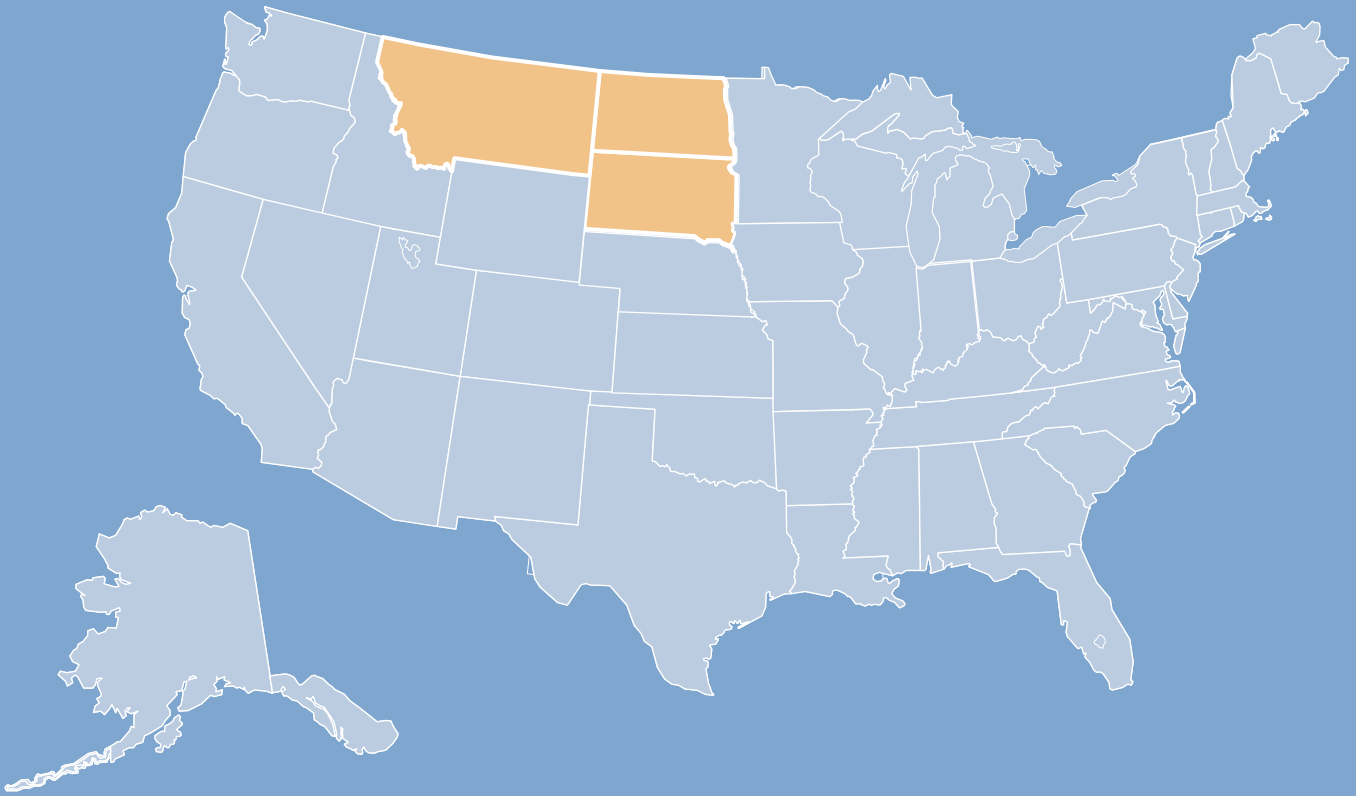


BASIN ORIENTED STRATEGIES FOR CO₂ ENHANCED OIL RECOVERY: WILLISTON BASIN



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

**Prepared by
Advanced Resources International**

February 2006

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility of the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. The findings and conclusions in this report are those of the authors and do not necessarily represent the views of the Department of Energy.

**BASIN ORIENTED STRATEGIES FOR
CO₂ ENHANCED OIL RECOVERY:
WILLISTON BASIN OF NORTH DAKOTA, SOUTH
DAKOTA, AND MONTANA**

Prepared for
U.S. Department of Energy

Prepared by
Advanced Resources International

February 2006

TABLE OF CONTENTS

1. SUMMARY OF FINDINGS

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

2. INTRODUCTION

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

3. OVERVIEW OF GULF COAST OIL PRODUCTION

- 3.1 HISTORY OF OIL PRODUCTION
- 3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY
- 3.3 THE "STRANDED OIL" PRIZE
- 3.4 REVIEW OF PRIOR STUDIES

4. MECHANISMS OF CO₂-EOR

- 4.1 MECHANISMS OF MISCIBLE CO₂-EOR.
- 4.2 MECHANISMS OF IMMISCIBLE CO₂-EOR
- 4.3 INTERACTIONS BETWEEN INJECTED CO₂ AND RESERVOIR OIL.

5. STUDY METHODOLOGY

- 5.1 OVERVIEW
- 5.2 ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE
- 5.3 SCREENING RESERVOIRS FOR CO₂-EOR.
- 5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE
- 5.5 CALCULATING OIL RECOVERY
- 5.6 ASSEMBLING THE COST MODEL
- 5.7 CONSTRUCTING AN ECONOMICS MODEL
- 5.8 PERFORMING SCENARIO ANALYSES

6. RESULTS BY STATE

- 6.1 NORTH AND SOUTH DAKOTA
- 6.2 MONTANA

LIST OF FIGURES

Figure 1	Impact of Technology and Financial Conditions on Economically Recoverable Oil from Williston Basin's Major Reservoirs Using CO ₂ -EOR (Million Barrels)
Figure 2	Location of Major Williston Basin Region Oil Fields that Screen for CO ₂ -EOR
Figure 3	Location of Existing and Potential CO ₂ Supply Pipelines in North Dakota
Figure 4	Williston Basin Production since 1950
Figure 5	One-Dimensional Schematic Showing the CO ₂ Miscible Process
Figure 6A	Carbon Dioxide, CH ₄ and N ₂ densities at 105°F
Figure 6B	Carbon Dioxide, CH ₄ and N ₂ viscosities at 105°F
Figure 7A	Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid
Figure 7B	Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey
Figure 8	Viscosity Reduction Versus Saturation Pressure
Figure 9	Estimating CO ₂ Minimum Miscibility Pressure
Figure 10	Correlation of MW C5+ to Tank Oil Gravity
Figure 11	Large North and South Dakota Oil Fields
Figure 12	Large Montana Oil Fields

LIST OF TABLES

Table 1	Size and Distribution of Williston Basin's Oil Reservoirs Data Base
Table 2	The Williston Basin Region's "Stranded Oil" Amenable to CO ₂ -EOR
Table 3	Applicability of Miscible and Immiscible CO ₂ -EOR
Table 4	Economically Recoverable Resources - Scenario #1: "Traditional Practices" CO ₂ -EOR
Table 5	Economically Recoverable Resources - Alternative Scenarios
Table 6	Potential CO ₂ Supply Requirements in the Williston Basin Region: Scenario #4 ("Ample Supplies of CO ₂ ")
Table 7	Matching of CO ₂ -EOR Technology with Williston Basin's Oil Reservoirs
Table 8	Crude Oil Annual Production, Ten Largest Williston Basin Oil Fields, 2002-2004 (Million Barrels per Year)
Table 9	Oil Production History of Selected Major Oil Fields of the Williston Basin Region
Table 10	Ten North Dakota Fields with Probable EOR Oil Resources (Assume a Recovery Factor of 8% OOIP)
Table 11	Reservoir Data Format: Major Oil Reservoirs Data Base
Table 12	Williston Basin Oil Reservoirs Screened Amenable for CO ₂ -EOR
Table 13	Economic Model Established by the Study
Table 14	Recent History of North Dakota Oil Production
Table 15	Recent History of South Dakota Oil Production
Table 16	Status of Large North and South Dakota Oil Fields/Reservoirs (as of 2004)
Table 17	Reservoir Properties and Improved Oil Recovery Activity, Large North and South Dakota Oil Fields/Reservoirs
Table 18	Economic Oil Recovery Potential Under Two Technologic Conditions, North and South Dakota

Table 19	Economic Oil Recovery Potential with More Favorable Financial Conditions, North and South Dakota
Table 20	Recent History of Montana Onshore Oil Production
Table 21	Status of Large Montana Oil Fields/Reservoirs as of 2004
Table 22	Reservoir Properties and Improved Oil Recovery Activity, Large Montana Oil Fields/Reservoirs
Table 23	Economic Oil Recovery Potential Under Two Technologic Conditions, Montana

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 (CO₂) 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” CO₂-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” CO₂-EOR technology may be examined in a subsequent study.

This report evaluates the future CO₂-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 CO₂-EOR to recover “stranded oil” in the Williston Basin producing region.

- The first scenario captures how CO₂-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 CO₂-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 CO₂-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 CO₂-EOR.
- The final scenario, entitled “Ample Supplies of CO₂”, assumes that large volumes of low-cost, “EOR-ready” CO₂ supplies are aggregated from various industrial and natural sources. These sources include industrial high-concentration CO₂ emissions from hydrogen facilities, gas processing plants, chemical plants and other sources in the region. These CO₂ sources would be augmented, in the longer-term, from low concentration CO₂ emissions from refineries and electric power plants. Capture of industrial CO₂ 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 CO₂ 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 CO₂ 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 CO₂-EOR, as shown below by state, Table 2.

Table 2. The Williston Basin Region's “Stranded Oil” Amenable to CO₂-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 CO₂-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 CO₂-EOR. One field screens for immiscible CO₂-EOR. The total technically recoverable resource from applying CO₂-EOR in these 54 large oil reservoirs, ranges from 810 million barrels to 1,840 million barrels, depending on the type of CO₂-EOR technology that is applied — “Traditional Practices” or “State-of-the-art”, Table 3.

Table 3. Applicability of Miscible and Immiscible CO₂-EOR

Region	Miscible			Immiscible		
	No. of Reservoirs	Technically Recoverable (MMBbls)		No. of Reservoirs	Technically Recoverable (MMBbls)	
		Traditional Practices	State of the Art		Traditional Practices	State of the Art
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” CO₂ flooding technology, high CO₂ costs and high risks, very little of Williston Basin’s “stranded oil” will become economically recoverable. Traditional application of miscible CO₂-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 CO₂ in the Williston Basin region (assumed at \$1.50 per Mcf), risks surrounding future oil prices, and uncertainties as to the performance of CO₂-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" CO₂-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 CO₂ cost of \$1.50 per Mcf, and a ROR hurdle rate of 25% (before tax).*

5. Introduction of "State-of-the-art" CO₂-EOR technology, risk mitigation incentives and lower CO₂ costs would enable 510 million barrels of additional oil to become economically recoverable from the Williston Basin region. With "State-of-the-art" CO₂-EOR technology and its higher oil recovery efficiency (plus oil prices of \$30/B and CO₂ 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 CO₂ supplies (equal to \$0.80 per Mcf, assuming a large-scale CO₂ collection and transportation system) and incentives for capture of CO₂ 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 CO₂-EOR (Million Barrels)

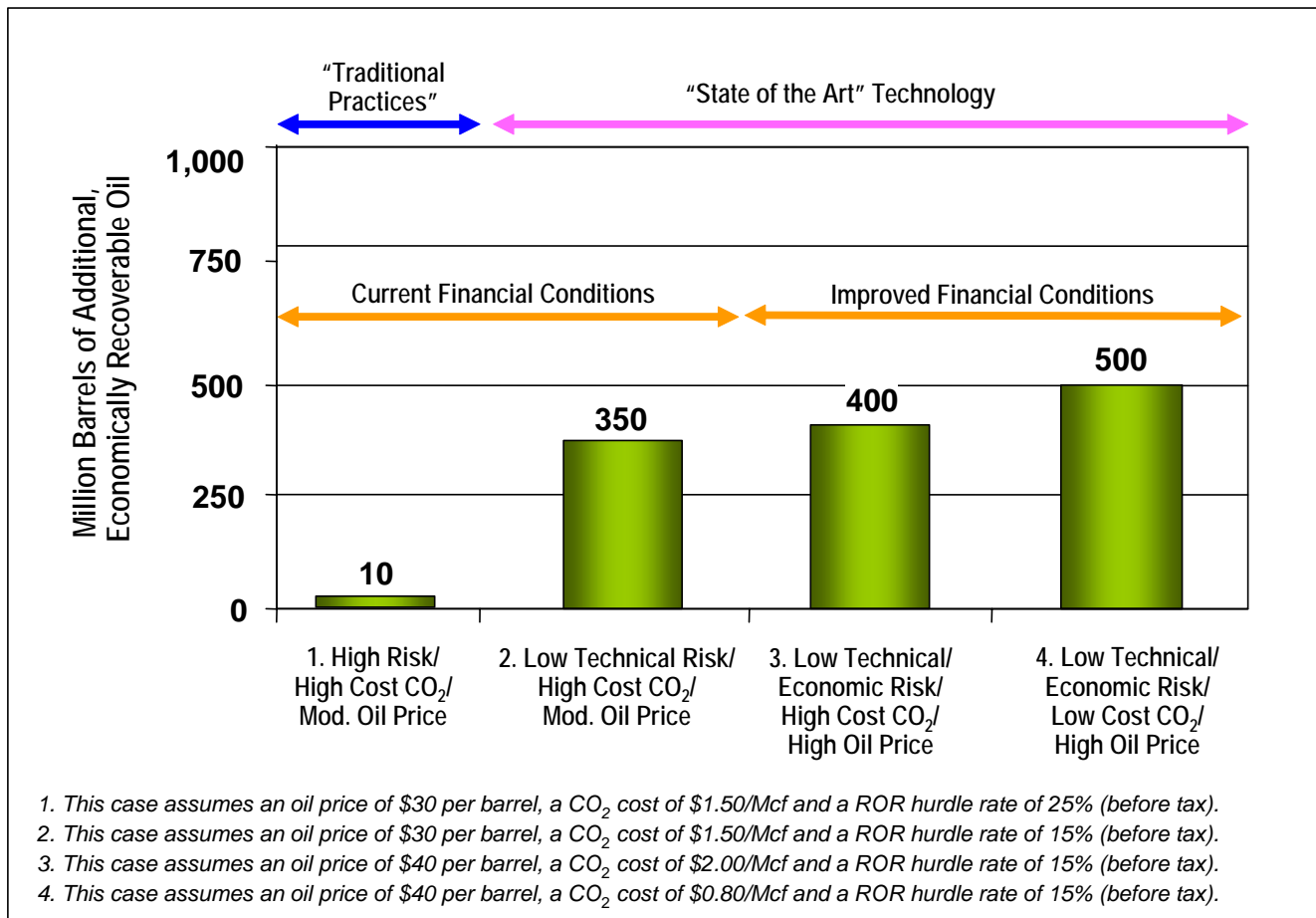


Table 5. Economically Recoverable Resources - Alternative Scenarios

Basin	Scenario #2: "State-of-the-art"		Scenario #3: "Risk Mitigation"		Scenario #4: "Ample Supplies of CO ₂ "	
	(Moderate Oil Price/ High CO ₂ Cost)		(High Oil Price/ High CO ₂ Cost)		(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 CO₂-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 CO₂-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 CO₂-EOR in the Williston Basin will, most likely, prove to be higher than defined by this study. Introduction of more advanced "next generation" CO₂-EOR technologies still in the research or field demonstration stage, such as gravity stable CO₂ injection, extensive use of horizontal or multi-lateral wells and CO₂ 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 CO₂ emissions. The benefits and impacts of using "advanced" CO₂-EOR technology on Williston Basin oil reservoirs are being examined in a separate study.

8. A portion of this CO₂-EOR potential has been examined, in the past, by operators in the Williston Basin. No full scale CO₂-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 CO₂ supplies will be required in the Williston Basin to achieve the CO₂-EOR potential defined by this study. The overall market for purchased CO₂ could be nearly 2 Tcf, plus another nearly 4 Tcf of recycled CO₂, Table 6. Assuming that the volume of CO₂ stored equals the volume of CO₂ purchased and that the bulk of purchased CO₂ is from industrial sources, applying CO₂-EOR to the Williston Basin's oil reservoirs would enable over 100 million metric tonnes of CO₂

emissions to be stored, greatly reducing greenhouse gas emissions. Advanced CO₂-EOR flooding and CO₂ storage concepts (plus incentives for storing CO₂) would significantly increase these volumes.

Table 6. Potential CO₂ Supply Requirements in the Williston Basin Region: Scenario #4 ("Ample Supplies of CO₂")

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 CO₂ 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 CO₂-EOR in the Williston Basin Region's oil fields. The challenging nature of the current barriers — lack of sufficient, low-cost CO₂ 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 CO₂ 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 CO₂-EOR based oil production in the Williston Basin. Successful introduction and wide-scale use of CO₂-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

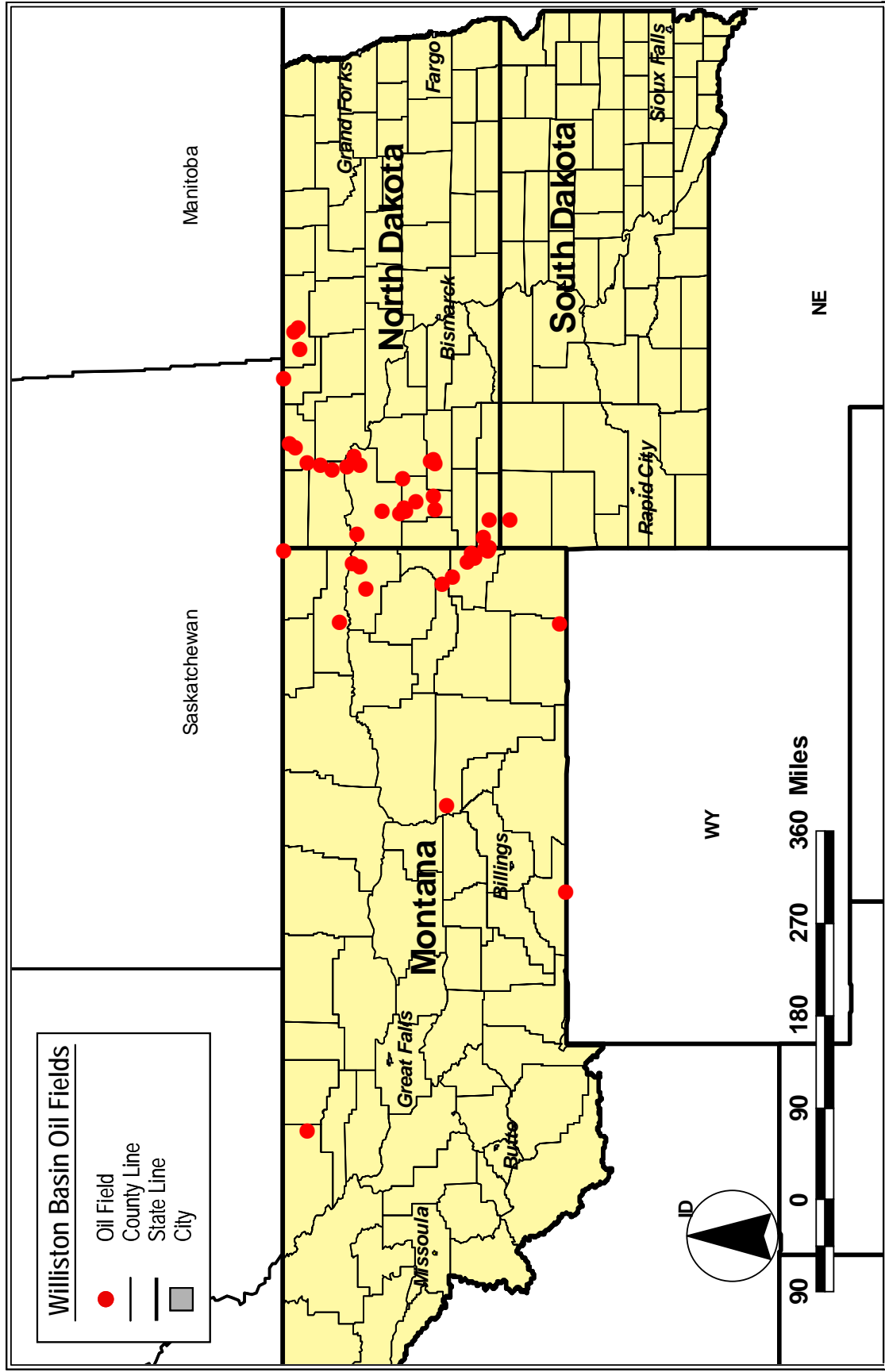
2.1 CURRENT SITUATION. The Williston Basin oil producing region had been in a slow decline up until 2004 when application of horizontal drilling technologies and discovery of new fields led to an increase in oil production. Sustaining and further increasing this production growth will be a challenge, 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 CO₂ enhanced oil recovery (CO₂-EOR) as one option for further increasing Williston Basin’s oil production.

