BASIN ORIENTED STRATEGIES FOR CO_2 ENHANCED OIL RECOVERY:

OFFSHORE LOUISIANA

Prepared for:

U.S. Department of Energy

Office of Fossil Energy – Office of Oil and Natural Gas

Prepared by:

Advanced Resources International, Inc.

March 2005

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TABLE OF CONTENTS

EXECUTIVE SUMMARY EX-1

1. SUPPLY SITUATION IN THE LOUISIANA OFFSHORE 2
   - 1.1 OVERVIEW OF STATE OF LOUISIANA OFFSHORE OIL AND GAS DEVELOPMENT 5
     - 1.1.1 Status of Oil Production 6
     - 1.1.2 Status of Natural Gas Production 6
   - 1.2 OVERVIEW OF FEDERAL SHALLOW WATER (SHELF) OIL AND GAS DEVELOPMENT 8
     - 1.2.1 Status of Oil Production 9
     - 1.2.2 Status of Natural Gas Production 9
   - 1.3 LOUISIANA/TEXAS OCS SLOPE 13
   - 1.4 ECONOMIC BENEFITS OF OIL AND GAS PRODUCTION IN THE LOUISIANA OFFSHORE 14

2. STUDY METHODOLOGY 15
   - 2.1 ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE 15
   - 2.2 SCREENING RESERVOIRS FOR CO2-EOR 17
   - 2.3 CALCULATING MINIMUM MISCIBILITY PRESSURE 17
   - 2.4 ESTIMATING OIL RECOVERY POTENTIAL 23
   - 2.5 DEVELOPING THE COST MODEL 24
   - 2.6 CONSTRUCTING THE ECONOMICS MODEL 24
   - 2.7 PERFORMING SCENARIO ANALYSES 25

3. RECOVERY POTENTIAL OF STRANDED OIL RESOURCES IN THE LOUISIANA OFFSHORE 27
   - 3.1 TECHNICAL RECOVERY POTENTIAL 27
   - 3.2 ECONOMIC RECOVERY POTENTIAL 29
   - 3.3 POTENTIAL ECONOMIC BENEFITS FROM INCREMENTAL SUPPLIES 31

4. CONCLUSIONS 33

REFERENCES 35

APPENDIX A USING CO2-PROPHET FOR ESTIMATING OIL RECOVERY A-1

APPENDIX B OFFSHORE LOUISIANA CO2-EOR COST MODEL B-1

LIST OF FIGURES

Figure 1-1	Central Planning Area, Gulf of Mexico, Outer Continental Shelf	2
Figure 1-2	Crude Oil Production in Offshore Louisiana Shallow Water (Less than 200 Meters) (1992-2003)	3
Figure 1-3	Natural Gas Production in Offshore Louisiana Shallow Water (Less than 200 Meters) (1992-2003)	4
Figure 1-4	Stranded Oil Resources in Offshore Louisiana	12
Figure 1-5	Stranded Natural Gas Resources in Offshore Louisiana	12
Figure 2-1	Estimating CO_2 Minimum Miscibility Pressure	22
Figure 2-2	Correlation of MW C5+ to Tank Oil Gravity	23
Figure 3-1	Breakout of Resource Potential in 12 State Offshore Louisiana Oil Reservoirs	28
Figure 3-2	Breakout of Resource Potential in 87 Large Federal Offshore Louisiana Oil Fields*	28
Figure 3-3	Impacts of CO_2 Accessibility and Risk Sharing on CO_2-EOR Economics	30
Figure 3-4	Impacts of CO_2 Costs and Risk Sharing on CO_2-EOR Economics	31

LIST OF TABLES

Table 1-1	Status of Crude Oil, Natural Gas, and Natural Gas Liquids Production and Remaining Reserves, Louisiana State Offshore	5
Table 1-2	Status of Crude Oil Production and Remaining Reserves, State of Louisiana Offshore (1996-2002)	6
Table 1-3	Status of Natural Gas Production and Remaining Reserves, State of Louisiana Offshore (1996-2002)	7
Table 1-4	Estimates of “Stranded” Oil and Natural Gas in State of Louisiana Offshore Waters	7
Table 1- 5	Status of Federal Offshore Fields, Central Planning Area Shelf GOM	8
Table 1-6	Status of Oil and Natural Gas Production and Remaining Reserves, Federal Central Planning Area, Shallow-Water Offshore	9
Table 1-7	Status of Oil Production and Remaining Reserves, Central Planning Area, Gulf of Mexico (Shelf) (1996 – 2002)	10
Table 1-8	Status of Natural Gas Production* and Remaining Reserves, Central Planning Area, Gulf of Mexico (Shelf)	10
Table 1-9	Estimates of “Stranded” Oil and Natural Gas, Central Planning Area, Gulf of Mexico (Shelf) Federal Waters	11
Table 2-1	Reservoir Data Format: Major Oil Reservoirs Data Base	16
Table 2-2	Reservoirs Passing Preliminary Screening for CO2-EOR Potential	18
Table 3-1	Estimated Economic Benefits from Incremental CO2-EOR Potential in Offshore Louisiana	32

EXECUTIVE SUMMARY

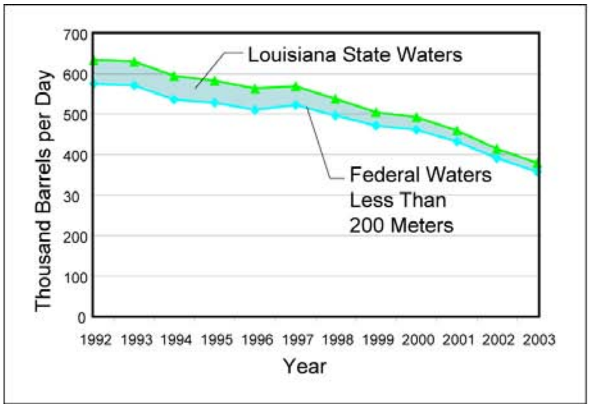
Shallow Offshore Oil and Gas Production in Louisiana is in Decline

Louisiana derives a significant portion of its general revenue and an important portion of its economic and employment base from the oil and natural gas sector. However, production from shallow waters of offshore Louisiana (less than 200 meters water depth) has been in decline:

- Crude oil production has dropped from over 630,000 barrels per day in 1992 to 380,000 barrels per day in 2003.
- Natural gas production has declined from 3.3 trillion cubic feet (Tcf) per year in 2002 to 2.3 Tcf per year in 2003.
- Increases in production from the deep federal waters (greater than 200 meters) have helped offset declines in shallow water production.

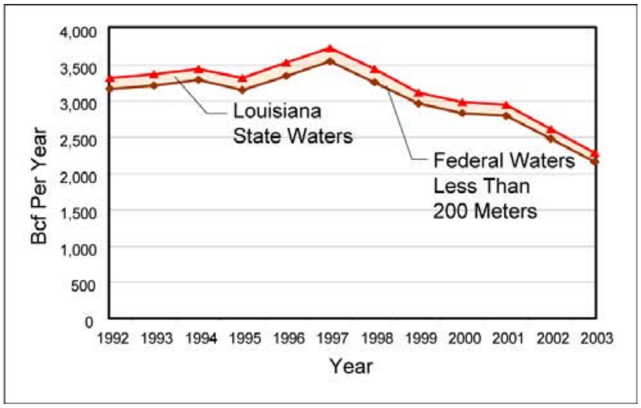
The Louisiana economy is also highly dependent on a wide variety of industries that depend on offshore oil and gas production. For example, Louisiana is the third largest consumer of natural gas in the U.S., and a large number of chemical industry jobs in Louisiana are highly dependent on the continued availability of adequate volumes of moderately priced natural gas. Moreover, offshore oil and gas production operations support a vast spectrum of other activities in the state, including platform fabrication, drilling and related services, offshore transport and helicopter operations, and gas processing.

Given the increasing maturity of these offshore fields off the coast of Louisiana, along with the relatively slow pace of development in the deep water areas, most analysts forecast a decline in oil and natural gas production from offshore Louisiana.



Crude Oil Production in Offshore Louisiana Shallow Water (< 200 Meters) (1992-2003)

Source: U.S. Dept. of Interior, Minerals Management Service and the Louisiana Dept. of Natural Resources



Natural Gas Production in Offshore Louisiana Shallow Water (< 200 Meters) (1992-2003)

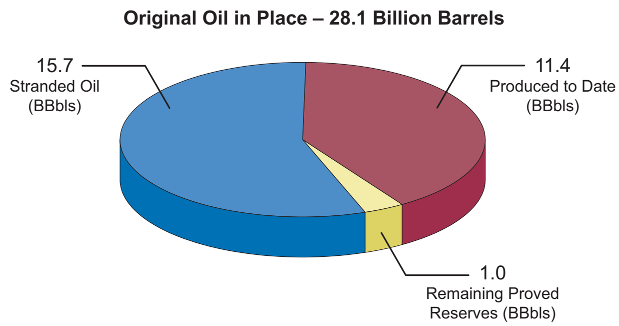
Source: U.S. Dept. of Interior, Minerals Management Service and the Louisiana Dept. of Natural Resources

Offshore Oil and Gas Infrastructure is Significant and Widely Dispersed

Approximately 3,600 platforms exist in federal offshore waters of Louisiana (MMS), and another 2,000 or more structures currently exist in state waters[1]. Connected to this production infrastructure is over 26,000 miles of oil and gas pipelines and gathering systems. Over 700 of the platforms in federal waters have been operating for over 40 years, and with appropriate maintenance and monitoring, these platforms can maintain their integrity for many more years. Nonetheless, on average, from 150 to 200 platforms are removed per year, following federal guidelines written in the mid-1970s. To date, over 2,000 platforms have already been removed.

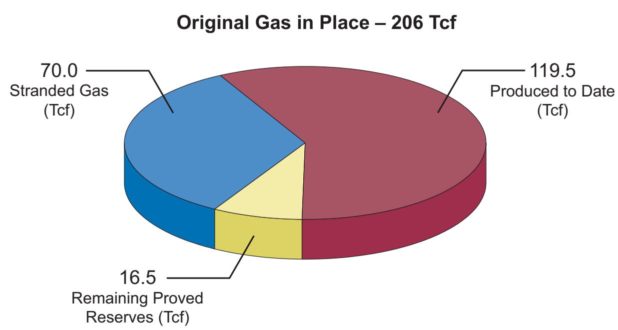
Offshore Oil and Gas Infrastructure is at Risk of More Rapid Abandonment

In these shallow waters off the coast of Louisiana, the decline of oil and gas production and the increasing maturity of these fields is causing platform abandonments that, unless reversed, could lead to significant volumes of oil and gas being "stranded," or left behind, in these fields. Some of this oil and gas resource could be produced with emerging oil and gas recovery technology in the future.



Stranded Oil Resources in Offshore Louisiana

Tabulation of stranded oil and natural gas volumes in the Louisiana offshore (consisting of the Central Planning Area (water depths less than 200 meters) in the Gulf of Mexico federal waters and offshore Louisiana state waters) shows that 56 percent of the original oil in-place and 33 percent of the original gas in-place will remain unrecovered with traditional technology and recovery practices:



Stranded Natural Gas Resources in Offshore Louisiana

- In Louisiana state waters, based on data from the Louisiana Department of Natural Resources and the U.S. Energy Information Administration, an estimated 60 percent of the crude oil and 44 percent of the natural gas will remain unrecovered with traditional practices.
- In offshore federal waters less than 200 meters deep, based upon MMS data for large fields, an estimated 55 percent of the original oil in-place and 33 percent of the original gas in-place will remain unrecovered without the introduction of improved recovery practices.

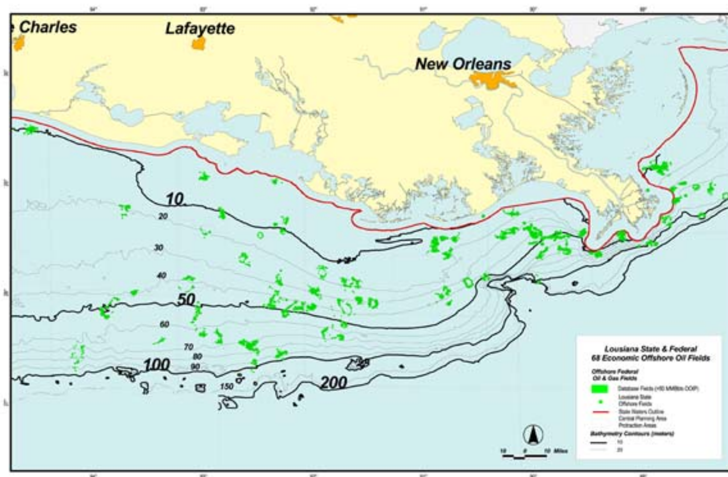
[1] *This number includes those structures within the three-mile state boundary and in coastal bays.*

Estimates of "Stranded" Oil and Natural Gas in Louisiana Offshore Waters						
	Crude Oil (Billion Bbls)			Natural Gas (Tcf)		
	State	Federal	Total	State	Federal	Total
Original In-Place	3.6	24.5	28.1	22	184	206
Produced to Date	1.4	10.0	11.4	12	108	120
Remaining Proved	0.1	0.9	1.0	1	16	17
"Stranded" Resource	2.2	13.5	15.7	10	61	71
% Recovery, Traditional Practices	40%	45%	44%	56%	67%	67%

This stranded oil resource is one "prize" awaiting the application of more advanced recovery practices. Important advances are being made in oil and gas extraction technologies that could enable the economic recovery of some of this stranded resource endowment. Perhaps the most promising is carbon dioxide (CO_2)-based enhanced oil recovery (EOR). However, should the fields be abandoned and the platforms removed, the feasibility of returning to these fields with improved technology would be economically prohibitive.

