TECHNICAL REPORT

ENHANCED OIL RECOVERY (EOR)
FIELD DATA
LITERATURE SEARCH

Prepared for:

Danish North Sea Partner

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EXECUTIVE SUMMARY

There has been considerable enhanced oil recovery (EOR) activity in the North Sea. Eighteen of the 19 reported EOR projects have been gas processes. Most importantly, 16 of the 18 projects are economic successes. The outlook for EOR in the North Sea is promising.

In a contract signed August 27, 2007, we were authorized to conduct an EOR literature search and carry out model development work. This contract was preceded by an proposal dated August 24, 2007, and entitled "Proposal: Enhanced Oil Recovery (EOR) Field Data Literature Search."

Not all reservoirs are amenable to EOR. Effective screening practices must be employed to identify suitable candidates. Economic evaluations require an estimate of the recovery performance. Empirical methods are invariably used to predict performance for early evaluations. The objective of our literature search was to collect enough field data to develop an empirical model to predict the oil-rate history of a prospect reservoir. Owing to past and current EOR trends in the North Sea, efforts focused on miscible gas EOR.

We have successfully developed an EOR rate model. This model is based on hyperbolic decline curves and material balance. The model effectively matches the production history of tertiary miscible floods. The model can easily be incorporated into pre-existing discounted cash-flow models.

The public literature is rich in EOR field data references. Over 390 papers were collected on 70 separate miscible gas projects. Our search sought rate history data with specific supplemental information. The process of gathering and analyzing papers was very time-consuming but informative. In the end, seven case histories suitable for validating the empirical model were identified. All of the cases were onshore U.S. CO_2 floods. Additional testing, however, is needed as new data becomes available. The model is simple enough to add such data.

The work here also includes compiled sets of screening criteria from our literature search. The screening criteria are informative.

In summary, the results of this work should be helpful in evaluating prospects for gas injection EOR.

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INTRODUCTION

One definition of enhanced oil recovery (EOR) is "the recovery of oil by injection of a fluid that is not native to the reservoir." EOR is a means to extend the productive life of an otherwise depleted and uneconomic oil field. It is usually practiced after recovery by other, less risky and more conventional methods, such as pressure depletion and waterflooding, have been exhausted.

Not all reservoirs are amenable to EOR. Effective screening practices must be employed to identify suitable candidates. As part of the screening, discounted cash-flow projections are routinely performed to assess profitability. At the core of these projections is an estimate of recovery performance. In the initial screening studies, invariably, performance predictions from numerical simulation studies are not yet available. Therefore, other methods—usually empirical—are needed to estimate future performance.

OBJECTIVES

The objectives of this work are:

1. To carry out a current literature search for enhanced oil recovery (EOR) case histories (oil rate vs. time);
2. To document, categorize, and inventory the literature search;
3. To use the rate histories to develop a non-simulation (empirical) predictive model;
4. To carry out a current literature search for screening criteria for the different EOR processes;
5. To summarize the screening criteria for the different EOR methods; and
6. To submit an electronic archive of the literature search.

The purpose of the predictive model is to provide an approximate method to estimate the rate history for candidate reservoirs. The model is intended for scoping or screening studies.

AUTHORITY

This report was authorized by Mr. Peter Helmer Steen, Director General, of the Danish North Sea Partner, Ministry of Transport and Energy. Mr. Steen was the project manager.

NORTH SEA EOR

There have been 19 past or current EOR projects in the North Sea, according to a 2006 survey (Awan, et al. 2006). Eighteen of the 19 projects have been or are gas EOR projects; the remaining project is a microbial EOR project. Table 1 lists the project reservoirs, operator, country sector, and type of gas EOR project.

Twelve of the 18 gas EOR projects are located in the Norwegian sector; 5 in the United Kingdom (UK) sector; and one project in the Danish sector. All of the projects have used hydrocarbon (HC) gas as the EOR injectant. Sixteen of the projects have used lean gas; 2 have used rich gas.