This report, “Basin Oriented Strategies for CO₂ Enhanced Oil Recovery: Williston Basin of North Dakota, South Dakota and Montana,” provides information on the size of the technical and economic potential for CO₂-EOR in the Williston Basin oil producing region. It also identifies the many barriers — insufficient and costly CO₂ supplies, high market and economic risks, and concerns over technology performance — that currently impede the cost-effective application of CO₂-EOR in the 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 (CO₂-EOR). The outline of the Williston Basin’s oil producing region and the concentration of its major oil fields that screen for CO₂-EOR are shown in Figure 2.

Figure 2. Location of Major Williston Basin Region Oil Fields that Screen for CO₂-EOR



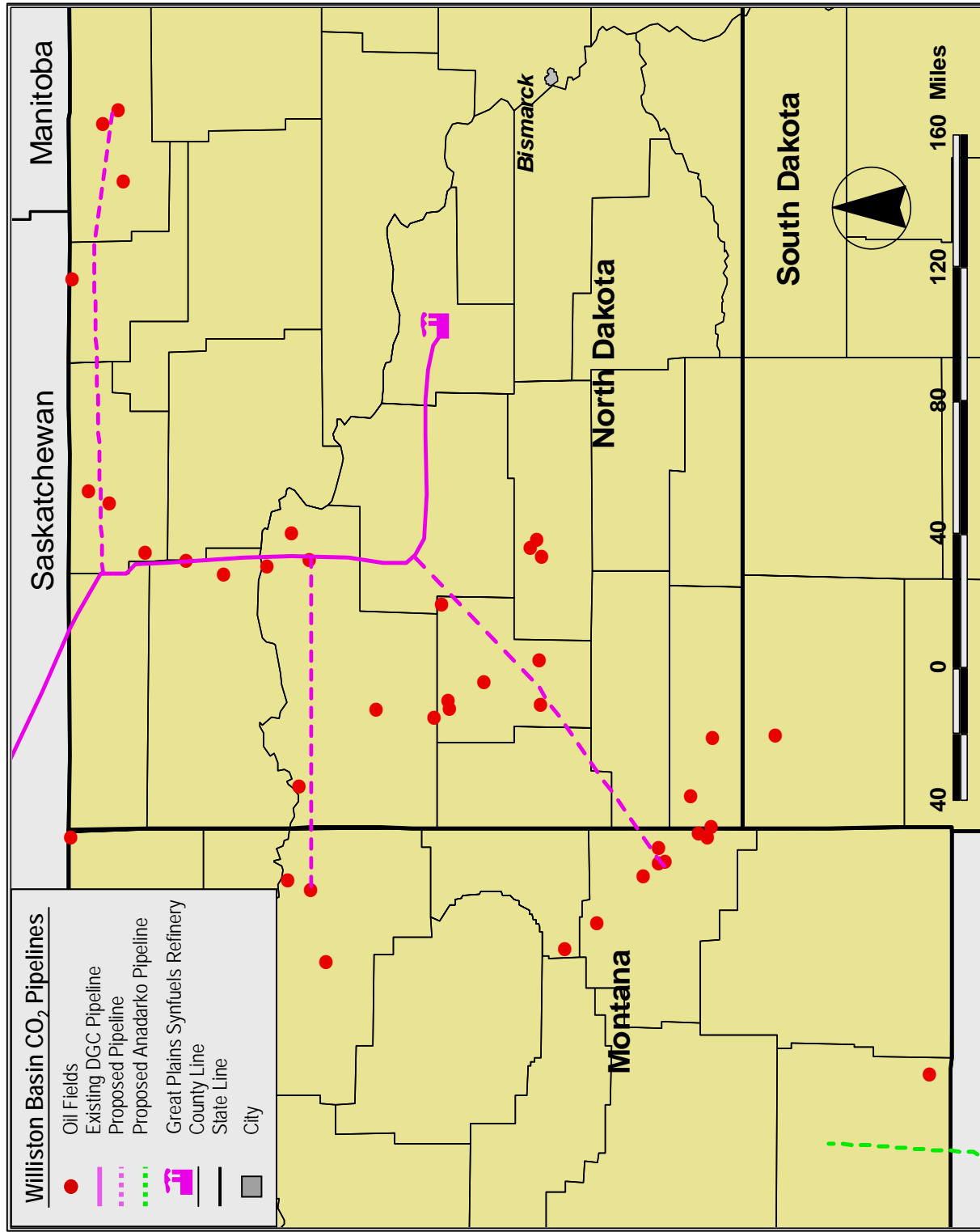
2.3 PURPOSE. This report, “Basin Oriented Strategies for CO₂ Enhanced Oil Recovery: Williston Basin of North Dakota, South Dakota and Montana” is part of a larger effort to examine the enhanced oil recovery and CO₂ storage potential in key U.S. oil basins. The work involves establishing the geological and reservoir characteristics of the major oil fields in the region; examining the available CO₂ sources, volumes and costs; calculating oil recovery and CO₂ storage capacity; and, examining the economic feasibility of applying CO₂-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 CO₂ capture technology; (2) launching R&D/pilot projects of advanced CO₂ flooding technology; and, (3) structuring royalty/tax incentives and policies that would help accelerate the application of CO₂-EOR and CO₂ 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 CO₂ will become available, from natural sources in western Montana and/or from industrial sources in the region. The industrial CO₂ 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 CO₂ that is transported to the Weyburn oil field in Canada for CO₂-EOR. (An expansion in the supply of CO₂ from the Dakota Gasification Plant to Canadian oil fields is currently underway.) The study assumes that sufficient CO₂ 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 CO₂ 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 CO₂ pipeline system that could transport additional CO₂ from DGC to the nearby oil fields of western North Dakota and eastern Montana. In addition, discussions are underway for extending of Anadarko's CO₂ pipeline, currently supplying fields in Wyoming, to southeastern Montana.

Figure 3. Location of Existing and Potential CO₂ 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 CO₂ flooding and reservoir selection practices. It is distinguished by using miscible CO₂-EOR technology in light oil reservoirs and by injecting moderate volumes of CO₂, on the order of 0.4 hydrocarbon pore volumes (HCPV), into these reservoirs. (Immiscible CO₂ is not included in the “Traditional Practices” technology option). Given the still limited application of CO₂-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 CO₂-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 CO₂-EOR and the shallower light oil and the heavier oil reservoirs are targeted for immiscible CO₂-EOR. “State-of-the-art” technology entails injecting and managing much larger volumes of CO₂, on the order of 1 HCPV, with considerable CO₂ recycling.

Under “State-of-the-art” technology, with CO₂ injection volumes more than twice as large, oil recovery is projected to be higher than reported for past field projects using “Traditional Practices”. The CO₂ injection/oil recovery ratio may also be higher under this technology option, further spotlighting the importance of lower cost CO₂ 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 CO₂-EOR would be applied fall into two groups, as set forth below:

1. *Favorable Light Oil Reservoirs Meeting Stringent CO₂ Miscible Flooding Criteria.* These are the moderately deep, higher gravity oil reservoirs where CO₂ becomes miscible (after extraction of hydrocarbon components into the CO₂ phase and solution of CO₂ 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 °API would be selected for miscible CO₂-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 CO₂-EOR floods have been conducted in these types of “favorable reservoirs”.
2. *Challenging Reservoirs Involving Immiscible Application of CO₂-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 CO₂ flooding technology matching is applied to the Williston Basin’s reservoirs amenable to CO₂-EOR, Table 7.

Table 7. Matching of CO₂-EOR Technology With the Williston Basin’s Oil Reservoirs

CO ₂ -EOR Technology Selection	Oil Reservoir Selection
“Traditional Practices” Miscible CO ₂ -EOR	<ul style="list-style-type: none"> ▪ 53 Deep, Light Oil Reservoirs
“State-of-the-art” Miscible and Immiscible CO ₂ -EOR	<ul style="list-style-type: none"> ▪ 53 Deep, Light Oil Reservoirs ▪ 1 Shallow, Light Oil Reservoir ▪ No Deep, Moderately Heavy Oil Reservoirs

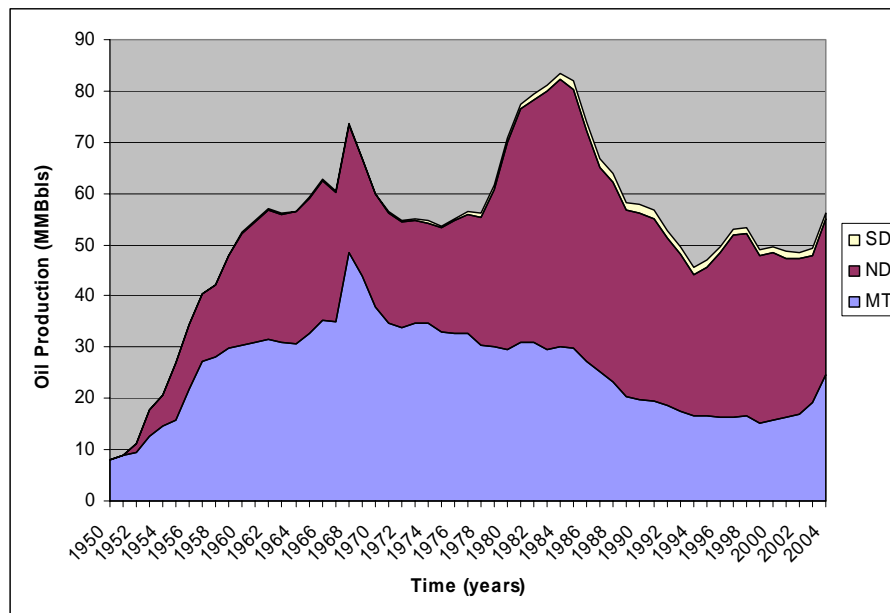
2.6 OTHER ISSUES. This study draws on a variety of sources for basic data on the reservoir properties and the expected technical and economic performance of CO₂-EOR in the Williston Basin. Because of confidentiality and proprietary issues, the results of the study have been aggregated and presented for 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 CO₂ 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 CO₂-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 CO₂-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 CO₂-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 CO₂-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 CO₂-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 CO₂-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 CO₂-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 CO₂-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)**

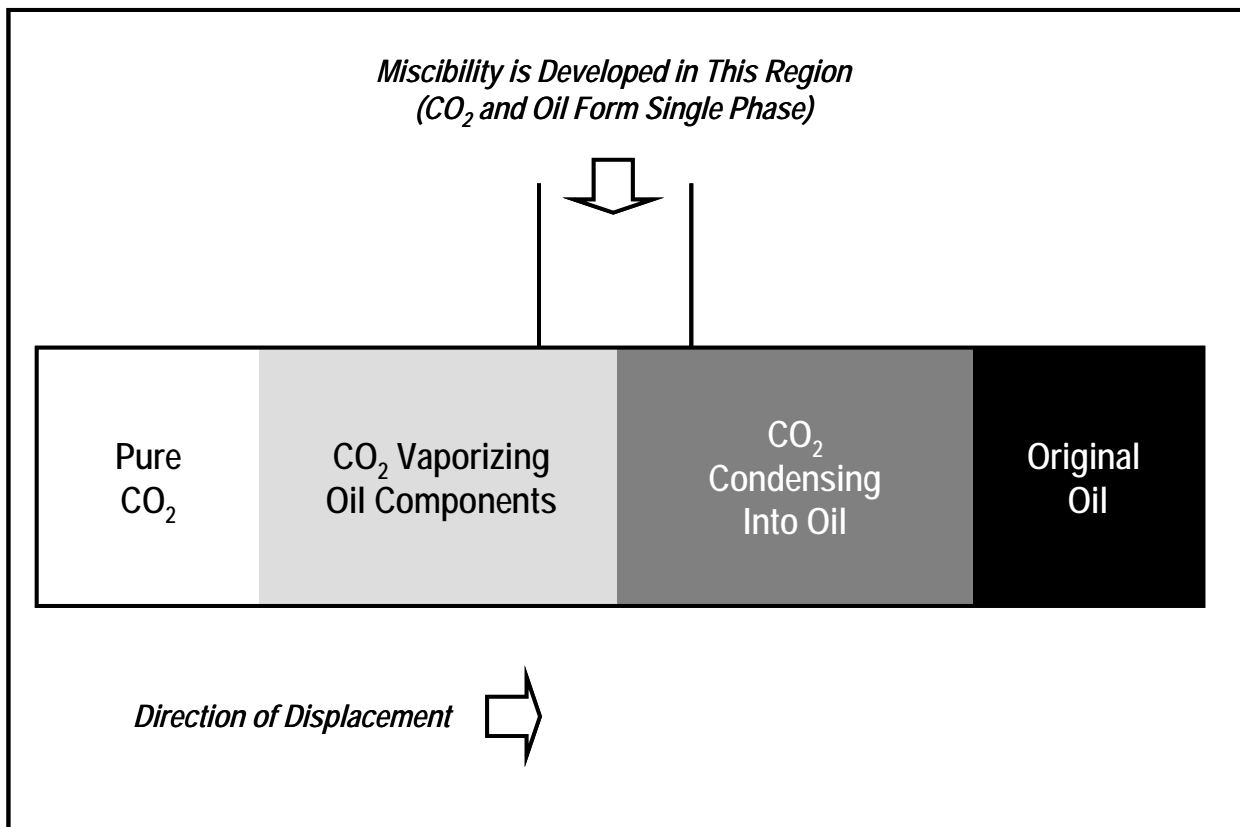
	Field/Reservoir	CO ₂ -EOR Recoverable Resources (MMBbl)
1	Beaver Lodge (Madison)	17.6
2	Tioga (Madison)	17.2
3	Big Stick (Madison)	13.3
4	Fryburg (Heath-Tyler)	12.4
5	Beaver Lodge (Devonian)	11.1
6	Newburg (Spearfish, Charles)	7.7
7	Wiley (Glenburn)	7.6
8	Blue Buttes (Madison)	7.4
9	North Tioga (Madison)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

4. MECHANISMS OF CO₂-EOR

4.1 MECHANISMS OF MISCIBLE CO₂-EOR. Miscible CO₂-EOR is a multiple contact process, involving the injected CO₂ and the reservoir's oil. During this multiple contact process, CO₂ will vaporize the lighter oil fractions into the injected CO₂ phase and CO₂ 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 CO₂-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 CO₂ miscible process.

Figure 5. One-Dimensional Schematic Showing the CO₂ Miscible Process.



4.2 MECHANISMS OF IMMISCIBLE CO₂-EOR. When insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier), the injected CO₂ is immiscible with the reservoir's oil. As such, another oil displacement mechanism, immiscible CO₂ flooding, occurs. The main mechanisms involved in immiscible CO₂ flooding are: (1) oil phase swelling, as the oil becomes saturated with CO₂; (2) viscosity reduction of the swollen oil and CO₂ mixture; (3) extraction of lighter hydrocarbon into the CO₂ 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 CO₂-EOR is less efficient than miscible CO₂-EOR in recovering the oil remaining in the reservoir.

4.3 INTERACTIONS BETWEEN INJECTED CO₂ AND RESERVOIR OIL. The properties of CO₂ (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 CO₂ 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 CO₂-EOR. Figures 7A and 7B show the oil swelling (and implied residual oil mobilization) that occurs from: (1) CO₂ injection into a Williston Basin light reservoir oil; and, (2) CO₂ injection into a very heavy (12 °API) oil reservoir in Turkey. Laboratory work on the Bradford Field (Pennsylvania) oil reservoir showed that the injection of CO₂, 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 CO₂ 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 CO₂-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 CO₂ at high pressure.

Figure 6A. Carbon Dioxide, CH₄ and N₂ densities at 105^oF. At high pressures, CO₂ 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).

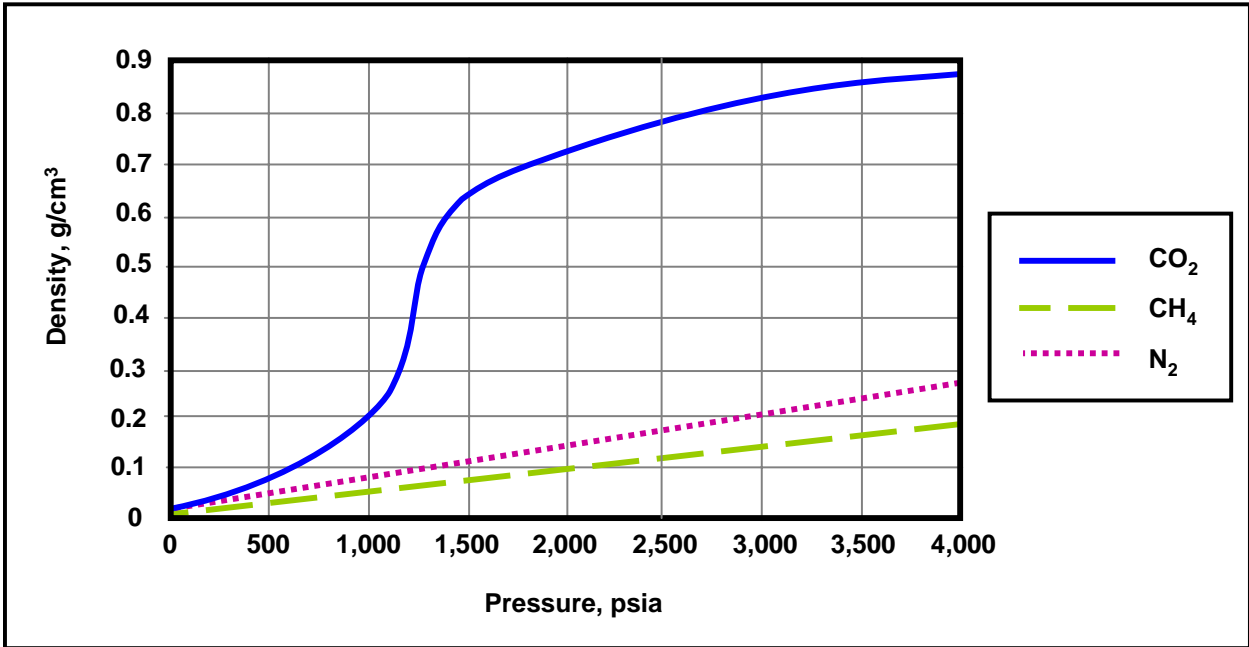


Figure 6B. Carbon Dioxide, CH₄ and N₂ viscosities at 105^oF. At high pressures, the viscosity of CO₂ is also greater than that of methane or nitrogen, although it remains low in comparison to that of liquids. Viscosities were calculated with an EOS.

