2-EOR in the Williston Basin is provided in Chapter 6.

3.3 THE "STRANDED OIL" PRIZE. The three states in the Williston Basin – North Dakota, South Dakota and Montana – still hold over 9 billion barrels or over 70% of their OOIP, after application of 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 oil production history of 10 large Williston Basin oil fields, each with estimated ROIP of 200 million barrels or more.

Table 9. Oil Production History of Selected Major Oil Fields of the Williston Basin Region

	Field/State	Year Discovered	Cumulative Production (MMBbl)	Estimated Reserves (MMBbl)	Remaining Oil In-Place (MMBbl)
1	CUT BANK, MT	1926	139	5	420
2	BEAVER LODGE, ND	1951	135	18	381
3	BELL CREEK, MT	1967	133	3	251
4	PINE, MT	1951	121	20	259
5	PENNEL, MT	1955	111	39	350
6	CABIN CREEK, MT	1953	110	17	281
7	ELK BASIN, MT	1915	85	8	216
8	LITTLE KNIFE, ND	1977	73	10	204
9	LOOKOUT BUTTE, MT	1960	41	47	207
10	CEDAR HILLLS, ND	1995	39	76	523

3.4 REVIEW OF PRIOR STUDIES. In 2004, a joint effort was undertaken by the Westport Oil and Gas Company and the North Dakota Geological Survey in which 97 North Dakota Oil fields were screened for their potential for CO_2-EOR. The fields were screened for depth (>2,500 feet), oil gravity (>27 °API), porosity (>12%) and permeability (>10 md). After screening, the reservoirs were then compared to the economic CO_2-EOR fields in the Permian Basin.

The study determined that many North Dakota fields have favorable reservoir characteristics when compared with Permian EOR projects, with one notable exception. Permian Basin oil fields, in general, have a much tighter well spacing, an average of 28 acre per well spacing, while many North Dakota fields have well spacing of greater than 80 acres. These greater than 80 acre well spacing fields were considered to be unfavorable for CO_2-EOR. Other unfavorable characteristics identified by the study for North Dakota oil fields included a high degree of vertical fracturing, deep oil reservoirs (high drilling costs), and considerable reservoir heterogeneity, reducing sweep efficiency.

In total, the authors considered 55 of the oil fields with the most favorable reservoir characteristics as having *probable* recoverable CO_2-EOR oil resources of 171 MMBbls (Table 10). In addition, 26 fields with less favorable reservoir characteristics were judged to have *possible* recoverable resources of 106 MMBbls.

Table 10. Ten North Dakota Fields with Probable EOR Oil Resources
(Assume a Recovery Factor of 8% OOIP)

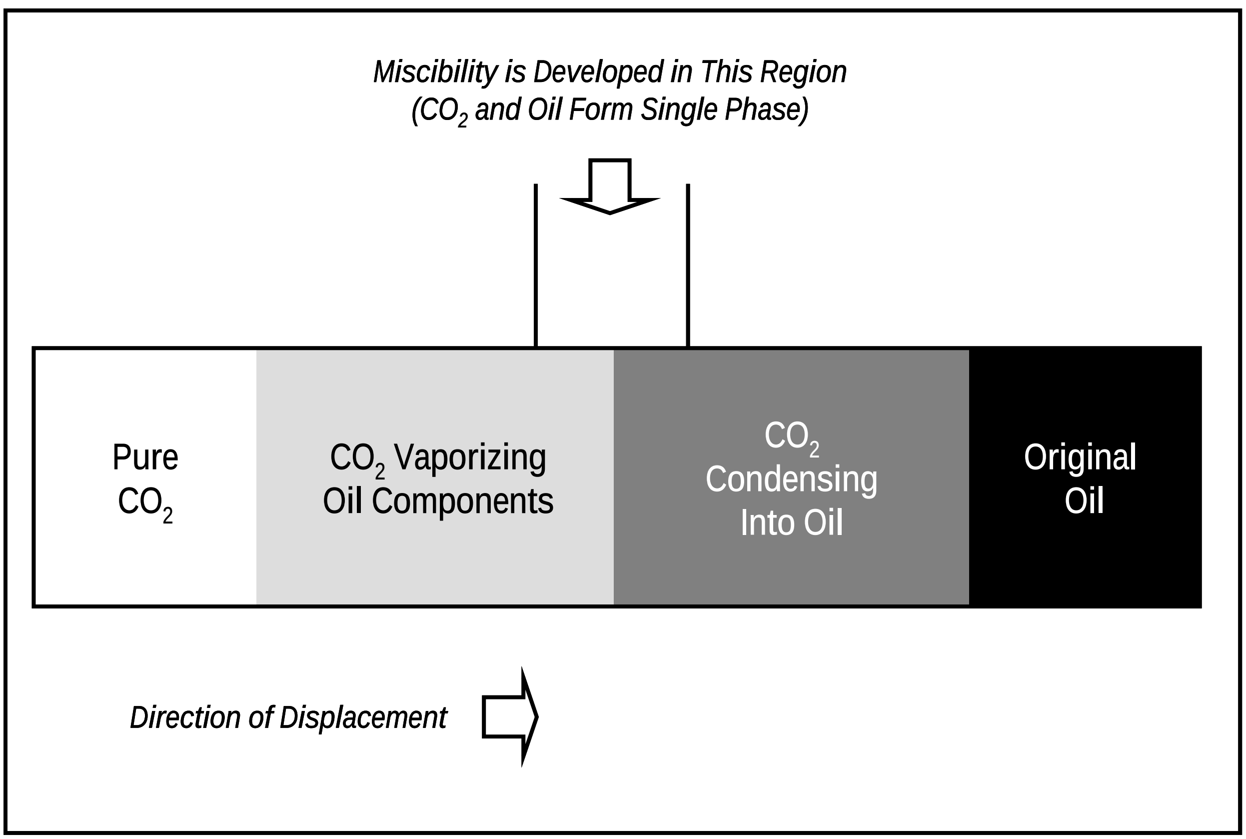
	Field/Reservoir	CO_2-EOR Recoverable Resources (MMBbl)
1	Beaver Lodge (Madison)	17.6
2	Tioga (Madison)	17.2
3	Big Stick (Madison)	13.3
4	Fryburg (Heath-Tyler)	12.4
5	Beaver Lodge (Devonian)	11.1
6	Newburg (Spearfish, Charles)	7.7
7	Wiley (Glenburn)	7.6
8	Blue Buttes (Madison)	7.4
9	North Tioga (Madison)	7.2
10	Charleson North (Madison)	6.4

4. MECHANISMS OF CO_2-EOR

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

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

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



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

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

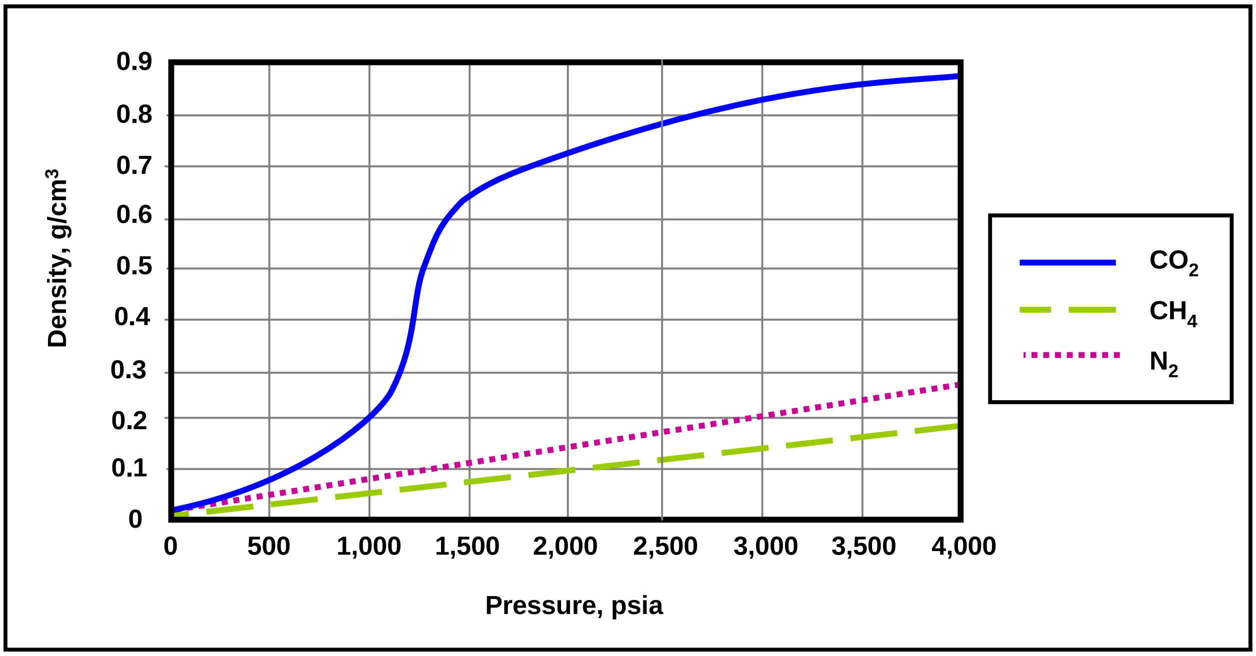


Figure 6B. Carbon Dioxide, CH_4 and N_2 viscosities at 105^0F. At high pressures, the viscosity of CO_2 is also greater then that of methane or nitrogen, although it remains low in comparison to that of liquids. Viscosities were calculated with an EOS.

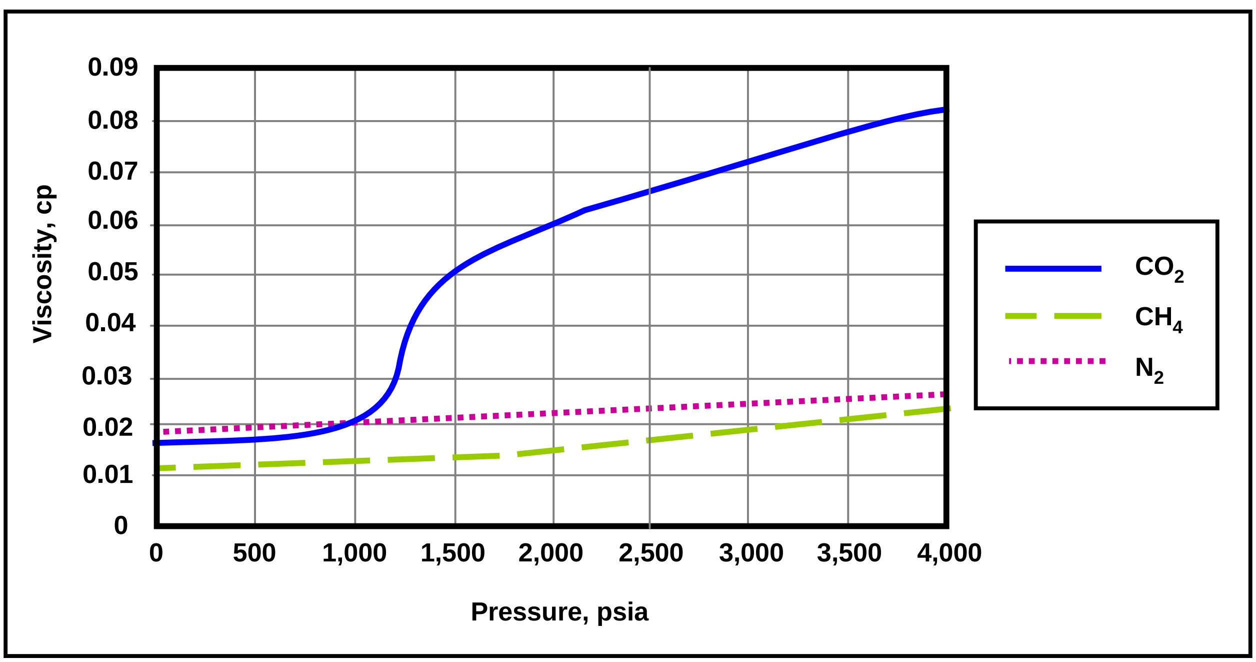


Figure 7A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid (Holm and Josendal).

