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# Screening Criteria for Application of Carbon Dioxide Miscible Displacement in Waterflooded Reservoirs Containing Light Oil

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## Abstract

In conjunction with a joint Texaco/DOE research project, the LSU Department of Petroleum Engineering developed an improved method of screening reservoirs for the application of the carbon dioxide miscible enhanced oil recovery (EOR) process. This method, which can be applied to a large number of reservoirs, considers both the technical and economic feasibility of the EOR process.

The technical parameters of each reservoir are first compared to those of an "ideal" reservoir; and from that comparison, each reservoir is assigned a technical ranking. The technical ranking is used to estimate expected recovery. Key technical parameters used in the screening process are remaining oil in place, minimum miscibility pressure, reservoir depth, oil API gravity, and formation dip angle.

The reservoirs are subsequently screened for economic feasibility based on standardized capital costs and operation expenses that are representative of the reservoirs under consideration. The reservoirs are finally ranked based on the present worth value of revenues to costs ratio.

Using this method, we screened a database containing 197 light-oil reservoirs in Louisiana. The database includes three reservoirs where $CO_2$ miscible floods are ongoing; these reservoirs ranked first, fifth, and thirtieth. The high ranking of these reservoirs, which were identified based on detailed and comprehensive reservoir studies, validates the screening method.

Different application options in a specific reservoir can be screened, if warranted, by using $CO_2$ -PROPHET, a PC compatible software. $CO_2$ -PROPHET is a relatively simple numerical model capable of simulating water and gas floods. An example of its application is included.

## Introduction

In 1992, Texaco Exploration and Production Inc. (TEPI) and the U. S. Department of Energy (DOE) entered into a cost-sharing cooperative agreement to conduct an enhanced oil recovery demonstration at Port Neches field, Orange County, Texas. The agreement was formulated under the DOE Class I oil program, which encourages the development of innovative technical approaches to enhanced oil recovery. The innovative aspect of this project is the application of $CO_2$ miscible flooding in waterflooded light-oil fluvial-dominated reservoirs. TEPI agreed to disseminate the knowledge and the experience gained at Port Neches to other operators in the petroleum field.

Louisiana State University (LSU) has agreed to assist TEPI with technology transfer efforts. LSU's role was mainly to identify and rank waterflooded Louisiana reservoirs where the $CO_2$ EOR process may be used. To achieve this goal, LSU needed to develop a screening process that could be applied to reservoirs listed in the Louisiana Office of Conservation database. To be meaningful to interested operators, the screening method had to consider both the technical and economic feasibility of the EOR process. Because economic feasibility depends highly on $CO_2$ availability, identifying $CO_2$ sources and their distances to prospective reservoirs was imperative.

Once a prospect is identified, management options need to be considered. This task requires a user friendly numerical simulator. The effect of reservoir heterogeneity and well locations which is not considered in the initial screening can be investigated during the numerical simulations.

## Screening for Technical Feasibility

Screening is usually performed following certain guidelines and criteria developed from laboratory tests and field experience. Screening methods include reservoir performance prediction, binary comparison, and parametric optimization. Reservoir performance prediction was excluded because of the relatively large number of reservoirs screened.

Binary comparison is easy to perform; it involves comparing a candidate reservoir's parameters against established ranges. The binary screening method does not, however, account for the synergistic effects of reservoir parameters. For example, with the binary comparison method, a reservoir that has properties marginally within the recommended ranges would be selected over a reservoir that has very good values of all properties except one.

We used a parametric optimization method developed by Rivas *et al.*[1] Their screening method is based on determining for each property (j) of the reservoir (i) being ranked a corresponding normalized parameter, $X_{i,j}$, defined by:

$$X_{i,j} = \frac{|P_{i,j} - P_{o,j}|}{|P_{w,j} - P_{o,j}|} \quad \text{.......... (1)}$$

where $P_{o,j}$ is the magnitude of the property (j) in a fictitious reservoir called the optimum reservoir, which gives the best response to $CO_2$ flooding. $P_{w,j}$, on the other hand, is the value of the property (j) in another fictitious reservoir, called the worst reservoir, which is not suited to $CO_2$ flooding. The variable $X_{i,j}$ varies linearly between 0 and 1.

Because an exponential function is more adequate than a linear function for comparing different elements within a set, the normalized linear parameter, $X_{i,j}$, is transformed to exponential varying parameter, $A_{i,j}$ using the following heuristic equation:[1]

$$A_{i,j} = 100e^{-4.6X_{i,j}^2} \quad \text{.......... (2)}$$

$A_{i,j}$ ranges from a minimum of 1 to a maximum of 100.

To take into account the relative importance, or weight, of each reservoir parameter, a weighted grading matrix, $W_{i,j}$, is determined as follows:

$$W_{i,j} = A_{i,j} w_j, \quad \text{.......... (3)}$$

where $w_j$ is the weight of property (j).

The reservoirs are then ranked using a ranking parameter, $R_i$, defined as:

$$R_i = 100 * \frac{\sum_{j=1}^{j} M_{i,j}}{\sum_{j=1}^{j} M_{1,j}}, \quad \text{.......... (4)}$$

where $M_{i,j}$ is the product of the weighted matrix $W_{i,j}$ by its transpose, $W_{j,i}$.