Substantial Portions of This "Stranded" Resource Could Be Economic to Develop

An analysis of 99 large state and federal offshore oil fields, representing 80 percent of the crude oil resource off the coast of Louisiana in water depths less than 200 meters, shows that, with "state-of-the-art" CO_2-EOR technology, a significant fraction of the stranded oil in these fields — amounting to approximately 4.5 billion barrels of incremental oil (another 20 percent of the original oil in place, or 28 percent of the stranded resource) — is technically recoverable, as summarized below:

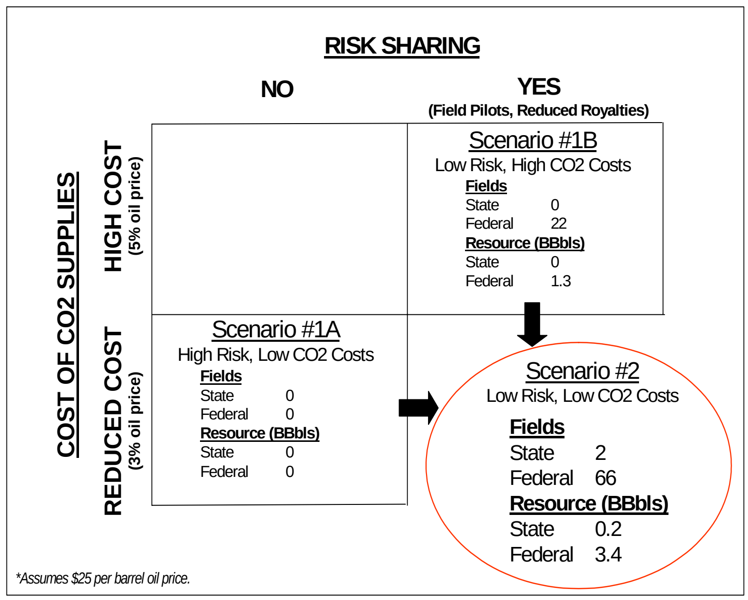


Offshore Louisiana Fields with Future Incremental Oil Recovery Potential

Estimates of Technical Recoverable Oil Resources in the Louisiana Offshore			
	No. of Fields	OOIP (MM Bbls)	Technically Recoverable (MM Bbls)
State Offshore	12	1,100	237
Federal Offshore	87	20,950	4,213
Total	99	22,050	4,450

The economic recovery potential of this resource was assessed under several "scenarios" incorporating alternative oil price, CO_2 cost, and risk mitigation incentives:

- Under Reference conditions (Scenario #1), with oil prices of $25 per barrel, delivered CO_2 costs at 5 percent of the oil price, and a hurdle rate of return (ROR) of 25 percent before taxes (to account for the technical/economic risk associated with CO_2-EOR technology in offshore applications), no incremental resource is economically recoverable.
- To improve the economic feasibility of using CO_2-EOR in these fields, two "risk mitigation" and cost reduction options that could provide possible routes for better economic performance were evaluated:
  - ***Scenario #1A – Reduced CO_2 Costs:*** An assumed CO_2 emission reduction incentive, combined with improved technology, could allow CO_2 to be delivered to the platform at reduced costs (3 percent of the oil price). However, this action is not sufficient to encourage economic recovery from CO_2-EOR.
  - ***Scenario #1B – Public/Private "Risk Mitigation":*** An assumed risk mitigation incentive, reducing risk to investors (15 hurdle ROR after taxes, achieved through significant field demonstration pilot projects), and royalty relief on incremental oil produced by CO_2-EOR (even when still relying on higher cost "EOR-ready" CO_2), would provide 1.3 billion barrels of economic oil recovery potential.



Impacts of CO_2 Costs and Risk Sharing on CO_2-EOR Economics

  - ***Scenario #2:*** When both "Risk Mitigation" and reduced CO_2 costs are combined, 3.6 billion barrels could be economically recoverable.

Economic Benefits of Producing Incremental Oil from CO_2-EOR

Assuming that 3.6 billion barrels are developed over a 40-year time frame, by 2025 this would amount to:

- Incremental crude oil production of 200,000 to 250,000 barrels per day
- Over 8,000 jobs retained by the Louisiana oil and gas industry
- Increased economic activity in Louisiana amounting to over $500 million per year
- Increased state and federal revenues of over $250 million per year.

1. SUPPLY SITUATION IN THE LOUISIANA OFFSHORE

This section discusses the status of oil and gas production in the Louisiana offshore. Particular emphasis is given to documenting the decline in production in recent years. The discussion focuses on the Louisiana State and shallow water Federal offshore portion of the Gulf of Mexico (GOM), and the implications this decline in production has on field and platform abandonment and the loss of economic activity in Louisiana.

The offshore Gulf of Mexico areas that are the focus of this report include Louisiana State offshore waters, from the shoreline to the statutory three mile limit, and the Federal waters of Central Planning Area, Gulf of Mexico Outer Continental Shelf (OCS), Figure 1-1.

Source: Outer Continental Shelf, Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 2000, OCS Report MMS 2003-050.

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Figure 1-1. Central Planning Area, Gulf of Mexico, Outer Continental Shelf.

The Federal waters are further divided into shallow water (shelf) and deep water (slope), with the 200 meter water depth providing the dividing line. Because the shallow water (shelf) area is the mature portion of the OCS, and very few bottom fixed platforms exist in the deeper water areas, the bulk of the discussion will focus on the status of oil and natural gas production in the Louisiana State and shallow Federal waters in the Central Planning Area of the OCS.

Louisiana derives a significant portion of its general revenue and an important portion of its economic and employment base from the oil and natural gas sector. However, production in shallow waters of offshore Louisiana (less than 200 meters water depth) has been in decline. Crude oil production has dropped from over 630,000 barrels per day in 1992 to 380,000 barrels per day in 2003, Figure 1-2. During this same time period, natural gas production has declined from 3.3 trillion cubic feet (Tcf) to 2.3 Tcf per year in 2003, Figure 1-3.

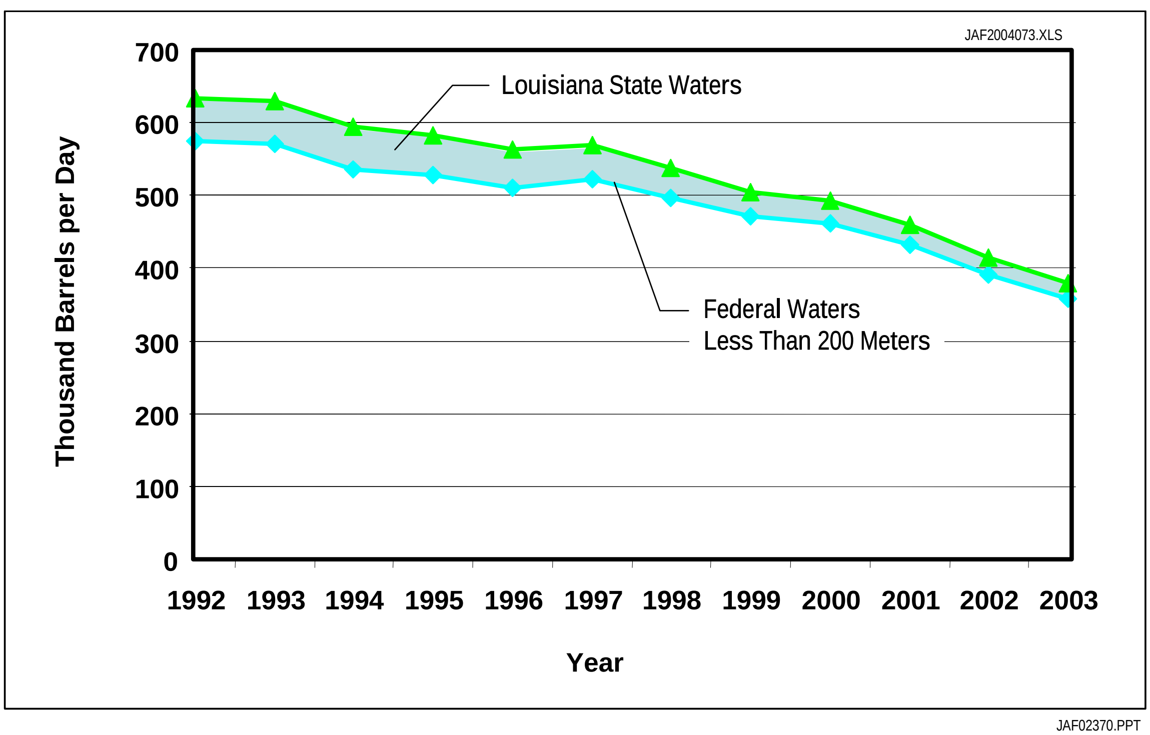

Figure 1-2. Crude Oil Production in Offshore Louisiana Shallow Water (Less than 200 Meters) (1992-2003)

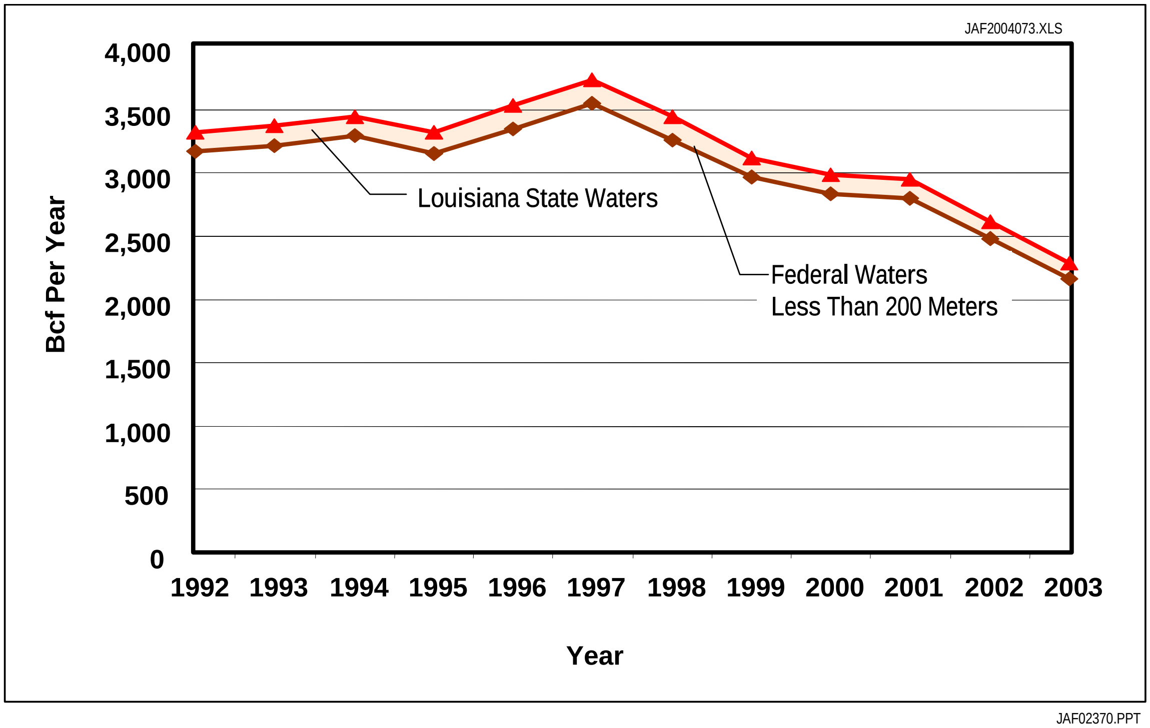

Figure 1-3. Natural Gas Production in Offshore Louisiana Shallow Water (Less than 200 Meters) (1992-2003)

Given the increasing maturity of these offshore fields, along with the relatively slow pace of development in the deep water areas, most analysts forecast continued decline in production from offshore Louisiana.

Approximately 3,600 platforms currently exist in the offshore waters of the Gulf of Mexico (GOM), and another 2,000 or more structures currently exist in state waters[2] (LA DNR 2004 c). Over 700 of the platforms in federal waters have been operating for over 40 years. Nonetheless, because of this decline in shallow water offshore production, from 150 to 200 platforms are removed per year, following federal guidelines written in the mid-1970s. To date, over 2,000 platforms have already been removed. From an oil and gas reserve and production perspective, the removal of these offshore platforms and their associated pipeline systems could economically strand a large volume of oil and natural gas that could be produced with emerging recovery technology in the future.