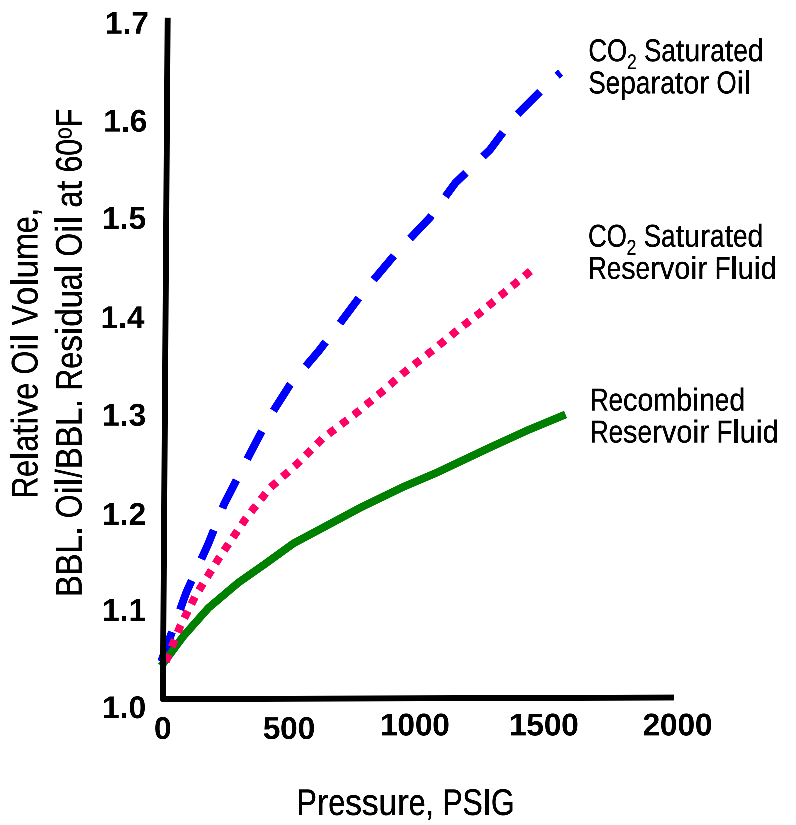


Figure 7B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

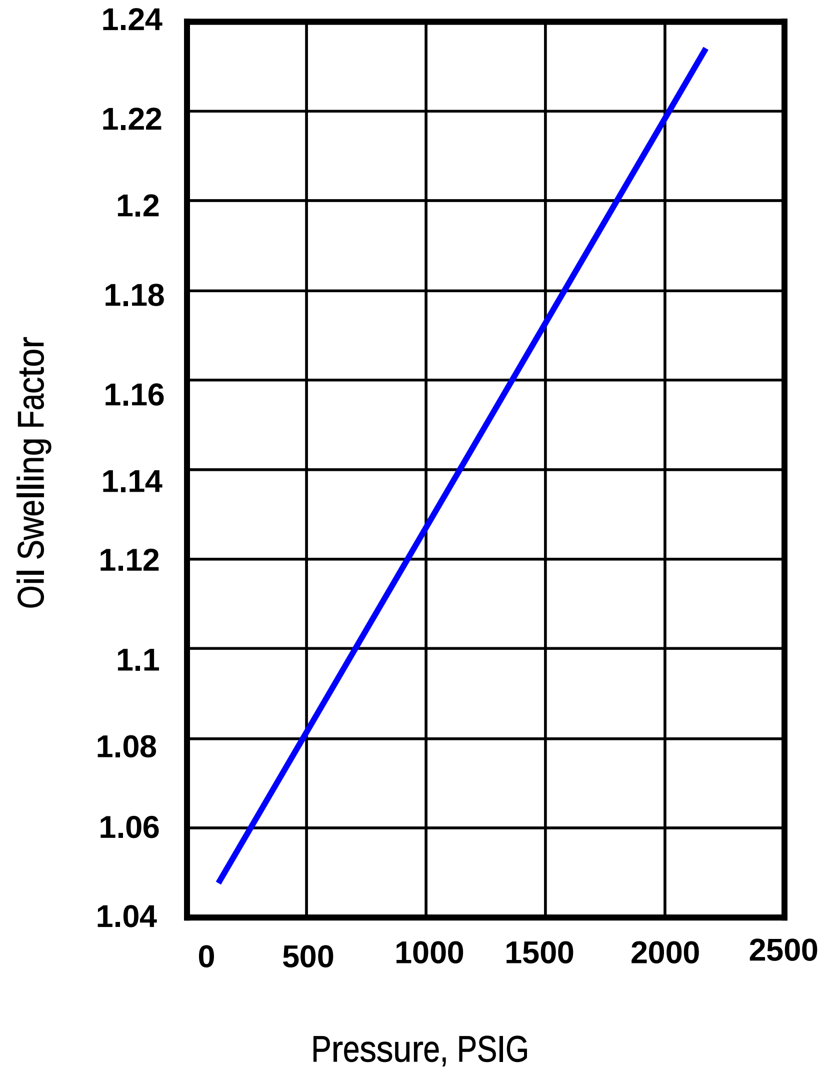
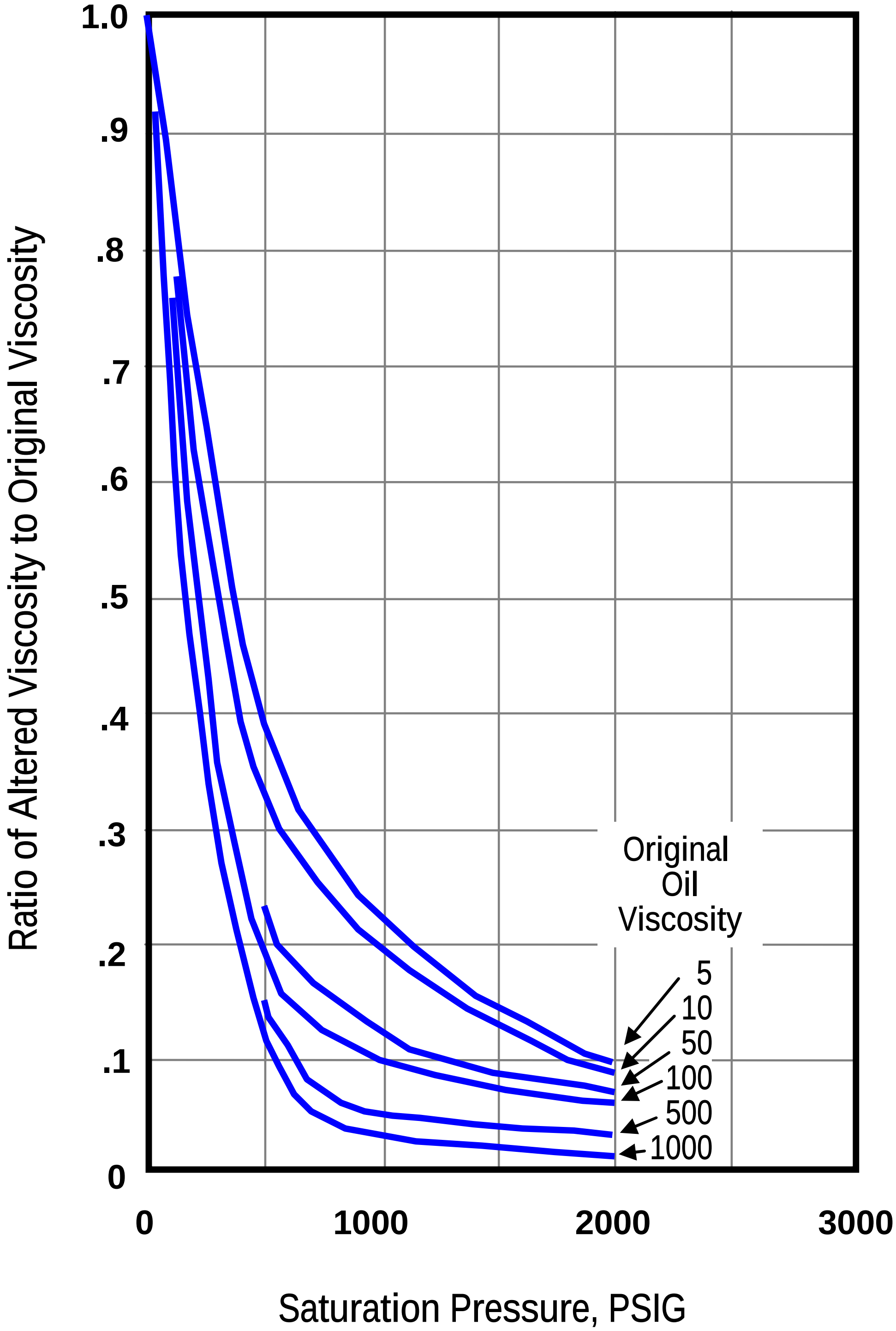


Figure 8. Viscosity Reduction vs. Saturation Pressure (Simon and Graue)



5. STUDY METHODOLOGY

5.1 OVERVIEW. A seven part methodology was used to assess the CO_2-EOR potential of the Williston Basin's oil reservoirs. The seven steps were: (1) assembling the Williston 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 Williston Basin Major Oil Reservoirs Data Base for North Dakota, South Dakota and Montana.

Table 11 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 Williston Basin Major Oil Reservoirs Data Base contains 93 reservoirs, accounting for 71% of the oil expected to be ultimately produced in Williston Basin by primary and secondary oil recovery processes.

Table 11. Reservoir Data Format: Major Oil Reservoirs Data Base

Basin Name	
Field Name	
Reservoir	

Print Sheets

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)		
2004 Production (Mbbl)		
Daily Prod - Field (Bbl/d)		
Cum Oil Production (MMbbl)		
EOY 2004 Oil Reserves (MMbbl)		
Water Cut		
Water Production		
2004 Water Production (Mbbl)		
Daily Water (Mbbl/d)		
Injection		
Injection Wells (active)		
Injection Wells (shut-in)		
2004 Water Injection (MMbbl)		
Daily Injection - Field (Mbbl/d)		
Cum Injection (MMbbl)		
Daily Inj per Well (Bbl/d)		

EOR	
Type	
2004 EOR Production (MMbbl)	
Cum EOR Production (MMbbl)	
EOR 2004 Reserves (MMbbl)	
Ultimate Recovery (MMbbl))	

Volumes	**TORIS**	**ARI P/S**
OOIP (MMbl) P/S		
Cum Oil (MMbl) P/S		
EOY P/S 2004 Reserves (MMbl)		
Ultimate P/S Recovery (MMbl)		
Remaining (MMbbl)		
Ultimate Recovered P/S (%)		
OOIP Volume Check		
Reservoir Volume (AF)		
Bbl/AF		
OOIP Check (MMbl)		
SROIP Volume Check		
Reservoir Volume (AF)		
Swept Zone Bbl/AF		
SROIP Check (MMbbl)		
ROIP Volume Check		
ROIP Check (MMbl)		

Considerable effort was required to construct an up-to-date, volumetrically consistent data base that contained all of the essential data, formats and interfaces to enable the study to: (1) develop an accurate estimate of the size of the original and remaining oil in-place in the Williston 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, reservoir temperature and oil composition. These values were used to establish the minimum miscibility pressure for conducting miscible CO_2-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the miscibility pressure standard were considered for immiscible CO_2-EOR.

The preliminary screening steps involved selecting the deeper oil reservoirs that had sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet, at the mid-point of the reservoir, was used to ensure the reservoir could accommodate high pressure CO_2 injection. A minimum oil gravity of 17.5 ^{o}API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection. Table 12 tabulates the oil reservoirs that passed the preliminary screening step. Many of these fields contain multiple reservoirs, with each reservoir holding a great number of stacked sands. Because of data limitations, this screening study combined the sands into a single reservoir.

Table 12. Williston Basin Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
A. North Dakota		
North Dakota	ANTELOPE	MADISON
North Dakota	ANTELOPE	SANISH
North Dakota	BEAVER LODGE	DEVONIAN
North Dakota	BEAVER LODGE	MADISON
North Dakota	BEAVER LODGE	RED RIVER
North Dakota	BEAVER LODGE	SILURIAN
North Dakota	BIG STICK FIELD	MISSION CANYON
North Dakota	BLACK SLOUGH	MIDALE-RIVAL
North Dakota	BLUE BUTTES	MADISON
North Dakota	CEDAR CREEK (LITTLE BEAVER EAST)	RED RIVER/ORDOCIVIAN
North Dakota	CEDAR HILLLS	RED RIVER
North Dakota	CHARLSON	MADISON
North Dakota	DICKINSON	HEATH
North Dakota	DICKINSON	LODGEPOLE
North Dakota	ELAND	LODGEPOLE
North Dakota	ELKHORN RANCH	MISSION CANYON
North Dakota	ELKHORN RANCH NORTH	MISSION CANYON
North Dakota	FRYBURG	HEATH
North Dakota	FRYBURG	MADISON
North Dakota	FRYBURG	TYLER
North Dakota	GLASS BLUFF	MADISON
North Dakota	LITTLE KNIFE	MISSION CANYON
North Dakota	MEDICINE POLE HILLS	RED RIVER
North Dakota	MEDORA	MADISON
North Dakota	NEWBURG	SPEARFISH & CHARLES
North Dakota	RED WING CREEK	MADISON
North Dakota	RIVAL	MADISON
North Dakota	ROUGH RIDER	MADISON - MISSION CANYON
North Dakota	SHERWOOD	MADISON - MISSION CANYON
North Dakota	STADIUM	LODGEPOLE
North Dakota	TIOGA	MADISON - RIVAL
North Dakota	TIOGA NORTH	MADISON - MIDALE
North Dakota	WESTHOPE SOUTH	SPEARFISH-CHARLES
North Dakota	WILEY	MISSION CANYON
B. South Dakota		
South Dakota	BUFFALO	RED RIVER
C. Montana		
Montana	BELL CREEK	MUDDY

Table 12. Williston Basin Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Montana	CABIN CREEK	INTERLAKE + RED RIVER + STNY MTN
Montana	CORAL CREEK	RED RIVER
Montana	CUT BANK	MADISON
Montana	ELK BASIN	EMBAR - TENSLEEP
Montana	ELK BASIN	MADISON
Montana	ELM COULEE	BAKKEN SHALE
Montana	FLAT LAKE	RATCLIFFE
Montana	LITTLE BEAVER	RED RIVER
Montana	LITTLE BEAVER	RED RIVER EAST
Montana	LOOKOUT BUTTE	INTERLAKE & RED RIVER
Montana	LOOKOUT BUTTE	INTERLAKE & RED RIVER EAST
Montana	MONDAK WEST	ALL
Montana	PENNEL	RED RIVER + STONY MOUNTAIN
Montana	PINE	INTERLAKE + RED RIVER + STNY MTN
Montana	POPLAR EAST	MADISON - CHARLES
Montana	SIOUX PASS	RED RIVER C
Montana	SIOUX PASS-NORTH	RED RIVER
Montana	SUMATRA	TYLER

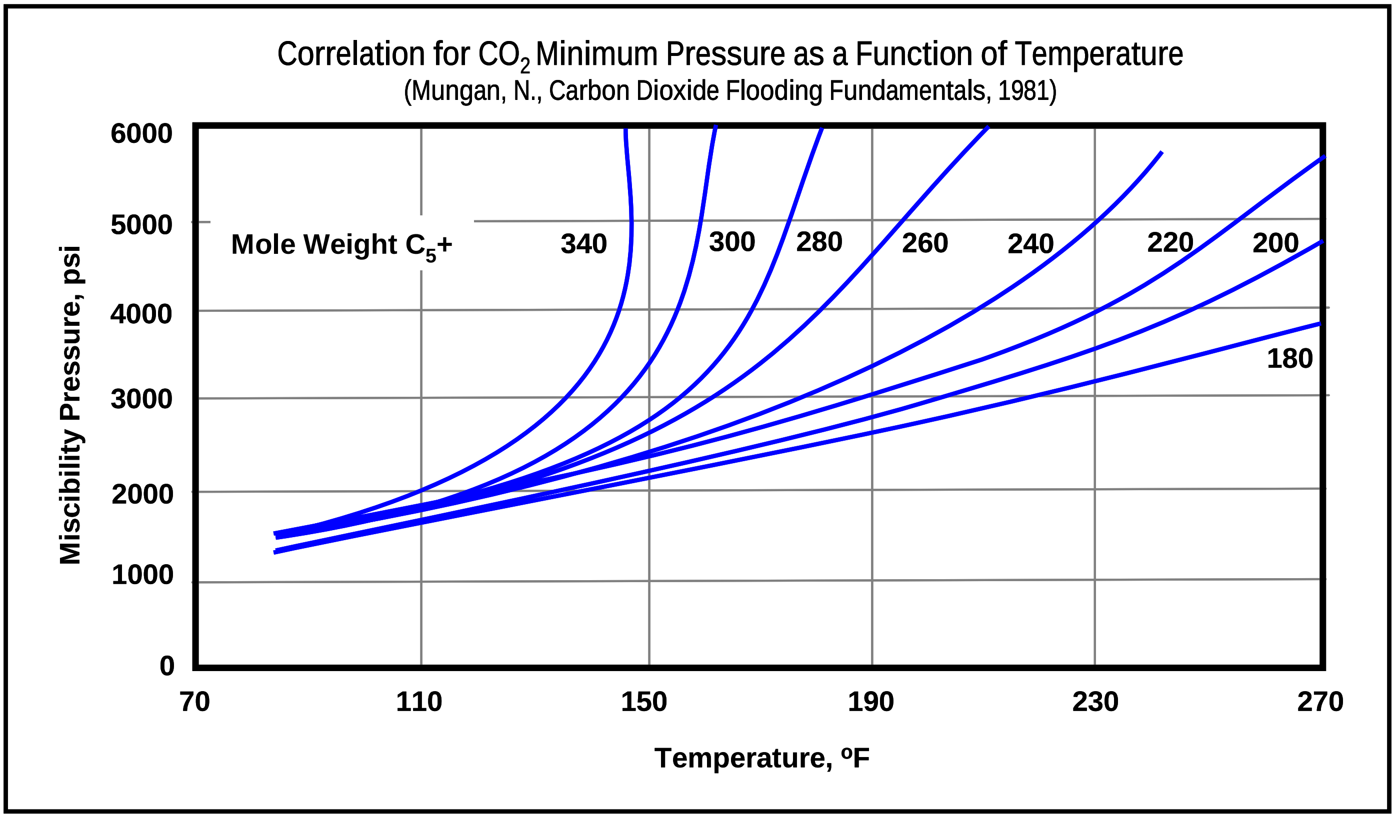
5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and 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. The Cronquist correlation is set forth below:

MMP = 15.988*T (0.744206+0.0011038*MW C5+)

Where: T is Temperature in oF, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

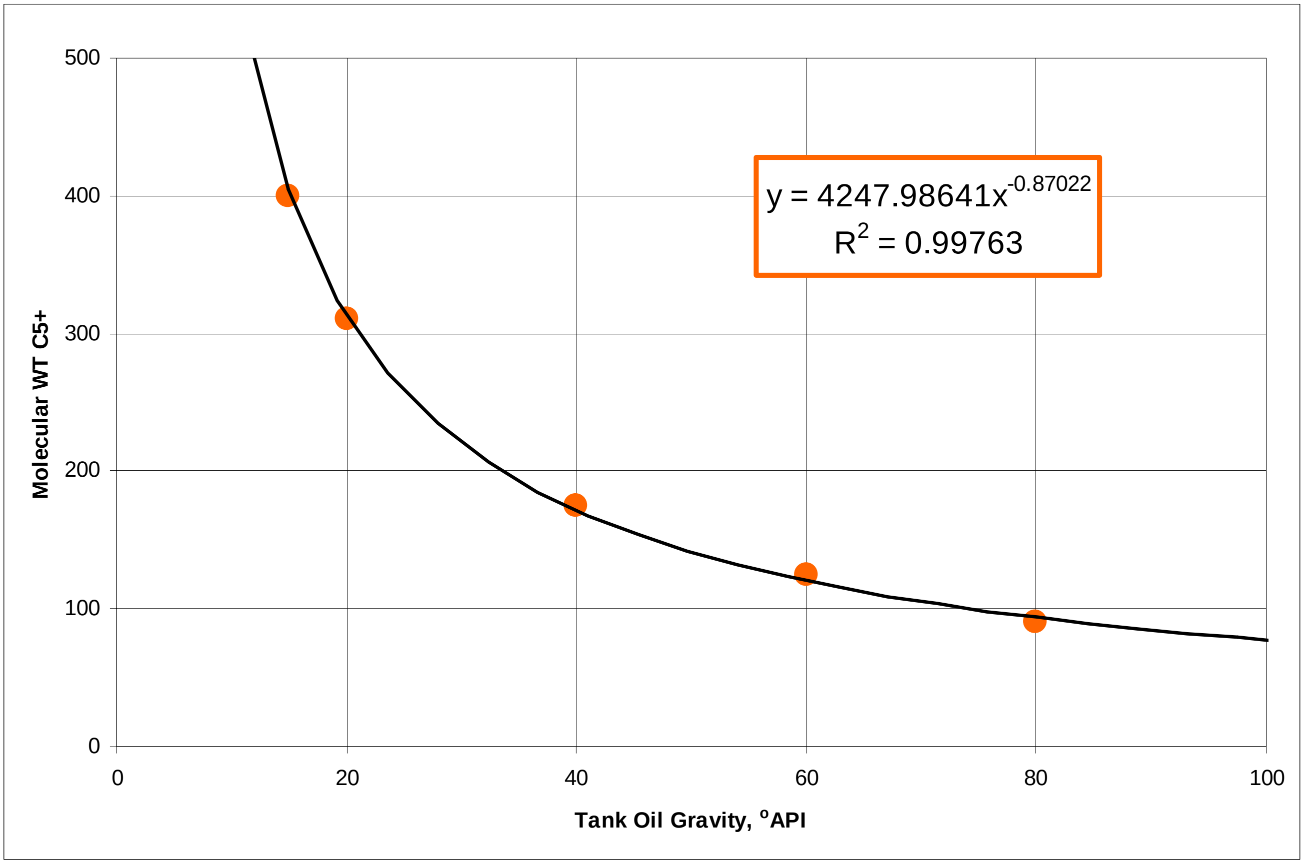
Figure 9. Estimating CO_2 Minimum Miscibility Pressure



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



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

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

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

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

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

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

The cost model also accounts for normal well operation and maintenance (O&M), for lifting costs of the produced fluids, and for costs of capturing, separating and reinjecting the produced CO_2. A variety of CO_2 purchase and reinjection costs options are available to the model user. (Appendices B, C 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 Williston 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 Williston 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. This low technology, high risk scenario, is called "Traditional Practices".