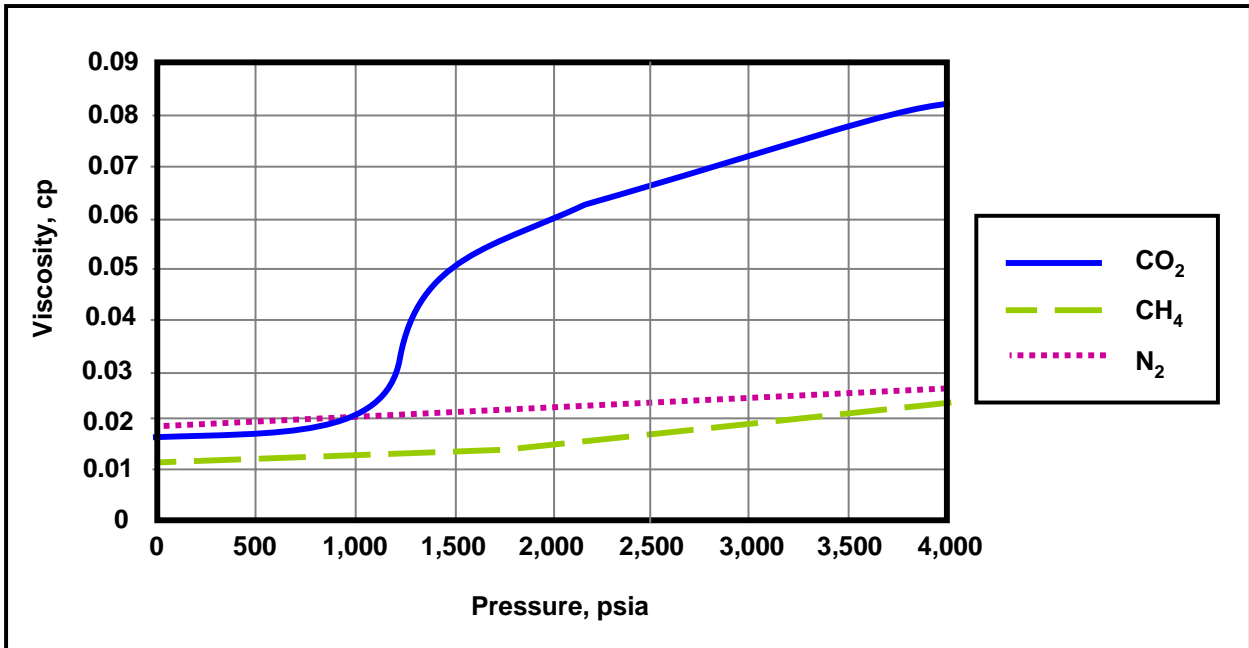


Figure 7A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid (Holm and Josendal).

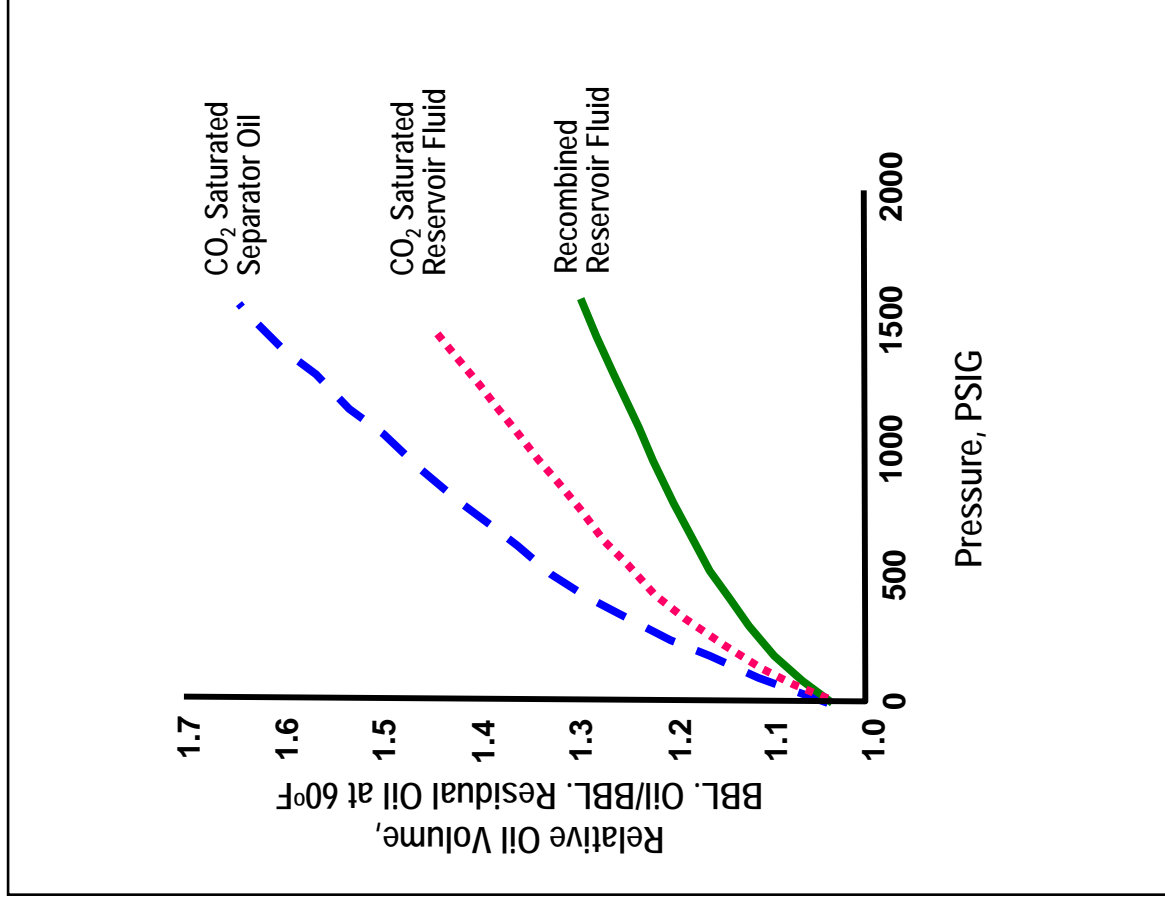


Figure 7B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

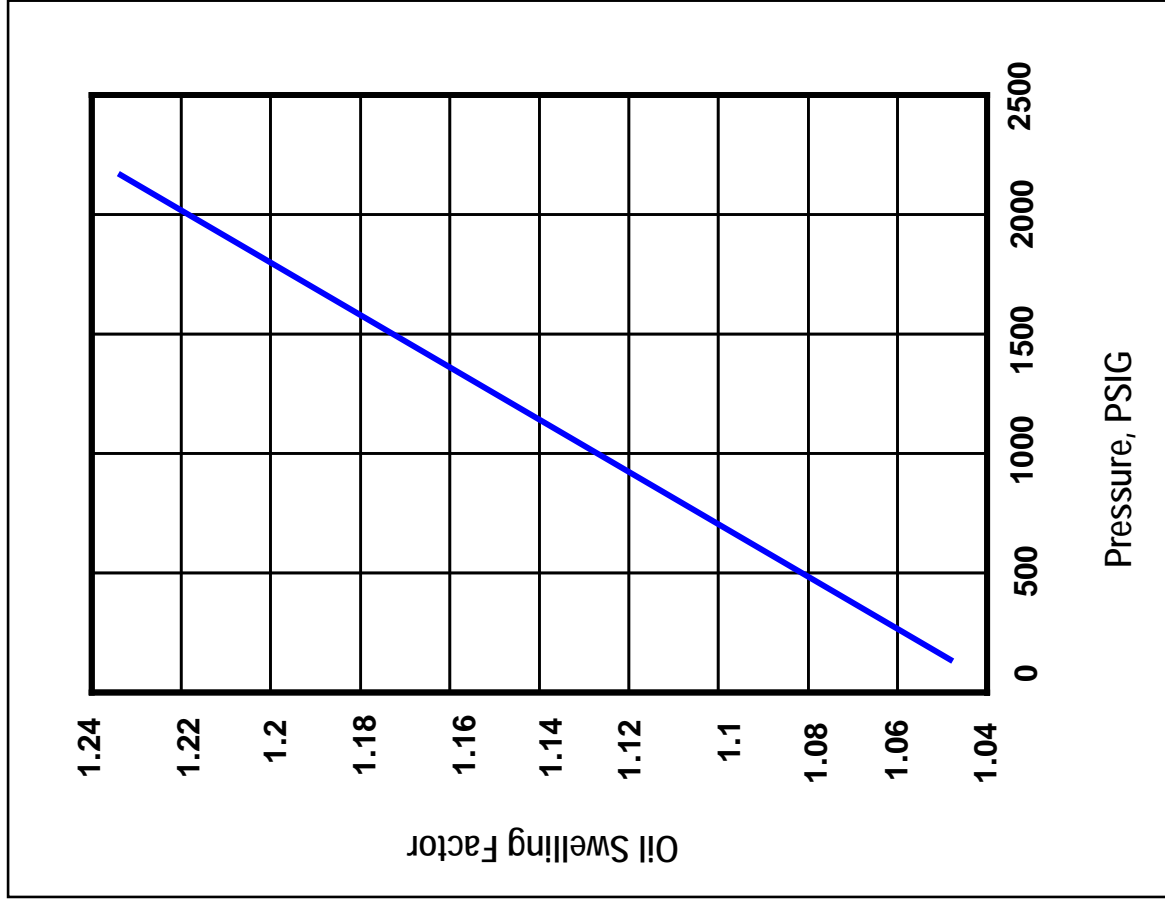
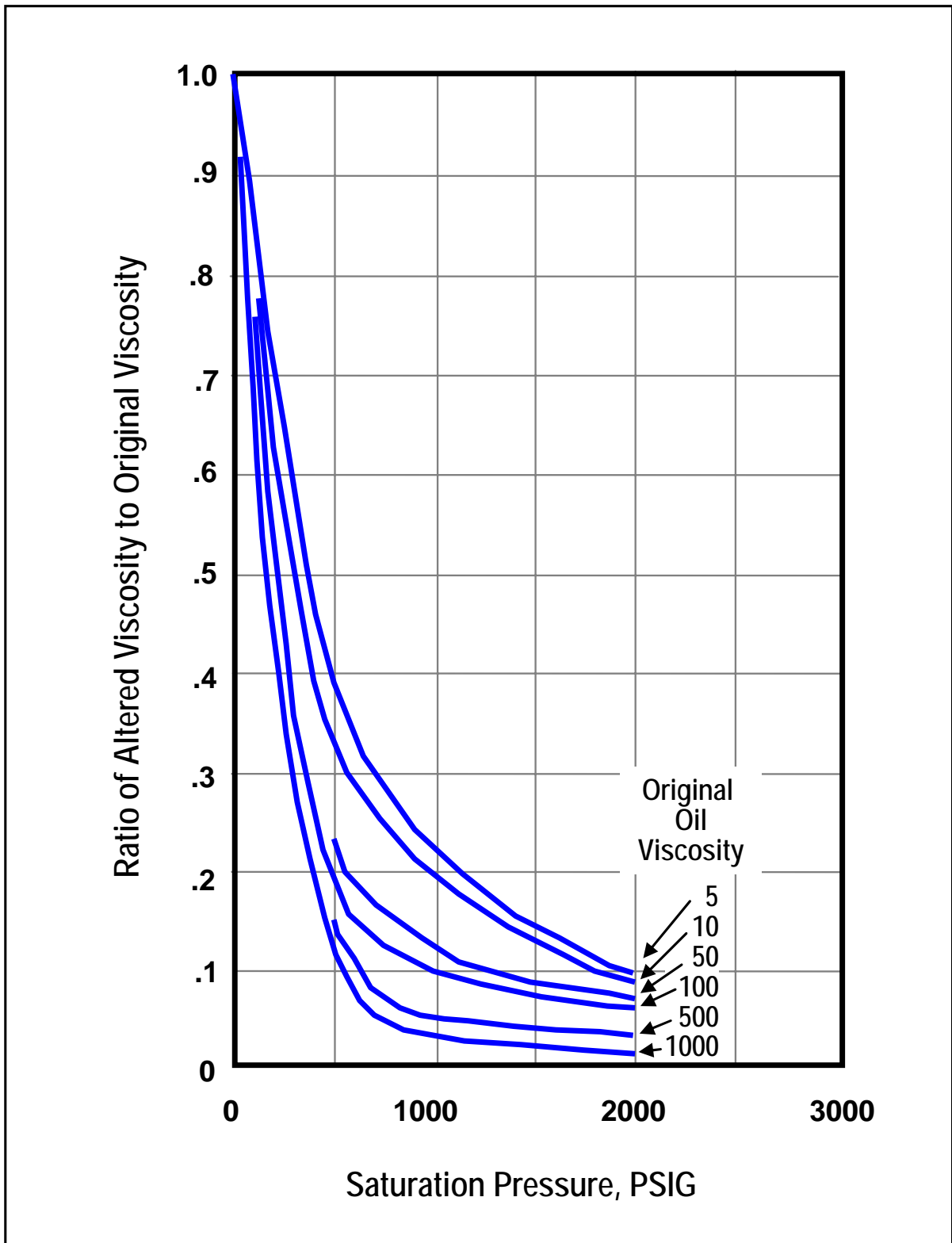


Figure 8. Viscosity Reduction vs. Saturation Pressure (Simon and Graue)



5. STUDY METHODOLOGY

5.1 OVERVIEW. A seven part methodology was used to assess the CO₂-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 CO₂-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 CO₂-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							
Reservoir Parameters:							
Area (A)	TORIS	ARI	TORIS	ARI	TORIS	ARI	P/S
Net Pay (ft)							
Depth (ft)							
Porosity							
Reservoir Temp (deg F)							
Initial Pressure (psi)							
Pressure (psi)							
B_{oi}							
$B_o @ S_{o_0}$ swept							
S_{oi}							
S_{or}							
Swept Zone S_{o_0}							
S_{wi}							
S_w							
API Gravity							
Viscosity (cp)							
Dykstra-Parsons							



Print Sheets

Volumes
 OOIP (MMbl) P/S
 Cum Oil (MMbl) P/S
 EOY P/S 2004 Reserves (MMbl)
 Ultimate P/S Recovery (MMbl)
 Remaining (MMbl)
 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 (MMbl)

ROIP Volume Check
 ROIP Check (MMbl)

Oil Production
 Producing Wells (active)
 Producing Wells (shut-in)
 2004 Production (Mbbbl)
 Daily Prod - Field (Bbl/d)
 Cum Oil Production (MMbbl)
 EOY 2004 Oil Reserves (MMbbl)
 Water Cut

Water Production
 2004 Water Production (Mbbbl)
 Daily Water (Mbbbl/d)

Injection
 Injection Wells (active)
 Injection Wells (shut-in)
 2004 Water Injection (MMbbl)
 Daily Injection - Field (Mbbbl/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)

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 CO₂-EOR; and, (3) provide the *CO₂-PROPHET* Model (developed by Texaco for the DOE Class I cost-share program) the essential input data for calculating CO₂ injection requirements and oil recovery.

5.3 SCREENING RESERVOIRS FOR CO₂-EOR. The data base was screened for reservoirs that would be applicable for CO₂-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 CO₂-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 CO₂-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 CO₂ injection. A minimum oil gravity of 17.5 °API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection. Table 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 CO₂-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 HILLS	RED RIVER
North Dakota	CHARLSON	MADISON
North Dakota	DICKINSON	HEATH
North Dakota	DICKINSON	LOGGEPOLE
North Dakota	ELAND	LOGGEPOLE
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	LOGGEPOLE
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 CO₂-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

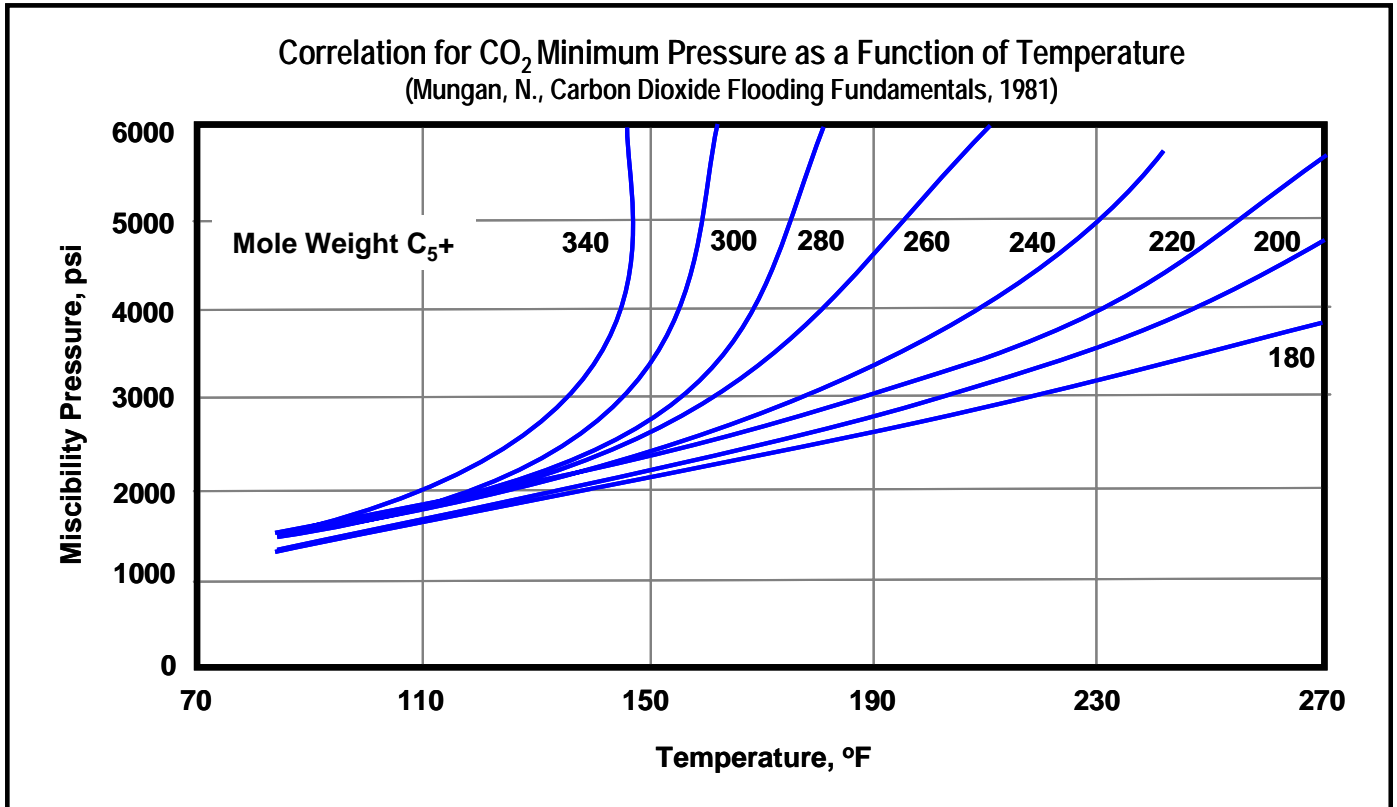
5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO₂ is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO₂, given fixed temperature and oil 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:

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

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

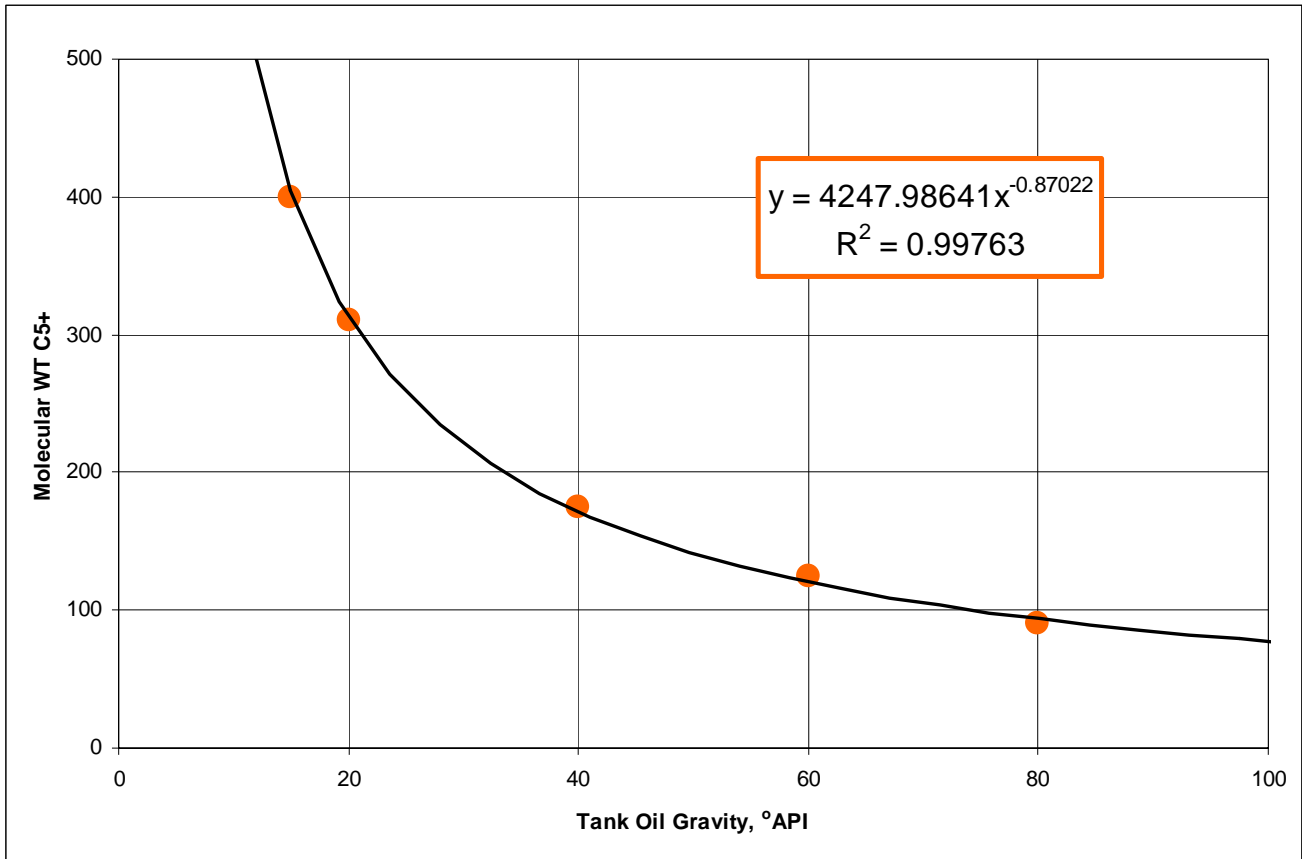
Figure 9. Estimating CO₂ Minimum Miscibility Pressure



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 CO₂-EOR were selected for consideration by immiscible CO₂-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 *CO₂-PROPHET* to calculate incremental oil produced using *CO₂-EOR*. *CO₂-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 *CO₂* Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir” (DOE Contract No. DE-FC22-93BC14960). *CO₂-PROPHET* was developed as an alternative to the DOE’s *CO₂* miscible flood predictive model, *CO₂PM*. According to the developers of the model, *CO₂-PROPHET* has more capabilities and fewer limitations than *CO₂PM*. For example, according to the above cited report, *CO₂-PROPHET* performs two main operations that provide a more robust calculation of oil recovery than available from *CO₂PM*:

- *CO₂-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 *CO₂-PROPHET* model and the calibration of this model with an industry standard reservoir simulator.

Even with these improvements, it is important to note the CO₂-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 CO₂-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 CO₂ recycle plant; (4) constructing a CO₂ spur-line from the main CO₂ 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 CO₂. A variety of CO₂ 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 CO₂-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 CO₂-EOR used by the study.

5.8 PERFORMING SCENARIO ANALYSES. A series of analyses were prepared to better understand how differences in oil prices, CO₂ supply costs and financial risk hurdles could impact the volumes of oil that would be economically produced by CO₂-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 CO₂-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 CO₂ supply costs were considered. The high CO₂ 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 CO₂ to the Williston Basin's oil basins. A lower CO₂ 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 CO₂ from industrial and power plants as part of CO₂ 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 CO₂-EOR in a new reservoir setting. The lower ROR hurdle represents application of CO₂-EOR after the geologic and technical risks have been mitigated with a robust program of field pilots and demonstrations.

These various technology, oil price, CO₂ supply cost and rate of return hurdles were combined into four scenarios, as set forth below:

- The first scenario captures how CO₂-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 CO₂-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 CO₂-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 CO₂-EOR.
- The final scenario, entitled “Ample Supplies of CO₂,” low-cost, “EOR-ready” CO₂ supplies are aggregated from various industrial and natural sources. These include industrial high-concentration CO₂ 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 CO₂ emissions from refineries and electric power plants. Capture of industrial CO₂ 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												
	ND	1	2	3	4	5	6	7	8	9	10	11	
State Field			New Injectors	0.00									
Formation			Existing Producers	0.49									
Depth			Converted Producers	0.51									
Distance from Trunkline (mi)			New Producers	0.0									
# of Patterns			Existing Producers	1.25									
Miscibility:			Disposal Wells	0.00									
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	13
H2O Production (Mbw)			-	-	86	51	40	40	40	39	37	38	38
CO2 Production (MMcf)			-	-	0	4	44	75	86	93	98	108	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	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	Deg	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)			\$ -	\$ -	\$ -	\$ 247	\$ 1,056	\$ 919	\$ 609	\$ 477	\$ 422	\$ 432	\$ 320
Royalty (\$M)			\$ -	\$ -	\$ -	\$ (31)	\$ (132)	\$ (115)	\$ (76)	\$ (60)	\$ (53)	\$ (54)	\$ (40)
Severance Taxes (\$M)			\$ -	\$ -	\$ -	\$ (11)	\$ (46)	\$ (40)	\$ (27)	\$ (21)	\$ (18)	\$ (19)	\$ (14)
Extraction Tax (\$M)			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (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)											
Cap Ex G&A	\$	-											
CO2 Costs (\$M)			\$ (216)	\$ (215)	\$ (216)	\$ (215)	\$ (211)	\$ (163)	\$ (126)	\$ (112)	\$ (104)	\$ (97)	\$ (86)
Total CO2 Cost (\$M)			\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)
O&M Costs													
Operating & Maintenance (\$M)			\$ (24)	\$ (24)	\$ (24)	\$ (24)	\$ (23)	\$ (19)	\$ (16)	\$ (15)	\$ (14)	\$ (14)	\$ (13)
Lifting Costs (\$/bbl)	\$	0.25	\$ (11)	\$ (11)	\$ (11)	\$ (11)	\$ (11)	\$ (10)	\$ (10)	\$ (9)	\$ (9)	\$ (9)	\$ (9)
G&A	\$	20%	\$ (68)	\$ (68)	\$ (68)	\$ (68)	\$ (67)	\$ (62)	\$ (59)	\$ (57)	\$ (56)	\$ (56)	\$ (54)
Total O&M Costs			\$ (146)	\$ (146)	\$ (146)	\$ (146)	\$ (146)	\$ (146)	\$ (146)	\$ (146)	\$ (146)	\$ (146)	\$ (146)
Net Cash Flow (\$M)			\$ (146)	\$ (284)	\$ (506)	\$ (78)	\$ 600	\$ 538	\$ 322	\$ 227	\$ 191	\$ 206	\$ 100
Cum. Cash Flow			\$ (146)	\$ (429)	\$ (713)	\$ (1,297)	\$ (697)	\$ (159)	\$ 163	\$ 390	\$ 581	\$ 787	\$ 887
Discount Factor			1.00	0.80	0.64	0.51	0.41	0.33	0.26	0.21	0.17	0.13	0.09
Disc. Net Cash Flow			\$ (146)	\$ (227)	\$ (182)	\$ (258)	\$ (32)	\$ 197	\$ 141	\$ 67	\$ 38	\$ 26	\$ 22
Disc. Cum Cash Flow			\$ (146)	\$ (373)	\$ (554)	\$ (813)	\$ (845)	\$ (649)	\$ (508)	\$ (440)	\$ (376)	\$ (354)	\$ (346)
NPV (BTx)			\$ (5336)										
NPV (BTx)			\$ (247)										
NPV (BTx)			\$ (105)										
NPV (BTx)			\$ 121										
IRR (BTx)			12.38%										

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

Pattern-Level Cashflow Model	12	13	14	15	16	17	18	19	20	21	22	23	24	25
State														
Field														
Formation														
Depth														
Distance from Trunkline (mi)														
# of Patterns														
Miscible														
Year														
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 (Mbbbl)	9	10	12	9	4	4	4	4	4	4	6	7	7	7
H2O Production (MBw)	39	39	43	45	46	46	46	46	46	46	45	43	42	44
CO2 Production (MMcf)	114	115	101	102	108	112	114	114	114	112	113	113	114	111
CO2 Purchased (MMcf)	29	14	29	27	21	17	15	15	15	17	16	16	15	19
CO2 Recycled (MMcf)	114	115	101	102	108	112	114	114	114	112	113	113	114	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
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
Gross Revenues (\$M)	\$ 222	\$ 242	\$ 287	\$ 227	\$ 145	\$ 100	\$ 87	\$ 92	\$ 100	\$ 120	\$ 150	\$ 165	\$ 177	\$ 180
Royalty (\$M)	\$ (28)	\$ (30)	\$ (36)	\$ (28)	\$ (18)	\$ (12)	\$ (11)	\$ (12)	\$ (12)	\$ (15)	\$ (19)	\$ (21)	\$ (22)	\$ (22)
Severance Taxes (\$M)	\$ (10)	\$ (11)	\$ (13)	\$ (10)	\$ (6)	\$ (4)	\$ (4)	\$ (4)	\$ (4)	\$ (5)	\$ (7)	\$ (7)	\$ (8)	\$ (8)
Extraction Tax (\$M)	\$ (18)	\$ (19)	\$ (23)	\$ (18)	\$ (11)	\$ (8)	\$ (7)	\$ (7)	\$ (7)	\$ (8)	\$ (9)	\$ (12)	\$ (13)	\$ (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	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
CO2 Costs (\$M)	\$ (77)	\$ (56)	\$ (73)	\$ (71)	\$ (64)	\$ (59)	\$ (57)	\$ (57)	\$ (57)	\$ (59)	\$ (58)	\$ (58)	\$ (57)	\$ (61)
Total CO2 Cost (\$M)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)
O&M Costs	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)
Operating & Maintenance (\$M)	\$ (12)	\$ (12)	\$ (14)	\$ (13)	\$ (13)	\$ (13)	\$ (12)	\$ (12)	\$ (12)	\$ (12)	\$ (12)	\$ (12)	\$ (12)	\$ (18)
Lifting Costs (\$/bbl)	\$ (9)	\$ (9)	\$ (9)	\$ (9)	\$ (9)	\$ (9)	\$ (9)	\$ (9)	\$ (9)	\$ (9)	\$ (9)	\$ (9)	\$ (9)	\$ (10)
G&A	\$ (54)	\$ (54)	\$ (56)	\$ (56)	\$ (55)	\$ (54)	\$ (54)	\$ (54)	\$ (54)	\$ (54)	\$ (54)	\$ (54)	\$ (54)	\$ (61)
Total O&M Costs	\$ 36	\$ 73	\$ 87	\$ 45	\$ (10)	\$ (38)	\$ (45)	\$ (42)	\$ (38)	\$ (22)	\$ 1	\$ 13	\$ 11	\$ 13
Net Cash Flow (\$M)	\$ 923	\$ 996	\$ 1,083	\$ 1,128	\$ 1,118	\$ 1,079	\$ 1,034	\$ 993	\$ 955	\$ 933	\$ 934	\$ 947	\$ 959	\$ 972
Cum. Cash Flow	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
Discount Factor	25%													
Disc. Net Cash Flow	\$ 2	\$ 4	\$ 4	\$ 2	\$ (0)	\$ (1)	\$ (1)	\$ (1)	\$ (1)	\$ (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	26	27	28	29	30	31	32	33	34	35	36
State											
Field											
Formation											
Depth											
Distance from Trunkline (mi)											
# of Patterns											
Miscibility:											
Year											
CO2 Injection (MMcf)	129	129	129	129	129	129	105	-	-	-	-
H2O Injection (Mbw)	43	43	43	43	43	43	55	107	107	107	21
Oil Production (Mbbbl)	8	8	8	8	7	7	6	6	5	5	1
H2O Production (MBw)	43	42	42	42	42	43	44	48	84	96	20
CO2 Production (MMcf)	111	112	112	112	113	114	116	127	42	16	2
CO2 Purchased (MMcf)	19	18	17	17	16	15	-	-	-	-	-
CO2 Recycled (MMcf)	111	112	112	112	113	114	105	-	-	-	-
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
Gravity Adjustment	\$ 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
Royalty (\$M)	\$ (23)	\$ (25)	\$ (25)	\$ (24)	\$ (22)	\$ (21)	\$ (19)	\$ (18)	\$ (16)	\$ (14)	\$ (2)
Severance Taxes (\$M)	\$ (8)	\$ (9)	\$ (9)	\$ (8)	\$ (8)	\$ (7)	\$ (7)	\$ (6)	\$ (6)	\$ (5)	\$ (1)
Extraction Tax (\$M)	\$ (15)	\$ (16)	\$ (16)	\$ (15)	\$ (14)	\$ (13)	\$ (12)	\$ (11)	\$ (10)	\$ (9)	\$ (2)
Net Revenue(\$M)	\$ 141	\$ 152	\$ 150	\$ 145	\$ 135	\$ 126	\$ 117	\$ 109	\$ 98	\$ 85	\$ 15
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	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
CO2 Costs (\$M)	\$ (61)	\$ (60)	\$ (59)	\$ (60)	\$ (58)	\$ (57)	\$ (32)	\$ -	\$ -	\$ -	\$ (3,015)
Total CO2 Cost (\$M)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (33)	\$ (1,181)
O&M Costs											
Operating & Maintenance (\$M)	\$ 0.25	\$ (18)	\$ (18)	\$ (18)	\$ (18)	\$ (17)	\$ (17)	\$ (18)	\$ (26)	\$ (28)	\$ (6)
Lifting Costs (\$/bbl)	20%	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(12)	(12)	(8)
G&A	\$ (61)	\$ (62)	\$ (61)	\$ (61)	\$ (61)	\$ (60)	\$ (60)	\$ (61)	\$ (71)	\$ (73)	\$ (46)
Total O&M Costs	\$ 19	\$ 31	\$ 30	\$ 24	\$ 16	\$ 9	\$ 25	\$ 48	\$ 27	\$ 11	\$ (31)
Net Cash Flow (\$M)	\$ 991	\$ 1,022	\$ 1,051	\$ 1,075	\$ 1,091	\$ 1,100	\$ 1,125	\$ 1,173	\$ 1,200	\$ 1,211	\$ 1,180
Cum. Cash Flow	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)
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

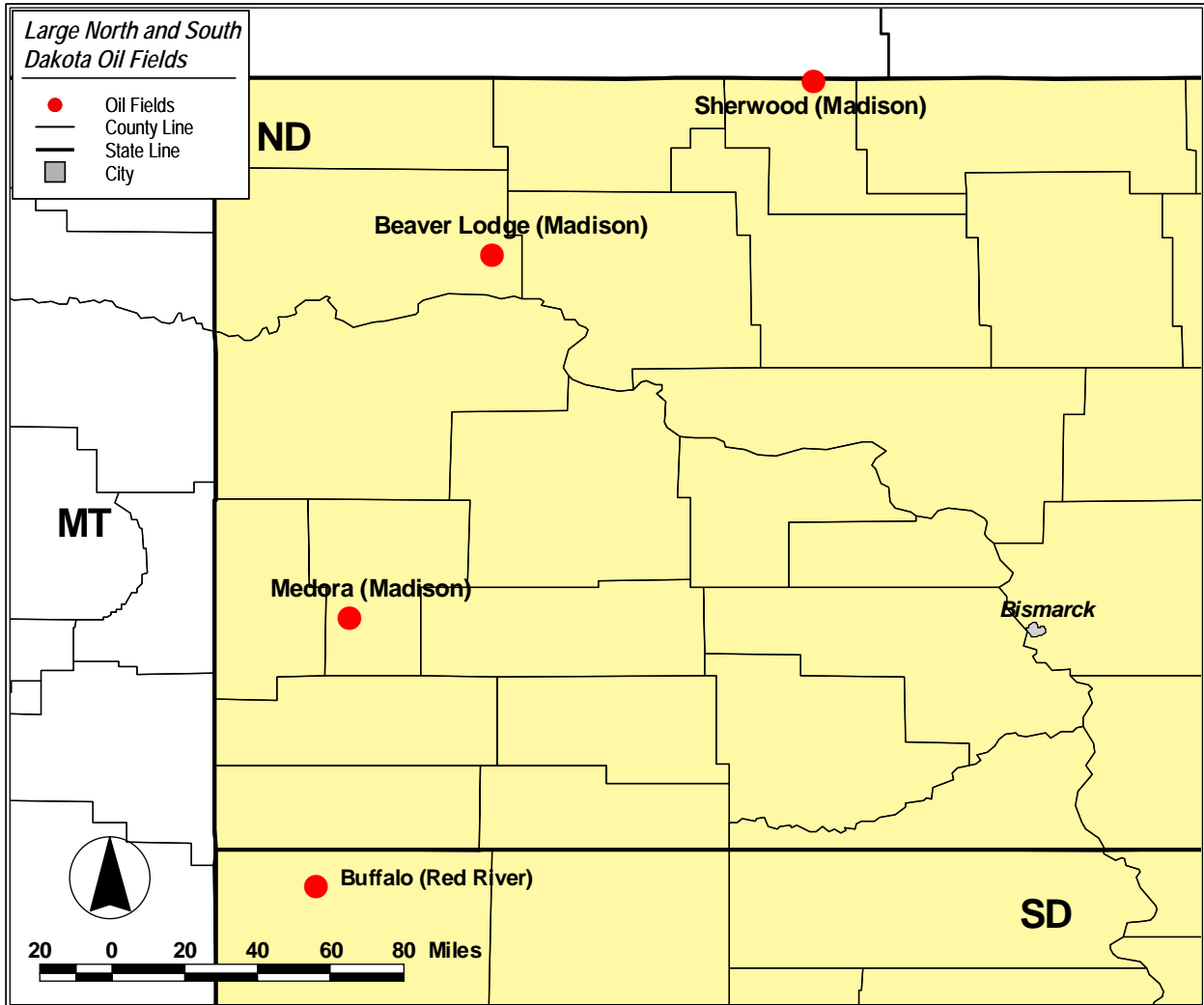
	Annual Oil Production	
	(MMBbls/year)	(MBbls/day)
1999	1	3
2000	1	3
2001	1	3
2002	1	3
2003	1	3
2004	1	4

North Dakota Oil Fields. To better understand the potential of using CO₂-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 CO₂- 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 CO₂-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	Sherwood (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 CO₂-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 CO₂-EOR Projects. A five acre CO₂ 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 CO₂ 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 unproduced. 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 CO₂-WAG injection was conducted. This involved injecting 2,095 tons of CO₂ (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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂-EOR Potential. North and South Dakota contain 35 reservoirs that are candidates for miscible CO₂-EOR. Under “Traditional Practices” (and Base Case financial conditions, defined above), there is only one economically attractive oil reservoir for miscible CO₂ flooding in North and South Dakota. Applying “State-of-the-art Technology” (involving higher volume CO₂ 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	Technical Potential	Economic Potential*	
		(MMBbls)	(MMBbls)	(No. of Reservoirs)	(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; CO₂ costs of \$1.50/Mcf.