[2] *This number includes those structures within the three-mile state boundary and in coastal bays.*

1.1 OVERVIEW OF STATE OF LOUISIANA OFFSHORE OIL AND GAS DEVELOPMENT

Offshore Louisiana State waters contain approximately 70 oil and natural gas fields. Of these, 28 are no longer producing. Through 2003, these fields have produced on the order of 1.4 billion barrels of oil and 12 Tcf of natural gas, based on data from the Department of Natural Resources (DNR) of the State of Louisiana (LA DNR 2004 a). According to the U.S. Energy Information Administration (EIA), these fields have 72 million barrels of remaining proved crude oil reserves, 506 billion cubic feet (Bcf) of proved natural gas reserves, and 46 million barrels of natural gas liquids reserves (EIA 2004).

At the current rate of annual production, these proved reserves and fields will be depleted in five to ten years, Table 1-1. Extension drilling and production optimization will help extend the life of these fields, but even with these actions, the vast majority of the State offshore oil and gas fields will likely be abandoned in the next ten to fifteen years.

Table 1-1. Status of Crude Oil, Natural Gas, and Natural Gas Liquids Production and Remaining Reserves, Louisiana State Offshore

	Annual Production		
Year	Crude Oil [1] (Million Bbls)	Natural Gas [1] (Bcf)	Natural Gas Liquids [2] (Million Bbls)
2002	10	151	12
2003	8	135	12
	Remaining Proved Reserves		
Beginning of Year	Crude Oil [2] (Million Bbls)	Natural Gas [2] (Bcf)	Natural Gas Liquids [2] (Million Bbls)
2003	91	491	48
2004	72	506	46

[1] Source: LA DNR 2004 a
[2] Source: EIA 2004

1.1.1 Status of Oil Production. According to the Louisiana (LA DNR 2004 a), oil production from Louisiana State waters peaked in 1972 at 65 million barrels (179,000 barrels per day), and has declined steadily though the early 1980s. From the early 1980s through the mid-1990s, production stabilized in the range of 20 to 25 million barrels per year (55,000 to 68,000 barrels per day). However, since the mid-1990s, production has again been in rapid decline, dropping from 19.1 million barrels per year (52,000 barrels per day) in 1996 to 8.0 million barrels per year (22,000 barrels per day) in 2003 (Table 1-2), with this decline projected to continue.

Table 1-2. Status of Crude Oil Production and Remaining Reserves, State of Louisiana Offshore (1996-2002)

Year	Annual Production (Million Barrels per Year)
1996	19.1
1997	17.2
1998	15.1
1999	12.1
2000	11.1
2001	10.1
2002	8.1
2003	8.0

Source: LA DNR 2004 a

1.1.2 Status of Natural Gas Production. Similarly, natural gas production in Louisiana State waters peaked in 1971, at 620 Bcf per year, and has been in a relative decline ever since. As shown in Table 1-3, natural gas production has dropped from 186 Bcf per year in 1996 to 118 Bcf per year in 2003, and again is forecast to continue to decline.

Table 1-3. Status of Natural Gas Production and Remaining Reserves, State of Louisiana Offshore (1996-2002)

Year	Annual Production (Billion Cubic Feet per Year)
1996	186
1997	186
1998	180
1999	150
2000	149
2001	151
2002	135
2003	118

Source: LA DNR 2004 a

Once these fields are depleted, the wells are shut in and the platforms are generally removed. However, considerable oil and gas still remains in these fields, after the volumes proved by traditional recovery methods have been produced. Tabulation of "stranded" volumes of hydrocarbon resources estimated by Advanced Resources, based on data from the Louisiana Department of Natural Resources and the EIA, shows that 60% of the crude oil and 44% of the natural gas will remain unrecovered with traditional practices in Louisiana State waters, Table 1-4.

Table 1-4. Estimates of "Stranded" Oil and Natural Gas in State of Louisiana Offshore Waters

	Crude Oil (Billion Bbls)	Natural Gas (Tcf)
Original In-Place	3.6	22.0
Produced to Date	1.4	11.8
Remaining Proved	0.1	0.5
"Stranded" Resource	2.2	9.7
% Recovery, Traditional Practices	40%	56%

1.2 OVERVIEW OF FEDERAL SHALLOW WATER (SHELF) OIL AND GAS DEVELOPMENT

The Central Planning Area of the Federal Gulf of Mexico Shelf (less than 200 meters water depth) contains 1,000 oil and gas fields. Of these, 98 have been depleted and another 36 are abandoned as non-producing. The status of the Federal offshore fields in this area is summarized in Table 1-5:

Table 1- 5. Status of Federal Offshore Fields,
Central Planning Area Shelf GOM

Proved, Active Producing	534
Proved, Active Non-Producing	39
Proved, Expired/Depleted	98
Unproved, Active Producing	17
Expired, Non-Producing	36

Source: MMS 2004

The fields in the shallow water shelf of the coast of Louisiana have produced 108 Tcf of natural gas and 10 billion barrels of oil and condensate as of the end of 2002, the year for the latest comprehensive data from MMS for the Gulf of Mexico (MMS 2004). According to MMS, these fields had 16 Tcf of remaining proved natural gas reserves and 1.0 billion barrels of proved crude oil reserves. Given this, an estimated 87% of the original proved natural gas reserves and 91% of the original proved oil reserves have been produced. In these fields

Moreover, according to EIA estimates, at the current rate of annual production, even with the growth of reserves in these fields from extension drilling, the majority of these fields will become depleted in the next twenty years, Table 1-6.

Table 1-6. Status of Oil and Natural Gas Production and Remaining Reserves, Federal Central Planning Area, Shallow-Water Offshore

	Estimated Annual Production	
Year	Crude Oil (Million Bbls)	Natural Gas* (Bcf)
2002	143	2,479
2003	131	2,161

**Wet after lease separation*

	Estimated Remaining Proved Reserves	
Beginning of Year	Crude Oil (Million Bbls)	Natural Gas* (Bcf)
2003	985	11,162
2004	867	9,511

**Wet after lease separation*
Source: Estimates based on EIA data (EIA 2004)

1.2.1 Status of Oil Production. Since the mid-1990s, oil production in the Federal OCS shallow water (less than 200 meter water depth) off the coast of Louisiana has been in steady decline, from 191 million barrels per year (523,000 barrels per day) in 1997 to 131 million barrels per year (358,000 barrels per day) in 2003, Table 1-7. This decline in shelf production is projected to continue.

1.2.2 Status of Natural Gas Production. Natural gas production from the Central Planning Area, Gulf of Mexico (shelf) reached a peak in 1972, and has declined since then, along with remaining proved reserves. The decline has been most notable in recent years, as shown on Table 1-8.

Table 1-7. Status of Oil Production and Remaining Reserves, Central Planning Area, Gulf of Mexico (Shelf) (1996 – 2002)

	Annual Production (Million Barrels)	Remaining Proved Reserves (Million Barrels)
1996	186	1,153
1997	191	1,112
1998	181	1,048
1999	172	994
2000	168	933/999*
2001	158	977
2002	143	985
2003	131	867

** First number represents MMS estimate (MMS 2004), while the second is based on EIA data (EIA 2004).
Source: Estimates based on EIA data (EIA 2004)

Table 1-8. Status of Natural Gas Production* and Remaining Reserves, Central Planning Area, Gulf of Mexico (Shelf)

	Annual Production (Bcf)	Remaining Proved Reserves (Bcf)
1996	3,343	17,098
1997	3,546	16,529
1998	3,260	15,287
1999	2,967	14,201
2000	2,833	12,629/13,815**
2001	2,798	11,890
2002	2,479	11,162
2003	2,161	9,511

*Wet, after lease separation.
**First number represents MMS estimate (MMS 2004), while the second is based on EIA data (EIA 2004).

Recent developments in the deep water portion of the Central Planning Area (Central Slope) have helped stem the overall decline. Like that for oil, the recent developments in the deep water have added some natural gas reserves and production capacity. However, the challenges of development in the deep water and the corresponding high costs have slowed development. Moreover, so far, the deepwater portion of the Central Planning area has tended to be oil prone, with much lower than initial anticipated volumes of associated gas. As such, overall natural gas production from both the shallow and deep water has declined.

Tabulation of volumes of "stranded" oil and gas by Advanced Resources, based upon MMS data for the large oil and gas fields that account for over 80% of the oil and gas produced or proved to date, shows that 55% of the original oil in-place (and 33% of the original gas in-place) will remain unrecovered in shallow Federal waters without the introduction of more advanced technology and recovery practices, Table 1-9.

Table 1-9. Estimates of "Stranded" Oil and Natural Gas, Central Planning Area, Gulf of Mexico (Shelf) Federal Waters

	Crude Oil (Billion Bbls)	Natural Gas (Tcf)
Original In-Place	24.5	184
Produced to Date	10.0	108
Remaining Proved	0.9	16
"Stranded" Resource	13.5	61
% Recovery, Traditional Practices	45%	67%

Based on MMS data (MMS 2004) for large oil and gas fields

In total, stranded oil and natural gas volumes in the Louisiana offshore (consisting of Federal and State waters) amount to 56% of the original oil in-place (Figure 1-4) and 33% of the original gas in-place (Figure 1-5).

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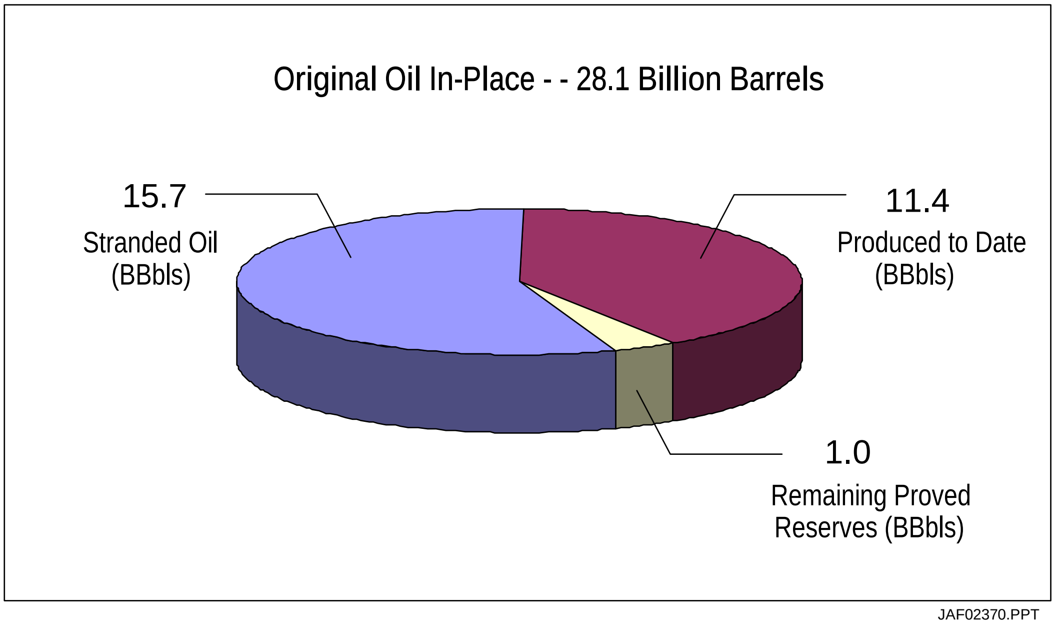

Figure 1-4. Stranded Oil Resources in Offshore Louisiana

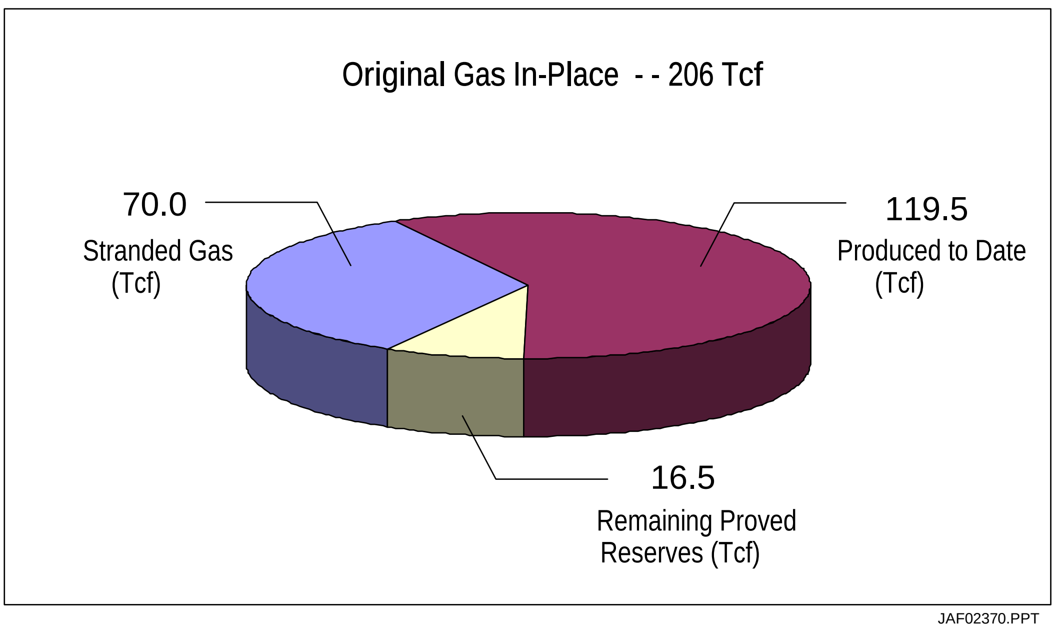

Figure 1-5. Stranded Natural Gas Resources in Offshore Louisiana

This large “stranded”, or left behind, oil and gas resource is the “prize” awaiting the application of advanced recovery practices, particularly CO_2-EOR and alternative well completion and production practices for enhanced gas recovery. Important advances are being made in technologies that could enable the economic recovery of some of this stranded resource endowment. However, should the fields be abandoned and the platforms removed, the feasibility of returning to these field with advanced recovery technology would be economically prohibitive.