The parameters used in the parametric optimization screening are oil API gravity, reservoir temperature, saturation of oil before the process application, porosity, permeability, ratio of reservoir pressure to $CO_2$ minimum miscibility pressure, net pay oil thickness, and reservoir dip. Other important parameters such as oil viscosity, gas to oil ratio, and bubble-point pressure were excluded for simplicity purposes. These properties, however, correlate with oil gravity, which is included in the screening.

The properties of the optimum reservoir, $P_{o,j}$, used in equation 1 were obtained by performing numerical simulation on a base case to determine the set of parameters that optimized reservoir response to $CO_2$ flooding. The relative importance or weight of each parameter on process performance was determined from the average normalized slopes of the reservoir performance around the optimum value of the parameter.[1] Optimum reservoir parameters and weighting factors are given in Table 1.

The properties of the worst reservoir, $P_{w,j}$, are determined using the data of the reservoirs to be ranked. The value farthest away from the optimum is the worst value. It is conceivable to have two worst values, one lower and one higher than the optimum. Worst parameters of the reservoirs considered in this study are listed in Table 2.

## $CO_2$ Sources and Providers in Louisiana

Critical to the economic feasibility of the process is the availability and location of $CO_2$ sources. A list of $CO_2$ industrial sources and providers was compiled through personal interviews and by reviewing a brochure published by the Louisiana Chemical Association.[2] Some potential commercial sources/providers of $CO_2$ were also identified from a computer database compiled by Louisiana State University.[3]

Naturally occurring $CO_2$ reservoirs are associated with the Jackson Dome geologic structure in Mississippi. Shell operates a pipeline that runs from Jackson Dome to Week's Island field. The pipeline has two sections: a 20 inch and a 10 inch. The 20-inch pipeline crosses from Mississippi into Louisiana in St. Helena Parish and continues across St. Helena, Livingston, East Baton Rouge, Ascension, and Iberville parishes. A site just northeast of Pierre Part serves as a pumping station where the 20-inch and 10-inch pipelines connect. The 10-inch pipeline crosses Assumption, St. Martin, St. Mary, and Iberia parishes, and terminates at Week's Island field. The last 16 miles of this pipeline were leased and are temporarily being used for hydrocarbon transportation. The remaining northern portion is still used to transport a small amount of $CO_2$ to Shell projects. The pipeline is available for tap-ins. Figure 1 shows fields with at least one waterflooded reservoir, plant sources of $CO_2$, and the location of the Shell pipeline.

## Economic Screening

To be practical, the screening method considers the economic feasibility of the process. The economic screening was based on before-tax, present-worth, benefit-to-cost ratio. The economic evaluation relied heavily on data and experience gained from similar projects. Data specific to the reservoir at hand was limited to initial oil in place, area, depth, number of wells, distance to the $CO_2$ source, and the ranking characteristic parameter calculated in the technical screening phase.

In determining the project's cost, it was assumed that the $CO_2$ project could take advantage of the existing infrastructure. It was also assumed that the operating cost is charged to the $CO_2$ project. This last assumption implies that production from the candidate reservoir is at or near the economic limit.

**Production Schedule.** Recent studies[4,5] of many field-scale $CO_2$ projects concluded that vastly different projects exhibit similar production responses to $CO_2$. Based on these studies, the estimated potential recovery of the $CO_2$ process when applied to an optimum reservoir is 15% of the original oil in place, N . The potential recovery from the reservoirs in the database is obtained by multiplying the optimum recovery by the ranking parameter, $R_i$ . This is expressed by:

$$N_{pi} = 0.15 * N^* R_i \quad (5)$$

The potential recovery is produced according to the schedule shown in Figure 2. The expected life of the project is 15 years. The annual revenues are calculated using the schedule with the price of oil set at $17/STB in the base case.

**Capital Outlay.** The capital needed to start a $CO_2$ project is field dependent. However, estimates using typical costs are acceptable for the purpose of screening. Capital outlay considered in this screening accounted for costs of new wells, pipeline to the $CO_2$ source, and injection and production equipment. Other equipment was assumed to be available as part of the existing infrastructure.

Drilling and completion cost, $C_d$, was estimated using the following equation developed in a DOE study:[6]

for onshore wells, $C_d = 30{,}430 * n^* e^{0.00035D}$, ................ (6)

and for offshore wells, $C_d = 688{,}514 * n^* e^{0.00011D}$, ....... (7)

where $C_d$ is the drilling and completion cost, in U.S. dollars;
D is the formation depth in feet; and
n is the number of required new wells.

The number of required new wells depends on the optimum spacing and the number of active wells. It is estimated from:

$$n = \frac{A}{S} - n_a \quad (8)$$

where A is the reservoir area in acres;
$n_a$ is the number of active wells; and
S is the optimum spacing.

For the purpose of screening , S is assumed in the base case to be 40 acres for onshore reservoirs and 80 acres for offshore reservoirs. The number of total wells, $n_t$, should not be less than two, an injector and a producer, or:

$$n_t = n + n_a \geq 2 \quad (9)$$

Injection and production equipment costs, $C_{inj}$ and $C_{pd}$ respectively, were estimated from the same DOE study using the equations:[6]

$$C_{inj} = 22{,}892\, n_{inj}\, e^{0.00009\,D} \quad (10)$$

and $C_{pd} = 24{,}908\, n_p\, e^{0.00014\,D}$ , ........ (11)

where D is the formation depth in feet;
$n_p$ is the number of producers; and
$n_{inj}$ is the number of injection wells, which is taken to be half of the total number of wells.