Combining "State-of-the-art" technologies with risk mitigation incentives and/or higher oil prices and lower cost CO₂ supplies would enable CO₂-EOR in North and South Dakota to recover 390 million barrels of CO₂-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)	(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; CO₂ supply costs of \$2/Mcf

** CO₂ 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.

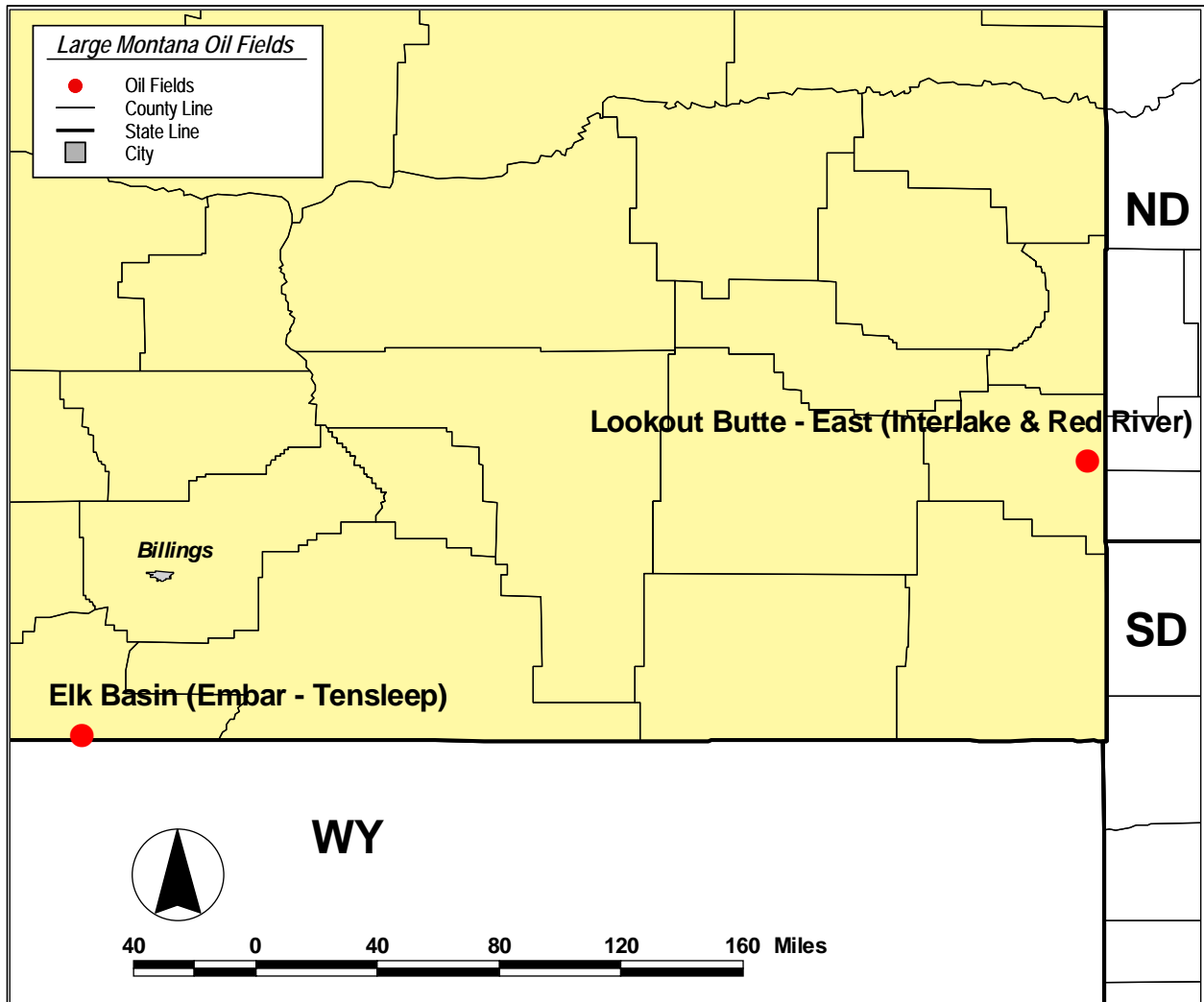
Table 20. Recent History of Montana Onshore Oil Production

	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 CO₂-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	Cumulative Production	Proved Primary/ Secondary Reserves	Remaining Oil In-Place
		(MMBbls)	(MMBbls)	(MMBbls)	(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 CO₂-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 (°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 CO₂ 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 CO₂ flood was then conducted for 62 days during which 48 MMSCF of CO₂ was injected. The CO₂ flood was then followed by a brine flood. Results of the flood were encouraging with the following observations:

- The CO₂ flood behaved very similarly to the water flood in its breakthrough pattern, suggesting that a field with good waterflood conformability should have good CO₂ flood conformability.

- The CO₂ 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 CO₂-EOR has promise in the Montana. However, the lack of a nearby CO₂ sources and low oil prices in the mid - 1980's spelled the end of CO₂-EOR research in the region.

Future CO₂-EOR Potential. Montana contains 19 oil reservoirs that are candidates for miscible CO₂-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, CO₂ 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 CO₂ 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	Technical Potential	Economic Potential	
		(MMBbls)	(MMBbls)	(No. of Reservoirs)	(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; CO₂ supply costs of \$2/Mcf

***CO₂ supply costs of \$0.80/Mcf

Appendix A

Using *CO₂-PROPHET* for Estimating Oil Recovery

Model Development

The study utilized the *CO₂-PROPHET* model to calculate the incremental oil produced by CO₂-EOR from the large Williston Basin oil reservoirs. *CO₂-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 CO₂ Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir” (DOE Contract No. DE-FC22-93BC14960). *CO₂-PROPHET* was developed as an alternative to the DOE’s CO₂ miscible flood predictive model, *CO₂PM*.

Input Data Requirements

The input reservoir data for operating *CO₂-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, CO₂ and oil are provided (or can be modified) to ensure proper operation of the model.

Calibrating CO₂-PROPHET

The *CO₂-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 *CO₂-PROPHET* might influence the calculation of oil recovery. *CO₂-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 CO₂-EOR model using one hydrocarbon pore volume of CO₂ injection.

The initial comparison of *CO₂-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 *CO₂-PROPHET* output is bounded by the two *GEM* reservoir simulation cases of alternative reservoir permeability structures in an oil reservoir.

A second comparison of *CO₂-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 *CO₂-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 *CO₂-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, *CO₂-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 *CO₂-PROPHET* and *CO₂PM*

According to the *CO₂-PROPHET* developers, the model performs two main operations that provide a more robust calculation of oil recovery than available from *CO₂PM*:

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

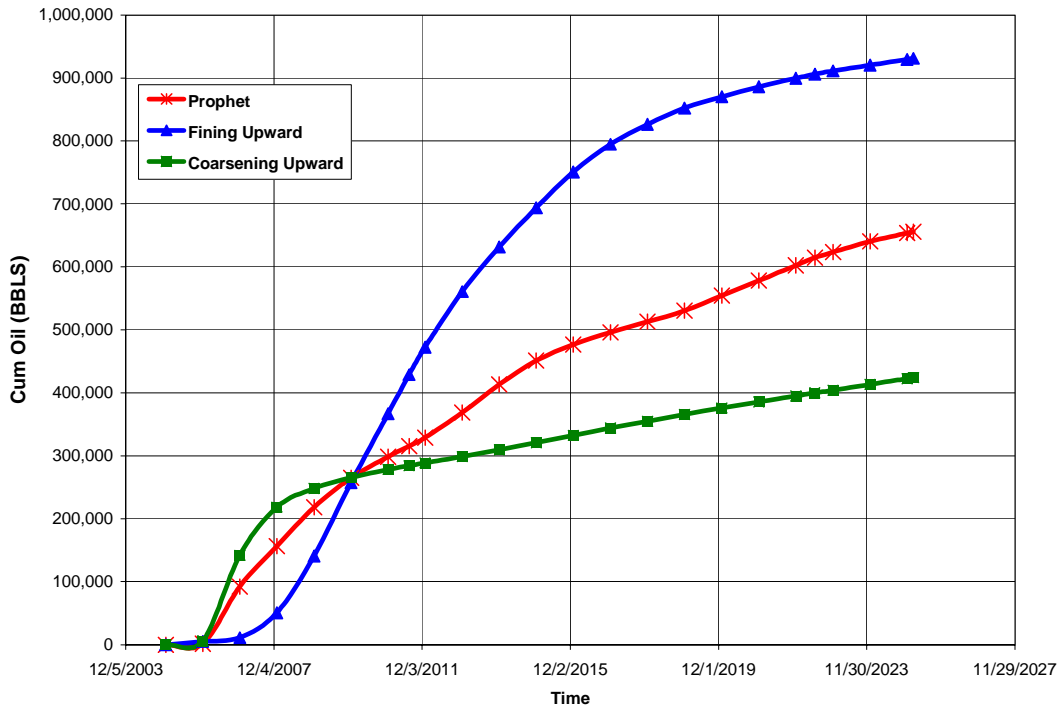
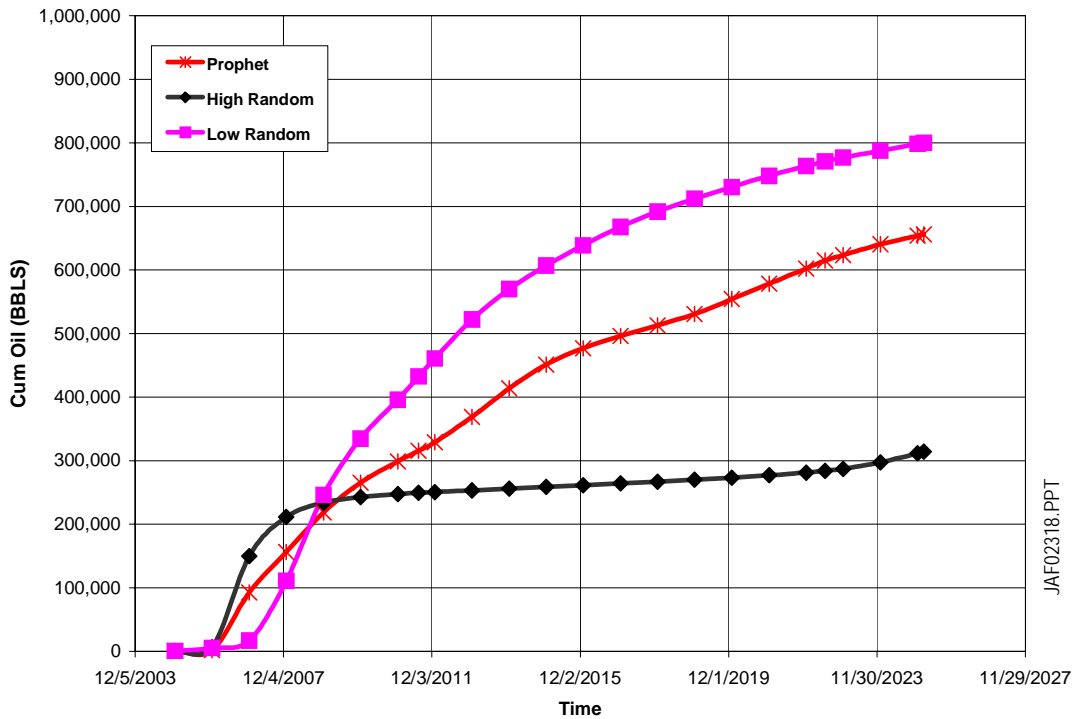


Figure A-2. *CO2-PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



JAF02318.PPT

- *CO₂-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 *CO₂-PROPHET* and its comparison with the technical capability of *CO₂PM* are also set forth below:

- Areal sweep efficiency in *CO₂-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 *CO₂PM*.
- Mixing parameters, as defined by Todd and Longstaff, are used in *CO₂-PROPHET* for simulation of the miscible CO₂ process, particularly CO₂/oil mixing and the viscous fingering of CO₂.
- A series of reservoir patterns, including 5 spot, line drive, and inverted 9 spot, among others, are available in *CO₂-PROPHET*, expanding on the 5 spot only reservoir pattern option available in *CO₂PM*.
- *CO₂-PROPHET* can simulate a variety of recovery processes, including continuous miscible CO₂, WAG miscible CO₂ and immiscible CO₂, as well as waterflooding. *CO₂PM* is limited to miscible CO₂.

Appendix B

North Dakota CO₂-EOR Cost Model

Cost Model for CO₂-Based Enhanced Oil Recovery (CO₂-EOR)

This appendix provides documentation for the cost module of the desktop CO₂-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 CO₂-EOR project:

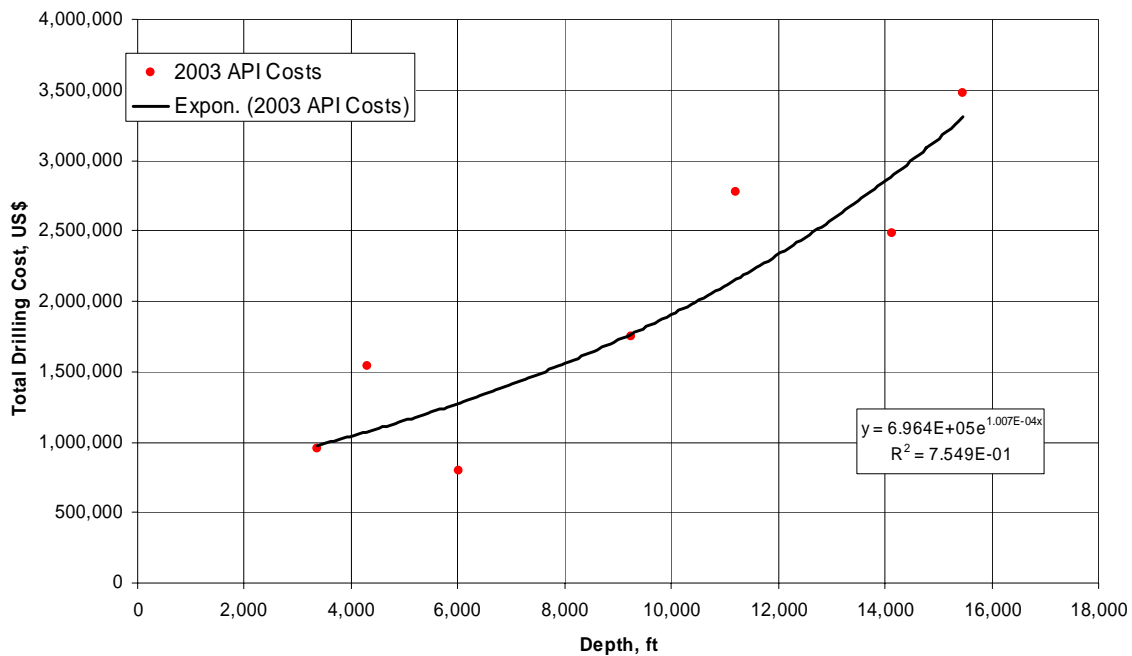
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for North Dakota.

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:

$$\begin{aligned} \text{Well D\&C Costs} &= a_0 D^{a_1} \\ \text{Where: } a_0 &\text{ is } 6.96 \times 10^5 \\ a_1 &\text{ is } 1.04 \\ D &\text{ is well depth} \end{aligned}$$

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:

$$\text{Drilling costs (per foot)} = \$5.04(\text{annual oil price}) - \$3.2116.$$

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. 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:

$$\text{Production Well Equipping Costs} = c_0 + c_1D$$

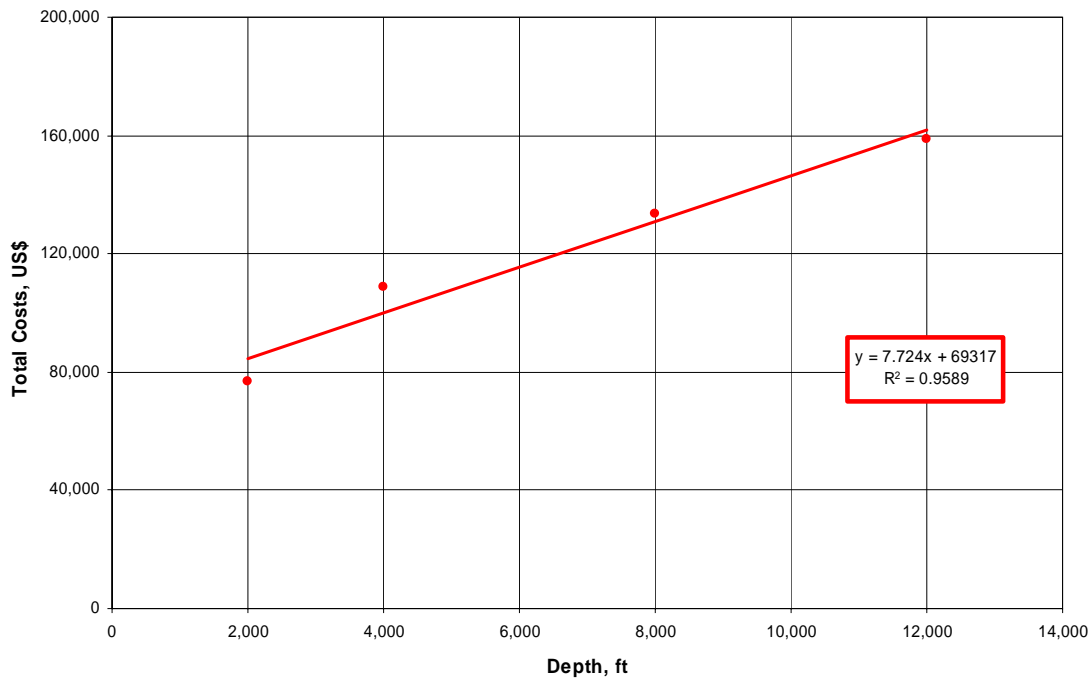
Where: $c_0 = \$69,317$ (fixed)

$c_1 = \$7.724$ 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. Lease Equipment Costs for New Injection Wells. 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:

$$\text{Injection Well Equipping Costs} = c_0 + c_1D$$

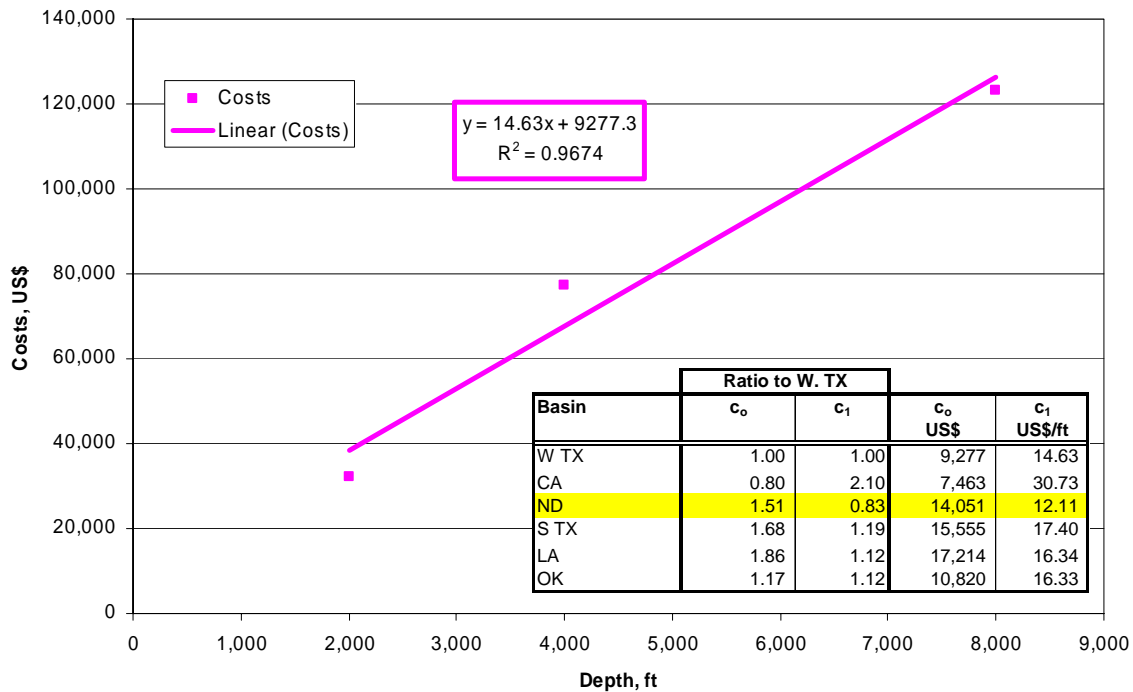
Where: $c_0 = \$14,051$ (fixed)

$c_1 = \$12.11$ 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



4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO₂ 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.