1.3 LOUISIANA/TEXAS OCS SLOPE

The Louisiana and Texas OCS deep water slope (greater that 200 meters water depth) is still considered a frontier oil and gas development area. Only one field and platform system, the Cognac field (MC 194) has been on production for more than 20 years. Nine additional fields have been on production for more than 10 years, with four of these (GC 75, GC 29, Diamond (MC 445) and Seattle Slew (EW 914)) no longer on production.

While the overall OCS slope is vast, extending more than 200 miles from the edge of the shelf, the portion of the shelf area of interest to mariculture or other potential future applications for existing offshore oil and gas infrastructure may be limited, because of the rapid increase in water depth as a function of distance from shore in this region. For example, using 1,400 feet of water depth as the limit for the current interest for mariculture (except for ornamental fish and coral), only a five mile (or less) wedge of area exists from the area of the edge of the shelf before the water depths exceed these amounts. This water depth is also the practical limits for fixed structures, with the Bullwinkle platform placed in 1,300 feet of water.

Moreover, because of their distance from shore, the use of these facilities for applications like wind power may also be limited.

1.4 ECONOMIC BENEFITS OF OIL AND GAS PRODUCTION IN THE LOUISIANA OFFSHORE

While increases in production in the deep Federal waters (greater than 200 meters) have helped offset a portion of the decline in shallow water production, the result, nonetheless, has been progressively lower State revenues derived from oil production from the shallow water. In 2001 (the last year for which complete data are publicly available):

- Including the federal OCS, Louisiana was still the largest oil producing state and second largest gas producing state in the U.S., despite rapidly declining production
- The oil and gas exploration and production industry directly employed 50,000 people in Louisiana
- The state of Louisiana collected nearly $940 million in revenues (royalties, bonuses, and rents) from coastal and offshore oil and gas production off its coast. (LA DNR 2004 b)
- The Federal government collected nearly $5.5 billion from offshore oil and gas production in federal waters off the coast of Louisiana, representing 73% of all Federal revenues from oil and gas production in the U.S. (MMS 2004)
- The State of Louisiana receives 27% of the revenues from oil and gas production in the area defined by the Federal "8g zone," which encompasses the area up to 3 miles seaward from the state coastal area boundary (which is 3 miles from shore). In 2001, state revenues from the 8g zone amounted to about $40 million, or less than 1% of the total Federal revenues collected from oil and gas production off the Louisiana coast. (LA DNR 2004 b)
- The Louisiana industry facilitates the transport and distribution of nearly 2 billion barrels of crude oil and petroleum products and 4.5 Tcf of natural gas annually to consumers throughout the nation. ((LA DNR 2004 b)

2. STUDY METHODOLOGY

A seven part methodology was used to assess the CO_2-EOR potential of the Offshore Louisiana oil reservoirs examined in this analysis. The seven steps were: (1) assembling a oil reservoirs data base; (2) screening reservoirs for CO_2-EOR potential; (3) calculating the minimum miscibility pressure; (4) estimating potential oil recovery; (5) assembling the cost model; (6) constructing an economics model; and, (7) performing sensitivity analyses.

The study was based on a desktop model developed with the 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 Total Oil Recovery Information System (TORIS) maintained by DOE/FE’s National Energy Technology Laboratory (NETL).

2.1 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. 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 offshore Louisiana; (2) reliably screen the reservoirs as to their amenability for miscible and immiscible CO_2-EOR; and, (3) provide the *CO_2-PROPHET* Model the essential data for calculating CO_2 injection requirements and oil recovery.

Table 2-1 illustrates the oil reservoir data recording format developed by the study. The data format readily integrates with the input data required by the CO_2-EOR

Table 2-1. Reservoir Data Format: Major Oil Reservoirs Data Base

Basin Name	
Field Name	
Reservoir	

Reservoir Parameters:

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

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Oil Production

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

Water Production

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

Injection

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

Volumes

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

OOIP Volume Check

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

SROIP Volume Check

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

ROIP Volume Check

ROIP Check (MMbl)	

screening and oil recovery models, discussed below. Overall, the Offshore Louisiana Major Oil Reservoirs Data Base contains 99 reservoirs, accounting for 76% of the oil expected to be ultimately produced from offshore Louisiana by primary and secondary oil recovery processes.

2.2 SCREENING RESERVOIRS FOR CO2-EOR

The data base was screened for reservoirs that would be applicable for CO_2-EOR. Five prominent screening criteria were used to identify favorable reservoirs: reservoir depth, oil gravity, reservoir pressure, reservoir temperature and oil composition. These values were used to establish the minimum miscibility pressure for conducting miscible CO_2-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the miscibility pressure standard could be considered for immiscible CO_2-EOR.

The preliminary screening steps involved selecting the deeper oil reservoirs that had sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet, at the mid-point of the reservoir, was used to ensure the reservoir could accommodate high pressure CO_2 injection. A minimum oil gravity of 17.5^o API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection. Table 2-2 tabulates the oil reservoirs that passed the preliminary screening step.

2.3 CALCULATING MINIMUM MISCIBILITY PRESSURE

The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and oil composition, was to determine whether the reservoir would hold sufficient pressure to attain miscibility. Where oil composition data was missing, a correlation was used for translating the reservoir's oil gravity to oil composition.

Table 2-2. Reservoirs Passing Preliminary Screening for CO_2-EOR Potential

FIELD	RESERVOIR/BLOCK	API°	DEPTH (FT)
BAY MARCHAND BLOCK 0002	3650' UPPER BLOCK D, 3650' U RD SAND	24.0	3,850
BAY MARCHAND BLOCK 0002	4400 G	35.5	5,132
BAY MARCHAND BLOCK 0002	4600 A-B SAND	37.0	5,500
BAY MARCHAND BLOCK 0002	8350 NN	29.5	8,200
BAY MARCHAND BLOCK 0002	8400 NN	29.5	8,067
BAY MARCHAND BLOCK 0002	O-SAND RESERVOIR D UNIT	35.0	12,200
EUGENE ISLAND BLOCK 0018	P RB SU	28.0	10,000
EUGENE ISLAND BLOCK 0018	O-RA SU	35.5	10,071
MAIN PASS BLOCK 0069	72 RESERVOIRS	31.0	9,000
MAIN PASS BLOCK 0069	8150 B-C SAND	31.0	8,100
MAIN PASS BLOCK 0069	8400 SAND, RESERVOIR C	33.0	7,500
MAIN PASS BLOCK 0069	BQ RESERVOIR A SAND UNIT	35.2	7,730
MAIN PASS BLOCK 0069	A RESERVOIR Q SAND	26.0	7,450
MAIN PASS BLOCK 0069	B RESERVOIR Q2 SAND	29.0	7,900
MAIN PASS BLOCK 0069	T1 RESERVOIR B SAND UNIT	36.0	6,450
SOUTH PASS BLOCK 0027	L2 RA S	25.0	6,420
SOUTH PASS BLOCK 0027	M2 RA SU	29.5	6,775
SOUTH PASS BLOCK 0027	N4 RB SU	24.2	7,800
SOUTH PASS BLOCK 0027	M RB SU	32.4	7,500
SOUTH PASS BLOCK 0027	M RESERVOIR C SAND UNIT	32.8	7,450
SOUTH PASS BLOCK 0027	M2 RESERVOIR B SAND UNIT	25.0	6,280
SOUTH PASS BLOCK 0027	M2 RESERVOIR D SAND UNIT	31.5	7,500
SOUTH PASS BLOCK 0027	M6 RESERVOIR A SAND UNIT	27.0	6,750
SOUTH PASS BLOCK 0027	N RESERVOIR B SAND UNIT	26.8	7,500
SOUTH PASS BLOCK 0027	N RESERVOIR C SAND UNIT	32.0	7,400
SOUTH PASS BLOCK 0027	N RESERVOIR D SAND UNIT	27.0	7,300
SOUTH PASS BLOCK 0027	N RESERVOIR E SAND UNIT	26.0	7,000
SOUTH PASS BLOCK 0027	N1A RESERVOIR F SAND UNIT	27.0	7,250
SOUTH PASS BLOCK 0027	N1A RESERVOIR B SAND UNIT	26.8	7,520
SOUTH PASS BLOCK 0027	N1A RESERVOIR C SAND UNIT	32.0	7,350
SOUTH PASS BLOCK 0027	N1A RESERVOIR D SAND UNIT	27.0	7,450
SOUTH PASS BLOCK 0027	N1A RESERVOIR E SAND UNIT	26.0	7,000
SOUTH PASS BLOCK 0027	N1B RESERVOIR B SAND UNIT	26.8	7,550
SOUTH PASS BLOCK 0027	N1B RESERVOIR C SAND UNIT	32.0	7,450
SOUTH PASS BLOCK 0027	N1B RESERVOIR D SAND UNIT	27.0	7,350
SOUTH PASS BLOCK 0027	N1B RESERVOIR F SAND UNIT	28.0	7,300
SOUTH PASS BLOCK 0027	N1B RESERVOIR E SAND UNIT	26.0	7,000
SOUTH PASS BLOCK 0027	N1C RESERVOIR E SAND UNIT	26.0	7,000
SOUTH PASS BLOCK 0027	N2 RESERVOIR B SAND UNIT	27.0	7,500
SOUTH PASS BLOCK 0027	N2 RESERVOIR C SAND UNIT	27.0	7,600
SOUTH PASS BLOCK 0027	N4 RESERVOIR C SAND UNIT	27.5	7,700
SOUTH PASS BLOCK 0027	N4 SAND UNIT RESERVOIR A	36.0	8,650
SOUTH PASS BLOCK 0027	N4A SAND RESERVOIR A	24.2	7,800
SOUTH PASS BLOCK 0027	N4A SAND RESERVOIR B	24.2	7,800
SOUTH PASS BLOCK 0027	N4A SAND RESERVOIR A	24.2	7,875

FIELD	RESERVOIR/BLOCK	API°	DEPTH (FT)
SOUTH PASS BLOCK 0027	N4B RC SU	26.8	7,600
SOUTH PASS BLOCK 0027	N4B SAND RESERVOIR B	24.2	7,850
SOUTH PASS BLOCK 0027	NO RESERVOIR B SAND UNIT	26.6	7,470
SOUTH PASS BLOCK 0027	NO RESERVOIR C SAND UNIT	32.0	7,550
SOUTH PASS BLOCK 0027	NO RESERVOIR D SAND UNIT	27.0	7,650
SOUTH PASS BLOCK 0027	NO RESERVOIR E SAND UNIT	26.0	7,000
SOUTH PASS BLOCK 0027	NO SAND RESERVOIR A	35.0	8,100
SOUTH PASS BLOCK 0027	PROPOSED N2 RE SU	30.0	8,650
SOUTH PASS BLOCK 0027	PROPOSED N2 RG SU	35.0	5,750
SOUTH PASS BLOCK 0027	PROPOSED N4 RI SU	31.0	8,750
SOUTH PASS BLOCK 0027	PROPOSED O1 RH SU	32.0	8,100
SOUTH PASS BLOCK 0027	PROPOSED SPB 27 K RA SU	27.5	6,200
SOUTH PASS BLOCK 0027	PROPOSED SPB 27 K RB SU	27.5	6,300
SOUTH PASS BLOCK 0027	PROPOSED SPB 27 M RD SU	32.0	7,530
SOUTH PASS BLOCK 0027	PROPOSED SPB 27 N4 RD SU	31.0	8,660
SOUTH PASS BLOCK 0027	RESERVOIR A L2 SAND UNIT	25.5	6,420
SOUTH PASS BLOCK 0027	SPB27 L2 RC SU	29.0	7,350
SOUTH PASS BLOCK 0027	SPB27 L2 RE SU	31.0	7,200
SOUTH PASS BLOCK 0027	SPB27 L4 RD SU	32.0	7,430
TIMBALIER BAY	S-1D SAND, RESERVOIR BA	29.0	6,850
TIMBALIER BAY	D-14 SAND, G FAULT BLOCK	32.1	11,400
TIMBALIER BAY	D-3-4 SAND, RESERVOIR A	33.0	8,450
TIMBALIER BAY	D-5 SAND, RESERVOIR B	32.5	6,987
TIMBALIER BAY	MEDIUM	30.0	9,000
BAY MARCHAND 002	002 BLOCK	28.0	10,633
EAST CAMERON 271	271 BLOCK	31.0	7,156
EAST CAMERON 321	321 BLOCK	32.0	5,407
EAST CAMERON 338	338 BLOCK	40.0	6,543
EUGENE ISLAND 032	032 BLOCK	38.0	10,758
EUGENE ISLAND 100	100 BLOCK	37.0	9,843
EUGENE ISLAND 126	126 BLOCK	34.0	8,858
EUGENE ISLAND 128	128 BLOCK	37.0	9,475
EUGENE ISLAND 175	175 BLOCK	36.0	11,400
EUGENE ISLAND 188	188 BLOCK	34.0	10,423
EUGENE ISLAND 208	208 BLOCK	36.0	10,610
EUGENE ISLAND 238	238 BLOCK	39.0	10,553
EUGENE ISLAND 258	258 BLOCK	34.0	7,769
EUGENE ISLAND 276	276 BLOCK	35.0	9,219
EUGENE ISLAND 330	330 BLOCK	33.0	6,597
EUGENE ISLAND 342	342 BLOCK	35.0	3,082
EUGENE ISLAND 361	361 BLOCK	34.0	3,714
EWING BANK 826	826 BLOCK	35.0	11,744
EWING BANK 910	910 BLOCK	32.0	11,807
GRAND ISLE 016	016 BLOCK	36.0	8,794
GRAND ISLE 041	041 BLOCK	32.0	10,529
GRAND ISLE 043	043 BLOCK	30.0	9,558
GRAND ISLE 047	047 BLOCK	33.0	9,943
MAIN PASS 041	041 BLOCK	32.0	6,050