For projects requiring $CO_2$ injection, $CO_2$ can be transported by tank truck, railcar, or pipeline. Transportation by pipeline is considered the least expensive of all these methods.[5] Depending on the pipeline pressure conditions, $CO_2$ can be transported either at subcritical or supercritical conditions or as a liquid. The supercritical $CO_2$ pipeline system is the most economical system for transporting the large quantities of $CO_2$ needed for enhanced oil recovery.[7] The following equation can be used to estimate the cost of the pipeline:[6]

$$C_{pip} = (100{,}000 + 2{,}008\, q_{inj}^{0.834})\, d, \quad (12)$$

where $C_{pip}$ is the pipeline cost in U.S. dollars;
d is the distance to the Shell pipeline, in miles; and
$q_{inj}$ is the estimated $CO_2$ pipeline capacity, in MMSCF/D.

$q_{inj}$ is estimated from the following correlation:[6]

$$q_{inj} = 2 * N_{pi}, \quad (13)$$

where $N_{pi}$ is the projected incremental oil in million barrels estimated by Equation 5, in STB.

If more than one reservoir is located in the same field, the pipeline cost is shared by the reservoirs. The pipeline capacity is calculated from Equation 13 using the incremental production from all the reservoirs to share the cost. The pipeline cost, $C_{pip}$, calculated from Equation 12 is then shared between the reservoirs on the basis of the individual incremental oil value. All capital outlay is charged during the first year of the project.

**$CO_2$ Cost.** Published studies suggest that 6 MSCF per one STB of incremental oil is a representative average value of $CO_2$ utilization.[4,8] The purchase of $CO_2$ is a major expense for miscible projects, especially if $CO_2$ is obtained from industrial sources. The $CO_2$ cost for the purpose of this screening was based on availability from natural sources via the Shell pipeline. The $CO_2$ cost was estimated at $0.60/MSCF and remained constant throughout the injection period. The $CO_2$ project was not burdened with separation and recycling costs.

It was assumed that the value of produced natural gas would offset the cost of $CO_2$/natural gas separation.

**Operating costs.** Operating costs are site and operator specific. The average annual operating cost, $C_{op}$ , in U.S. dollars, however, can be predicted from the following equation:[6]

$$C_{op} = 13{,}298\, n_t e^{0.00011D} \quad (14)$$

It is assumed that all wells will require future workovers at an average of 0.25 workovers per well per year. The cost of a workover is estimated to be half the cost of the equipment. The annual workover cost, $C_{wo}$, can then be determined using the following equation:

$$C_{wo} = 0.25\left(\frac{n_t}{2}\right)\left(C_{inj} + C_{pd}\right) \quad (15)$$

where $C_{inj}$ and $C_{pd}$ are expressed by equations 10 and 11, respectively.

Both the technical and economic screening algorithms were written in FORTRAN™ code. The economic screening may also be run on an electronic spreadsheet.

## Louisiana Waterflooded Reservoirs Database

The approach described in this paper was used to screen waterflooded reservoirs in Louisiana. These reservoirs are listed in a database available from the Louisiana Office of Conservation and Reserves. Initially, the database listed 499 reservoirs that were waterflooded. These reservoirs represented a total original-oil-in-place of 5.289 billion STB, or an average of 10.6 million STB/reservoir.

Many reservoirs were eliminated in the initial stage of screening for various reasons. Because of the high cost of transporting $CO_2$, all of the 101 reservoirs located in North Louisiana were eliminated. An additional 188 reservoirs, mostly inactives, were eliminated because current saturation and pressure data, two key screening parameters were unavailable. Inconsistent data also led us to eliminate 13 reservoirs, leaving 197 reservoirs for screening and ranking.

**Screening Results.** Table 3 lists the 40 top ranked reservoirs and their relevant data. The reservoirs are ranked based on before-tax, present-worth, benefit-to-cost ratio. The economic evaluation considered shared pipeline cost. A discount rate of 15% was used in the base case. A positive value of the benefit-to-cost ratio indicates profitability.

As expected, the final ranking did not correlate with the technical ranking parameter, $R_i$. Under the conditions established for the model, the majority of the possible candidates are not economically suitable for miscible displacement with $CO_2$. Only 20% of the reservoirs in the database look economically attractive. Nevertheless, the potential incremental oil from these reservoirs is a significant 70.6 MMSTB of oil. The economic potential of $CO_2$ depends on the well spacing, $CO_2$ price, oil price, and discount factor.

The ranking shown in Table 3 was for a base case in which a 40-and 80-acre spacing were used for onshore and offshore reservoirs, respectively. The base case used 0.6$/Mcf, 17$/STB and 15% for $CO_2$ price, oil price, and discount factor. Sensitivity of the $CO_2$ performance to these parameters is shown in Table 4.

The validity of the screening approach is demonstrated by the fact that of the $CO_2$ projects contained in the database are highly ranked. These cases were considered to be profitable by the individual operator prior to the implementation of the process.