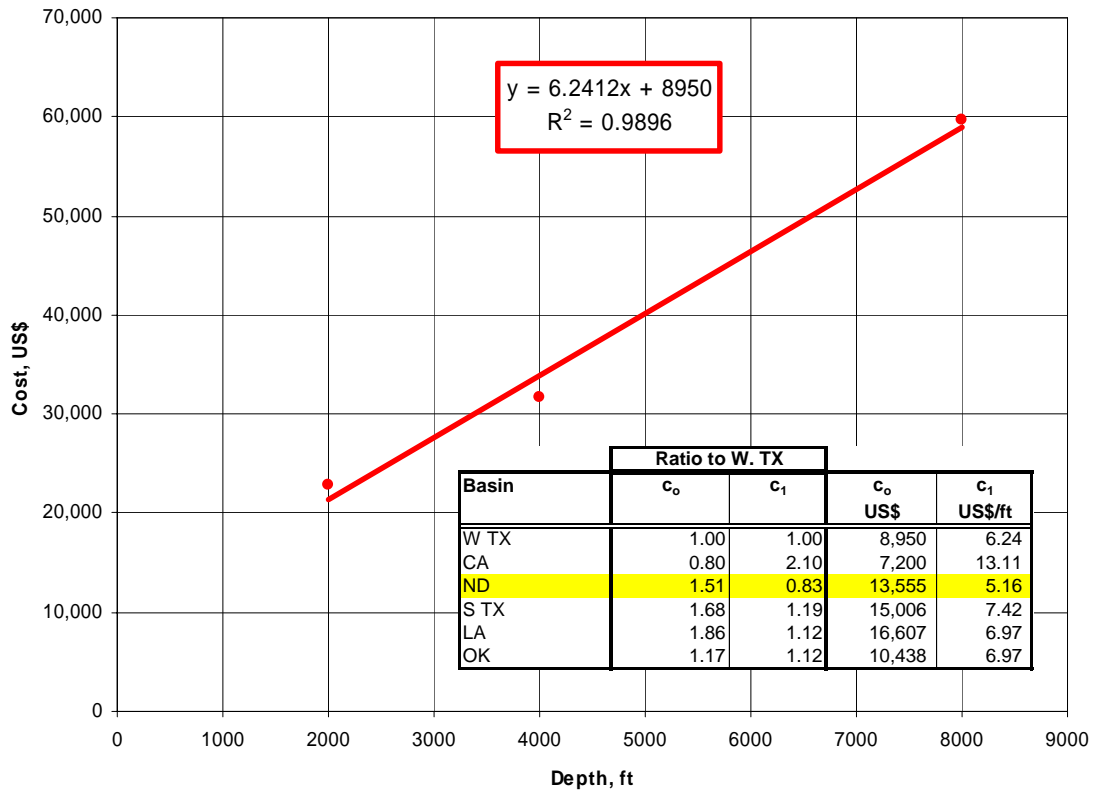
The existing well conversion costs include a fixed cost component and a depth-related cost component, which varies based on the required surface pressure and tubing length. The equation for North Dakota is:

$$\text{Well Conversion Costs} = c_0 + c_1 D$$

Where: c₀ = \$13,555 (fixed)
 c₁ = \$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



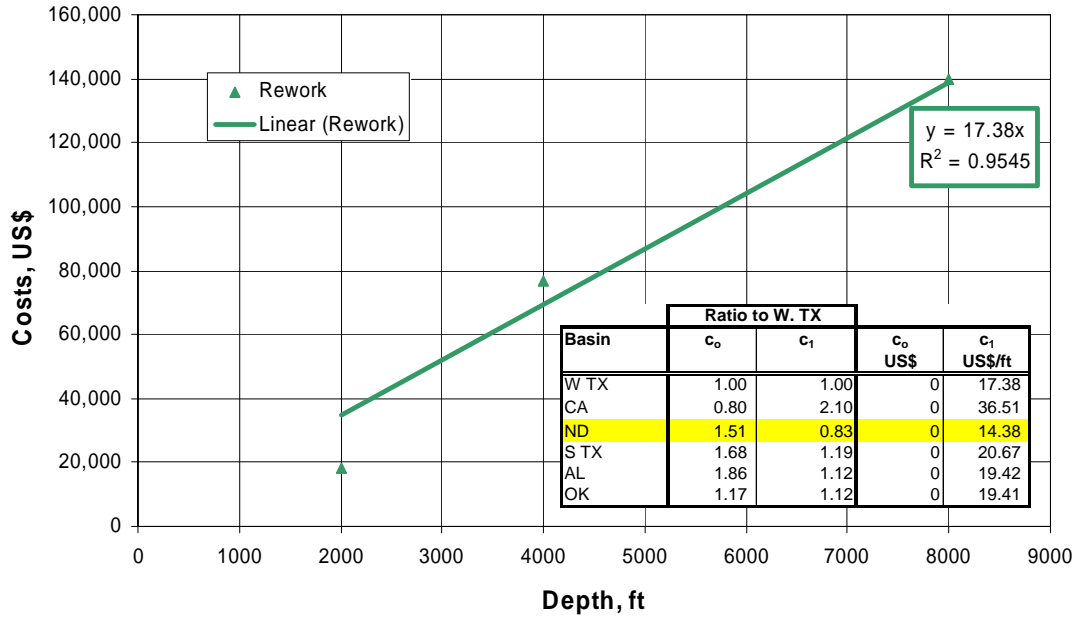
5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO₂-EOR (First Rework). The reworking of existing oil production or CO₂-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for North Dakota is:

$$\text{Well Rework Costs} = c_1 D$$

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 CO₂-EOR in West Texas vs. Depth



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

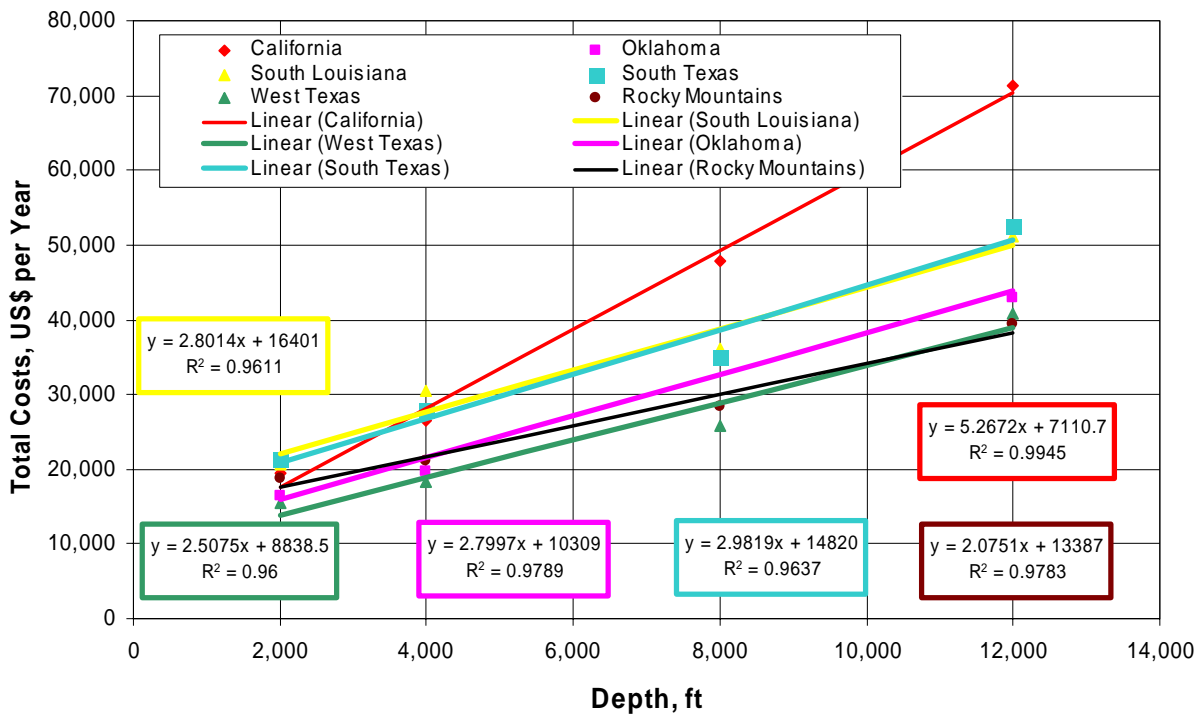


Table B-1. Regional Lease O&M Costs and Their Relationship to West Texas

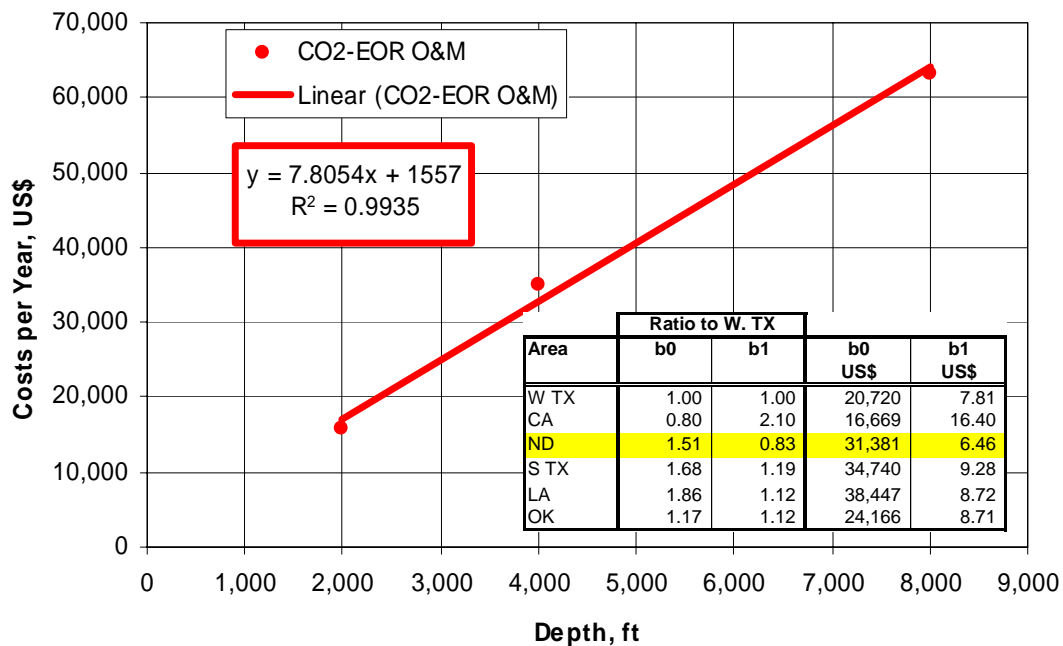
Basin	c ₀ US\$	c ₁ US\$/ft	Ratio to W. TX	
			c ₀	c ₁
West Texas	8,839	2.508	1.00	1.00
California	7,111	5.267	0.80	2.10
North Dakota	13,387	2.075	1.51	0.83
South Texas	14,820	2.982	1.68	1.19
Louisiana	16,401	2.801	1.86	1.12
Oklahoma	10,309	2.800	1.17	1.12

To account for the O&M cost differences between waterflooding and CO₂-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 CO₂-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 CO₂-EOR. (Liquid lifting costs for CO₂-EOR are discussed in a later section of this appendix.)

Figure B-7 shows the depth-relationship for CO₂-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 CO₂-EOR O&M Costs for West Texas



7. CO₂ Recycle Plant Investment Cost. Operation of CO₂-EOR requires a recycling plant to capture and reinject the produced CO₂. The size of the recycle plant is based on peak CO₂ production and recycling requirements.

The cost of the recycling plant is set at \$700,000 per MMcf/d of CO₂ capacity. As such, small CO₂-EOR project in the Madison formation of the Rival field, with 24 MMcf/d of CO₂ reinjection, will require a recycling plant costing \$16 million. A large project in the Big Stick field, with 104 MMcf/d of peak CO₂ reinjection and 104 injectors requires a recycling plant costing \$73million.

The model has three options for installing a CO₂ recycling plant. The default setting costs the entire plant one year prior to CO₂ breakthrough. The second option places the full CO₂ recycle plant cost at the beginning of the project (Year 0). The third option installs the CO₂ recycle plant in stages. In this case, half the plant is built (and half the

cost is incurred) in the year of CO₂ breakthrough. The second half of the plant is built when maximum recycle capacity requirements are reached.

8. Other COTWO Model Costs.

a. CO₂ Recycle O&M Costs. The O&M costs of CO₂ 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. CO₂ Distribution Costs. The CO₂ distribution system is similar to the gathering systems used for natural gas. A distribution “hub” is constructed with smaller pipelines delivering purchased CO₂ 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 CO₂ injection requirements. These range from \$80,000 per mile for 4” pipe (CO₂ rate less than 15MMcf/d), \$120,000 per mile for 6” pipe (CO₂ rate of 15 to 35 MMcf/d), \$160,000 per mile for 8” pipe (CO₂ rate of 35 to 60 MMcf/d), and \$200,000 per mile for pipe greater than 8” diameter (CO₂ rate greater than 60 MMcf/d). Aside from the injection volume, cost also depends on the distance from the CO₂ “hub” (transfer point) to the oil field. Currently, the distance is set at 10 miles.

The CO₂ distribution cost equation for North Dakota is:

$$\text{Pipeline Construction Costs} = \$150,000 + C_D * \text{Distance}$$

Where: C_D is the cost per mile of the necessary pipe diameter (from the CO₂ injection rate)

$$\text{Distance} = 10.0 \text{ miles}$$

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 °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for North Dakota is:

$$\text{Wellhead Oil Price} = \text{Oil Price} + (-\$2.00) - [\$0.25*(40 - \text{°API})]$$

Where: Oil Price is the marker oil price (West Texas intermediate)
°API is oil gravity

If the oil gravity is less than 40 °API, the wellhead oil price is reduced; if the oil gravity is greater than 40 °API, the wellhead oil price is increased. In addition, some fields within 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 CO₂-EOR Cost Model

Cost Model for CO₂-Based Enhanced Oil Recovery (CO₂-EOR)

This appendix provides documentation for the cost module of the desktop CO₂-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 CO₂-EOR project:

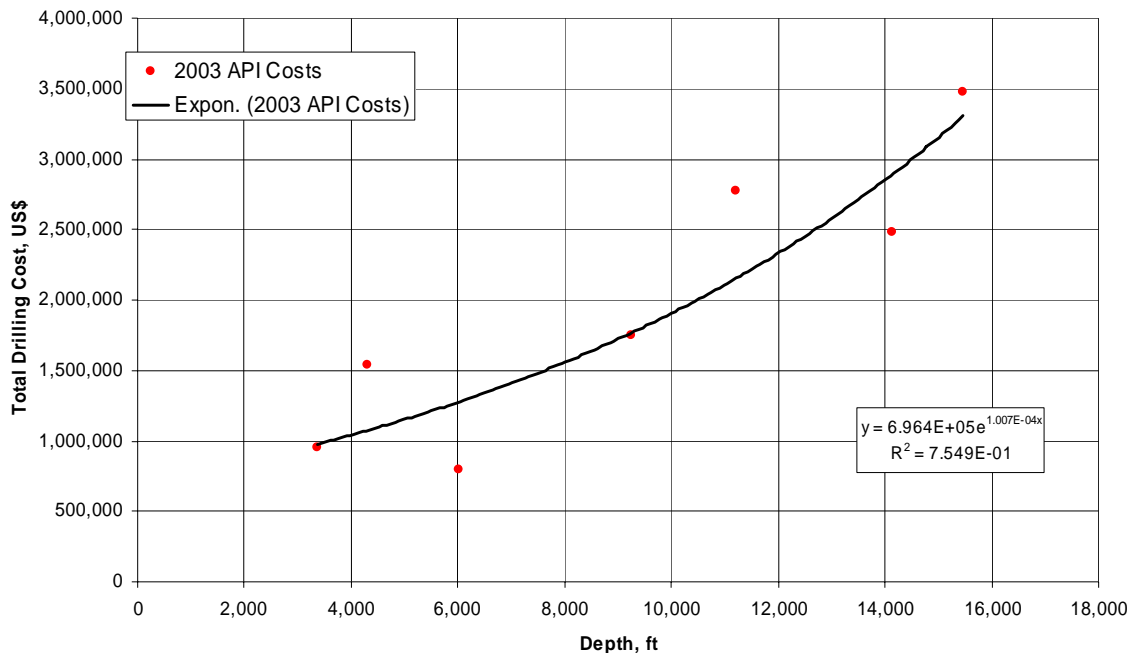
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for North Dakota where more drilling data are available.