FIELD	RESERVOIR/BLOCK	API°	DEPTH (FT)
MAIN PASS 073	073 BLOCK	34.0	8,157
MAIN PASS 140	140 BLOCK	29.0	6,621
MAIN PASS 144	144 BLOCK	31.0	4,859
MAIN PASS 151	151 BLOCK	34.0	6,785
MAIN PASS 290	290 BLOCK	25.0	4,845
MAIN PASS 299	299 BLOCK	33.0	5,230
MAIN PASS 306	306 BLOCK	36.0	5,999
MAIN PASS 310	310 BLOCK	29.0	6,076
MAIN PASS 311	311 BLOCK	30.0	7,460
MISSISSIPPI CANYON 311	311 BLOCK	34.0	10,364
SOUTH PELTO 020	020 BLOCK	34.0	9,828
SOUTH PELTO 023	023 BLOCK	36.0	12,602
SMI SOUTH MARSH ISLAND 006	006 BLOCK	33.0	9,829
SMI SOUTH MARSH ISLAND 073	073 BLOCK	34.0	9,979
SMI SOUTH MARSH ISLAND 115	115 BLOCK	35.0	8,902
SMI SOUTH MARSH ISLAND 128	128 BLOCK	39.0	6,520
SMI SOUTH MARSH ISLAND 130	130 BLOCK	30.0	4,777
SMI SOUTH MARSH ISLAND 236	236 BLOCK	34.0	10,171
SMI SOUTH MARSH ISLAND 239	239 BLOCK	37.0	9,937
SMI SOUTH MARSH ISLAND 269	269 BLOCK	36.0	11,189
SPA SOUTH PASS 027	027 BLOCK	30.0	6,934
SPA SOUTH PASS 049	049 BLOCK	32.0	8,820
SPA SOUTH PASS 061	061 BLOCK	35.0	6,984
SPA SOUTH PASS 062	062 BLOCK	36.0	7,201
SPA SOUTH PASS 065	065 BLOCK	29.0	7,135
SPA SOUTH PASS 078	078 BLOCK	35.0	6,793
SPA SOUTH PASS 089	089 BLOCK	35.0	12,979
SHIP SHOALS 069	069 BLOCK	33.0	11,669
SHIP SHOALS 107	107 BLOCK	34.0	10,583
SHIP SHOALS 113	113 BLOCK	31.0	8,815
SHIP SHOALS 154	154 BLOCK	32.0	6,046
SHIP SHOALS 169	169 BLOCK	30.0	8,988
SHIP SHOALS 176	176 BLOCK	36.0	7,363
SHIP SHOALS 207	207 BLOCK	33.0	10,998
SHIP SHOALS 208	208 BLOCK	34.0	9,861
SHIP SHOALS 222	222 BLOCK	35.0	9,316
SHIP SHOALS 230	230 BLOCK	36.0	8,899
SHIP SHOALS 253	253 BLOCK	36.0	7,342
SHIP SHOALS 274	274 BLOCK	36.0	5,193
SHIP SHOALS 291	291 BLOCK	32.0	4,319
SHIP SHOALS 349	349 BLOCK	23.0	14,403
STI SOUTH TIMBALIER 021	021 BLOCK	31.0	10,791
STI SOUTH TIMBALIER 036	036 BLOCK	33.0	9,551
STI SOUTH TIMBALIER 037	037 BLOCK	33.0	11,226
STI SOUTH TIMBALIER 052	052 BLOCK	35.0	5,104
STI SOUTH TIMBALIER 054	054 BLOCK	34.0	9,017
STI SOUTH TIMBALIER 131	131 BLOCK	36.0	7,176
STI SOUTH TIMBALIER 135	135 BLOCK	37.0	11,597

FIELD	RESERVOIR/BLOCK	API°	DEPTH (FT)
STI SOUTH TIMBALIER 176	176 BLOCK	36.0	10,494
VERMILION 120	120 BLOCK	41.0	7,706
VERMILION 245	245 BLOCK	33.0	8,972
VERMILION 284	284 BLOCK	32.0	10,753
VERMILION 331	331 BLOCK	35.0	6,241
WCA WEST CAMERON 066	066 BLOCK	38.0	9,304
WEST DELTA 030	030 BLOCK	29.0	8,932
WEST DELTA 041	041 BLOCK	33.0	9,978
WEST DELTA 073	073 BLOCK	29.0	9,151
WEST DELTA 079	079 BLOCK	36.0	12,537
WEST DELTA 105	105 BLOCK	31.0	7,895
WEST DELTA 109	109 BLOCK	34.0	10,603
WEST DELTA 117	117 BLOCK	34.0	9,152
WEST DELTA 133	133 BLOCK	33.0	11,513
WEST DELTA 152	152 BLOCK	32.0	10,437

To determine the minimum miscibility pressure (MMP) for any given reservoir, the study used the Cronquist correlation, Figure 2-1. This formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, without considering the mole percent of methane. (Most offshore oil reservoirs will have produced the bulk of their methane during primary and secondary recovery.) The Cronquist correlation is set forth below:

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

Where:

T is Temperature in ^{o}F,

MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

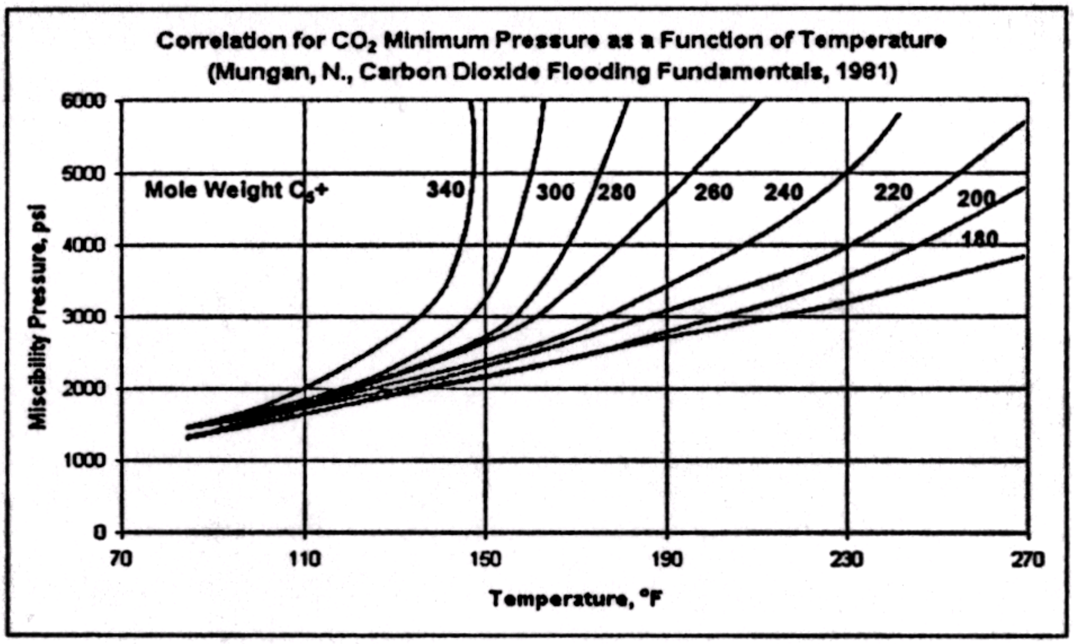

Figure 2-1. Estimating CO_2 Minimum Miscibility Pressure

The temperature of the reservoir was taken from the data base or estimated from the thermal gradient in the basin. The molecular weight of the pentanes and heavier fraction of the oil was obtained from the data base or was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure 2-2.

The next step was calculating MMP for a given reservoir and comparing it to the maximum allowable injection pressure. Data on current and initial reservoir pressure were obtained and/or estimated based on MMS data. The maximum injection pressure was determined using a pressure gradient of 0.6 psi/foot. If the minimum miscibility pressure was below the maximum injection pressure, the reservoir was classified as a miscible flood candidate. Oil reservoirs that did not screen positively for miscible CO_2-EOR were selected for potential future consideration as an immiscible CO_2-EOR flooding candidate.

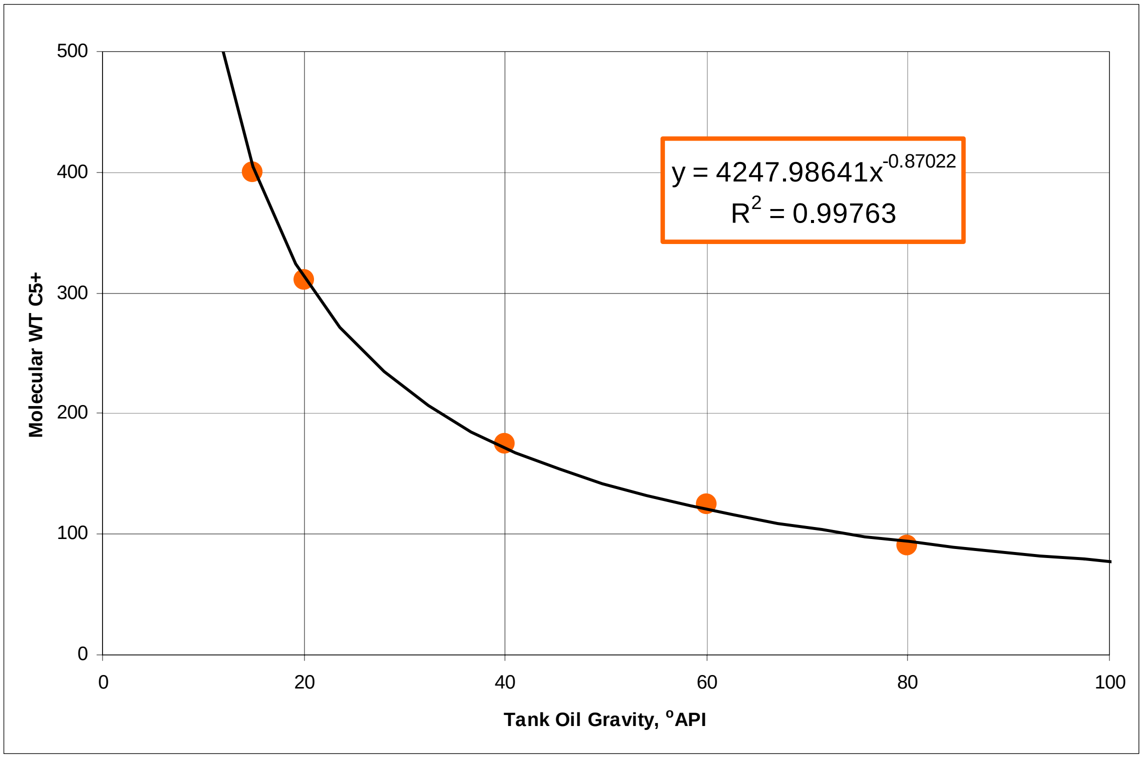

Figure 2-2. Correlation of MW C5+ to Tank Oil Gravity

2.4 ESTIMATING OIL RECOVERY POTENTIAL

The study utilized *CO_2-PROPHET* to estimate incremental oil produced using CO_2-EOR. *CO_2-PROPHET* was developed by the Texaco Exploration and Production Technology Department as part of the DOE Class I cost-share program.[3] *CO_2-PROPHET* was developed as an alternative to the DOE's CO_2 miscible flood predictive model, *CO_2PM*. According to the developers of the model, *CO_2-PROPHET* has more capabilities and fewer limitations than *CO_2PM*. For example, according to the above cited report, *CO_2-PROPHET* performs two main operations that provide a more robust calculation of oil recovery than available from *CO_2PM*:

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

[3]. The specific project was "Post Waterflood CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir" (DOE Contract No. DE-FC22-93BC14960).