- The second scenario, entitled "State-of-the-art", assumes that the technology progress in CO_2-EOR, achieved in the past ten years in other areas, is successfully applied to the oil reservoirs of the Williston 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 Williston 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 13. Economic Model Established by the Study

Pattern-Level Cashflow Model		**Advanced**											
State		**ND**		New Injectors	0.00								
Field				Existing Injectors	0.49			68					
Formation				Converted Producers	0.51								
Depth				New Producers	0.0								
Distance from Trunkline (mi)				Existing Producers	1.25								
# of Patterns				Disposal Wells	0.00								
Miscibility:	**Miscible**												
	Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
CO2 Injection (MMcf)			144	144	144	144	144	144	144	144	144	144	144
H2O Injection (Mbw)			36	36	36	36	36	36	36	36	36	36	36
Oil Production (Mbbl)			-	-	-	10	42	37	24	19	17	17	13
H2O Production (MBw)			96	96	96	86	51	40	40	40	39	37	38
CO2 Production (MMcf)			-	-	-	0	4	44	75	86	93	98	108
CO2 Purchased (MMcf)			144	144	144	144	140	100	69	58	51	45	36
CO2 Recycled (MMcf)			-	-	-	0	4	44	75	86	93	98	108
Oil Price ($/Bbl)	**$ 30.00**		$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Gravity Adjustment	**28**	Deg	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98
Gross Revenues ($M)			$ -	$ -	$ -	$ 247	$ 1,056	$ 919	$ 609	$ 477	$ 422	$ 432	$ 320
Royalty ($M)	**-12.5%**		$ -	$ -	$ -	$ (31)	$ (132)	$ (115)	$ (76)	$ (60)	$ (53)	$ (54)	$ (40)
Severance Taxes ($M)	**-5.0%**		$ -	$ -	$ -	$ (11)	$ (46)	$ (40)	$ (27)	$ (21)	$ (18)	$ (19)	$ (14)
Extraction Tax ($M)	**-6.5%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (25)
Net Revenue($M)			$ -	$ -	$ -	$ 206	$ 878	$ 764	$ 507	$ 397	$ 351	$ 359	$ 241
Capital Costs ($M)													
New Well - D&C		$ -											
Reworks - Producers to Producers		$ (74)											
Reworks - Producers to Injectors		$ (18)											
Reworks - Injectors to Injectors		$ (30)											
Surface Equipment (new wells only)		$ -											
CO2 Recycling Plant		$ -	$ -	$ -	$ (222)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (24)											
Total Capital Costs		$ (146)	$ -	$ -	$ (222)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	**0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)													
Total CO2 Cost ($M)			$ (216)	$ (215)	$ (216)	$ (215)	$ (211)	$ (163)	$ (126)	$ (112)	$ (104)	$ (97)	$ (86)
O&M Costs													
Operating & Maintenance ($M)			$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)
Lifting Costs ($/bbl)	**$ 0.25**		$ (24)	$ (24)	$ (24)	$ (24)	$ (23)	$ (19)	$ (16)	$ (15)	$ (14)	$ (14)	$ (13)
G&A	**20%**		(11)	(11)	(11)	(11)	(11)	(10)	(10)	(10)	(9)	(9)	(9)
Total O&M Costs			$ (68)	$ (68)	$ (68)	$ (68)	$ (67)	$ (62)	$ (59)	$ (57)	$ (56)	$ (56)	$ (54)
Net Cash Flow ($M)		$ (146)	$ (284)	$ (284)	$ (506)	$ (78)	$ 600	$ 538	$ 322	$ 227	$ 191	$ 206	$ 100
Cum. Cash Flow		$ (146)	$ (429)	$ (713)	$ (1,219)	$ (1,297)	$ (697)	$ (159)	$ 163	$ 390	$ 581	$ 787	$ 887
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		$ (146)	$ (227)	$ (182)	$ (259)	$ (32)	$ 197	$ 141	$ 67	$ 38	$ 26	$ 22	$ 9
Disc. Cum Cash Flow		$ (146)	$ (373)	$ (554)	$ (813)	$ (845)	$ (649)	$ (508)	$ (440)	$ (402)	$ (376)	$ (354)	$ (346)
NPV (BTx)	25%	($336)											
NPV (BTx)	20%	$ (247)											
NPV (BTx)	15%	$ (105)											
NPV (BTx)	10%	$ 121											
IRR (BTx)		12.38%											

Table 13. Economic Model Established by the Study (cont'd)

Pattern-Level Cashflow Model															
State															
Field															
Formation															
Depth															
Distance from Trunkline (mi)															
# of Patterns															
Miscibility:	**Miscible**														
	Year	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
CO2 Injection (MMcf)		143	129	129	129	129	129	129	129	129	129	129	129	129	129
H2O Injection (Mbw)		36	43	43	43	43	43	43	43	43	43	43	43	43	43
Oil Production (Mbbl)		9	10	12	9	6	4	4	4	4	5	6	7	7	7
H2O Production (MBw)		39	39	43	45	46	46	46	46	46	45	43	42	44	43
CO2 Production (MMcf)		114	115	101	102	108	112	114	114	112	113	113	114	110	111
CO2 Purchased (MMcf)		29	14	29	27	21	17	15	15	17	16	16	15	19	19
CO2 Recycled (MMcf)		114	115	101	102	108	112	114	114	112	113	113	114	110	111
Oil Price ($/Bbl)	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Gravity Adjustment	28	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98
Gross Revenues ($M)		$ 222	$ 242	$ 287	$ 227	$ 145	$ 100	$ 87	$ 92	$ 100	$ 120	$ 150	$ 165	$ 177	$ 180
Royalty ($M)	-12.5%	$ (28)	$ (30)	$ (36)	$ (28)	$ (18)	$ (12)	$ (11)	$ (12)	$ (12)	$ (15)	$ (19)	$ (21)	$ (22)	$ (22)
Severance Taxes ($M)	-5.0%	$ (10)	$ (11)	$ (13)	$ (10)	$ (6)	$ (4)	$ (4)	$ (4)	$ (4)	$ (5)	$ (7)	$ (7)	$ (8)	$ (8)
Extraction Tax ($M)	-6.5%	$ (18)	$ (19)	$ (23)	$ (18)	$ (11)	$ (8)	$ (7)	$ (7)	$ (8)	$ (9)	$ (12)	$ (13)	$ (14)	$ (14)
Net Revenue($M)		$ 167	$ 182	$ 216	$ 171	$ 109	$ 75	$ 66	$ 70	$ 75	$ 90	$ 113	$ 124	$ 133	$ 135
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)		$ (77)	$ (56)	$ (73)	$ (71)	$ (64)	$ (59)	$ (57)	$ (57)	$ (59)	$ (58)	$ (58)	$ (57)	$ (61)	$ (61)
O&M Costs															
Operating & Maintenance ($M)		$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)
Lifting Costs ($/bbl)	$ 0.25	$ (12)	$ (12)	$ (14)	$ (13)	$ (13)	$ (13)	$ (12)	$ (12)	$ (12)	$ (12)	$ (12)	$ (12)	$ (18)	$ (18)
G&A	20%	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(10)	(10)
Total O&M Costs		$ (54)	$ (54)	$ (56)	$ (56)	$ (55)	$ (54)	$ (54)	$ (54)	$ (54)	$ (54)	$ (54)	$ (54)	$ (61)	$ (61)
Net Cash Flow ($M)		$ 36	$ 73	$ 87	$ 45	$ (10)	$ (38)	$ (45)	$ (42)	$ (38)	$ (22)	$ 1	$ 13	$ 11	$ 13
Cum. Cash Flow		$ 923	$ 996	$ 1,083	$ 1,128	$ 1,118	$ 1,079	$ 1,034	$ 993	$ 955	$ 933	$ 934	$ 947	$ 959	$ 972
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		$ 2	$ 4	$ 4	$ 2	$ (0)	$ (1)	$ (1)	$ (1)	$ (0)	$ (0)	$ 0	$ 0	$ 0	$ 0
Disc. Cum Cash Flow		$ (343)	$ (339)	$ (335)	$ (334)	$ (334)	$ (335)	$ (336)	$ (336)	$ (337)	$ (337)	$ (337)	$ (337)	$ (337)	$ (337)
NPV (BTx)	25%														
NPV (BTx)	20%														
NPV (BTx)	15%														
NPV (BTx)	10%														
IRR (BTx)															

Table 13. Economic Model Established by the Study (cont'd)

Pattern-Level Cashflow Model													
State													
Field													
Formation													
Depth													
Distance from Trunkline (mi)													
# of Patterns													
Miscibility:	**Miscible**												
	Year	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	
CO_2 Injection (MMcf)		129	129	129	129	129	129	105	-	-	-	-	4,280
H_2O Injection (Mbw)		43	43	43	43	43	43	55	107	107	107	21	1,641
Oil Production (Mbbl)		8	8	8	8	7	7	6	6	5	5	1	339
H_2O Production (MBw)		43	42	42	42	42	43	44	48	84	96	20	1,815
CO_2 Production (MMcf)		111	112	112	112	113	114	116	127	42	16	2	3,033
CO_2 Purchased (MMcf)		19	18	17	17	16	15	-	-	-	-	-	1,443
CO_2 Recycled (MMcf)		111	112	112	112	113	114	105	-	-	-	-	2,837
Oil Price ($/Bbl)	**$ 30.00**	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	
Gravity Adjustment	**28**	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	$ 24.98	
Gross Revenues ($M)		$ 187	$ 202	$ 200	$ 192	$ 180	$ 167	$ 155	$ 145	$ 130	$ 112	$ 20	$ 8,469
Royalty ($M)	**-12.5%**	$ (23)	$ (25)	$ (25)	$ (24)	$ (22)	$ (21)	$ (19)	$ (18)	$ (16)	$ (14)	$ (2)	$ (1,059)
Severance Taxes ($M)	**-5.0%**	$ (8)	$ (9)	$ (9)	$ (8)	$ (8)	$ (7)	$ (7)	$ (6)	$ (6)	$ (5)	$ (1)	$ (371)
Extraction Tax ($M)	**-6.5%**	$ (15)	$ (16)	$ (16)	$ (15)	$ (14)	$ (13)	$ (12)	$ (11)	$ (10)	$ (9)	$ (2)	$ (339)
Net Revenue($M)		$ 141	$ 152	$ 150	$ 145	$ 135	$ 126	$ 117	$ 109	$ 98	$ 85	$ 15	$ 6,701
Capital Costs ($M)													
New Well - D&C													$ -
Reworks - Producers to Producers													$ (74)
Reworks - Producers to Injectors													$ (18)
Reworks - Injectors to Injectors													$ (30)
Surface Equipment (new wells only)													$ -
CO_2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (222)
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction													$ (24)
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (368)
Cap Ex G&A	**0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO_2 Costs ($M)													
Total CO_2 Cost ($M)		$ (61)	$ (60)	$ (59)	$ (60)	$ (58)	$ (57)	$ (32)	$ -	$ -	$ -	$ -	$ (3,015)
O&M Costs													
Operating & Maintenance ($M)		$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (33)	$ (1,181)
Lifting Costs ($/bbl)	**$ 0.25**	$ (18)	$ (19)	$ (18)	$ (18)	$ (18)	$ (17)	$ (17)	$ (18)	$ (26)	$ (28)	$ (6)	$ (600)
G&A	**20%**	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(12)	(12)	(8)	$ (356)
Total O&M Costs		$ (61)	$ (62)	$ (61)	$ (61)	$ (61)	$ (60)	$ (60)	$ (61)	$ (71)	$ (73)	$ (46)	$ (2,138)
Net Cash Flow ($M)		$ 19	$ 31	$ 30	$ 24	$ 16	$ 9	$ 25	$ 48	$ 27	$ 11	$ (31)	$ 1,180
Cum. Cash Flow		$ 991	$ 1,022	$ 1,051	$ 1,075	$ 1,091	$ 1,100	$ 1,125	$ 1,173	$ 1,200	$ 1,211	$ 1,180	
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	$ 0	$ 0	$ 0	$ 0	$ 0	$ (0)	$ (336)
Disc. Cum Cash Flow		$ (337)	$ (337)	$ (337)	$ (337)	$ (337)	$ (337)	$ (336)	$ (336)	$ (336)	$ (336)	$ (336)	
NPV (BTx)	25%												
NPV (BTx)	20%												
NPV (BTx)	15%												
NPV (BTx)	10%												
IRR (BTx)													

6. RESULTS BY STATE

6.1 NORTH AND SOUTH DAKOTA. North Dakota is a major oil producing state with a rich history of oil and gas development. Crude oil production in the state began in 1951, reaching a cumulative recovery of 1.5 billion barrels through 2004. In 2004, North Dakota ranked 9th in oil production in the onshore U.S., providing 30 MMBbls of oil (83 MBbls/day). North Dakota has about 9,000 producing oil wells and oil reserves of 390 MMBbls.

Despite still being one of the top oil producing states, North Dakota has seen a slow decline in production in recent years, Table 14.

Table 14. Recent History of North Dakota Oil Production

	Annual Oil Production	
	(MMBls/year)	(MBbls/day)
1999	33	90
2000	33	90
2001	31	85
2002	30	86
2003	29	79
2004	30	83

South Dakota produced 1.4 MMBbls (4 MBbls/day) of oil (in 2004), from about 320 wells and 15 MMBbls of crude oil reserves. Oil production in South Dakota began in 1954, and cumulative oil recovery has reached 41 million barrels. With only one major oil field in South Dakota, production has been relatively constant in recent years, Table 15.