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:

$$\begin{aligned} \text{Well D\&C Costs} &= a_0 D^{a_1} \\ \text{Where: } a_0 &\text{ is } 6.96 \times 10^5 \\ a_1 &\text{ is } 1.04 \\ D &\text{ is well depth} \end{aligned}$$

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



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:

$$\text{Drilling costs (per foot)} = \$5.04(\text{annual oil price}) - \$3.2116.$$

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. 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:

$$\text{Production Well Equipping Costs} = c_0 + c_1D$$

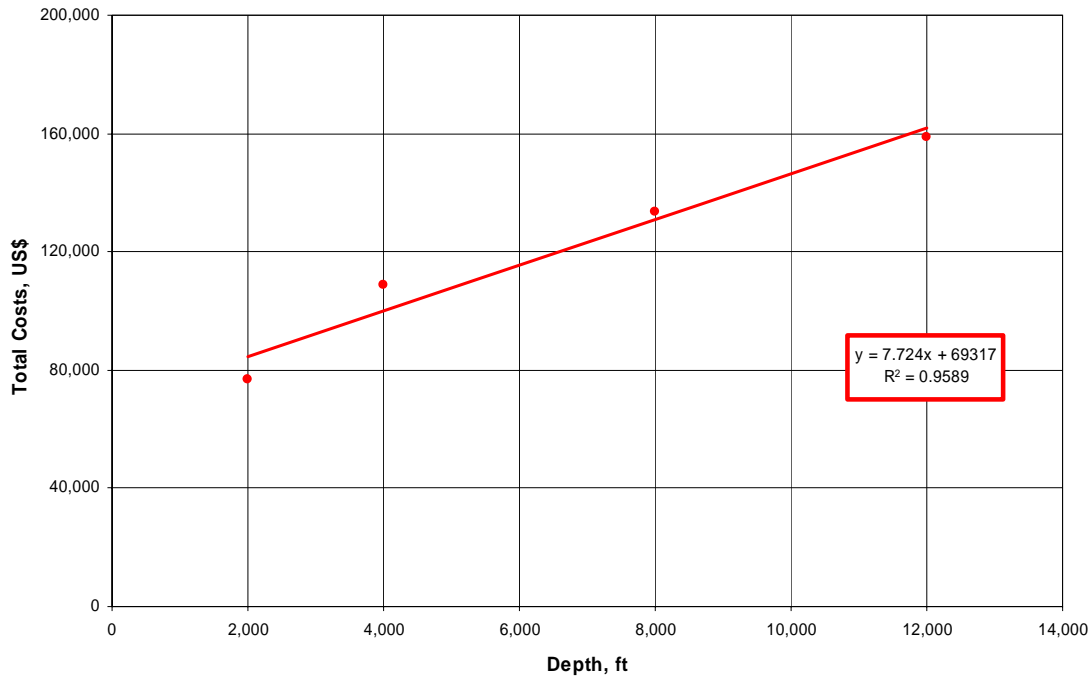
Where: $c_0 = \$69,317$ (fixed)

$c_1 = \$7.724$ 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:

$$\text{Injection Well Equipping Costs} = c_0 + c_1D$$

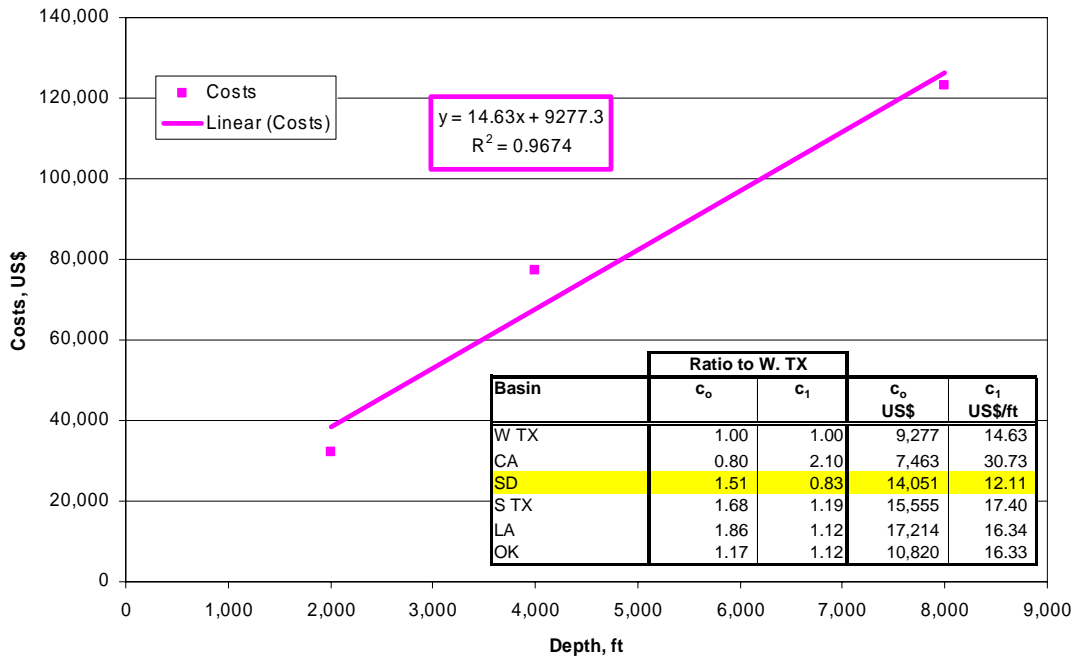
Where: $c_0 = \$14,051$ (fixed)

$c_1 = \$12.11$ 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



4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO₂ 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:

$$\text{Well Conversion Costs} = c_0 + c_1D$$

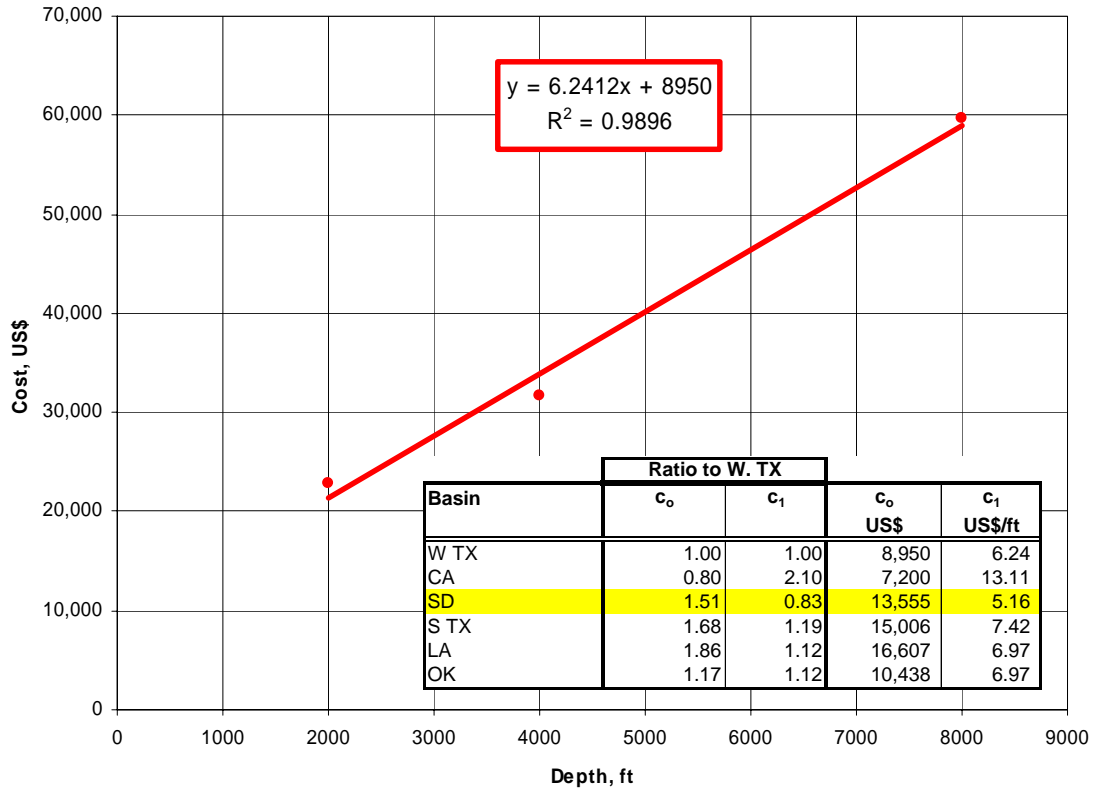
Where: c₀ = \$13,555 (fixed)

c₁ = \$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



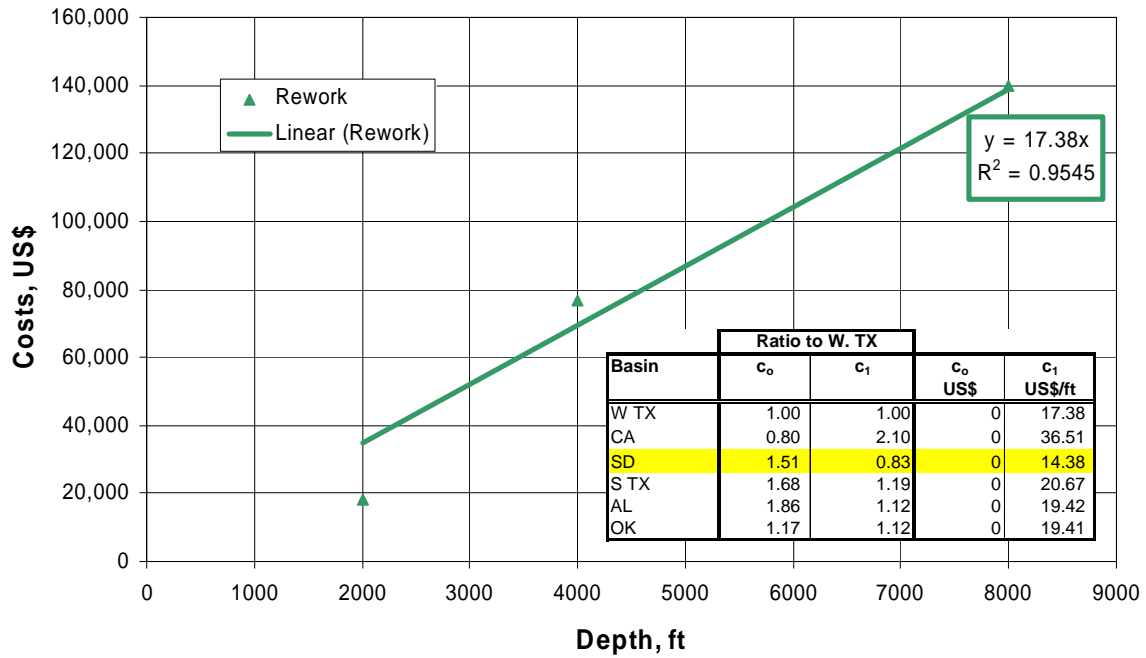
5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO₂-EOR (First Rework). The reworking of existing oil production or CO₂-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for South Dakota is:

$$\text{Well Rework Costs} = c_1 D$$

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 CO₂-EOR in West Texas vs. Depth



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

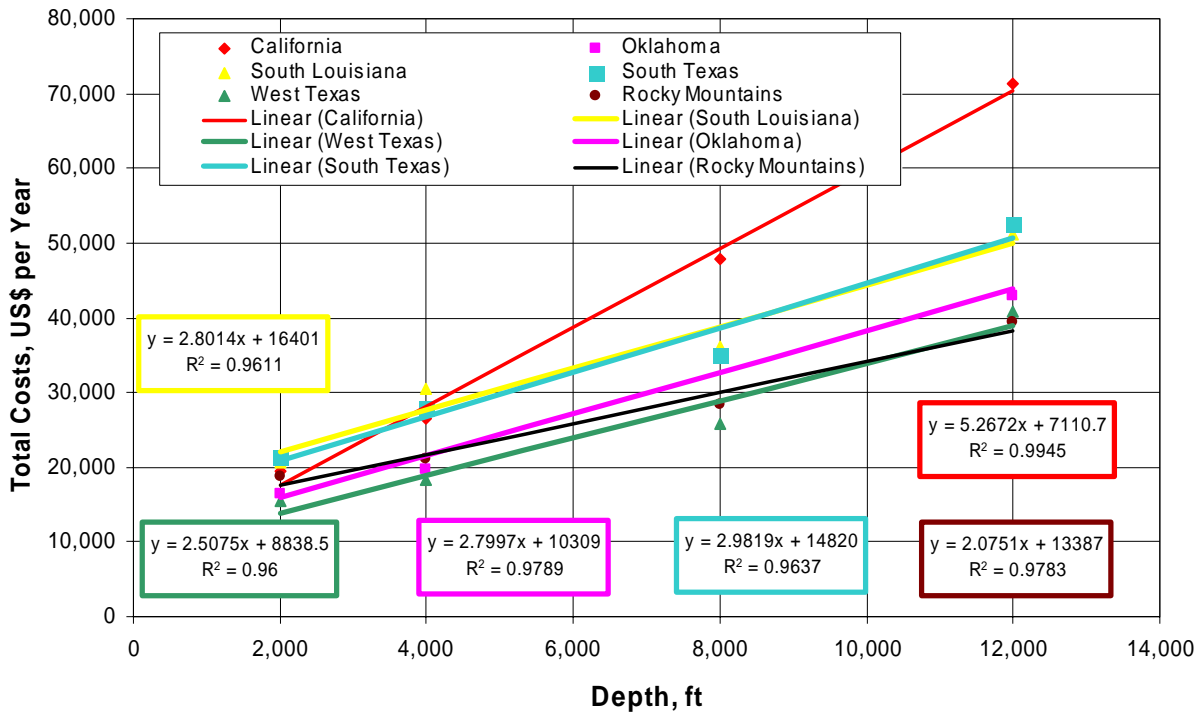


Table C-1. Regional Lease O&M Costs and Their Relationship to West Texas

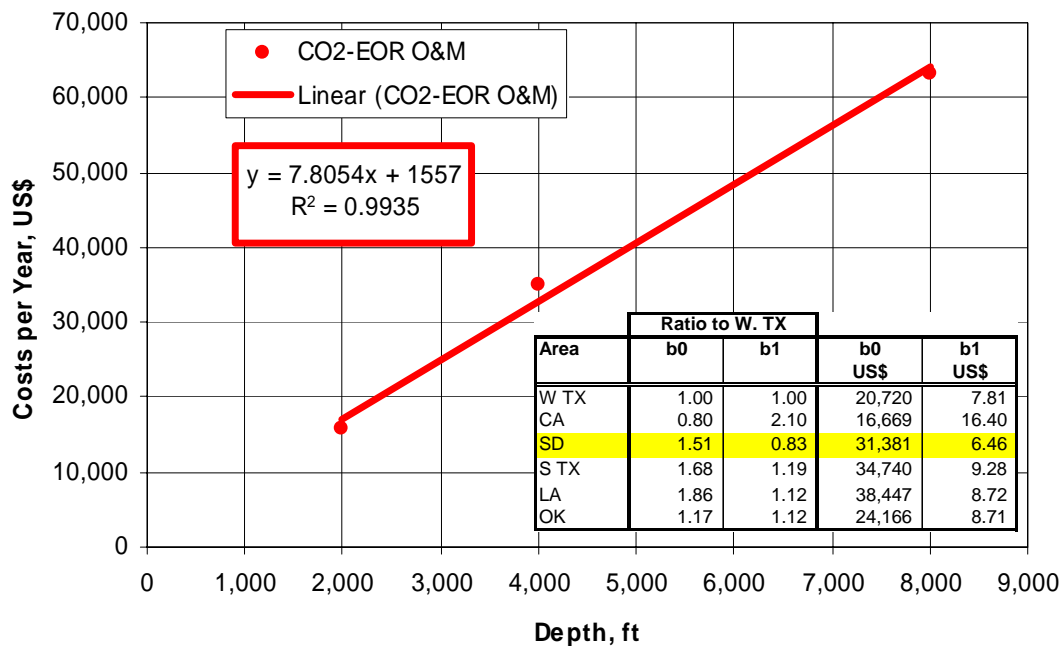
Basin	C ₀		Ratio to W. TX	
	US\$	US\$	C ₀	C ₁
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
South Dakota	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

To account for the O&M cost differences between waterflooding and CO₂-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 CO₂-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 CO₂-EOR. (Liquid lifting costs for CO₂-EOR are discussed in a later section of this appendix.)

Figure C-7 shows the depth-relationship for CO₂-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 CO₂-EOR O&M Costs for West Texas



7. CO₂ Recycle Plant Investment Cost. Operation of CO₂-EOR requires a recycling plant to capture and reinject the produced CO₂. The size of the recycle plant is based on peak CO₂ production and recycling requirements. The cost of the recycling plant is set at \$700,000 per MMcf/d of CO₂ capacity. As such, a project in the Buffalo field, with 21 MMcf/d of peak CO₂ reinjection requires a recycling plant costing \$15 million.

The model has three options for installing a CO₂ recycling plant. The default setting costs the entire plant one year prior to CO₂ breakthrough. The second option places the full CO₂ recycle plant cost at the beginning of the project (Year 0). The third option installs the CO₂ recycle plant in stages. In this case, half the plant is built (and half the cost is incurred) in the year of CO₂ breakthrough. The second half of the plant is built when maximum recycle capacity requirements are reached.

8. Other COTWO Model Costs.

- a. CO₂ Recycle O&M Costs. The O&M costs of CO₂ 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. CO₂ Distribution Costs. The CO₂ distribution system is similar to the gathering systems used for natural gas. A distribution “hub” is constructed with smaller pipelines delivering purchased CO₂ 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 CO₂ injection requirements. These range from \$80,000 per mile for 4” pipe (CO₂ rate less than 15MMcf/d), \$120,000 per mile for 6” pipe (CO₂ rate of 15 to 35 MMcf/d), \$160,000 per mile for 8” pipe (CO₂ rate of 35 to 60 MMcf/d), and \$200,000 per mile for pipe greater than 8” diameter (CO₂ rate greater than 60 MMcf/d). Aside from the injection volume, cost also depends on the distance from the CO₂ “hub” (transfer point) to the oil field. Currently, the distance is set at 10 miles.

The CO₂ distribution cost equation for South Dakota is:

$$\text{Pipeline Construction Costs} = \$150,000 + C_D * \text{Distance}$$

Where: C_D is the cost per mile of the necessary pipe diameter (from the CO₂ 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. South Dakota charges a 4.5% severance tax on oil production. The severance tax is taken off after the royalties are charged.
- 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 South Dakota (-\$2.00 per barrel) and the current gravity differential (-\$0.25 per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for South Dakota is:

$$\text{Wellhead Oil Price} = \text{Oil Price} + (-\$2.00) - [\$0.25 * (40 - \text{°API})]$$

Where: Oil Price is the marker oil price (West Texas intermediate)
 °API is oil gravity

If the oil gravity is less than 40 °API, the wellhead oil price is reduced; if the oil gravity is greater than 40 °API, the wellhead oil price is increased. In addition, some fields within 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 CO₂-EOR Cost Model

Cost Model for CO₂-Based Enhanced Oil Recovery (CO₂-EOR)

This appendix provides documentation for the cost module of the desktop CO₂-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 CO₂-EOR project:

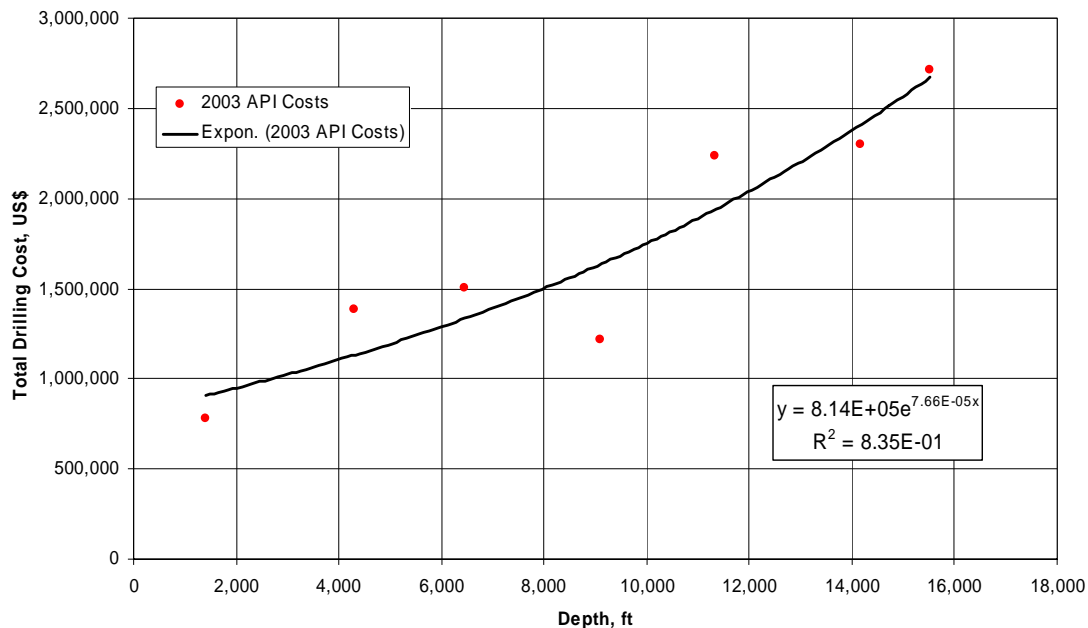
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for Montana.