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

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

Appendix A provides greater detail on the capabilities of *CO_2-PROPHET.*

2.5 DEVELOPING THE COST MODEL

A detailed, up-to-date Offshore CO_2-EOR Cost Model was developed for this study. The model includes costs for: (1) drilling new wells or reworking existing wells; (2) providing surface equipment for new wells on an existing platform; (3) installing the CO_2 recycle plant on the existing platform; (4) constructing a CO_2 spur-line from a main CO_2 trunk line to the oil platform; and, (5) various miscellaneous costs.

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

2.6 CONSTRUCTING THE 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.

2.7 PERFORMING SCENARIO ANALYSES

A series of analyses were prepared to better understand how differences in oil prices, CO_2 supply costs and financial risk hurdles could impact the volumes of oil that would be economically produced by CO_2-EOR from offshore Louisiana oil reservoirs.

- Two oil prices were considered. A \$25 per barrel oil price was used to represent a moderate oil price case; a \$35 per barrel oil price was used to represent the availability of Federal/state risk sharing and/or the continuation of current high oil price situation. These oil prices represent those used internally as the basis for corporate decision-making for capital expenditures, and may not necessarily represent the prices ultimately received from production for the project.
- Two CO_2 supply costs were considered. The high CO_2 cost was set at \$1.25 per Mcf (5% of the oil price) to represent the costs of a new transportation system bringing natural CO_2 to the offshore platforms. A lower CO_2 supply cost equal to \$0.75 per Mcf (3% of the oil price) was included to represent the potential future availability of low-cost CO_2 from industrial and power plants as part of CO_2 storage.
- Two minimum rate of return (ROR) hurdles were considered, a high ROR of 25%, before tax, and a lower 15% ROR, before tax. The high ROR hurdle incorporates a premium for the market, reservoir and technology risks inherent in using CO_2-EOR in a new reservoir setting. The lower ROR hurdle represents application of CO_2-EOR after the geologic and technical risks have been mitigated with a robust program of field pilots and demonstrations.

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

- The first scenario captures how "state-of-the-art CO_2-EOR technology has been applied and has performed in the past. In scenario, oil prices are assumed to be at more traditional, \$25 per barrel levels, a project hurdle rate of return of 25% before taxes is assumed, to account for the technical and economic risk associated with the application of state-of-the-art CO_2-EOR technology in offshore Louisiana, and CO_2

supply costs are assumed to be relatively high (equal to $1.25 per Mcf, or 5% of the crude oil price).

- The second scenario assumes a CO_2 sequestration incentive combined with improved technology allows CO_2 to be delivered to the offshore platform at reduced costs of $0.75 per Mcf, or 3% of the crude oil price). CO_2sources would likely include industrial high-concentration CO_2 emissions from hydrogen facilities, gas processing plants and other sources. These would be augmented, in the longer-term, from low CO_2 concentration industrial sources including combustion and electric generation plants. Capture of industrial CO_2 emissions would be part of national efforts for reducing greenhouse gas emissions.

- The third scenario assumes that technology progress in CO_2-EOR, achieved in other areas, is successfully applied to the offshore oil reservoirs. In addition, a comprehensive set of research, pilot tests and field demonstrations help lower the risk inherent in applying new technology to these complex oil reservoirs, to a 15%, before tax, ROR hurdle rate. In addition, it assumes that the economic potential of CO_2-EOR could be increased through a strategy involving royalty relief and/or higher world oil prices that together would be equal to $10 per barrel in the price that the producer receives for produced crude oil.

- In the fourth scenario, both “risk sharing” and reduced CO2 costs are assumed to combine to further enhance the economic potential of CO_2-EOR in these offshore oil reservoirs.

3. RECOVERY POTENTIAL OF STRANDED OIL RESOURCES IN THE LOUISIANA OFFSHORE

As discussed in the previous section, a majority of the oil fields in the Louisiana offshore waters are mature and in decline, with 126 already depleted and abandoned. With approximately 90% of the original proved reserves already produced, the time for abandonment of many of these fields is rapidly approaching. For these offshore fields, field abandonment involves removing platforms, plugging the wells, and disassembling the pipeline infrastructure.

3.1 TECHNICAL RECOVERY POTENTIAL

These offshore fields will still have significant volumes of their original oil in place after the application of traditional oil recovery methods. This "stranded oil", -- the "prize" for advanced recovery methods -- is estimated at 14 billion barrels, with approximately 80% of this in 99 large fields. An analysis of these 99 largest state and Federal offshore fields off the coast of Louisiana in water depths less that 200 meters shows that carbon-dioxide (CO_2) based enhanced oil recovery (EOR) could add significant additional oil reserves from these fields. With "state-of-the-art" CO_2-EOR technology, a significant fraction of the stranded oil in these fields – amounting to approximately 4.5 billion barrels of incremental oil (another 20% of the original oil in place, or 28% of the stranded resource) -- is technically recoverable, as summarized below:

	No. of Fields	OOIP (MM Bbls)	Tech. Recoverable (MM Bbls)
State Offshore	12	1,100	237
Federal Offshore	87	20,950	4,213
Total	99	22,050	4,450

The breakout of remaining oil resources is shown in Figure 3-1 for state waters, and in Figure 3-2 for Federal shallow waters.

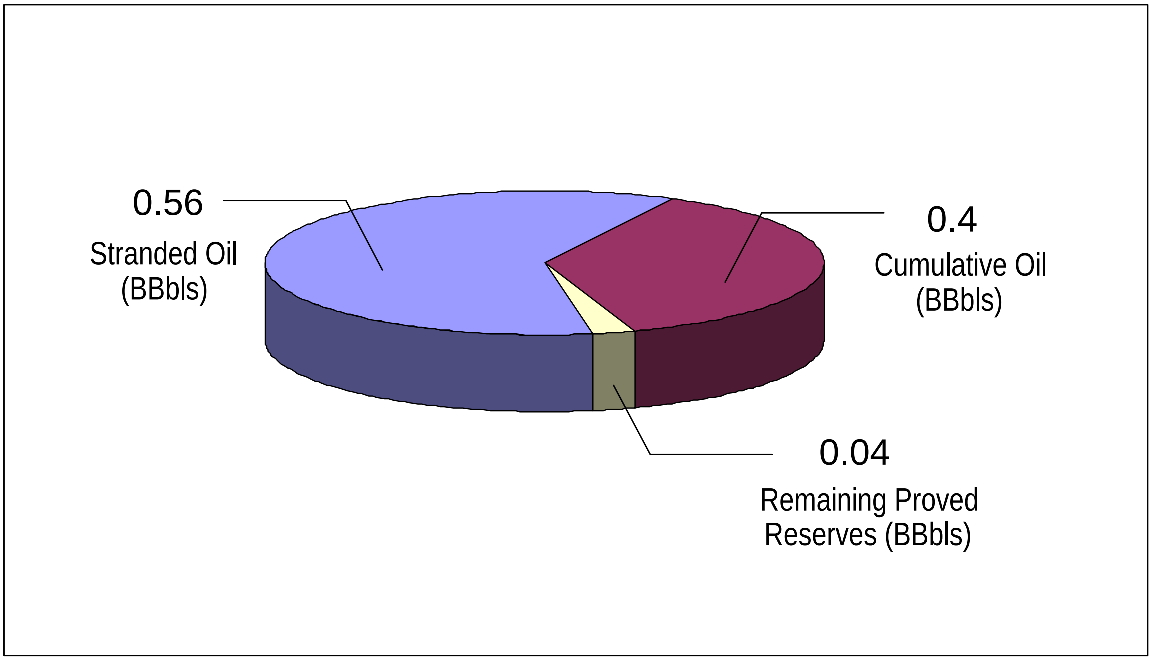

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Figure 3-1. Breakout of Resource Potential in 12 State Offshore Louisiana Oil Reservoirs

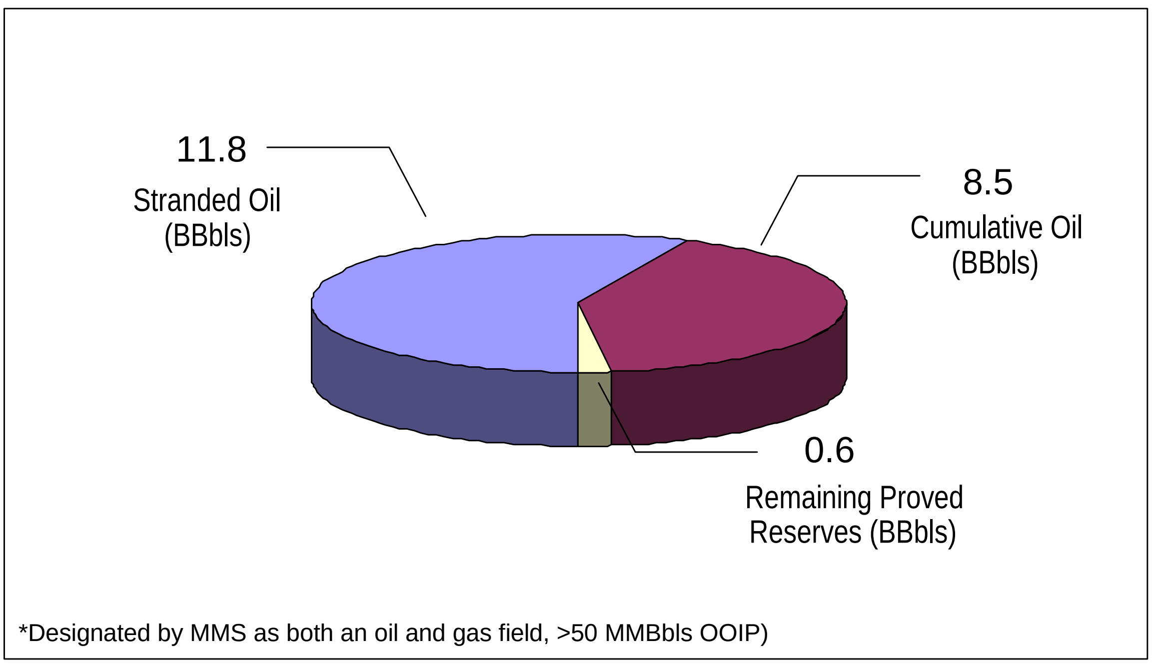

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Figure 3-2. Breakout of Resource Potential in 87 Large Federal Offshore Louisiana Oil Fields*

3.2 ECONOMIC RECOVERY POTENTIAL

The economic oil recovery potential was assessed under several "scenarios" incorporating alternative oil price, CO_2 cost, technology risk factors, and risk sharing. Under Reference conditions (Scenario #1), the economic evaluation assumed oil prices of $25 per barrel, CO_2 costs delivered to the platform at 5% of the crude oil price, and a project hurdle rate of return of 25% before taxes, to account for the technical and economic risk associated with the application of state-of-the-art CO_2-EOR technology in offshore Louisiana.

The analysis of CO_2-EOR potential under these Reference conditions concluded that no incremental resource is economically recoverable.

To improve the economic viability of using CO_2-EOR in these 99 offshore Louisiana fields/reservoirs, two "risk sharing" and cost reduction options that could provide possible routes for better economic performance were evaluated:

- *Scenario #1A: Improved CO_2 Accessibility.* Assumes a CO_2 sequestration incentive combined with improved technology that could allow CO_2 to be delivered to the offshore platform at reduced costs (3% of the crude oil price).
- *Scenario #1B: Public/Private "Risk Sharing".* Assumes risk sharing incentives - - involving reducing risk to investors (15% ROR aftbeforeer taxes), achieved through significant field demonstration pilot projects, along with reduced royalties on incremental oil produced by CO_2-EOR.

Reducing CO_2 costs as a result of a CO_2 sequestration incentive is not enough to encourage incremental recovery from CO_2-EOR with today's state-of-the-art technology (Scenario #1A). However, adding "risk sharing" incentives, even when still relying on higher cost "EOR ready" CO_2 (from refinery complexes and industrial plants), would lead to 22 economic fields and 1.3 billion barrels of incremental oil resource (Scenario #1B). These results are summarized in Figure 3-3.