Table 15. Recent History of South Dakota Oil Production

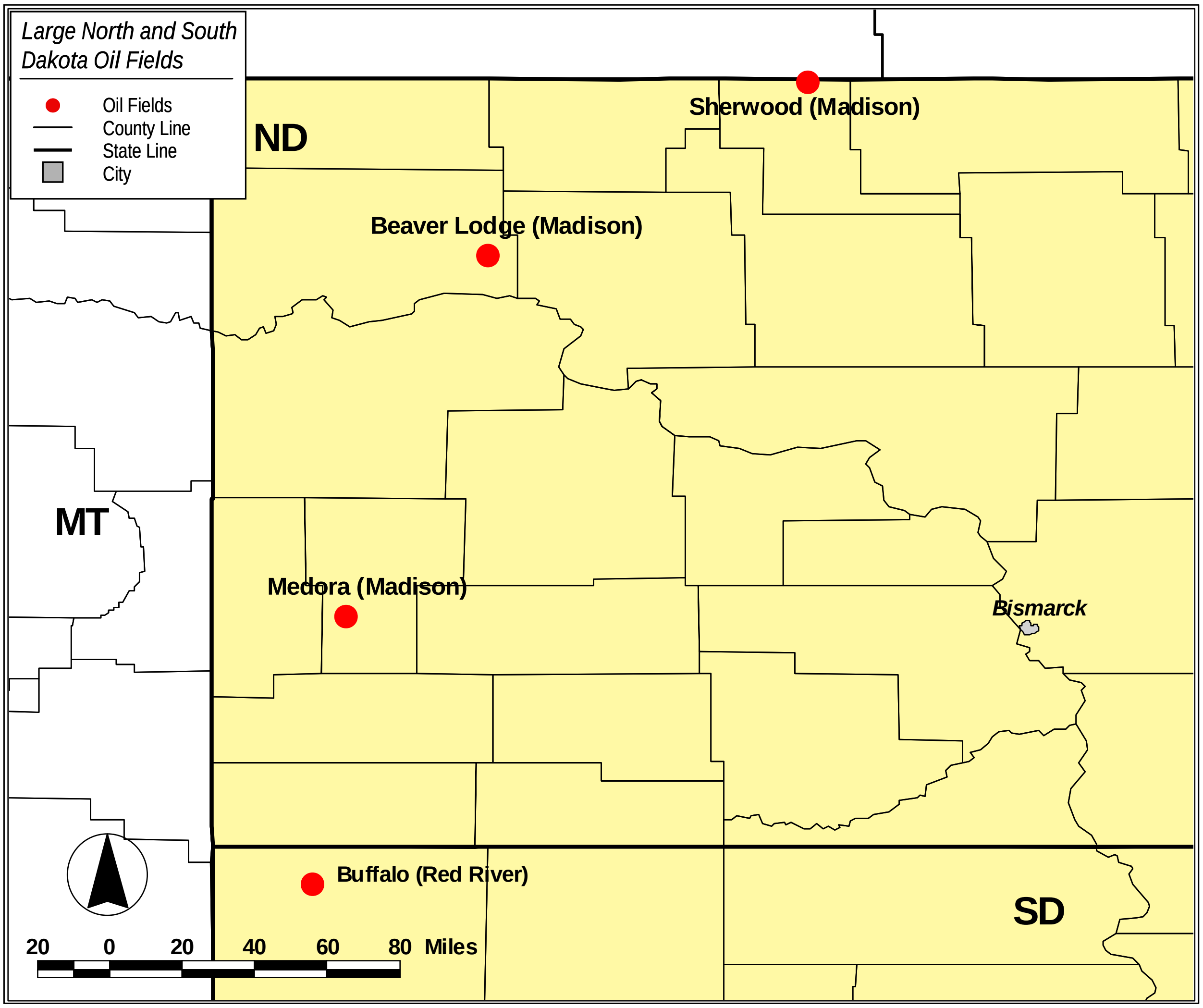
	Annual Oil Production	
	(MMBbls/year)	(MBbls/day)
1999	1	3
2000	1	3
2001	1	3
2002	1	3
2003	1	3
2004	1	4

North Dakota Oil Fields. To better understand the potential of using CO_2-EOR in North Dakota, this section examines, in more depth, three large light oil fields, shown in Figure 11.

- Beaver Lodge (Madison Reservoir)
- Medora (Madison Reservoirs)
- Sherwood (Madison Reservoir)

South Dakota Oil Fields. South Dakota has one large oil field that may be amenable to miscible CO_2- EOR, namely Buffalo (Red River), Figure 11.

Figure 11. Large North and South Dakota Oil Fields



These four fields, distributed across northwestern South Dakota and western North Dakota, could serve as the "anchor" sites for CO_2-EOR projects that could later be extended to other smaller oil fields. The cumulative oil production, proved reserves and remaining oil in place for these three North Dakota and one South Dakota large light oil fields are set forth in Table 16.

Table 16. Status of Large North and South Dakota Oil Fields/Reservoirs (as of 2004)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Primary/ Secondary Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Beaver Lodge (Madison), ND	172	54	6	112
2	Medora (Madison), ND	58	8	3	47
3	Sherwoon (Madison), ND	69	20	1	48
4	Buffalo (Red River), SD	106	25	12	69

These four large "anchor" fields, each with nearly 50 or more million barrels of ROIP, appear to be favorable for miscible CO_2 -EOR, based on their reservoir properties, Table 17.

Table 17. Reservoir Properties and Improved Oil Recovery Activity, Large North and South Dakota Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Beaver Lodge (Madison), ND	8,573	43	undergoing waterflooding
2	Medora (Madison), ND	9,044	40	none
3	Sherwood (Madison), ND	4,204	29	none
4	Buffalo (Red River), SD	8,450	31	HPAI Combustion

Past CO_2-EOR Projects. A five acre CO_2 WAG injection test was performed in the Little Knife Field (Mission Canyon Formation) in the early 1980's. This field pilot is discussed below. Also included is a brief discussion of High Pressure Air Injection EOR, which has been a successful and expanding EOR method in the Williston Basin for over 20 years.

Little Knife. From 1980 to 1981, a joint DOE-Gulf Oil Corporation mini test of a CO_2 miscible WAG flood was conducted in the Mission Canyon formation, a dolomitized carbonate, at Little Knife Field.

- One injection and three observation wells were drilled on the structural high in the center of the Little Knife field, in an area that had previously been un-produced. The wells were completed in a 31 foot thick pay zone. Detailed well logging and slug tests determined that there was little variation in reservoir permeability which averaged from 23-29 md, that the initial oil saturation was 79%, and that the net pay ranged from 25 to 35 feet. The tests also determined that the injected slugs remained largely in the completed pay zone.
- Water was first injected to increase the reservoir pressure from 2,750 to 3,400 psi to reach the MMP (3,100 psi) and to sweep the reservoir. Then a 1:1 CO_2-WAG injection was conducted. This involved injecting 2,095 tons of CO_2 (22% HCPV) at a rate of 40 tons/day plus 20,621 Bbls of water at an average rate of 1,150 Bbls/day.
- It was determined that the waterflood sweep had displaced 37% of the OOIP. After the CO_2 WAG, 50% of the oil was displaced for an incremental increase of 13% of OOIP. Extrapolation of these results to the field level suggested that at a 160 acre spacing, 8% of the field OOIP could be incrementally recovered by using the CO_2 WAG process.

High Pressure Air Injection (HPAI). HPAI has been successfully applied on a large scale to the Medicine Pole (ND) and Buffalo (SD) fields for the past 20 years. HPAI is an air injection method that, in contrast to in situ combustion, is used to oxidize and mobilize light gravity oils at 150-300°C (versus > 450°C for in situ combustion). HPAI may be considered for reservoirs with high water cuts that are unattractive for waterflooding. One of the challenges to using HPAI is the need to predict the oxidation characteristics for the reservoir hydrocarbons under the specific reservoir conditions (pressure and temperature). Depending on the reservoir conditions, two oxidation reactions are possible; bond scission and “oxygen addition” reactions. Bond scission oxidation reactions are desirable because they produce CO_2 and water which act to mobilize the surrounding oil. On the other hand, if the reaction is an "oxygen addition" reaction, where oxygen chemically bonds to the hydrocarbons, polymerization occurs, forming heavier, less mobile oil. Therefore, careful screening of reservoirs and their hydrocarbons must be undertaken. The Koch Exploration Company successfully pioneered HPAI in the Williston Basin, beginning in 1987.

Cedar Creek Anticline HPAI. The Cedar Creek Anticline is a 145 mile long structure that stretches from southeast Montana to southwest North Dakota and into northwest South Dakota. It is a prolific oil producer and contains several large oil fields including, from northeast to southwest, Pine, Cabin Creek, Pennel, Coral Creek and Little Beaver in Montana; Cedar Hills and Medicine Pole Hills in North Dakota, and, finally, Buffalo at its southeast terminus in South Dakota. In total, the structure contains an estimated 3,250 MMBbls of OOIP of which only 457 MMBbls (14%) has been produced.

HPAI has been used extensively in the Red River Formation reservoirs on the anticline where the right combination of light oil (~ 39 °API), high temperatures, and low permeabilities (~5 md) are ideal for HPAI (SPE 27792). This technology was applied by Koch Exploration Company to the Buffalo Field in 1983 and to the Medicine Pole Hills Field in 1987. Both floods have been successful and have produced 14% and 9% of the OOIP due to HPAI, respectively. Continental Resources now manages these field and has expanded the HPAI to Cedar Hills, North in 2003. In addition, Encore Acquisition Company has initiated HPAI projects in Pennel (2002) and Little Beaver fields in Montana (2004).

Future CO_2-EOR Potential. North and South Dakota contain 35 reservoirs that are candidates for miscible CO_2-EOR. Under "Traditional Practices" (and Base Case financial conditions, defined above), there is only one economically attractive oil reservoir for miscible CO_2 flooding in North and South Dakota. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection) and lower risk financial conditions, the number of economically favorable oil reservoirs in North and South Dakota increases to 10, including one immiscible field, providing 240 million barrels of additional oil recovery, Table 18.

Table 18. Economic Oil Recovery Potential Under Two Technologic Conditions, North and South Dakota

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"	34	3,650	480	1	10
"State-of-the-art" Technology	35	3,750	1,020	10	240

** 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 North and South Dakota to recover 390 million barrels of CO_2-EOR oil (from 14 major reservoirs), Table 19.

Table 19. Economic Oil Recovery Potential with More Favorable Financial Conditions, North and South Dakota

More Favorable Financial Conditions	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
Plus: Risk Mitigation Incentives*	1,070	12	290
Plus: Low Cost CO_2 Supplies**	1,070	14	390

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

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

6.2 MONTANA. Montana is the 10th largest oil producing state, providing 25 MMBbls (68 MBbls/day) of oil in 2004, from 13,946 producing wells. Oil production in the state of Montana began in 1916, and cumulative oil recovery has reached 1.5 billion barrels with 364 MMBbls of crude oil reserves. Oil production in Montana has increased in recent years due to utilization of horizontal drilling technology, particularly in the Elm Coulee Field, Table 20.

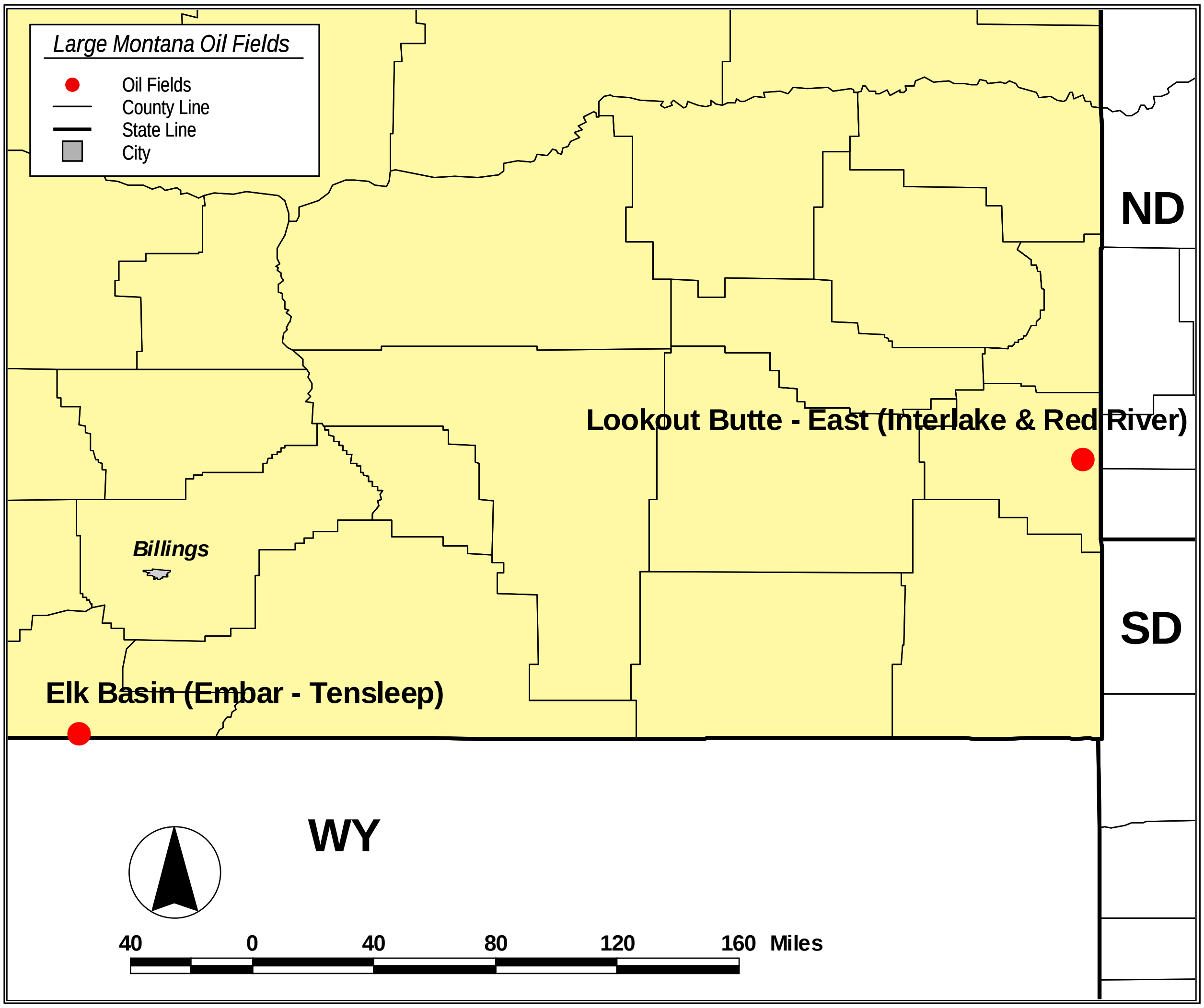
Table 20. Recent History of Montana Onshore Oil Production

	Annual Oil Production	
	(MMBbls/year)	(MBbls/day)
1999	15	42
2000	16	43
2001	16	44
2002	17	47
2003	19	53
2004	25	68

Montana Fields. Montana contains several large oil fields that may be amenable to miscible CO_2-EOR, Figure 12. These include:

- Elk Basin (Embar – Tensleep)
- Lookout Butte – East (Interlake & Red River)

Figure 12. Large Montana Oil Fields



The cumulative oil production, proved reserves and remaining oil in place (ROIP) in these two large oil reservoirs are provided in Table 21.

Table 21. Status of Large Montana Oil Fields/Reservoirs (as of 2004)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Primary/ Secondary Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Elk Basin (Embar – Tensleep)	190	62	5	121
2	Lookout Butte – East (Interlake & Red River)	206	15	37	154

These two large oil reservoirs, with 120 to 150 million barrels of ROIP, are technically amenable for miscible CO_2-EOR. Table 22 provides the reservoir and oil properties for these reservoirs and their current oil recovery activities.

Table 22. Reservoir Properties and Improved Oil Recovery Activity, Large Montana Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (^{o}API)	Active Waterflood or Gas Injection
1	Elk Basin (Embar – Tensleep)	5,000	29	undergoing waterflooding
2	Lookout Butte – East (Interlake & Red River)	8,900	33	undergoing waterflooding

Past and Current EOR Projects.

South Pine. In 1984, a CO_2 injectivity mini-test (non-producing) was conducted in the Red River Unit of the South Pine Field. The test consisted of an injection well and two observation wells located at a distance of 70 and 90 feet. Nearly 70,000 Bbls of brine was injected over 176 days to completely flush all mobile oil from the reservoir. A CO_2 flood was then conducted for 62 days during which 48 MMSCF of CO_2 was injected. The CO_2 flood was then followed by a brine flood. Results of the flood were encouraging with the following observations:

- The CO_2 flood behaved very similarly to the water flood in its breakthrough pattern, suggesting that a field with good waterflood conformability should have good CO_2 flood conformability.

- The CO_2 had a 14 times greater injectivity than the brine flood.
- Analysis of pressure cores showed a post-flood oil saturation of 21%, a 23% decrease from the 44% pre-flood oil saturation.

The success of the South Pine test suggests that CO_2-EOR has promise in the Montana. However, the lack of a nearby CO_2 sources and low oil prices in the mid - 1980's spelled the end of CO_2-EOR research in the region.

Future CO_2-EOR Potential. Montana contains 19 oil reservoirs that are candidates for miscible CO_2-EOR technology.

The potential for economically developing these oil reservoirs is examined first under Base Case financial criteria that combine an oil price of $30 per barrel, CO_2 supply costs ($1.50/Mcf), and a high risk rate of return (ROR) hurdle (25% before tax).

Under "Traditional Practices" (and Base Case financial conditions, defined above), there are no economically attractive oil reservoirs for miscible flooding in Montana. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection) and lower risk financial conditions, the number of economically favorable oil reservoirs in Montana increases to 5, providing 110 million barrels of additional oil recovery, Table 23.