Based on past and current activity, most operators feel gas EOR is the most promising method for North Sea reservoirs. This is not surprising inasmuch as North Sea reservoirs fit many of the criteria for miscible EOR application. They are deep enough to permit the high pressures required to attain miscibility and often contain sufficiently light and low-viscosity oils, both characteristics that are ideal for miscible EOR.

Not only do North Sea reservoirs appear amenable to gas EOR, but most (16 of the 18) have already been proven successful. The confidence in success is evidence by the willingness of some operators to implement projects (six of the 18) even though the miscibility pressure cannot be attained. These projects were classified as immiscible. Nine of the 18 projects were classified as miscible, and three of the projects were unclassified according to miscibility. We use the term solvent flooding to describe these types of floods.

Table 1. North Sea EOR Projects (Awan, et al., 2006)

FIELD	OPERATOR	SECTOR	TYPE	START DATE	SUCCESS
Ekofisk	ConocoPhillips	Nor.	HC Miscible[1]	1971	Success
Beryl	Exxon-Mobil	UK	HC Miscible	1976	Success
Statfjord	Statoil	Nor.	HC Miscible	1979	Success
Brent	Shell	UK	HC Miscible[2]	1976	Success
Alwyn North	Total	UK	HC Miscible	1987	Success
Smorbukk South	Statoil	Nor.	HC Miscible	1999	Success
Snorre	Statoil	Nor.	HC WAG Miscible	1992	Success
South Brae	Marathon	UK	HC WAG Miscible	1993	Success
Magnus	BP	UK	HC WAG Miscible	1983	Success
Thistle	Lundin Oil	Nor.	HC WAG Immiscible	1978	Success
Gullfaks	Statoil	Nor.	HC WAG Immiscible[3]	1986	Success
Brage	Norsk Hydro	Nor.	HC WAG Immiscible	1993	Success
Ekofisk	ConocoPhillips	Nor.	HC WAG Immiscible	1971	
Statfjord	Statoil	Nor.	HC WAG Immiscible	1979	Success
Oseberg	Norsk Hydro	Nor.	HC WAG Immiscible	1999	Success
Siri	Statoil	Danish	HC SWAG*	1999	Success
Snorre A (CFB)	Norsk Hydro	Nor.	HC FAWAG	1992	
Snorre A (WFB)	Norsk Hydro	Nor.	HC FAWAG	1992	Success

FAWAG = foam-assisted WAG
SWAG = simultaneous water-and-gas injection
* Ptincipally a gas-storage project.
1 Not currently operational (Damgaard, 2008).
2 In blowdown phase; not EOR project (Damgaard, 2008).
3 In EOR study phase (Damgaard, 2008).

SCOPE OF INVESTIGATION

We originally proposed investigating chemical EOR methods in this work. Other EOR methods were omitted because they either lacked applicability for North Sea conditions or lacked general reliability. For example, we did not investigate steamflooding because North Sea reservoirs are too deep and above the pressure limits for successful application. Alkaline flooding was not included because it is considered a developing and unproven technology.

There is a decided trend toward gas EOR in the North Sea (Awan, et al., 2006). Solvent EOR has been technically proven to be commercially successful worldwide. On the other hand, there has been no commercial chemical EOR activity in the North Sea, despite ongoing interest. Fayers et al. (1981) point out the difficulties in finding suitable polymers and low-cost surfactants for North Sea temperatures and salinities. Jensen et al. (2000) discount chemical EOR as a viable alternative in their study of Ekofisk.

In addition, though there is substantial current interest, the worldwide commercial success with chemical EOR has been marginal. According to an Oil and Gas Journal (2006) report, the worldwide chemical EOR production is less than 15,000 barrels/day,[1] with all of the production coming from only Chinese polymer floods, and no production from surfactant-polymer flooding. Recognizing these trends, we focused efforts on gas EOR. We will include qualitative descriptions of chemical EOR, in-situ combustion, electromagnetic heating, carbonated waterflooding, microbial EOR, and caustic/alkaline flooding.