## Specific Reservoir Performance

The objective of the reservoir screening and ranking is to attract the attention of operators to the potential of the miscible $CO_2$ EOR process in waterflooded reservoirs. Once this is accomplished, it is presumed that the operator will be interested in the absolute performance of a specific reservoir as opposed to its ranking relative to other reservoirs in the database. A user-friendly numerical simulator allows the screening of different implementation options. The effects of reservoir heterogeneity and well locations, which were not included in the initial screening, can be considered. Additional parameters can also be included in the simulation. $CO_2$-PROPHET™ software was recommended to perform this task[8]

$CO_2$-PROPHET, a water-and gas-flood prediction software, was developed by Texaco with support of the U.S. Department of Energy. The simulator has been shown to be a good tool for screening and reservoir management and is being released with a detailed user manual to the industry. The hardware required to run $CO_2$-PROPHET includes an Intel® 386-based PC or better with at least 4 megabytes of RAM and 4 megabytes of free disk space. A math coprocessor is required for the 386 or the 486SX systems.[8]

This software runs on PC compatible computers. Some of its features include: easy reservoir parameter input; several predefined patterns to simplify use; the ability to design patterns to fit most situations; fast computation; multiple flood regimes that model water, gas, and miscible floods; output in surface units and dimensionless formats; and output designed for importing data into a spreadsheet.[8]

$CO_2$-PROPHET computes streamlines between injection and production wells to form stream tubes. It then makes flow computations along the stream tubes. It uses the Dykstra-Parsons coefficient to distribute the initial injection into a maximum of ten layers. A new case can be set up and run in a few minutes, making this program ideal for screening of EOR projects and pattern comparisons.

The use of $CO_2$-PROPHET is demonstrated with one of the top-ranked reservoirs, fictitiously named Eden. The Eden reservoir is located in a salt dome related structure. Its initial pressure in 1949, when commercial development began, was 4500 psi. The reservoir had a large initial gas cap about 0.444

the size of the oil zone. The estimated original-oil-in-place was 11.7 million barrels of 35.2 API gravity oil. By 1972, the reservoir had produced 2.6 millions of barrels of oil, mostly due to gas cap expansion. In 1974, a waterflooding program was initiated to increase recovery. As of 1990, waterflooding had resulted in the recovery of 4.3 millions barrels of oil.

The Eden reservoir was simulated using an option that allowed for the development of a stream tube model which was stored for later investigation of implementation options. Figure 3 shows the stream tube model of the Eden reservoir and the well locations.

Two implementation options were investigated: waterflooding and waterflooding followed by hybrid $CO_2$ displacement. For the waterflooding option, the startup conditions were those existing in 1974 at the end of the primary recovery phase. A total of 1.25 pore volumes (P.V.) of water was injected in the waterflooding option. The hybrid $CO_2$ process started after 0.7 P.V. of water was injected. The two options are compared in Table 4 and Figure 4. Figure 4 shows the expected cumulative oil recovery versus time. These data can be imported to a spreadsheet for site and operator specific economic evaluation.

## Conclusions and Recommendations

A screening model was developed to rank a large number of potential reservoirs in a short period of time and with little effort. The model provides for rapid evaluation of both the technical and economic feasibility of the $CO_2$ miscible process. Of the 197 waterflooded reservoirs screened in this project, 39 looked economically attractive. The potential incremental recovery from these reservoirs is 70.6 million STB. To complement the screening model, $CO_2$-PROPHET numerical sumulator was used. This software allowed to incorporate site- and operator-specific data that are not considered in the initial screening.

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## SI Metric Conversion Factors

| | | |
|---|---|---|
| acre × 4.046 873 | E+03 | = $m^2$ |
| °API 141.5/(131.5+°API) | | = $g/cm^3$ |
| bbl × 1.589 873 | E-01 | = $m^3$ |
| cp × 1.0* | E-03 | = Pa-s |
| ft × 3.048* | E-01 | = m |
| $ft^3$ × 2.831 685 | E-02 | = $m^3$ |
| °F × (°F-32)/1.8 | | = °C |
| mile × 1.609 344* | E+00 | = km |
| psi × 6.894 757 | E+00 | = kPa |

* Conversion factor is exact

**Table 1: Optimum Reservoir Parameters and Weighting Factors.**[1]

| Parameter | Optimum | Weight |
|---|---|---|
| API Gravity | 37 | 0.24 |
| Oil saturation, % | 60 | 0.20 |
| Pressure/ MMP | 1.30 | 0.19 |
| Temperature, °F | 160 | 0.14 |
| Net oil thickness, ft | 50 | 0.11 |
| Permeability, md | 300 | 0.07 |
| Dip, ° | 20 | 0.03 |
| Porosity, % | 20 | 0.02 |

**Table 2: Worst Parameters from Louisiana's Reservoir Database.**

| Parameter | Lower Limit | Upper Limit |
|---|---|---|
| API Gravity | 24 | 48 |
| Oil saturation, % | 8 | 80 |
| Pressure/ MMP | 0.10 | 1.47 |
| Temperature, °F | 80 | 276 |
| Net oil thickness, ft | 5 | 175 |
| Permeability, md | 17 | 3485 |
| Dip, ° | 0.03 | 64 |
| Porosity, % | 17.6 | 34 |