Table 23. Economic Oil Recovery Potential Under Two Technologic Conditions, Montana

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"*	19	3,454	340	0	-
"State-of-the-art" Technology*	19	3,454	760	5	110
Plus: Risk Mitigation**	19	3,454	760	5	110
Plus: Low Cost CO_2***	19	3,454	760	5	110

**Oil price of $30 per barrel.*
***Oil price of $40 per barrel, adjusted for gravity differential; CO_2 supply costs of $2/Mcf*
****CO_2 supply costs of $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 Williston 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 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*

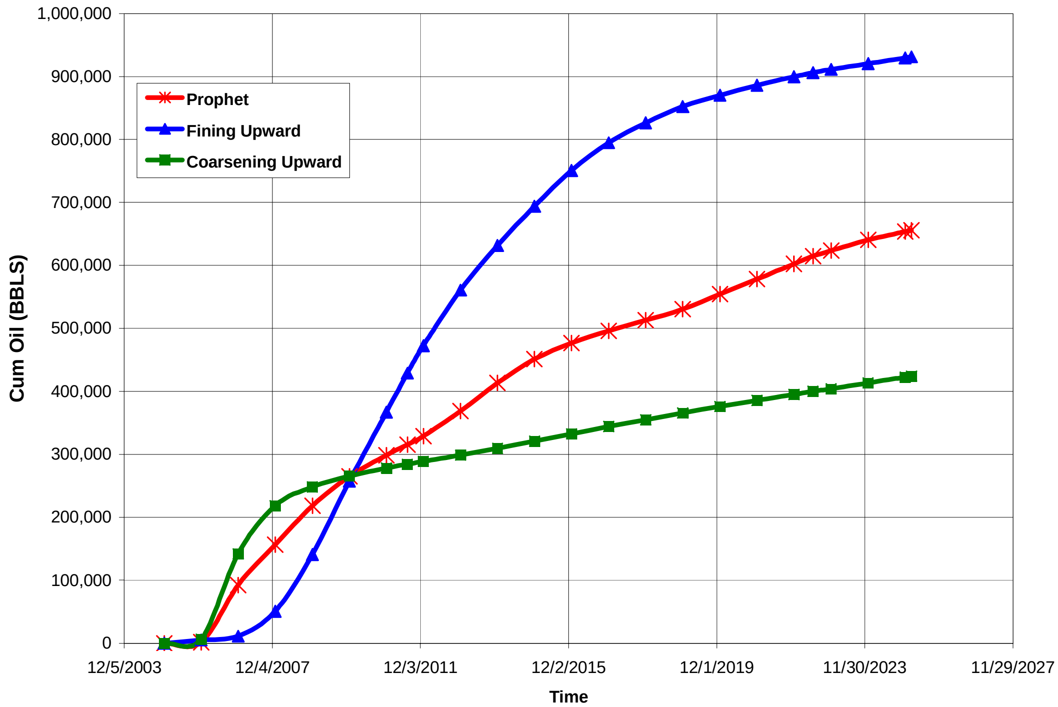
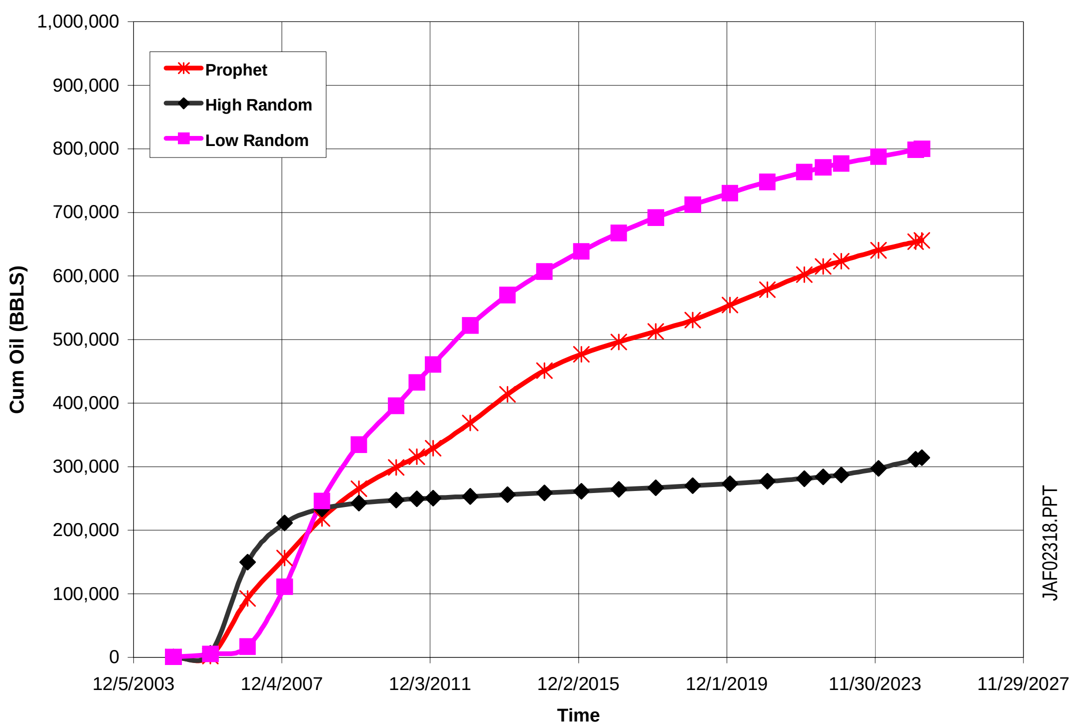


Figure A-2. *CO_2-PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



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- *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

North Dakota 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:

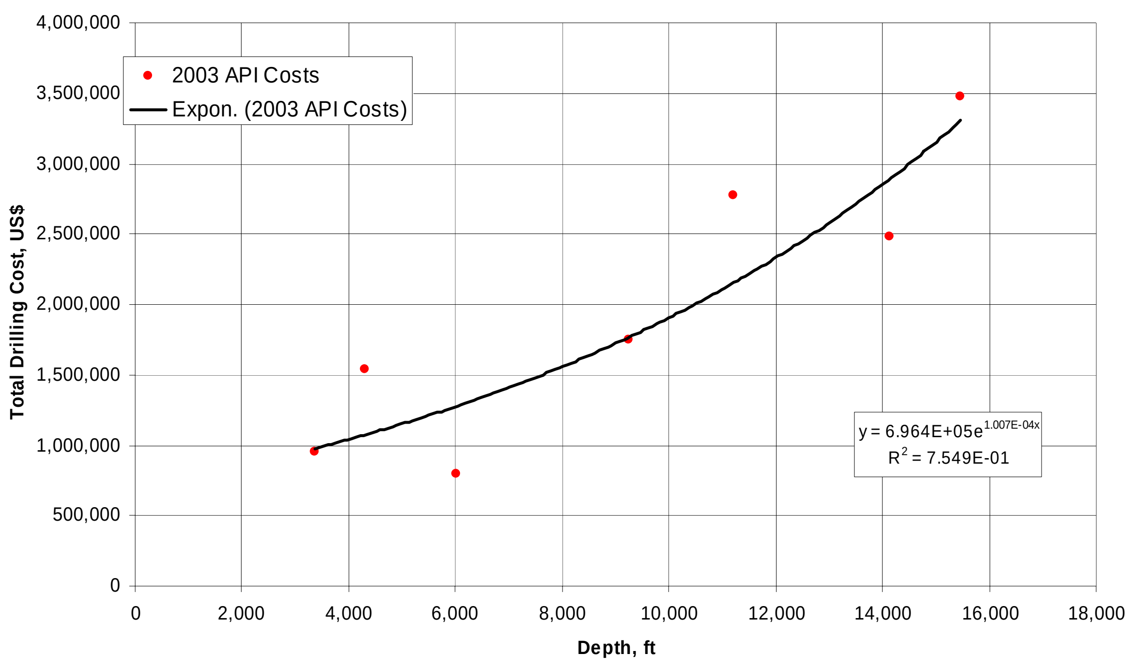
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for North Dakota.

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

Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 6.96×10^5
a_1 is 1.04
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 North Dakota.

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



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

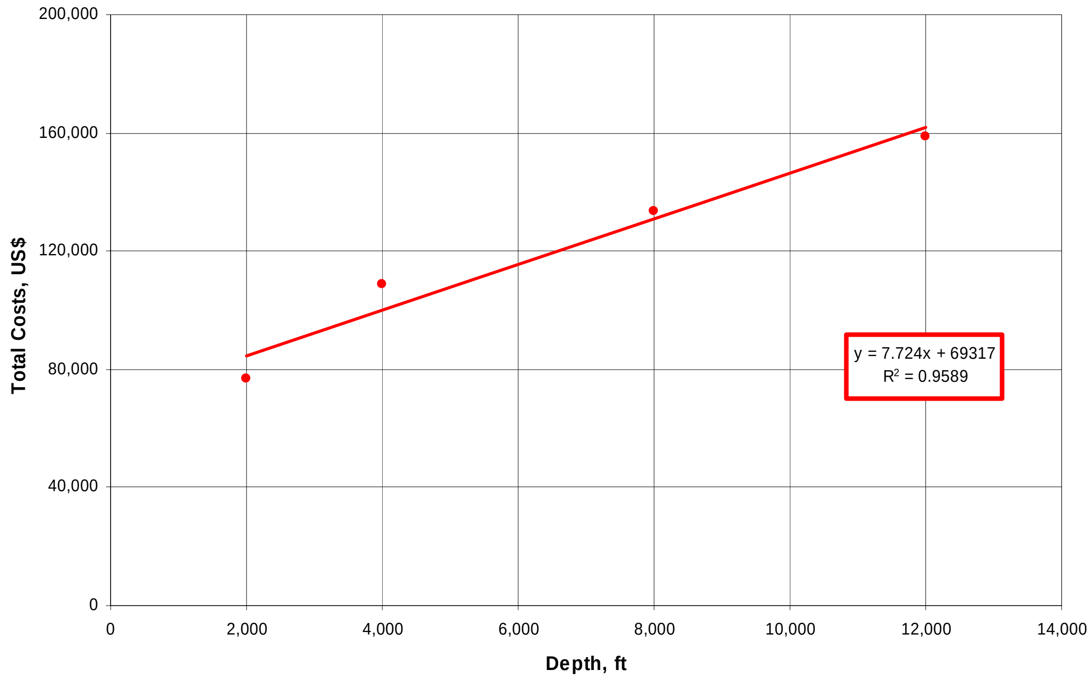
2. <u>Lease Equipment Costs for New Producing Wells.</u> The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 “Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations” report. This survey provides estimated lease equipment costs 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 = \$69,317 (fixed)
c_1 = \$7.724 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 North Dakota vs. Depth



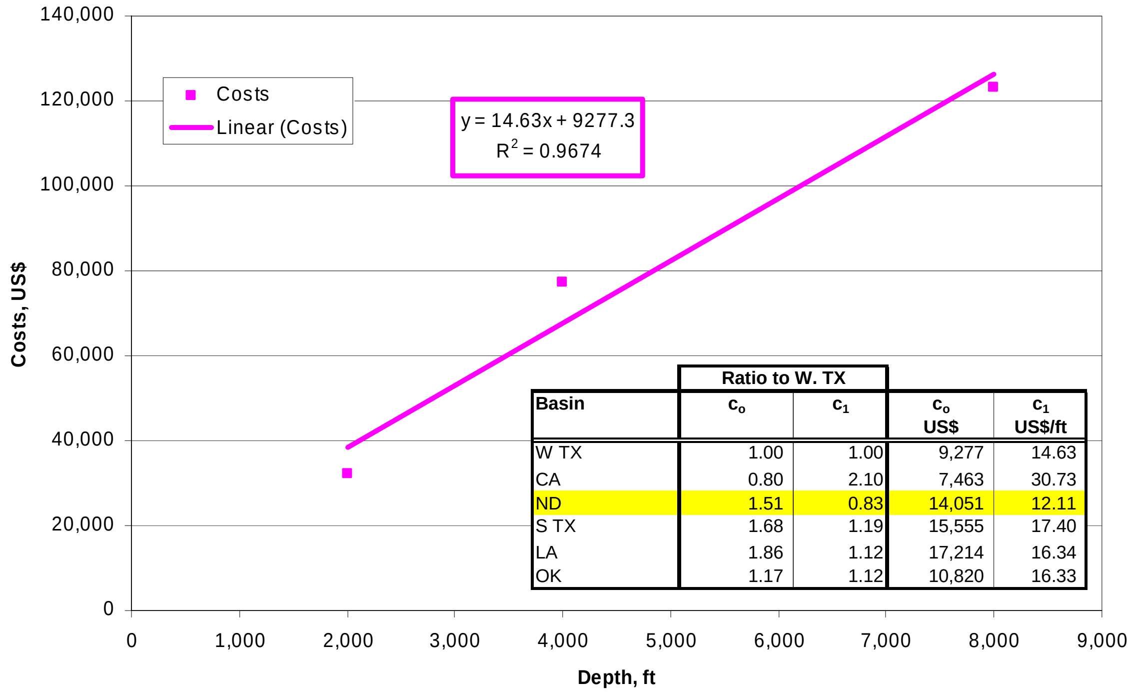
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in North Dakota include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$14,051 (fixed)
c_1 = \$12.11 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 North Dakota cost equation.

Figure B-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
ND	1.51	0.83	14,051	12.11
S TX	1.68	1.19	15,555	17.40
LA	1.86	1.12	17,214	16.34
OK	1.17	1.12	10,820	16.33

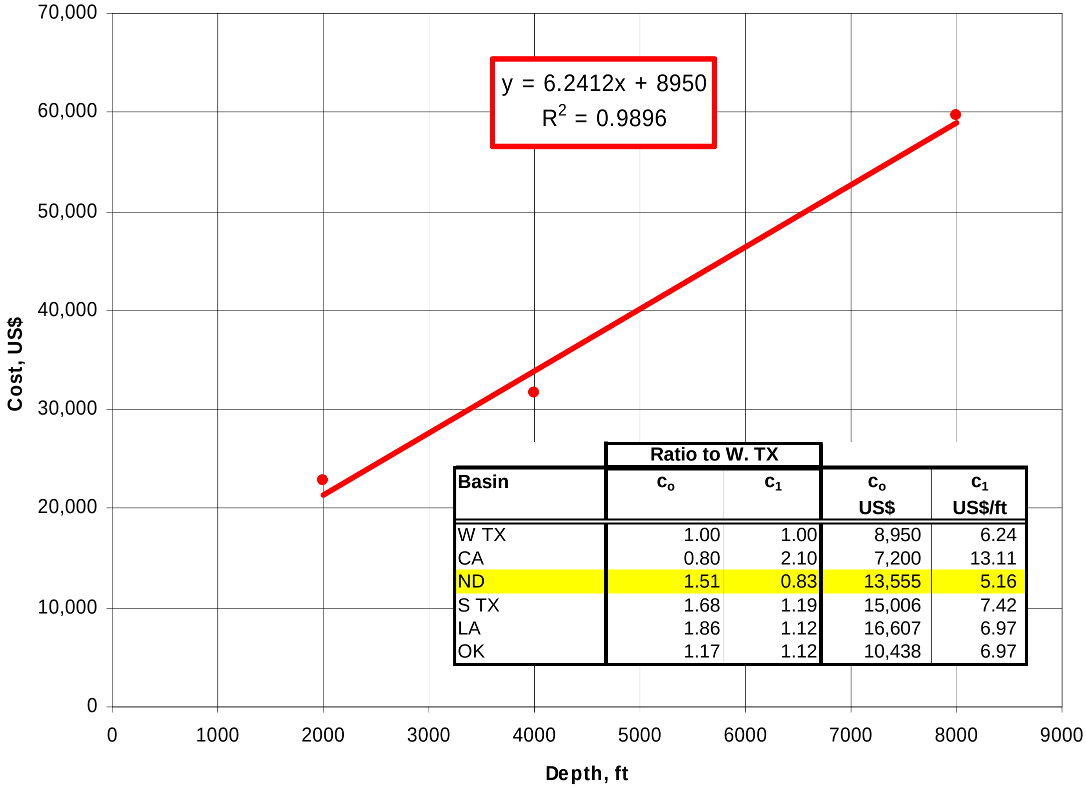
4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are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

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

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$13,555 (fixed)
c_1 = \$5.16 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 North Dakota cost equation.