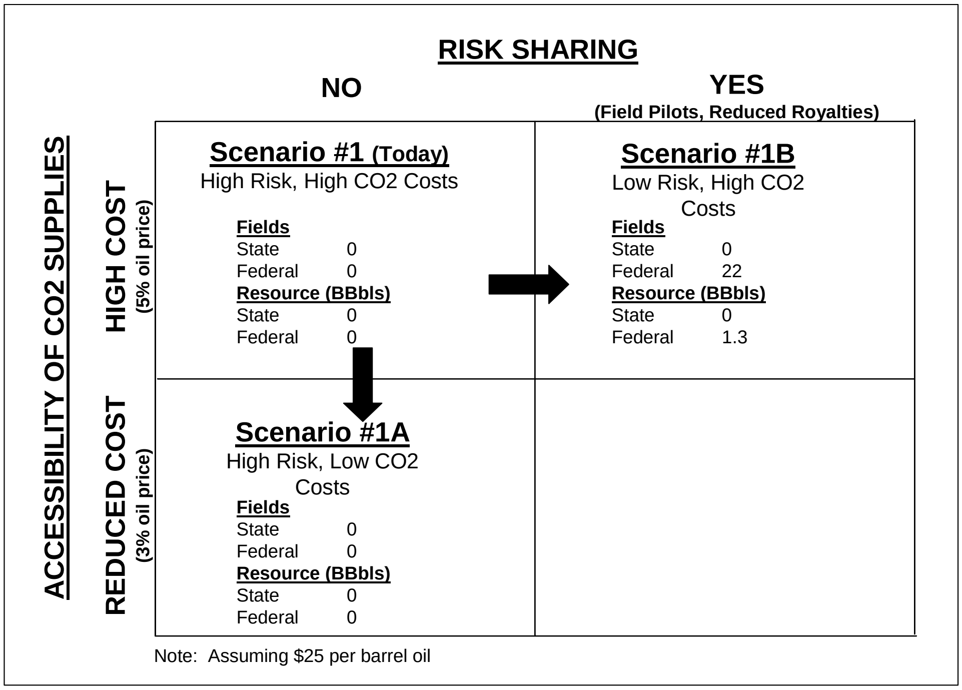


Figure 3-3. Impacts of CO_2 Accessibility and Risk Sharing on CO_2-EOR Economics

However, if both “risk sharing” and reduced CO_2 costs are combined, as shown in Scenario #2, the end result is the same, whether starting from Scenario #1A or #1B (Figure 3-4), resulting in as much as 3.6 billion barrels could be economically recoverable.

However, should the CO_2-EOR projects need to reinstall the platforms, redrill the wells and replace the infrastructure, the potential for affordably recovering this “stranded” oil would be lost.

Maintaining the infrastructure (platforms, wells and pipeline system) for these large oil fields and natural gas fields until the technology and/or economics of enhanced oil and natural gas recovery is demonstrated will be essential for conserving this domestic hydrocarbon resource endowment. Maintaining this infrastructure could require, in addition to cathodic protection of the platform and connecting pipelines, periodic subsea inspections to ensure joint integrity, perhaps the placement of accelerometers to measure stresses at critical locations, and other periodic non-destructive testing measures to ensure integrity over a sustained, dynamic life cycle in a marine environment.

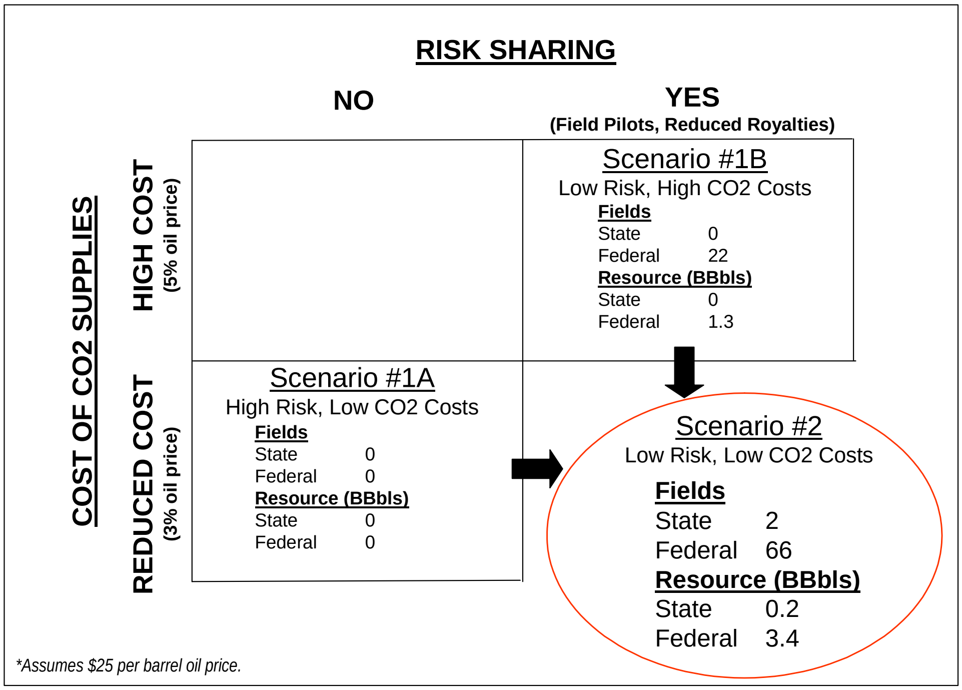


Figure 3-4. Impacts of CO_2 Costs and Risk Sharing on CO_2-EOR Economics

3.3 POTENTIAL ECONOMIC BENEFITS FROM INCREMENTAL SUPPLIES

Assuming that the 3.6 billion barrels of economically recoverable resource potential are developed (or booked as proved reserves) over a 40-year time frame, and assuming that these reserves are produced as a reserves-to-production ratio of 8 to 1, then this could result in incremental production amounting to over 200,000 barrels per day from offshore Louisiana by 2020, growing to nearly 230,000 barrels per day by 2025. This incremental production would contribute on the order of $250 million per year in increased revenues to the state and federal government.

Moreover, assuming that the number of jobs in the oil and gas industry per barrel of production remains the same as it is today, this would result in over 8,000 jobs retained by the Louisiana oil and gas industry that would likely otherwise be lost. Moreover, it could contributed to increased economic activity in Louisiana amounting to over $500 million per year.

These results are summarized in Table 3.1

Table 3.1. Estimated Economic Benefits from Incremental CO_2-EOR Potential in Offshore Louisiana

Year	Economic Resource	Booked Reserves	Production	Production	Jobs not Lost	Royalties	Taxes	Govt. Revenue	Economic Activity
	(Bbls)	(Bbls)	(Bbls/y)	(Bbls/day)		($ MM)	($ MM)	($ MM)	($ MM)
2005	3,600,000	90,000	11,250	30,822	1,078	$25	$10	$35	$68
2006		168,750	21,094	57,791	2,020	$47	$19	$66	$127
2007		237,656	29,707	81,389	2,845	$67	$27	$93	$178
2008		297,949	37,244	102,037	3,567	$83	$34	$117	$223
2009		350,706	43,838	120,105	4,199	$98	$39	$138	$263
2010		396,867	49,608	135,913	4,751	$111	$45	$156	$298
2011		437,259	54,657	149,746	5,235	$122	$49	$172	$328
2012		472,602	59,075	161,850	5,658	$132	$53	$185	$354
2013		503,526	62,941	172,441	6,028	$141	$57	$198	$378
2014		530,586	66,323	181,707	6,352	$149	$60	$208	$398
2015		554,262	69,283	189,816	6,636	$155	$62	$218	$416
2016		574,980	71,872	196,911	6,884	$161	$65	$226	$431
2017		593,107	74,138	203,119	7,101	$166	$67	$233	$445
2018		608,969	76,121	208,551	7,291	$171	$69	$239	$457
2019		622,848	77,856	213,304	7,457	$174	$70	$244	$467
2020		634,992	79,374	217,463	7,602	$178	$71	$249	$476
2021		645,618	80,702	221,102	7,730	$181	$73	$253	$484
2022		654,916	81,864	224,286	7,841	$183	$74	$257	$491
2023		663,051	82,881	227,072	7,938	$186	$75	$260	$497
2024		670,170	83,771	229,510	8,024	$188	$75	$263	$503
2025		676,398	84,550	231,643	8,098	$189	$76	$265	$507

4. CONCLUSIONS

An assessment of "stranded," oil and natural resources n the Louisiana offshore (consisting of the Central Planning Area (water depths less than 200 meters) in the Gulf of Mexico Federal waters and offshore Louisiana State Waters) shows that 56% of the original oil in-place and 34% of the original gas in-place will remain unrecovered with traditional technology and recovery practices. This large stranded oil and gas resource is the "prize" awaiting the application of more advanced recovery practices, particularly CO_2-EOR and alternative well completion and production practices for enhanced gas recovery.

The potential economic recovery of a portion of the crude oil resource base is dependent on several factors, some that government policy could influence:

- Future crude oil and natural gas prices

- Cost of future supplies of CO_2 (perhaps influenced via incentives for reducing CO_2 emissions, such as the geologic sequestration of anthropogenic CO_2)

- The economic risk associated with these projects, because of their technological challenges (perhaps influenced through government risk sharing programs or via fiscal incentives to encourage CO_2-EOR).

Using state-of-the-art CO_2-EOR technology, approximately 4.5 billion barrels of incremental crude oil resources (another 20% of the OOIP, or 38% of the stranded resource) are technically recoverable. At $25/Bbl, high risk premiums (25% ROR before taxes), and higher CO_2 costs (5% of oil price), very little of this resource will be economic to recover. Lowering CO_2 costs (3% of oil price) without reducing or sharing risks does not significantly enhance economic recovery potential. Alternatively, reducing the risk through public/private “risk sharing” programs (15% ROR before taxes, reduced royalties) results in 1.3 billion barrels of incremental recovery potential.

Finally, by both sharing risks and lowering delivered CO_2 costs, as much as 3.6 billion barrels could be economically recoverable.

Assuming that 3.6 billion barrels are developed over a 40-year time frame, by 2025 this would amount to:

- Incremental crude oil production of 200,000 to 250,000 barrels per day
- Over 8,000 jobs retained by the Louisiana oil and gas industry
- Increased economic activity in Louisiana amounting to over $500 million per year
- Increased state and federal revenues of over $250 million per year.

REFERENCES

Energy Information Administration 2004, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2003 Annual Report, DOE/EIA -0216 (2003) Advanced Summary, September 2004

LA DNR 2004 a. Oil and gas production data for offshore fields in Louisiana coastal waters were obtained from the Strategic Online Natural Resources Information System (SONRIS) (,http://sonris-www.dnr.state.la.us/www_root/sonrishomeIE.htm) maintained by the Louisiana Department of Natural Resources

LA DNR 2004 b. Louisiana Department of Natural Resources, *Louisiana Energy Facts Annual: 2003*, January 14, 2004

LA DNR 2004 c. Louisiana Department of Natural Resources maintains a coastal platform data base similar to the MMS platform database. The LDNR data base contains records of 2,885 installations of platforms along the Louisiana coast. This number was filtered for plugged and abandoned, salvaged, and removed platforms.

MMS 2004 Minerals Management Service On line Statistics http://www.mrm.mms.gov/Stats/pdfdocs/Loui_off.pdf

MMS 2004, MMS Platform Master Database and Report MMS Aug 2004. MMS provides a data base that offers information on each platform and whether or not it has been hauled inshore for disposal or re-use. The database was filtered to remove all platforms that have a removal date and accepted only major platforms (platforms with 6 or more wells). The database was then queried for the information cited above

Appendix A

Using *CO_2-PROPHET* for Estimating Oil Recovery

Model Development

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

Input Data Requirements

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

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

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

Calibrating CO_2-PROPHET

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

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

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

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

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

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

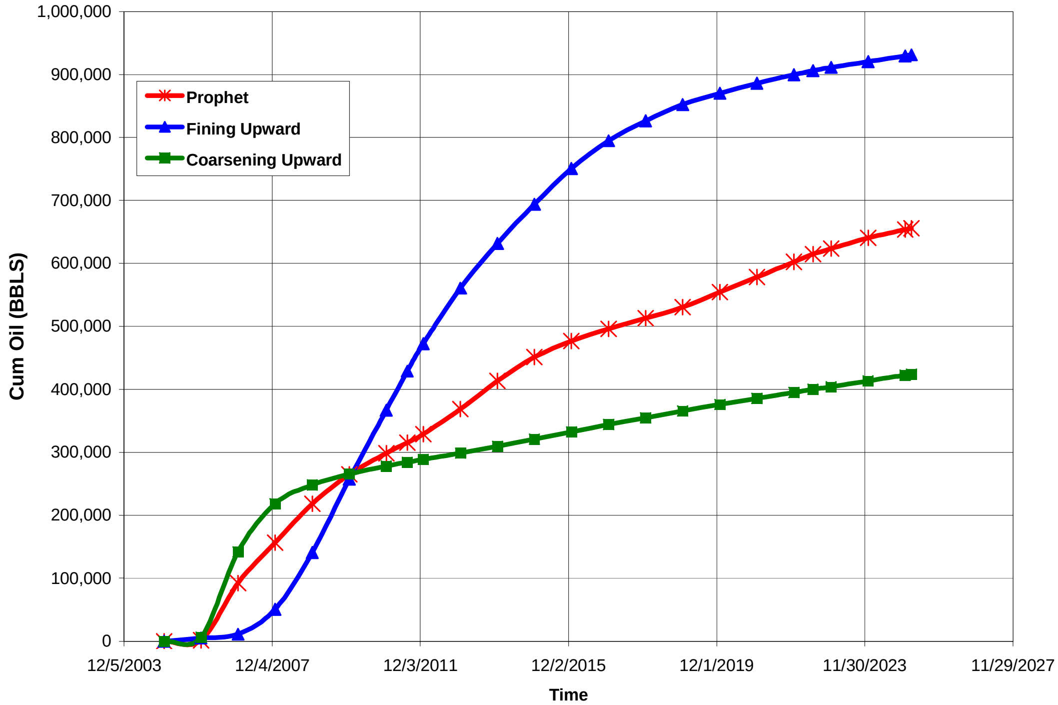
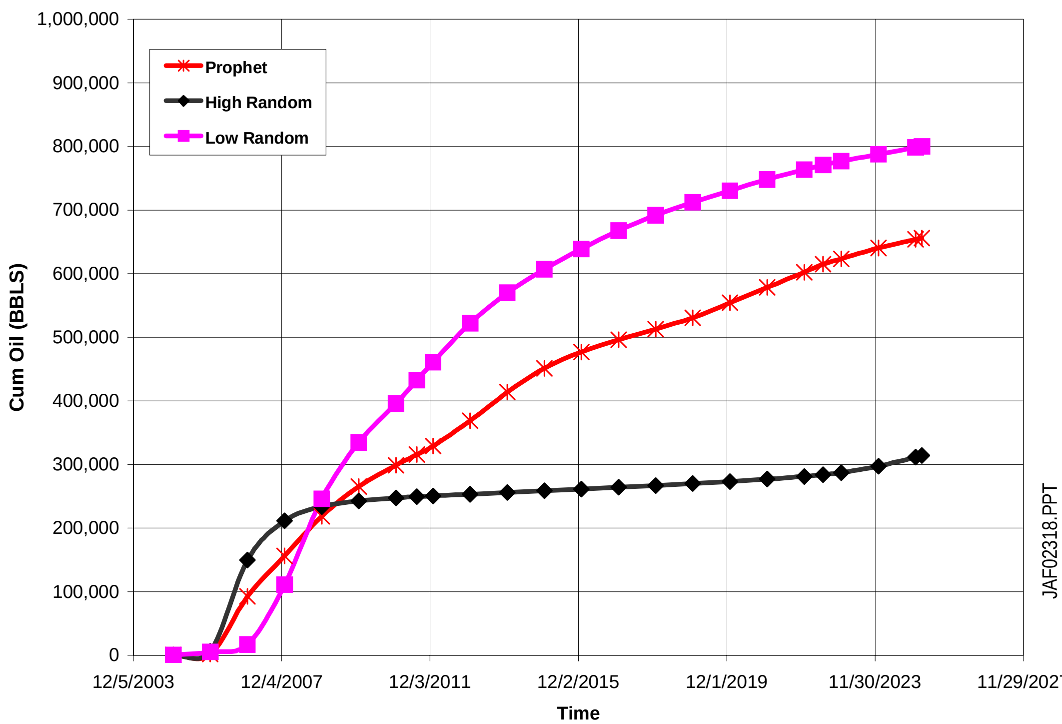