**Table 3: Potentially profitable reservoirs for CO2 miscible displacement in Louisiana**

Base case: 197 reservoirs with complete information

| Prospect Identification | | | | Reservoir Parameters | | | Screening Parameters | | | | | | | | Tech. | Economic Parameters | | | Rank |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Operator | Field | Reservoir | Depth Feet | EOOIP MMBbl | Recov. MMBbl | Area Acres | API | Temp o F | Perm, K, md | So % | P/MMP | Poros. % | H oil Feet. | dip o | Rank | Wells Now | New Wells | Shared Dist, ml | 40/80 15 % |
| Texaco | Paradise | Lower 9000 Sand RM | 10450 | 13.5 | 1.7 | 235 | 35.7 | 193 | 515 | 62.0 | 0.909 | 28.8 | 45 | 8 | 85.04 | 6 | 0 | 1.0 | 1.14 |
| Hassie | South Pass Block 24 | 8800' RD | 8295 | 36.7 | 3.1 | 960 | 30.0 | 178 | 447 | 61.0 | 0.341 | 26.0 | 39 | 3 | 55.79 | 12 | 0 | 11.6 | 1.04 |
| Shell | South Pass Block 27 | "N1b" Reservoir F Sand unit | 7300 | 3.7 | 0.2 | 70 | 28.0 | 165 | 537 | 43.5 | 0.478 | 30.0 | 35 | 7 | 42.99 | 1 | 0 | 1.4 | 0.96 |
| Shell | Eugene Island Block 18 | "O" Sand | 10071 | 35.6 | 4.1 | 273 | 38.5 | 151 | 1000 | 31.3 | 1.866 | 32.0 | 80 | 4 | 76.50 | 3 | 0 | 59.0 | 0.95 |
| Texaco | Paradise | Main Pay RT SU | 10300 | 11.7 | 1.3 | 114 | 36.8 | 205 | 1910 | 51.7 | 0.752 | 27.5 | 51 | 10 | 74.25 | 2 | 1 | 1.0 | 0.93 |
| Shell | South Pass Block 27 | "M" RB SU | 7500 | 7.4 | 0.7 | 150 | 32.4 | 178 | 200 | 47.5 | 0.465 | 30.0 | 40 | 9 | 60.03 | 3 | 0 | 3.9 | 0.89 |
| Shell | South Pass Block 27 | "N1b" Reservoir C Sand Unit | 7450 | 9.2 | 0.6 | 211 | 32.0 | 168 | 300 | 22.9 | 0.616 | 33.0 | 28 | 5 | 44.22 | 3 | 0 | 3.5 | 0.82 |
| Texaco | Caillou Island | Upper 8000 RA SU | 7900 | 6.4 | 0.6 | 182 | 38.2 | 103 | 285 | 17.1 | 1.484 | 31.0 | 25 | 18 | 58.62 | 2 | 0 | 6.0 | 0.76 |
| Shell | South Pass Block 27 | "N1a" Reservoir C Sand unit | 7350 | 14.4 | 1.1 | 328 | 32.0 | 168 | 300 | 36.9 | 0.340 | 33.0 | 27 | 5 | 49.67 | 6 | 0 | 6.2 | 0.72 |
| Gulf | West Bay | Proposed WB6B (RG) Sand Unit | 7419 | 49.7 | 3.6 | 530 | 31.3 | 80 | 470 | 38.4 | 1.306 | 32.6 | 41 | 5 | 48.52 | 5 | 2 | 29.9 | 0.71 |
| Shell | South Pass Block 27 | Proposed SPB 27 K RA SU | 6200 | 4.1 | 0.3 | 174 | 27.5 | 160 | 500 | 54.4 | 0.484 | 28.0 | 17 | 10 | 48.61 | 2 | 0 | 1.7 | 0.69 |
| Gulf | West Bay | 5 A 'B" | 7000 | 2.6 | 0.2 | 74.2 | 33.0 | 104 | 500 | 39.1 | 0.774 | 31.5 | 23 | 8 | 48.39 | 1 | 0 | 1.6 | 0.68 |
| Shell | South Pass Block 27 | "N4b" RC SU | 7600 | 7.4 | 0.5 | 157 | 26.6 | 172 | 400 | 48.8 | 0.312 | 30.0 | 34 | 5 | 43.61 | 3 | 0 | 2.8 | 0.63 |
| Shell | South Pass Block 27 | "N1b" Reservoir D Sand Unit | 7350 | 3.6 | 0.2 | 102 | 27.0 | 161 | 300 | 29.0 | 0.444 | 33.0 | 24 | 3 | 28.74 | 1 | 0 | 0.9 | 0.61 |
| Shell | South Pass Block 24 | Reservoir A, "Q" Sand | 8125 | 17.0 | 1.7 | 516 | 39.5 | 186 | 500 | 21.5 | 1.161 | 32.0 | 24 | 2 | 66.09 | 5 | 1 | 6.4 | 0.61 |
| Shell | South Pass Block 27 | "M2" Reservoir A Sand Unit | 6775 | 39.0 | 3.4 | 691 | 29.5 | 162 | 400 | 57.4 | 0.574 | 33.0 | 39 | 3 | 58.15 | 6 | 3 | 19.7 | 0.58 |
| Shell | South Pass Block 27 | "M6" Reservoir A Sand Unit | 6750 | 22.9 | 1.2 | 360 | 27.0 | 159 | 600 | 33.9 | 0.479 | 33.0 | 41 | 4 | 34.24 | 9 | 0 | 6.8 | 0.52 |
| Shell | South Pass Block 27 | "N1b" Reservoir B Sand Unit | 7550 | 3.5 | 0.1 | 116 | 26.8 | 168 | 300 | 26.7 | 0.329 | 33.0 | 22 | 2 | 26.03 | 1 | 0 | 0.8 | 0.48 |