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



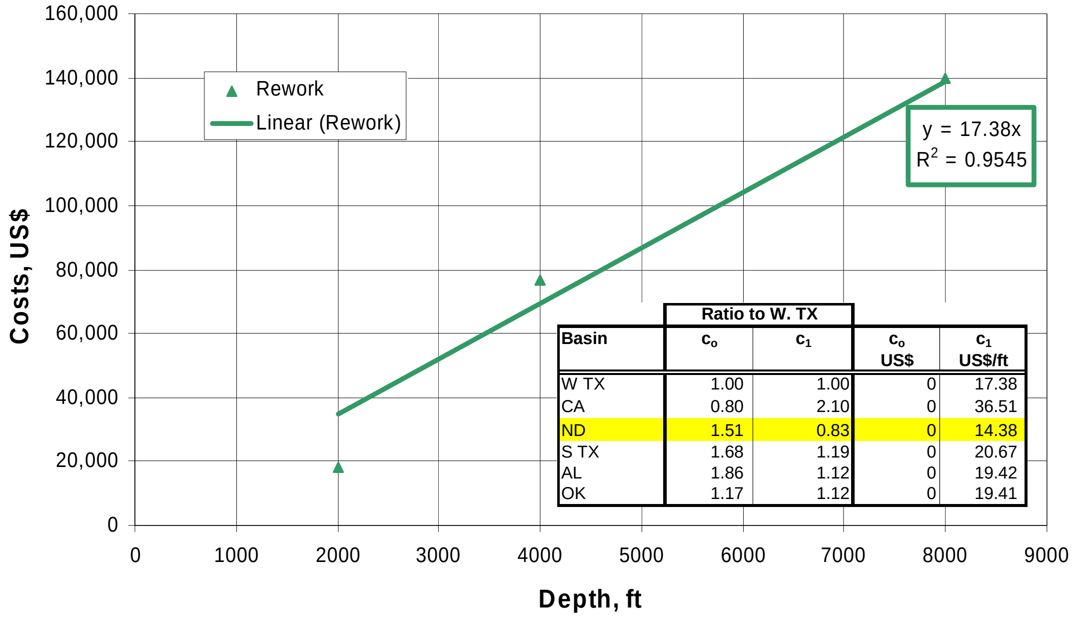
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
ND	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
OK	1.17	1.12	10,438	6.97

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

Well Rework Costs = c_1D
Where: c_1 = \$14.38 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 North Dakota 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	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
ND	1.51	0.83	0	14.38
S TX	1.68	1.19	0	20.67
AL	1.86	1.12	0	19.42
OK	1.17	1.12	0	19.41

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

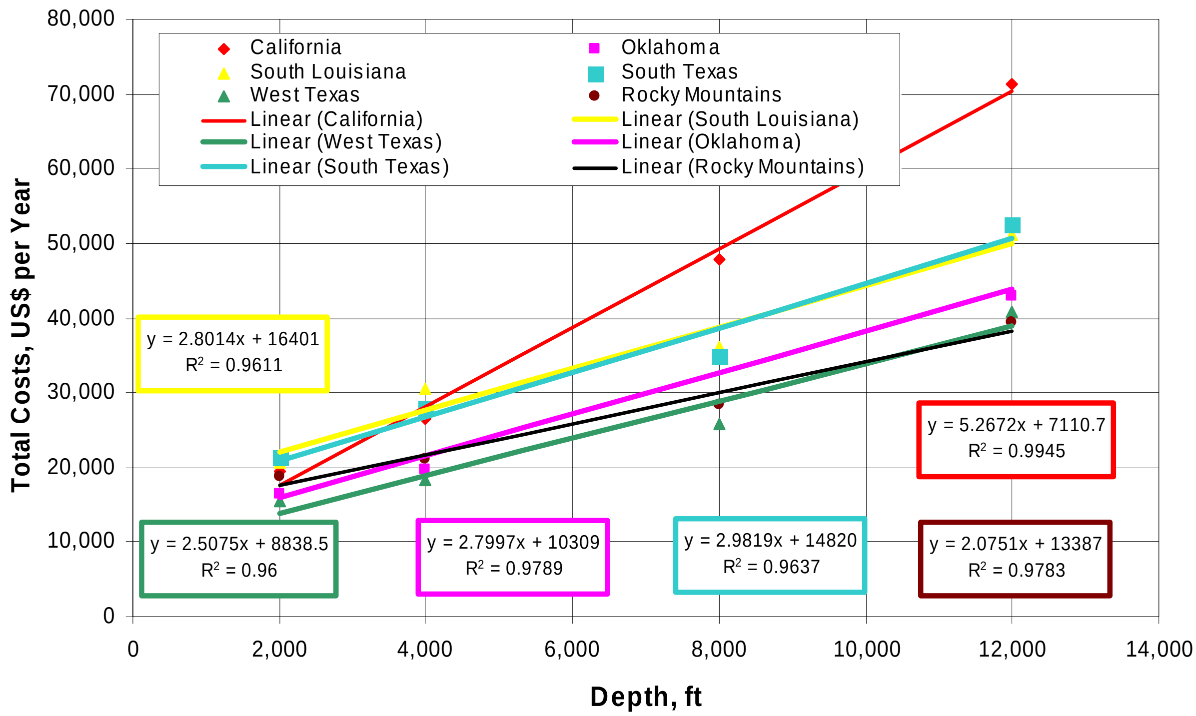


Table B-1. Regional Lease O&M Costs and Their Relationship to West Texas

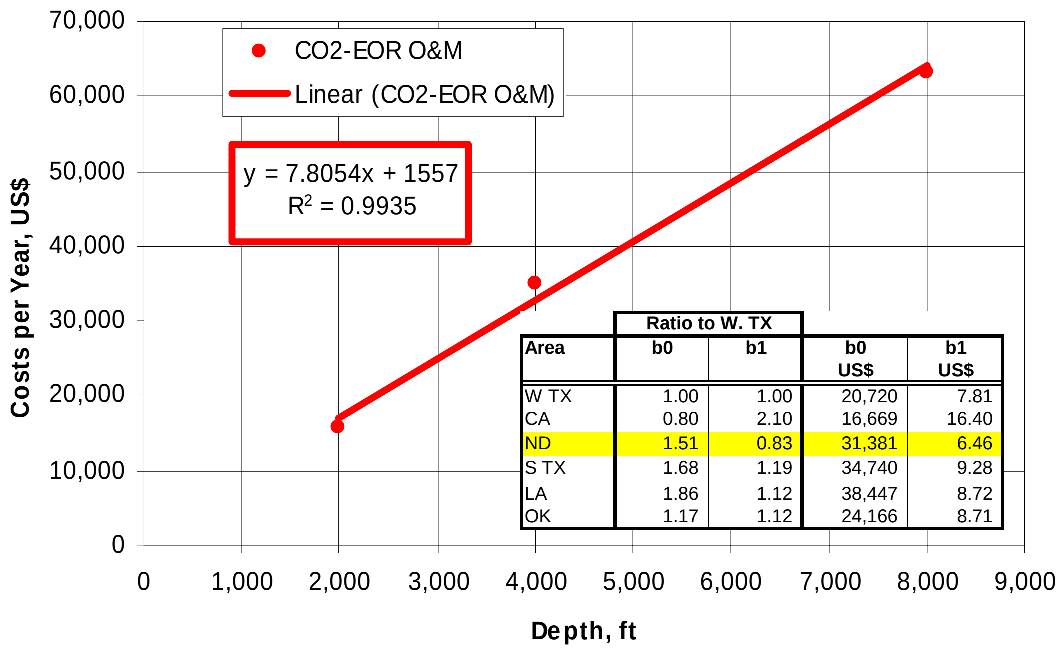
Basin	c_o US$	c_1 US$/ft	Ratio to W. TX c_o	Ratio to W. TX c_1
West Texas	8,839	2.508	1.00	1.00
California	7,111	5.267	0.80	2.10
North Dakota	13,387	2.075	1.51	0.83
South Texas	14,820	2.982	1.68	1.19
Louisiana	16,401	2.801	1.86	1.12
Oklahoma	10,309	2.800	1.17	1.12

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 North Dakota, shown in the inset of Figure B-7. The equation for North Dakota is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$31,381 (fixed)
b_1 = \$6.46 per foot
D is well depth

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



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

The cost of the recycling plant is set at \$700,000 per MMcf/d of CO_2 capacity. As such, small CO_2-EOR project in the Madison formation of the Rival field, with 24 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$16 million. A large project in the Big Stick field, with 104 MMcf/d of peak CO_2 reinjection and 104 injectors requires a recycling plant costing \$73million.

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

8. Other COTWO Model Costs.

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

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

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

The distribution pipeline cost is dependent on the injection requirements for the project. The fixed component is $150,000. The variable cost component accounts for increasing piping diameters associated with increasing CO_2 injection requirements. These range from $80,000 per mile for 4" pipe (CO_2 rate less than 15MMcf/d), $120,000 per mile for 6" pipe (CO_2 rate of 15 to 35 MMcf/d), $160,000 per mile for 8" pipe (CO_2 rate of 35 to 60 MMcf/d), and $200,000 per mile for pipe greater than 8" diameter (CO_2 rate greater than 60 MMcf/d). Aside from the injection volume, 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 North Dakota 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. North Dakota has enacted risk sharing actions for enhanced oil recovery. The North Dakota Century Code §§ 57-51.1-02 and 57-51.1-03 provides incentives for production tax rate reductions for various projects in North Dakota including qualified enhanced oil recovery projects.

The state charges a 5.0% severance tax on all oil production and a variable extraction tax rate on top of that. The provisions of the EOR statute are that no extraction tax shall be due on production from a qualified enhanced oil recovery project for 10 years after inception of the project and a 4% extraction rate thereafter for a total tax rate of 9.0% annually after 10 years. The statute contains a "trigger" provision where the EOR tax break is nullified when the monthly average daily closing price of west Texas intermediate oil price is above a certain value. For 2004 that value was $35.11 so we apply the tax break to the low oil price ($30 per barrel) economic runs and applied the non-EOR rate of 6.5% extraction tax for a total annual rate of 11.5% annually from inception of the project to the high oil price runs ($40 per barrel).

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 North Dakota (-$2.00 per barrel) and the current gravity differential (-$0.25 per ^{o}API, from a basis of 40 ^{o}API) into the average wellhead oil price realized by each oil reservoir. The equation for North Dakota is:

Wellhead Oil Price = Oil Price + (-$2.00) – [$0.25*(40 - ^{o}API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
^{o}API is oil gravity

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

Appendix C

South Dakota 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:

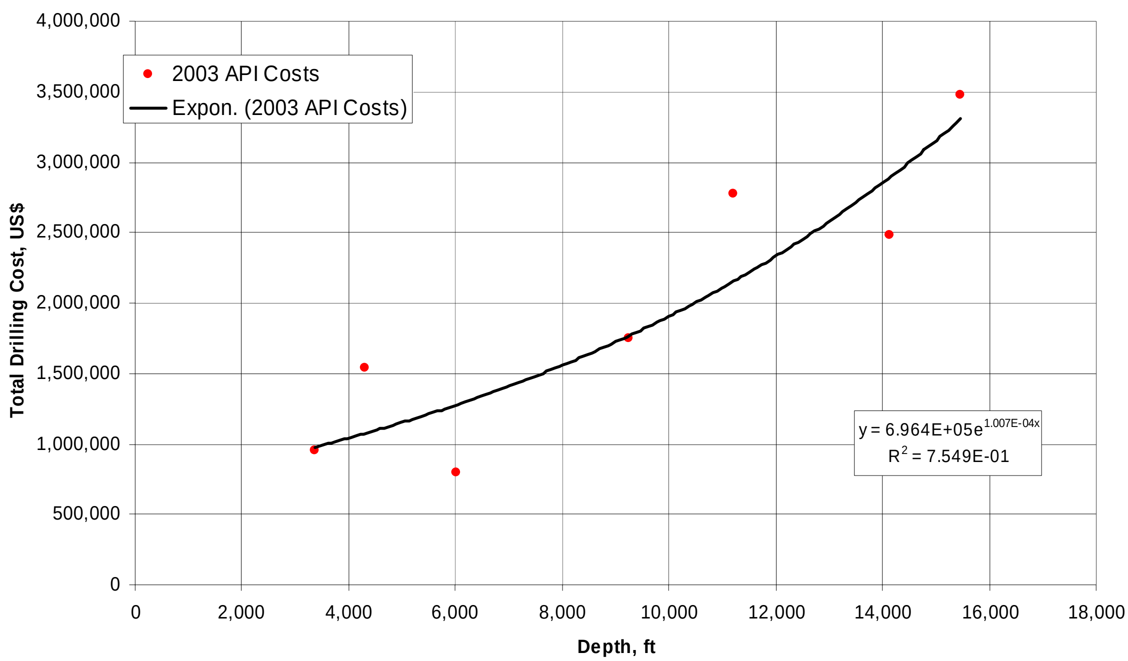
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for North Dakota where more drilling data are available.

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

Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 6.96×10^5
a_1 is 1.04
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 South Dakota.

Figure C-1. Oil Well D&C Costs for South Dakota



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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 South Dakota 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 = $c_0 + c_1D$

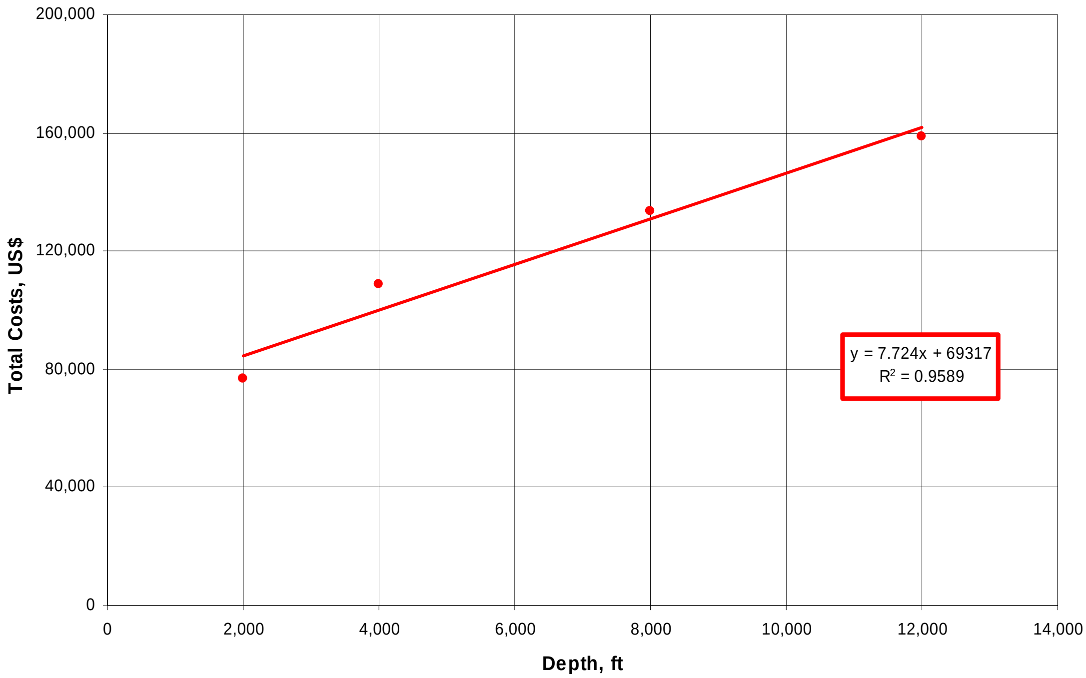
Where: c_o = $69,317 (fixed)

c_1 = $7.724 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 South Dakota vs. Depth



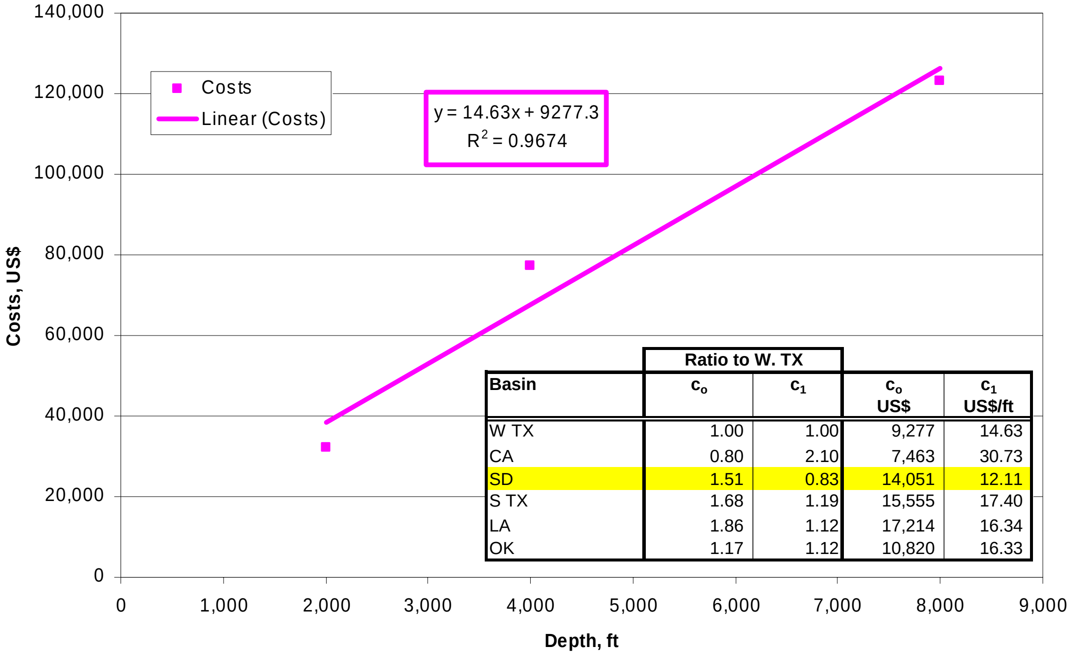
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in South Dakota include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$14,051 (fixed)
c_1 = \$12.11 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 South Dakota cost equation.