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:

$$\begin{aligned} \text{Well D\&C Costs} &= a_0 D^{a_1} \\ \text{Where: } a_0 &\text{ is } 8.14 \times 10^5 \\ a_1 &\text{ is } 7.66 \times 10^{-5} \\ D &\text{ is well depth} \end{aligned}$$

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:

$$\text{Drilling costs (per foot)} = \$5.04(\text{annual oil price}) - \$3.2116.$$

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:

$$\text{Production Well Equipping Costs} = c_0 + c_1D$$

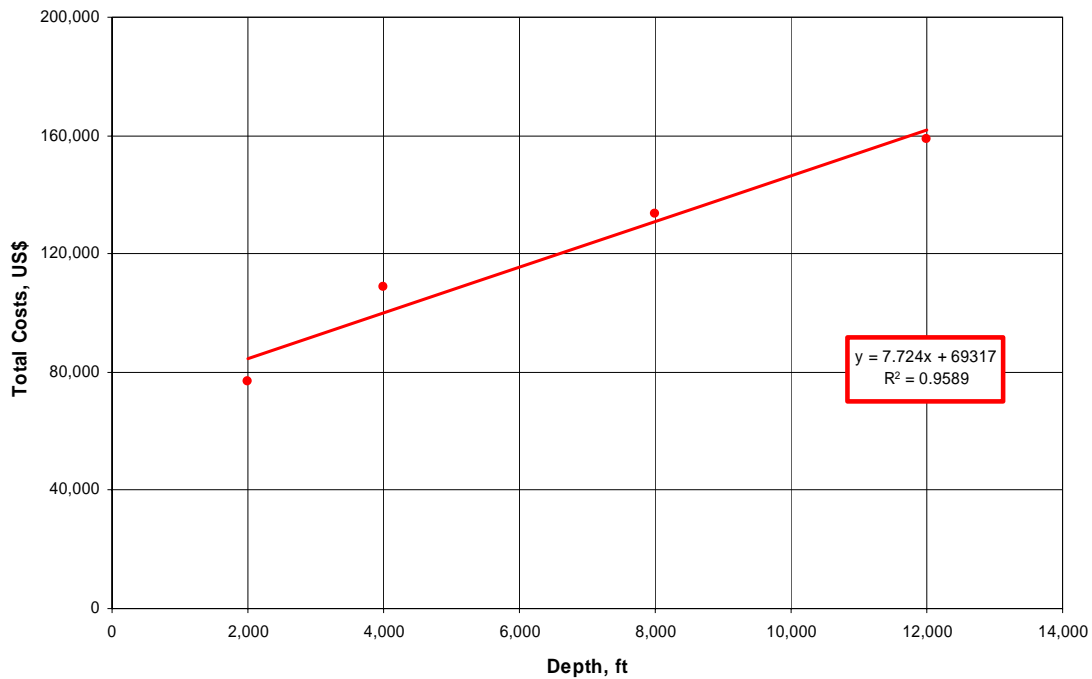
Where: $c_0 = \$69,317$ (fixed)

$c_1 = \$7.724$ 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:

$$\text{Injection Well Equipping Costs} = c_0 + c_1D$$

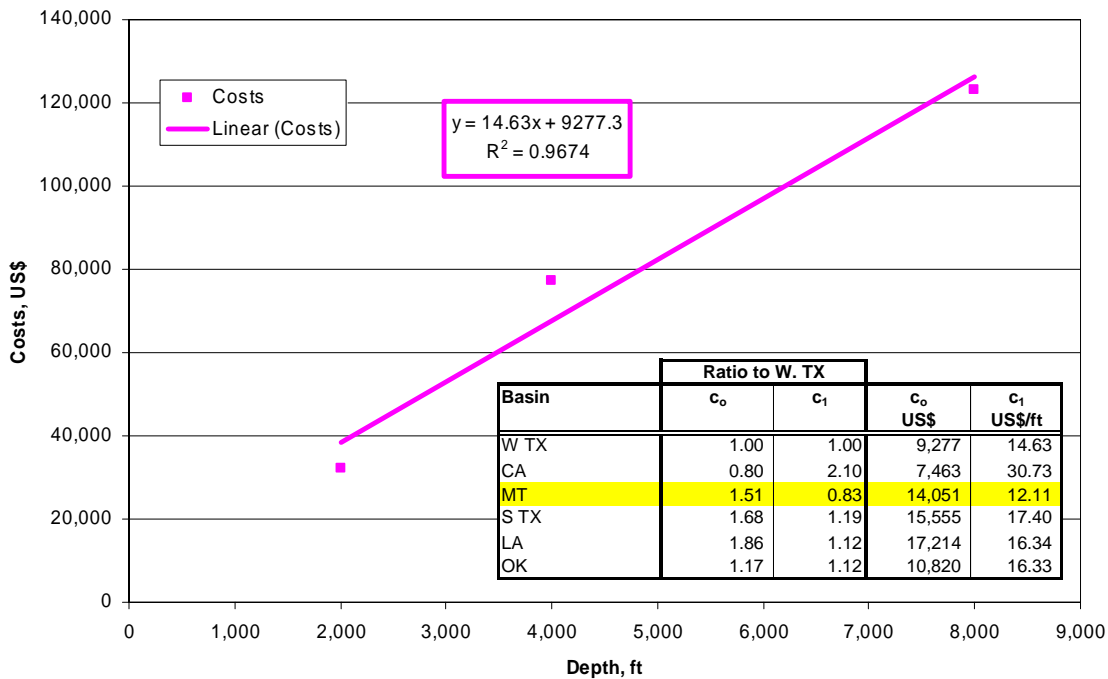
Where: $c_0 = \$14,051$ (fixed)

$c_1 = \$12.11$ 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



4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO₂ 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.

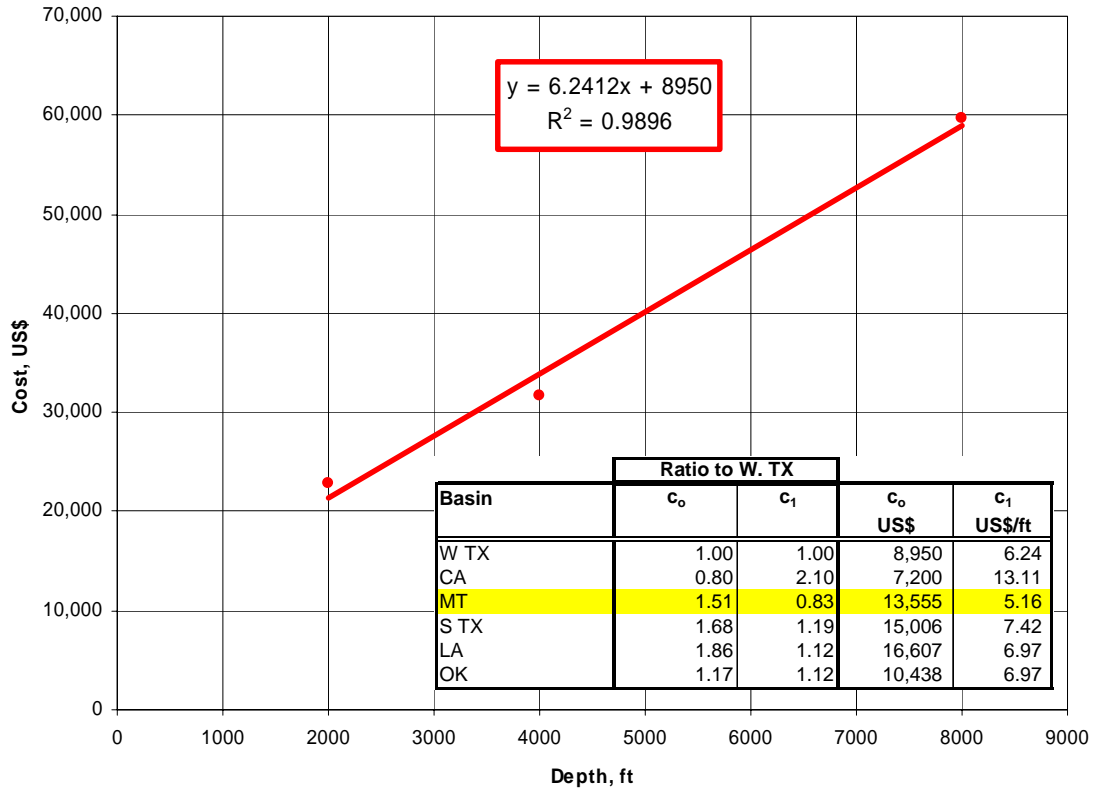
The existing well conversion costs include a fixed cost component and a depth-related cost component, which varies based on the required surface pressure and tubing length. The equation for Montana is:

$$\text{Well Conversion Costs} = c_0 + c_1 D$$

Where: c₀ = \$13,555 (fixed)
 c₁ = \$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



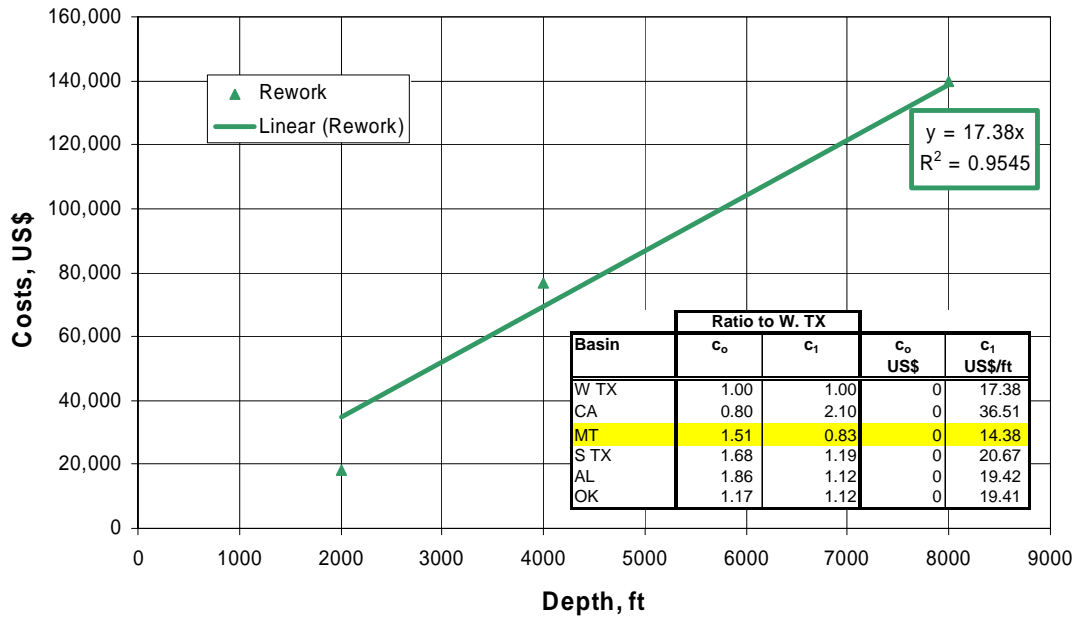
5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO₂-EOR (First Rework). The reworking of existing oil production or CO₂-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for Montana is:

$$\text{Well Rework Costs} = c_1 D$$

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 CO₂-EOR in West Texas vs. Depth



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 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

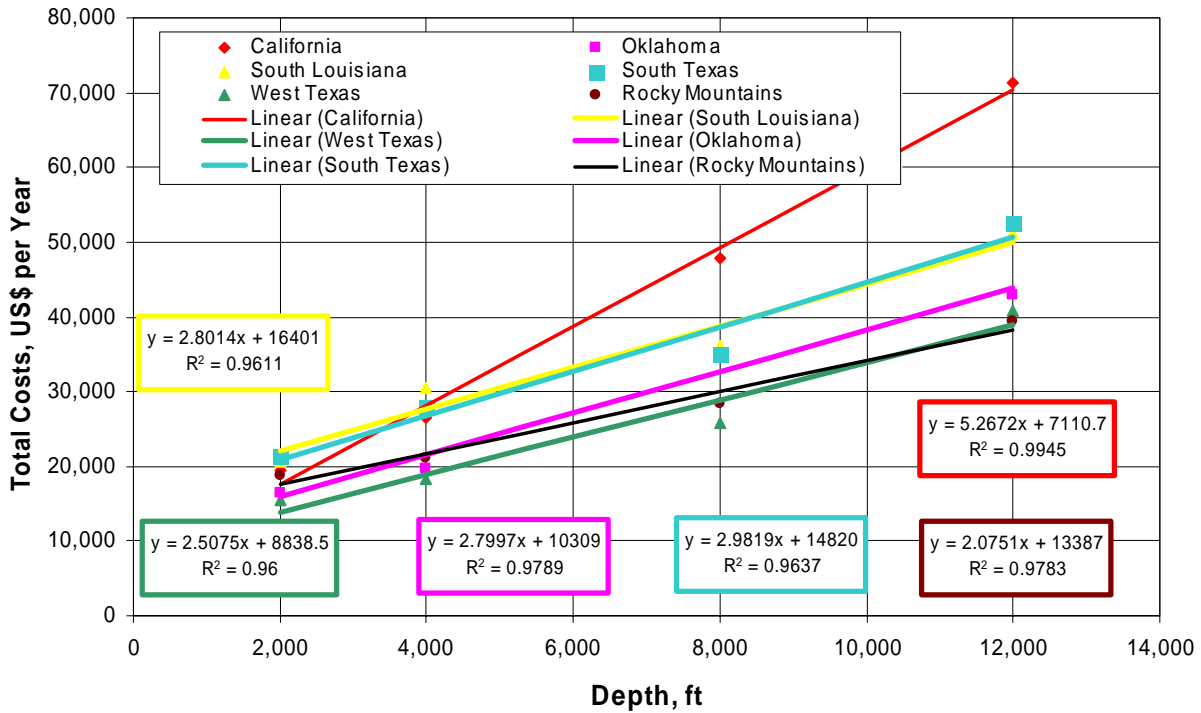


Table D-1. Regional Lease O&M Costs and Their Relationship to West Texas

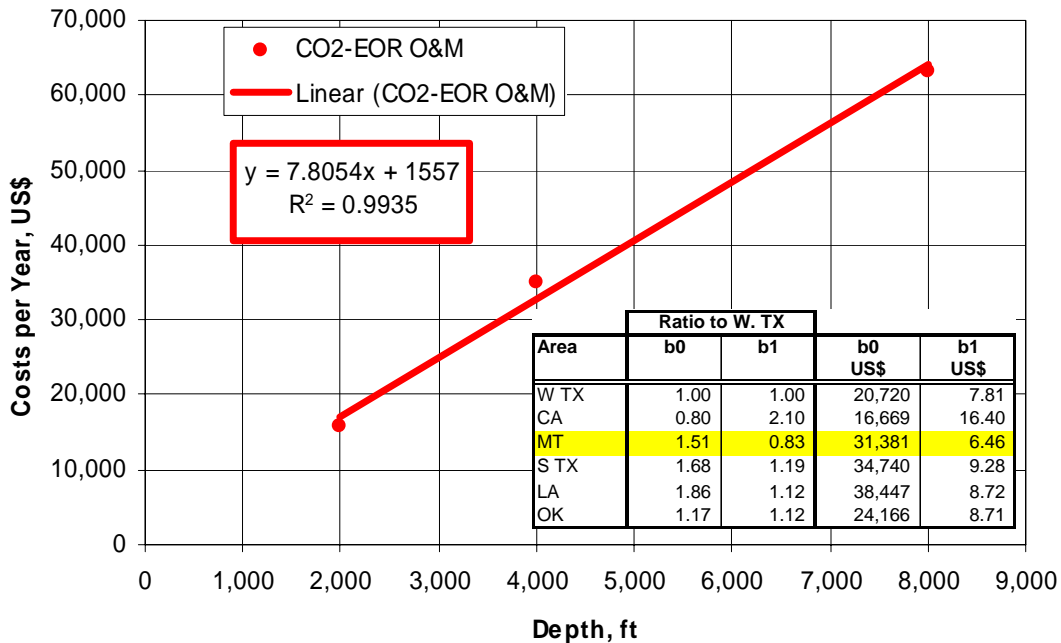
Basin	C ₀ US\$	C ₁ US\$	Ratio to W. TX	
			C ₀	C ₁
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Montana	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

To account for the O&M cost differences between waterflooding and CO₂-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 CO₂-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 CO₂-EOR. (Liquid lifting costs for CO₂-EOR are discussed in a later section of this appendix.)

Figure D-7 shows the depth-relationship for CO₂-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 CO₂-EOR O&M Costs for West Texas



7. CO₂ Recycle Plant Investment Cost. Operation of CO₂-EOR requires a recycling plant to capture and reinject the produced CO₂. The size of the recycle plant is based on peak CO₂ production and recycling requirements. The cost of the recycling plant is set at \$700,000 per MMcf/d of CO₂ capacity. As such, a project in the Pine field, with 155 MMcf/d of peak CO₂ reinjection and 935 injection wells requires a recycling plant costing \$110 million.

The model has three options for installing a CO₂ recycling plant. The default setting costs the entire plant one year prior to CO₂ breakthrough. The second option places the full CO₂ recycle plant cost at the beginning of the project (Year 0). The third option installs the CO₂ recycle plant in stages. In this case, half the plant is built (and half the cost is incurred) in the year of CO₂ breakthrough. The second half of the plant is built when maximum recycle capacity requirements are reached.

8. Other COTWO Model Costs.

a. CO₂ Recycle O&M Costs. The O&M costs of CO₂ 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. CO₂ Distribution Costs. The CO₂ distribution system is similar to the gathering systems used for natural gas. A distribution “hub” is constructed with smaller pipelines delivering purchased CO₂ 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 CO₂ injection requirements. These range from \$80,000 per mile for 4” pipe (CO₂ rate less than 15MMcf/d), \$120,000 per mile for 6” pipe (CO₂ rate of 15 to 35 MMcf/d), \$160,000 per mile for 8” pipe (CO₂ rate of 35 to 60 MMcf/d), and \$200,000 per mile for pipe greater than 8” diameter (CO₂ rate greater than 60 MMcf/d). Aside from the injection volume, cost also depends on the distance from the CO₂ “hub” (transfer point) to the oil field. Currently, the distance is set at 10 miles.

The CO₂ distribution cost equation for Montana is:

$$\text{Pipeline Construction Costs} = \$150,000 + C_D * \text{Distance}$$

Where: C_D is the cost per mile of the necessary pipe diameter (from the CO₂ 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 valorem 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 °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for Montanais:

$$\text{Wellhead Oil Price} = \text{Oil Price} + (-\$2.00) - [\$0.25 * (40 - \text{°API})]$$

Where: Oil Price is the marker oil price (West Texas intermediate)
°API is oil gravity

If the oil gravity is less than 40 °API, the wellhead oil price is reduced; if the oil gravity is greater than 40 °API, the wellhead oil price is increased. In addition, some fields within 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.