| Shell | South Pass Block 24 | RA P-Q Sand | 7860 | 44.2 | 3.8 | 1574 | 35.0 | 167 | 300 | 24.3 | 0.555 | 30.0 | 15 | 2 | 57.34 | 18 | 2 | 14.3 | 0.46 |
| Shell | South Pass Block 27 | "N1b" Reservoir E Sand Unit | 7000 | 25.3 | 1.5 | 434 | 26.0 | 160 | 500 | 44.8 | 0.279 | 33.0 | 33 | 3 | 40.31 | 3 | 2 | 8.9 | 0.31 |
| Shell | South Pass Block 24 | 8000' RS SU (Horstal "S") | 8150 | 14.6 | 1.1 | 577 | 32.0 | 176 | 500 | 42.2 | 0.362 | 29.0 | 24 | 3 | 52.39 | 11 | 0 | 4.3 | 0.27 |
| Gulf | Quarantine Bay | 9BC, C2 | 9430 | 3.1 | 0.3 | 90 | 35.9 | 200 | 200 | 32.0 | 0.946 | 28.0 | 20 | 2 | 60.63 | 1 | 0 | 6.4 | 0.26 |
| Chevron | Bay Marchand Blk 2 | 3650' Upper Block D. 3650' (U) | 3850 | 26.8 | 0.8 | 167 | 24.0 | 136 | 570 | 11.4 | 0.352 | 32.0 | 78 | 17 | 18.99 | 2 | 0 | 24.0 | 0.24 |
| Chevron | South Pass Block 24 | 8200' "T" Sand | 8294 | 84.3 | 6.4 | 1456 | 32.0 | 104 | 325 | 43.2 | 0.819 | 31.8 | 45 | 2 | 50.98 | 9 | 9 | 24.2 | 0.24 |
| Shell | South Pass Block 24 | Res. A "T1a" Sand | 8700 | 12.3 | 0.7 | 374 | 30.0 | 175 | 300 | 32.3 | 0.725 | 32.0 | 23 | 2 | 39.59 | 7 | 0 | 2.8 | 0.21 |
| Shell | South Pass Block 27 | "N2" Reservoir B Sand Unit | 7500 | 2.4 | 0.1 | 119 | 27.0 | 94 | 380 | 41.4 | 0.667 | 29.0 | 18 | 6 | 25.98 | 1 | 0 | 0.5 | 0.20 |
| Shell | South Pass Block 27 | "N4b" Sand Reservoir B | 7850 | 10.9 | 0.4 | 302 | 24.2 | 168 | 400 | 22.7 | 0.237 | 31.0 | 35 | 3 | 24.22 | 4 | 0 | 2.3 | 0.20 |
| Texaco | West Cote Blanche Bay | Lower No. 11 Sand, Reservoir N3 | 8600 | 7.0 | 0.6 | 40 | 33.8 | 108 | 1200 | 36.4 | 1.495 | 33.0 | 84 | 27 | 59.13 | 1 | 1 | 1.2 | 0.14 |
| Texaco | West Cote Blanche Bay | No. 17 Sand. Res. P-Q | 7700 | 4.7 | 0.5 | 75 | 33.1 | 116 | 400 | 44.1 | 1.314 | 28.0 | 42 | 20 | 66.76 | 0 | 1 | 0.9 | 0.12 |
| Texaco | Paradise | Paradis Zone, Seg. A-B | 10000 | 119.0 | 14.6 | 2057 | 38.0 | 200 | 1348 | 60.0 | 0.872 | 26.2 | 55 | 4 | 81.73 | 8 | 43 | 1.0 | 0.10 |
| Chevron | South Pass Block 24 | 8600' RA Sand Unit | 8721 | 85.3 | 7.0 | 1496 | 32.4 | 179 | 500 | 35.7 | 0.734 | 31.0 | 43 | 2 | 54.95 | 7 | 12 | 26.5 | 0.09 |
| Shell | South Pass Block 27 | "N1a" Reservoir E Sand Unit | 7000 | 21.2 | 0.9 | 529 | 26.0 | 160 | 500 | 31.5 | 0.391 | 33.0 | 22 | 3 | 28.49 | 6 | 1 | 5.3 | 0.08 |
| Gulf | Grand Bay | GB 10B (FBB) RA SU | 7870 | 7.7 | 0.7 | 440 | 35.3 | 98 | 300 | 23.9 | 1.402 | 32.6 | 11 | 2 | 56.17 | 6 | 0 | 10.5 | 0.05 |
| Gulf | West Bay | 11 Sand Fault Block B | 10850 | 26.2 | 2.4 | 436 | 30.0 | 136 | 500 | 47.3 | 1.163 | 30.0 | 55 | 3 | 60.26 | 2 | 3 | 19.7 | 0.05 |
| Shell | South Pass Block 27 | "N1c" Reservoir E Sand Unit | 7000 | 10.5 | 0.4 | 347 | 26.0 | 160 | 200 | 22.3 | 0.451 | 33.0 | 23 | 3 | 23.00 | 5 | 0 | 2.1 | 0.05 |
| Texaco | Caillou Island | 9400 ft Sand, RBB1C | 10000 | 23.3 | 2.3 | 427 | 39.0 | 138 | 1900 | 17.3 | 1.113 | 30.0 | 44 | 12 | 64.42 | 2 | 3 | 23.8 | 0.03 |
| Shell | South Pass Block 27 | SPB27 L4 RD SU | 7430 | 2.2 | 0.1 | 120 | 32.0 | 93 | 300 | 43.9 | 0.569 | 32.0 | 16 | 8 | 43.09 | 2 | 0 | 0.8 | 0.02 |
| Gulf | Quarantine Bay | 8 Sand, Reservoir "B" | 8950 | 17.0 | 1.3 | 303 | 34.5 | 112 | 1669 | 22.1 | 1.102 | 32.0 | 28 | 3 | 50.43 | 3 | 1 | 29.0 | 0.01 |
| Shell | South Pass Block 27 | "M2" Reservoir B Sand Unit | 6280 | 8.9 | 0.3 | 142 | 25.0 | 155 | 500 | 14.4 | 0.463 | 33.0 | 32 | 4 | 23.60 | 5 | 0 | 1.8 | 0.00 |
| Shell | South Pass Block 27 | Reservoir "A" "L2" Sand Unit | 6420 | 30.2 | 1.1 | 992 | 25.6 | 153 | 500 | 20.1 | 0.324 | 33.4 | 33 | 3 | 24.01 | 18 | 0 | 6.3 | -0.04 |