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



Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
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S TX	1.68	1.19	15,555	17.40
LA	1.86	1.12	17,214	16.34
OK	1.17	1.12	10,820	16.33

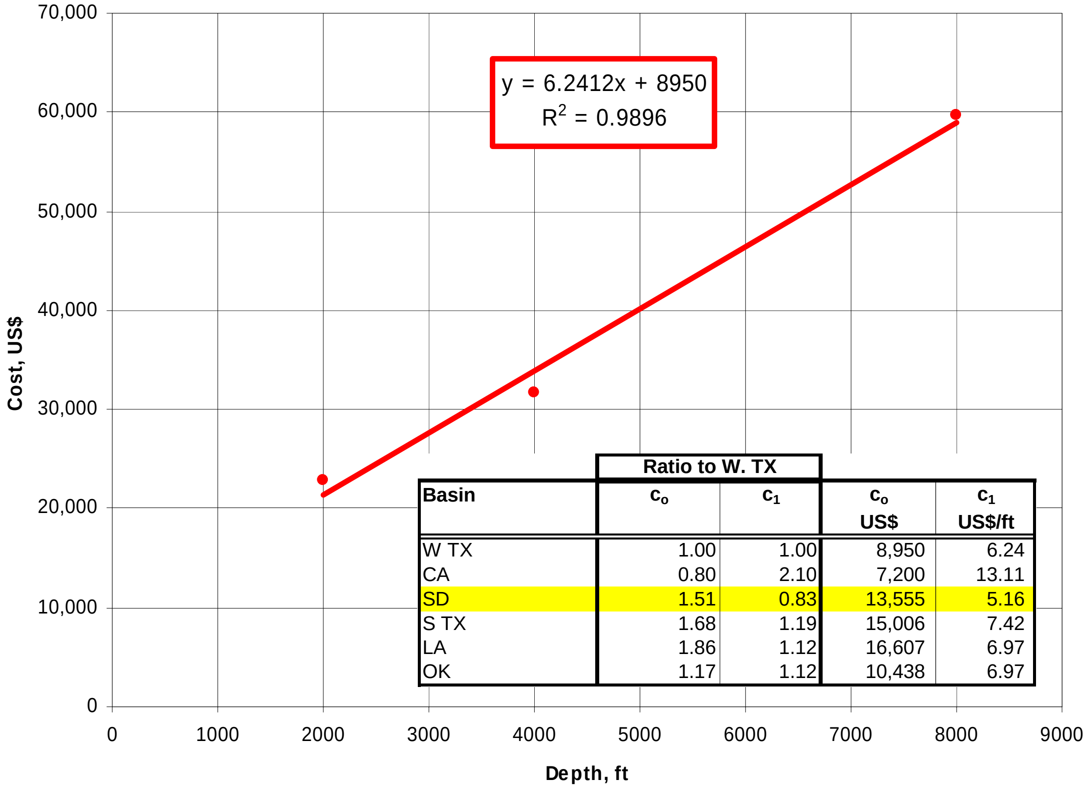
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection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

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

Well Conversion Costs = $c_0 + c_1D$
Where: c_0 = $13,555 (fixed)
c_1 = $5.16 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 South Dakota cost equation.

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



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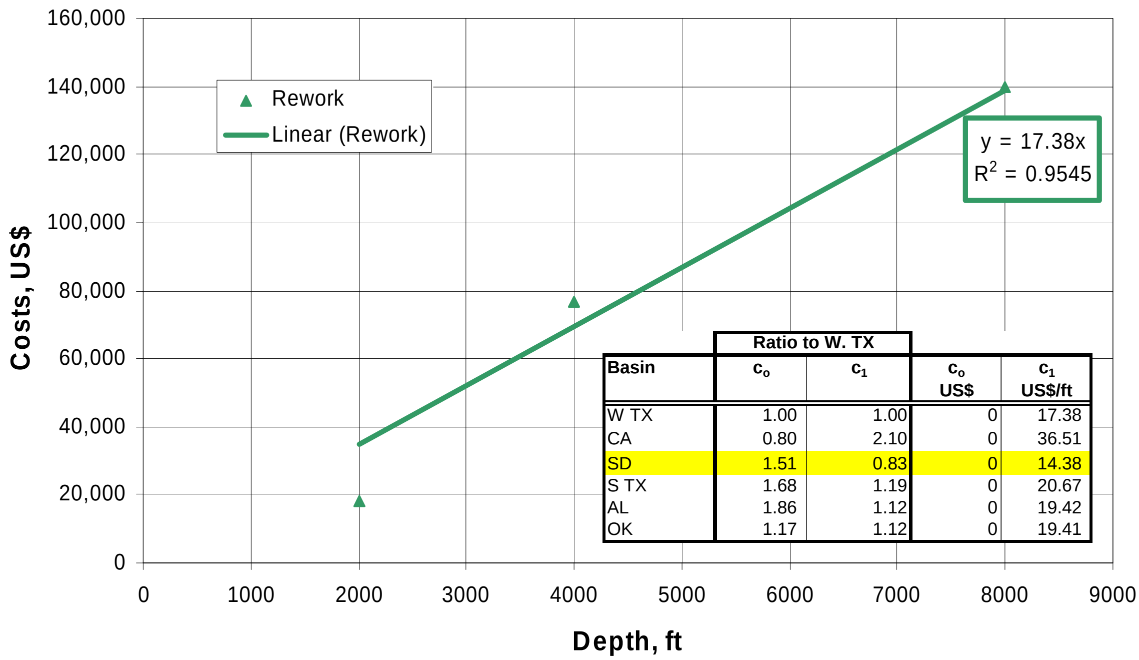
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
OK	1.17	1.12	10,438	6.97

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

Well Rework Costs = c_1D
Where: c_1 = $14.38 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 South Dakota cost equation.

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



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AL	1.86	1.12	0	19.42
OK	1.17	1.12	0	19.41

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

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

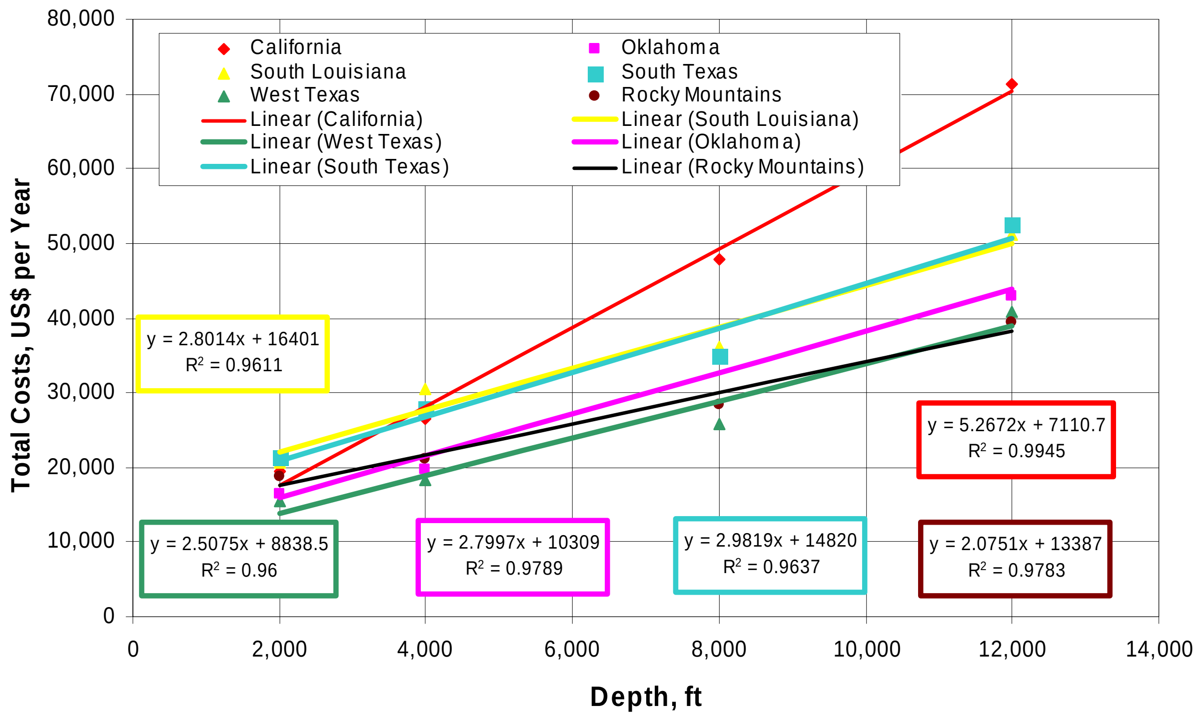


Table C-1. Regional Lease O&M Costs and Their Relationship to West Texas

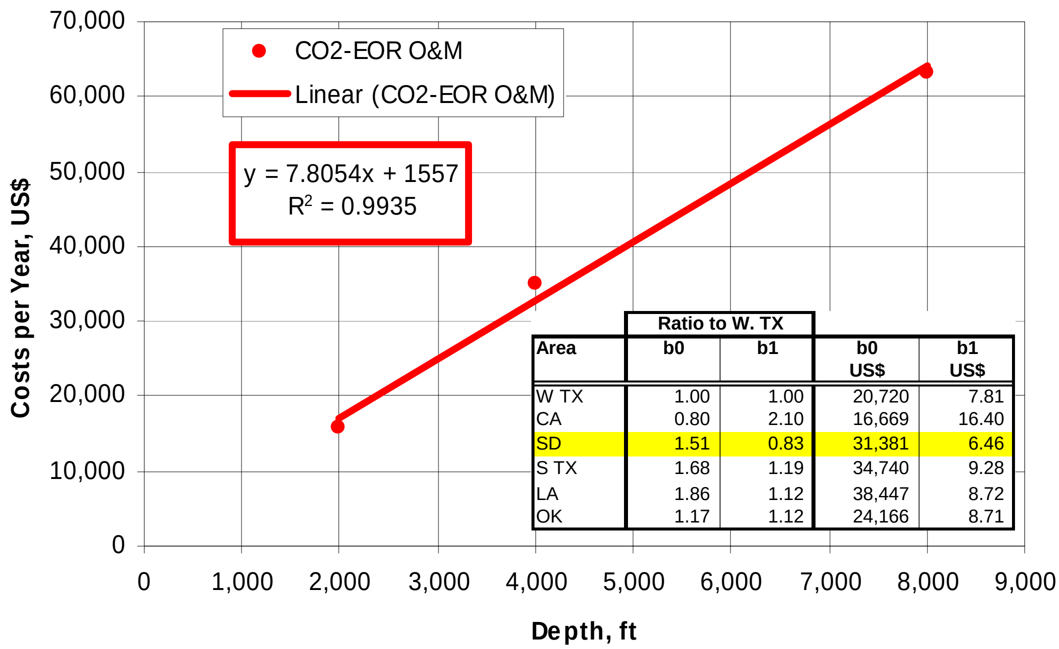
Basin	c_0 US$	c_1 US$	Ratio to W. TX c_0	Ratio to W. TX c_1
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
South Dakota	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

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

Figure 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 South Dakota, shown in the inset of Figure C-7. The equation for South Dakota is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$31,381 (fixed)
b_1 = \$6.46 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
SD	1.51	0.83	31,381	6.46
S TX	1.68	1.19	34,740	9.28
LA	1.86	1.12	38,447	8.72
OK	1.17	1.12	24,166	8.71

7. <u>CO_2 Recycle Plant Investment Cost.</u> Operation of CO_2-EOR requires a recycling plant to capture and reinject the produced CO_2. The size of the recycle plant is based on peak CO_2 production and recycling requirements. The cost of the recycling plant is set at \$700,000 per MMcf/d of CO_2 capacity. As such, a project in the Buffalo field, with 21 MMcf/d of peak CO_2 reinjection requires a recycling plant costing \$15 million.

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

8. <u>Other COTWO Model Costs.</u>

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

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

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

The distribution pipeline cost is dependent on the injection requirements for the project. The fixed component is $150,000. The variable cost component accounts for increasing piping diameters associated with increasing CO_2 injection requirements. These range from $80,000 per mile for 4" pipe (CO_2 rate less than 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 South Dakota is:

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

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

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

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

f. <u>Production Taxes.</u> South Dakota charges a 4.5% severance tax on oil production. The severance tax is taken off after the royalties are charged.

g. <u>Crude Oil Price Differential.</u> To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis differential for South Dakota (-$2.00 per barrel) and the current gravity differential (-$0.25 per ^{o}API, from a basis of 40 ^{o}API) into the average wellhead oil price realized by each oil reservoir. The equation for South Dakota is:

Wellhead Oil Price = Oil Price + (-$2.00) – [$0.25*(40 - ^{o}API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
^{o}API is oil gravity

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

Appendix D

Montana 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:

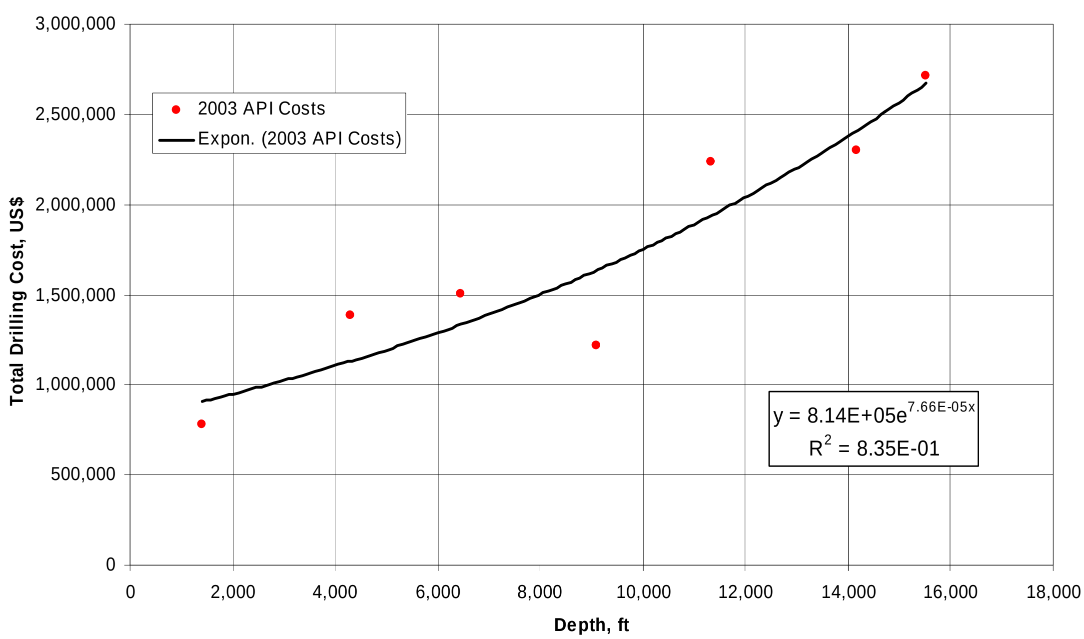
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for Montana.

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

Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 8.14×10^5
a_1 is 7.66×10^{-5}
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 Montana.