Figure A-2. CO_2-*PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



Comparison of *CO_2-PROPHET* and *CO_2PM*

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

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

Other key features of *CO_2-PROPHET* and its comparison with the technical capability of *CO_2PM* are also set forth below:

- Areal sweep efficiency in *CO_2-PROPHET* is handled by incorporating streamlines that are a function of well spacing, mobility ratio and reservoir heterogeneity, thus eliminating the need for using empirical correlations, as incorporated into *CO_2PM*.
- Mixing parameters, as defined by Todd and Longstaff, are used in *CO_2-PROPHET* for simulation of the miscible CO_2 process, particularly CO_2/oil mixing and the viscous fingering of CO_2.
- A series of reservoir patterns, including 5 spot, line drive, and inverted 9 spot, among others, are available in *CO_2-PROPHET*, expanding on the 5 spot only reservoir pattern option available in *CO_2PM*.
- *CO_2-PROPHET* can simulate a variety of recovery processes, including continuous miscible CO_2, WAG miscible CO_2 and immiscible CO_2, as well as waterflooding. *CO_2PM* is limited to miscible CO_2.

Appendix B

Offshore Louisiana CO_2-EOR Cost Model

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

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

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

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:

$$\text{Well D\&C Costs} = a_0 D^{a1}$$

Where:

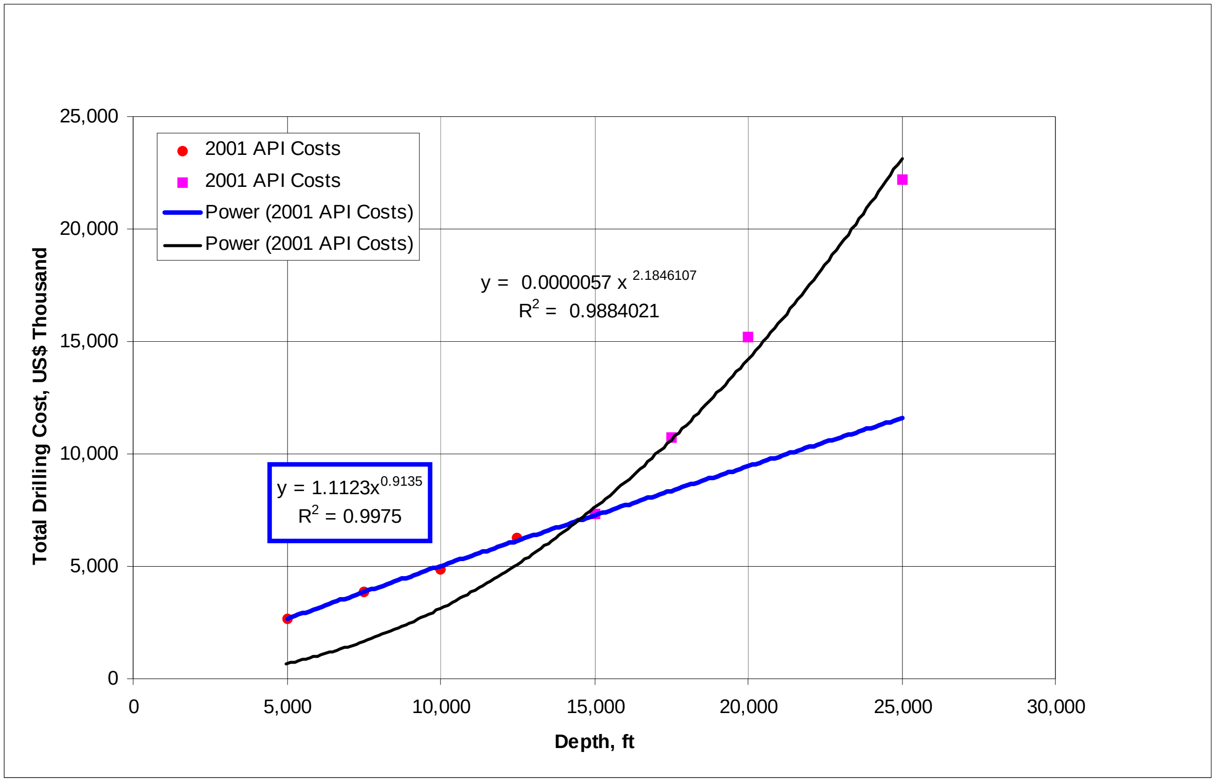
a_0= 1.11 for depths less than 15,000 ft. and 0.0000057 for depths greater than 15,000 ft.

a_1= 0.91 for depths less than 15,000 ft. and 2.18 for depths greater than 15,000 ft.

D is well depth

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

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



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2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well in Offshore Louisiana are set at zero. The cost model assumed that this type of equipment, including all subsurface and surface production equipment necessary to produce oil in a CO_2-EOR project (excluding tubing costs, which are included in drilling costs) would already be present on an offshore platform.

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

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

Injection Well Equipping Costs = $c_0 + c_1D$

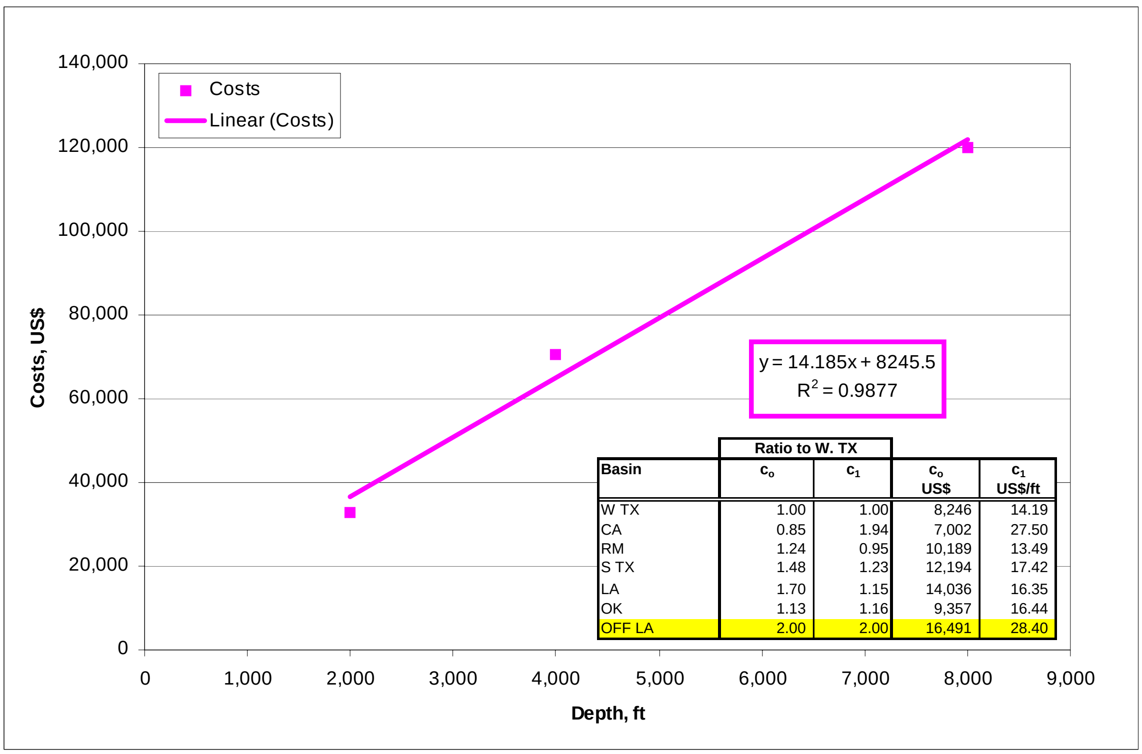
Where: c_o = \$16,491 (fixed)

c_1 = \$28.40 per foot

D is well depth

Figure B-2 illustrates the application of the lease equipping cost equation for a new injection well.

Figure B-2. Lease Equipping Costs for a New Injection Well in West Texas vs. Depth



Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,246	14.19
CA	0.85	1.94	7,002	27.50
RM	1.24	0.95	10,189	13.49
S TX	1.48	1.23	12,194	17.42
LA	1.70	1.15	14,036	16.35
OK	1.13	1.16	9,357	16.44
OFF LA	2.00	2.00	16,491	28.40

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

major reworking of the wells are required (which may be necessary if the platforms have been left idle for a long time), these costs could be considerably higher.

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 Offshore Louisiana is:

Well Conversion Costs = $c_0 + c_1D$

Where: c_o = \$205,000 (fixed)
c_1 = \$23.00 per foot
D is well depth

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

Well Rework Costs = $c_0 + c_1D$

Where: c_0 = \$40,000 (fixed)
c_1 = \$5.00 (per foot)
D is well depth

Existing oil production wells must also be reworked to be acceptable for production using CO_2-EOR. This requires pulling and replacing the tubing string and pumping equipment. Like above, the rework costs are depth-dependent.

Well Rework Costs = $c_0 + c_1D$

Where: c_0 = \$105,000 (fixed)

c_0 = \$23.00 (per foot)

D is well depth

6. Annual O&M Costs, Including Periodic Well Workovers. The 2002 EIA Direct Operating Costs Report and the 1984 NPC CO_2-EOR Study provide the basis for the operating and maintenance (O&M) costs for Gulf of Mexico platforms. Escalating the costs to 2004 dollars, platform O&M costs were estimated for Offshore Louisiana. The equation for the average per well O&M cost for CO_2-EOR in Offshore Louisiana is assumed to be \$212,000.

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

The cost of the recycling plant is set at \$1,400,000 per MMcfd of CO_2 capacity. As such, a large CO_2-EOR project in West Delta Block 30 in the 30 Block, with 370 MMcfd of CO_2 reinjection capacity, will require a recycling plant costing \$260 million. A smaller project in Ship Shoals 113 in the 113 Block, with 10 MMcfd of CO_2 reinjection capacity, requires a recycling plant costing \$107 million.

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

8. Other COTWO Model Costs.

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

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

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

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

The CO_2 distribution cost equation for Offshore Louisiana is:

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

Where:

C_D is the cost per mile of the necessary pipe (based on the CO_2 injection rate)

Distance = 10.0 miles

d. G&A Costs. General and administrative (G&A) costs of 5% are added to well O&M and lifting costs, because a number of the nominal G&A costs, such as insurance and accounting, are already in the well O&M costs set forth above..

e. Royalties. Royalty payments are assumed to be 16.6% of the value of the produced oil.

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 (transportation costs) differential for Offshore Louisiana (-\$0.00 per barrel) and the current gravity differential (-\$0.25 per ^{o}API, from a basis of 40 ^{o}API) into the average wellhead oil price realized by each oil reservoir. The equation for Alaska is:

Wellhead Oil Price = Oil Price + (-\$0.00) – [\$0.25*(40 - ^{o}API)]

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

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