EOR METHODS

All of currently available EOR is based on one or more of two principles: increasing the capillary number and/or lowering the mobility ratio, compared to their waterflood values. Increasing the capillary number means, practically speaking, reducing oil-water interfacial tension. The injectant mobility may be reduced by increasing water viscosity, reducing oil viscosity, reducing water permeability or all of the above.

Using the nomenclature adopted by the Oil and Gas Journal, EOR processes are divided into four categories: thermal, gas, chemical, and other. Table 2 summarizes the main processes within each category. The processes are typically defined by the nature of their injected fluid. For instance, gas EOR includes hydrocarbon miscible/immiscible and CO_2 miscible and immiscible processes.

Gas EOR Methods

These methods are capillary number increasing methods. They are also called solvent flooding, miscible-gas flooding or simply gas flooding. The injectant can be dry gas, enriched gas (hydrocarbon miscible), CO_2, nitrogen or flue gas, or combinations of these.

[1] All units in this report are expressed in English or oilfield units. For conversion factors to SI or metric units, see the Conversion Factors section near the end of this report.

Table 2. EOR categories and processes.

Thermal EOR processes	Gas EOR processes
Steamflooding	Hydrocarbon miscible/immiscible
Cyclic steam stimulation	CO_2 miscible
In-situ combustion	CO_2 immiscible
Hot waterflooding	Nitrogen
Steam-assisted gravity drainage	Flue gas (miscible and immiscible)
	Gravity drainage
Chemical EOR processes	**Other EOR processes**
Micellar-polymer	Carbonated waterflood
Polymer	Microbial
Caustic/alkaline	Electromagnetic heating
Alkaline/surfactant	

Solvent methods recovery oil by mass transfer. For some processes, the mass transfer of intermediate hydrocarbon components is from the crude to the solvent (vaporizing gas drive) and for others the transfer is from the solvent to the crude (condensing or rich gas drives). CO_2, nitrogen or flue gas are vaporizing gas drives and hydrocarbon miscible drives are the latter. In all cases it is the intermediate component, the component that is doing the transferring, that is key.

If the reservoir pressure is large enough (or if there is sufficient intermediate content at the current pressure), the mass transfer will result in a mixture that is miscible with the crude, in which case the predominant recovery mechanism is a miscible displacement. In a miscible displacement, interfacial tension vanishes and capillary number becomes infinite. Failing this, the displacement will be immiscible. Immiscible displacements are not as efficient as miscible displacements but may still recover oil by swelling, viscosity reduction or permeability increase, or pressure build up. CO_2 and enriched hydrocarbons tend to be miscible solvents; nitrogen and flue gas tend to be immiscible.

Miscible displacements in the laboratory result in nearly 100% ultimate oil recoveries. Field-scale displacements recover much less, primarily because the solvent tends to be more mobile that the oil/water mixtures they are displacing, which leads to bypassing of the solvent around or through the oil. Bypassing is the result of reservoir heterogeneity and viscous instability between two fluid fronts. Some types of heterogeneity can result in substantial mixing in the reservoir and a loss of miscibility.

The bypassing can be eliminated or at least reduced by co-injection of water with the solvent (the WAG process), conducting the flood in a gravity stable mode and/or using foams to reduce the gas mobility.

Most of the reported results have been on CO_2 solvent flooding in the US wherein ultimate recoveries of 12% of the original oil in place and utilization factors of 10 MCF solvent/incremental barrel of oil recovered are reported. These performances translate into chemical costs of 10-30 $/incremental bbl, depending on performance, and the cost of the solvent. Many potential CO_2 injection projects are on hold because of the lack of solvent.

Chemical EOR Methods

These methods are increasing capillary number processes (micellar-polymer, caustic/alkaline) or mobility ratio processes (polymer). All are based on injecting one or more chemicals into a reservoir to bring about the aforementioned changes.

Polymer Flooding. Polymer methods consist of injecting an aqueous phase (water, or brine) into which has been dissolved a small amount of a polymeric thickening agent. The thickening agent increases water viscosity and in some cases lowers the permeability to the phase to bring about the lowered mobility ratio. Polymer methods do not increase capillary number.