**Table 4: Summary of the sensitivity analysis for ranking of candidate reservoirs for CO2 miscible displacement in Louisiana**

| Parameter | Spacing, Onshore/Offshore | | | | Discount Rate | | | Oil Price, $/Bbl | | | CO2 Price, $/Mcf | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 20/40 | 40/40 | 40/80 | 80/160 | 12% | 15% | 20% | 15 | 17 | 20 | 0.6 | 0.8 | 1.0 |
| Attractive Reservoirs | 5 | 8 | 39 | 73 | 41 | 39 | 27 | 28 | 39 | 47 | 39 | 32 | 27 |
| Potential Oil, MMBbls | 6.9 | 24.5 | 70.6 | 110.4 | 74.6 | 70.6 | 39.7 | 40.3 | 70.6 | 86.3 | 70.6 | 63.3 | 39.6 |

**Table 5: Reservoir and simulation parameters. Eden field**

**RESERVOIR PARAMETERS**

| | |
|---|---|
| OOIP, MMBls | 11.723 |
| Permeability, md | 1910 |
| Temperature, F | 205 |
| Dip angle, o | 10 |
| Gravity, API | 35.2 |
| MMP, psi | 3500 |
| Dykstra- Parsons | 0.75 |
| C5+ MW | 230.3 |
| Swc, % | 14 |
| Rs. scf/stb | 900 |
| Oil viscosity, cp | 0.35 |
| Bo, rb/stb | 1.4 |
| Gas gravity | 0.7 |
| Water viscosity, cp | 0.8 |
| Salinity, ppm | 100000 |
| Mixing Parameter | 0.6666 |
| Area, sf | 3841632 |
| Thickness, ft | 139.5 |
| Porosity, % | 20 |
| Kh/Kv | 0.1 |

**SIMULATION PARAMETERS**

**RELATIVE PERMEABILITIES**

| | |
|---|---|
| Layers | 3 |
| Pattern | Custom |
| Krocw | 1 |
| Kwro | 0.116 |
| Krsmax | 0.477 |
| Krgcw | 0.477 |
| Nw | 2 |
| Now | 2 |
| Ns | 2 |
| Ng | 2 |
| Nog | 2 |
| Sorw | 0.3 |
| Sorg | 0.3 |
| Sorm | 0.05 |
| Sgr | 0.3 |
| Ssr | 0.3 |

**SIMULATION RUNS**

**WF & CO2 HYBRID**

| | |
|---|---|
| Pre- wf pres, psi | 3335 |
| Pre -wf So, % | 0.517 |
| Water inj, hcpv | 0.7 |
| CO2 slug, hcpv | 0.125 |
| WAG (CO2 hcpv) | 0.3 |
| WAG ratio (vol) | 2 |
| Chase water, hcpv | 0.3 |
| Qw inj. bpd/w | 1000 |
| QCO2, MMscf/d/w | 6.2 & 8.0 |

**WATERFLOODING**

| | |
|---|---|
| Pre- wf pres, psi | 1484 |
| Pre -wf So, % | 0.517 |
| Water inj, hcpv | 1.25 |
| Qw inj, bpd/well | 1000 |