Figure D-1. Oil Well D&C Costs for South Dakota



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

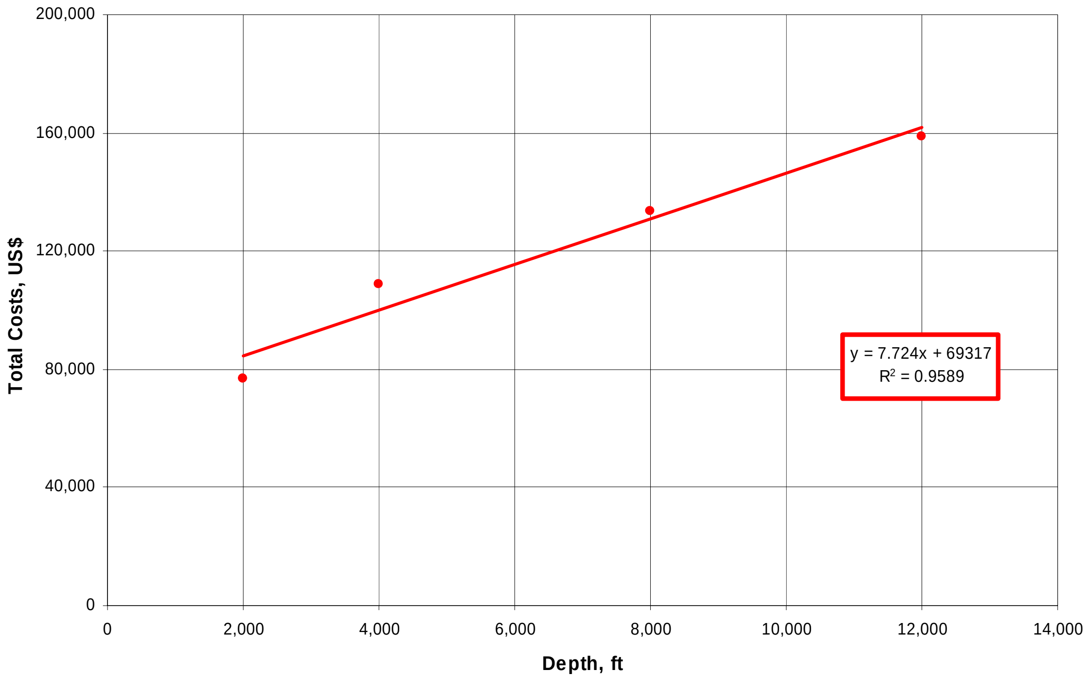
2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report. This survey provides estimated lease equipment costs for 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 = \$69,317 (fixed)
c_1 = \$7.724 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 Montana vs. Depth



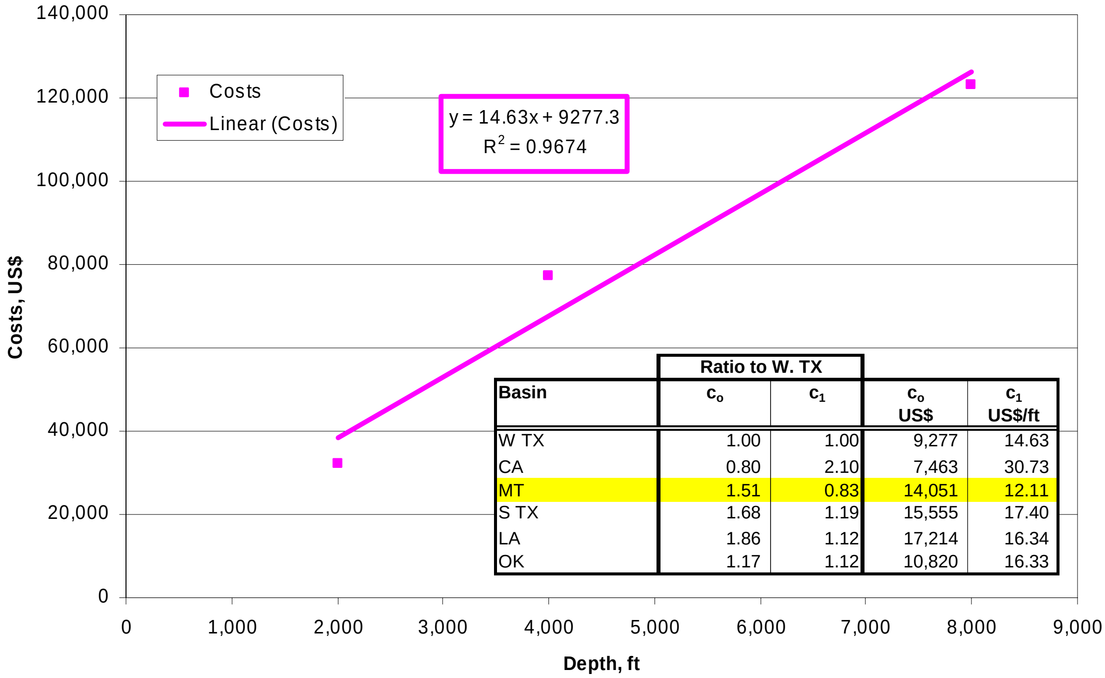
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in Montana include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$14,051 (fixed)
c_1 = \$12.11 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 Montana 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
MT	1.51	0.83	14,051	12.11
S TX	1.68	1.19	15,555	17.40
LA	1.86	1.12	17,214	16.34
OK	1.17	1.12	10,820	16.33

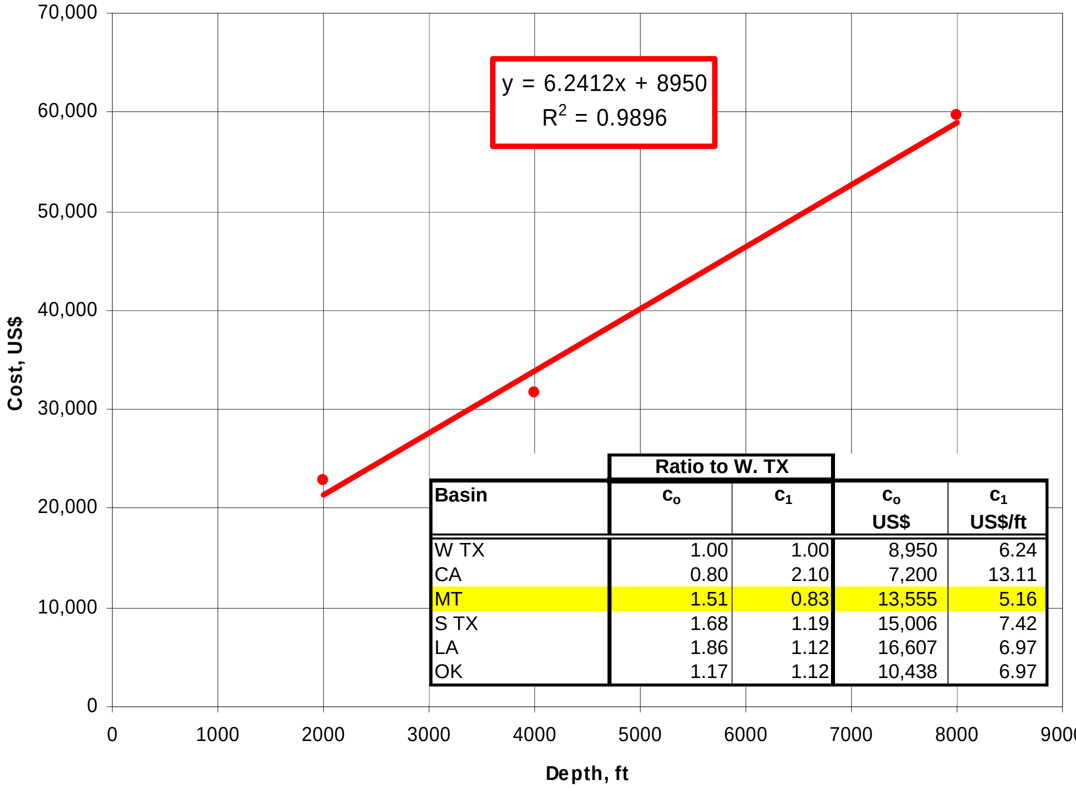
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection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

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

Well Conversion Costs = $c_0 + c_1 D$
Where: c_o = \$13,555 (fixed)
c_1 = \$5.16 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 Montana cost equation.

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



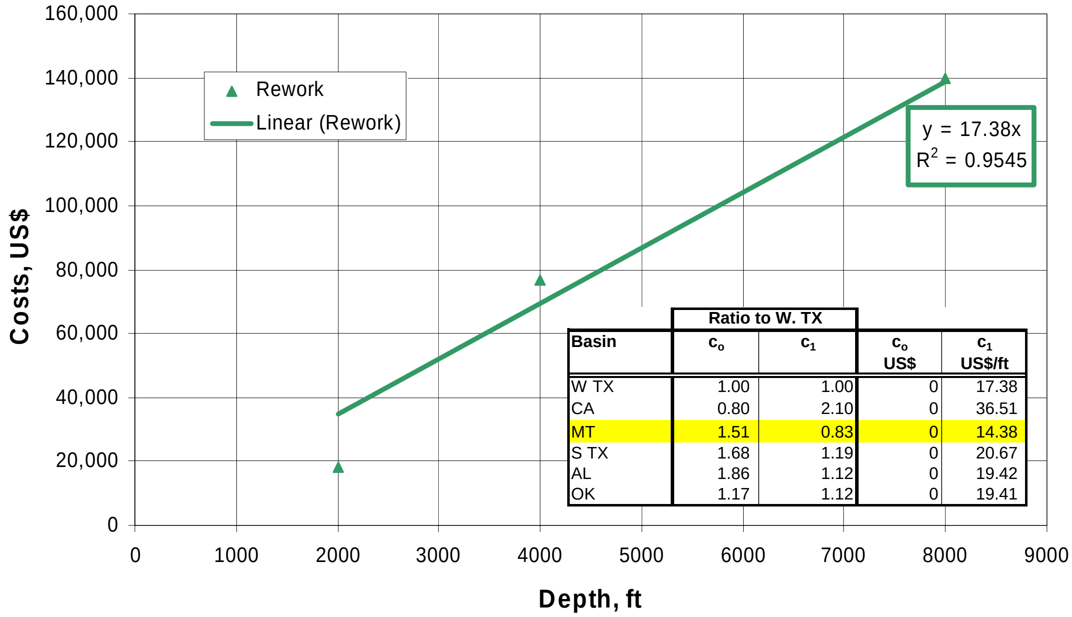
	Ratio to W. TX			
Basin	c_o	c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
MT	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
OK	1.17	1.12	10,438	6.97

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

Well Rework Costs = c_1D
Where: c_1 = \$14.38 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 Montana 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
MT	1.51	0.83	0	14.38
S TX	1.68	1.19	0	20.67
AL	1.86	1.12	0	19.42
OK	1.17	1.12	0	19.41

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

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

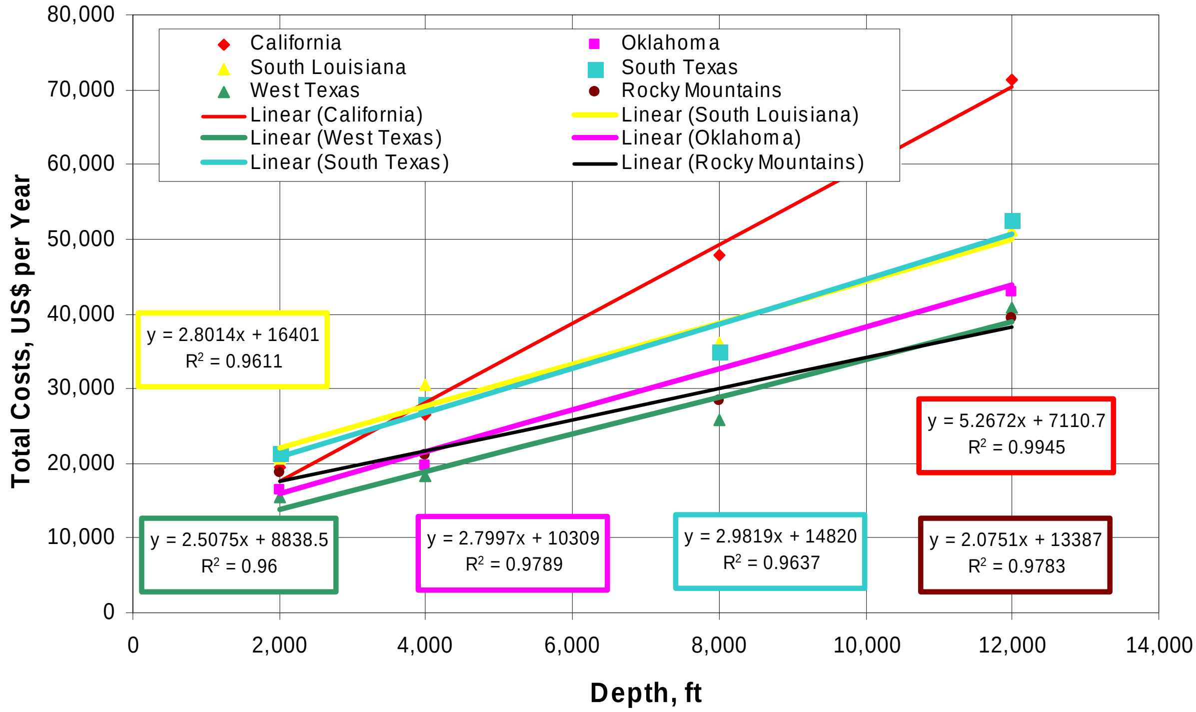


Table D-1. Regional Lease O&M Costs and Their Relationship to West Texas

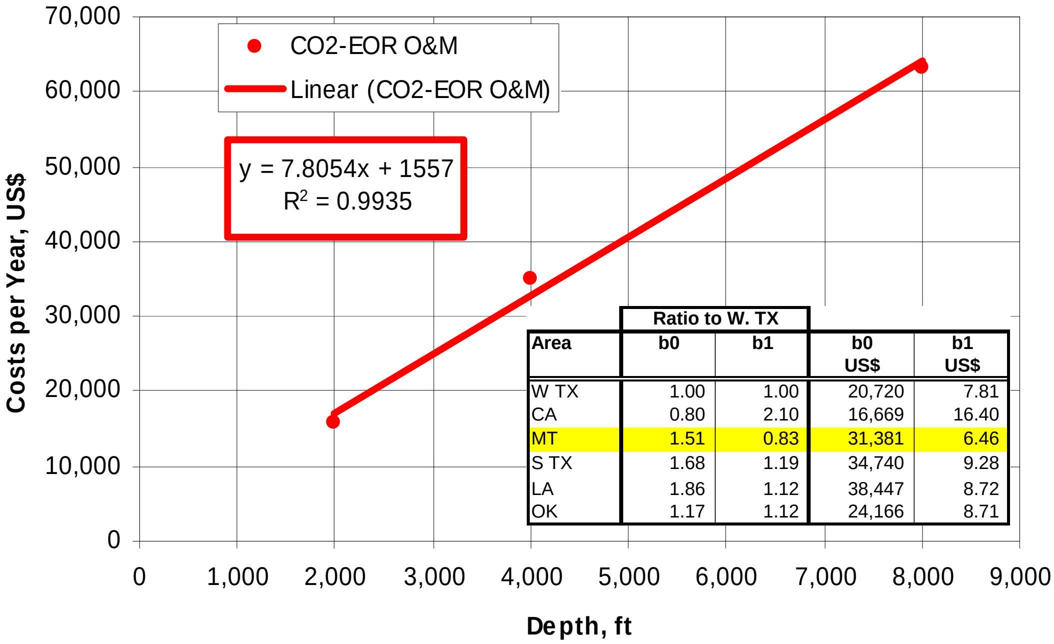
			Ratio to W. TX	
Basin	**c_0 US$**	**c_1 US$**	**c_0**	**c_1**
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Montana	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

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

Figure 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 South Dakota, shown in the inset of Figure D-7. The equation for Montana is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$31,381 (fixed)
b_1 = \$6.46 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
MT	1.51	0.83	31,381	6.46
S TX	1.68	1.19	34,740	9.28
LA	1.86	1.12	38,447	8.72
OK	1.17	1.12	24,166	8.71

7. <u>CO_2 Recycle Plant Investment Cost.</u> Operation of CO_2-EOR requires a recycling plant to capture and reinject the produced CO_2. The size of the recycle plant is based on peak CO_2 production and recycling requirements. The cost of the recycling plant is set at \$700,000 per MMcf/d of CO_2 capacity. As such, a project in the Pine field, with 155 MMcf/d of peak CO_2 reinjection and 935 injection wells requires a recycling plant costing \$110 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 Montana 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. Montana typically charges a 9.3% severance tax on oil production but there is a tax break for incremental production due to tertiary recovery where the severance rate is lowered to 6.1% under statute MCA 15-36-303. However, the tax reduction is cancelled when the "trigger" price of West Texas intermediate oil of greater than \$30 per barrel. Therefore, in this study, the full severance rate of 9.3% is charged for oil production, after royalty payments. There is no ad valorum tax in the state.

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 Montana (-\$2.00 per barrel) and the current gravity differential (-\$0.25 per ^{o}API, from a basis of 40 ^{o}API) into the average wellhead oil price realized by each oil reservoir. The equation for Montanais:

Wellhead Oil Price = Oil Price + (-\$2.00) – [\$0.25*(40 - ^{o}API)]

Where: Oil Price is the marker oil price (West Texas intermediate)
^{o}API is oil gravity

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