**INITIAL CO2 HYBRID**

| | |
|---|---|
| Pre-co2 pres, psi | 3335 |
| Pre-co2 So, % | 0.517 |

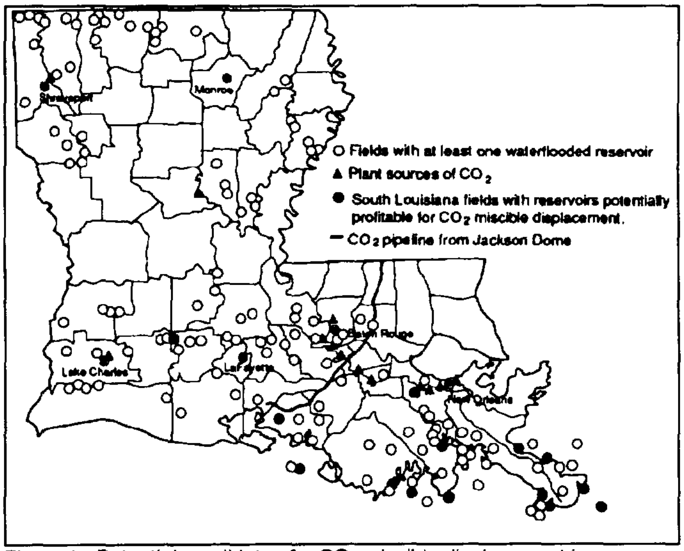


Figure 1. Potential candidates for $CO_2$ miscible displacement in Louisiana

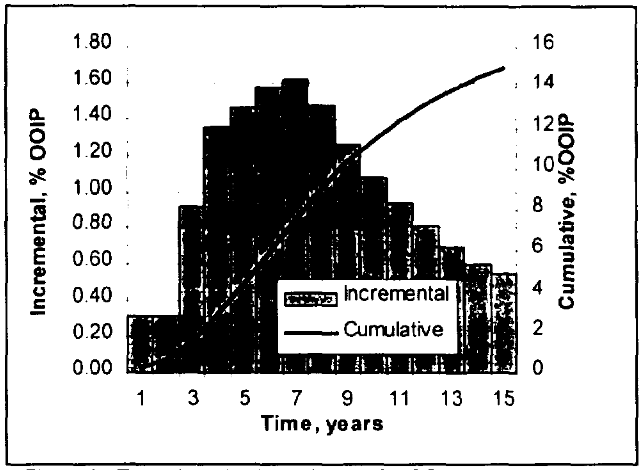


Figure 2. Typical production schedule for $CO_2$ miscible displacement

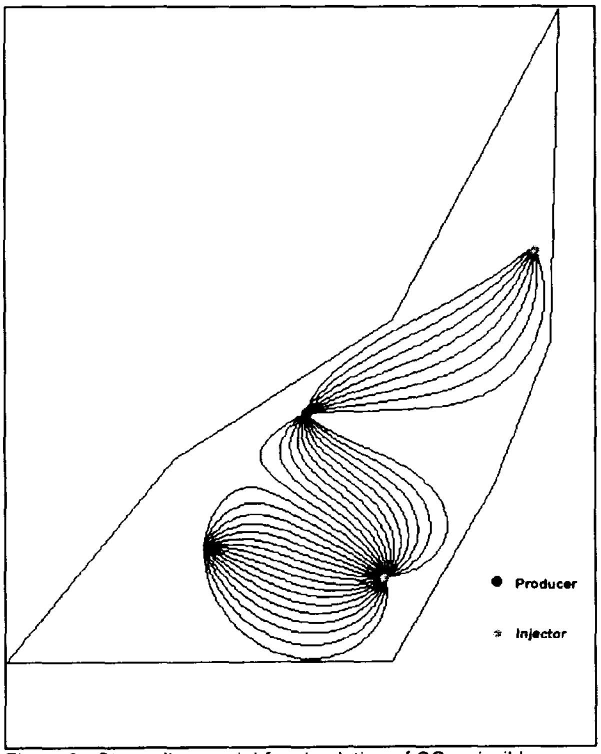


Figure 3. Streamline model for simulation of $CO_2$ miscible displacement at Eden reservoir

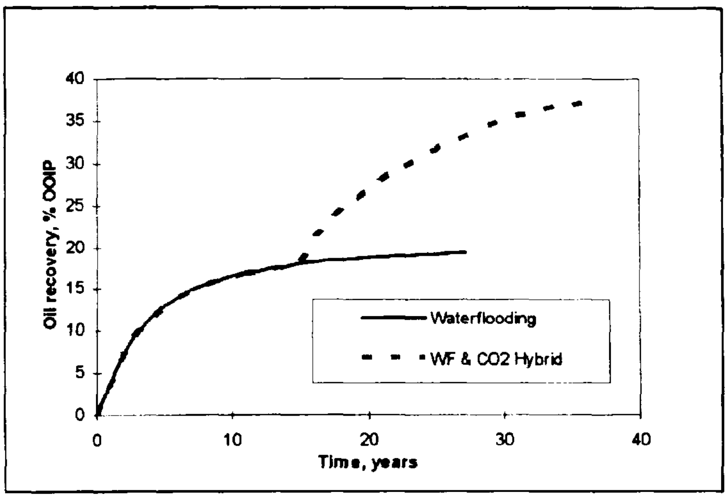


Figure 4. Comparison of alternatives of development for Eden reservoir