Primarily because of its small cost, there have been more polymer floods done than any other type of EOR process. Unfortunately most of these were take advantage of an artificial taxing policy in the US and not to recover much incremental oil. With the lapsing of the policy and the collapse of the oil price in the mid 80s, these projects virtually disappeared, giving way to a variation of the process based on polymer gels. With the restoration of the oil price, interest has picked up, especially because of the significant reported successes in the Chinese Daqing Field. Polymer processes have historically recovered about 5% of the original oil in place and taken about 1 lbm of polymer to produce an incremental barrel.

Micellar-Polymer Flooding. Micellar-polymer processes are similar to polymer process but with the addition of a surfactant to the injectant. The surfactant reduces oil-water interfacial tension making this process both a mobility ratio decreasing and a capillary number increasing process. This process virtually disappeared in the low price environment of the 80s but is experiencing revitalization, though as yet there are no current field projects. MP processes recover about 15% of the original oil in place, but there are not economical at oil prices less than about 30$/bbl.

Alkaline Flooding. Caustic/alkaline processes are an attempt to use the interfacial tension lowering properties of natural surfactants that exist in many crudes. A highly interesting innovation with this process is the use of a small amount of co-surfactant in the so-called alkaline surfactant process. Field experience is immature, but initial report suggest that incremental oil can be recovered for 20-25$/bbl.

Thermal EOR Methods

Thermal methods lower mobility ratio by decreasing oil viscosity. Since the effect of temperature is especially pronounced for viscous crudes, these processes are normally applied to heavy crudes. This "niche" is actually quite large world wide, consisting of more in-place hydrocarbon than light crudes. An approximate classification of viscous crude oils based on reservoir conditions viscosity is as follows:

viscosity less than 1,000 cp	heavy crude
1000 to 100,000 cp	tar sand
100,000 to 1,000,000 cp	bitumen or oil shale

Besides being aimed at viscous crudes, thermal methods will be successful if there is a rigorous heat management procedure in place. This means that heat losses are to be minimized as much as possible. Heat loss sources are:

1. Losses to rock and water - minimized by restricting application to reservoirs with small water saturation, large porosities or small shale content.

2. Losses to surface equipment - normally the smallest heat loss source, this is minimized by insulating surface lines and minimizing line length.

3. Losses to wellbores - minimizing wellbore heat loss is done by restricting application to shallow reservoirs. Heat loss in this manner can be controlled by insulating downhole tubulars, generating heat down hole, using in-situ combustion, injecting the steam at high rate or evacuating the production casing.

4. Losses to adjacent strata - minimizing this form of heat loss means minimizing the producing life of the field (normally done with small well spacing) or restricting application to thin reservoirs.

Cyclic Steam Stimulation. CSS is also known as steam soak, or huff and puff. In this process steam is injected into a well bore out to a heated radius of a few tens of meters. Then the original steam injector is converted to a producer and a mixture of steam, hot water, and oil produced. CSS is the most common steam injection process today. Most of the time most of the wells are producers: there are no dedicated injectors. CSS is often used as a precursor to steam drive discussed next.

Steam Drives. Also known as steam flooding, in this process steam is injected into dedicated wells and the fluids driven to a separate set of producers. Combined CSS and steam drives often recover more than 50% of the original oil in place. This combination is the first commercial EOR process and has been so since the mid 50s. Perhaps more than 2 billion barrels of oil have been produced in this manner to date.

In-situ Combustion. This process is an attempt to extend thermal recovery technology to deeper reservoirs and/ or more viscous crudes. In recent years it has become known as high-pressure air injection. In-situ combustion recovers 10-15% of the original oil in place.

INVENTORY OF PAPERS

The literature search was confined to papers dealing with gas-flood case histories and limited to papers in the Society of Petroleum Engineers (SPE) electronic library, with a few exceptions. We collected almost 400 papers. Appendix A shows a listing of the papers. The Excel file "EOR_Paper_Inventory" contains an electronic listing with additional information about the papers, such as SPE paper number, EOR method (hydrocarbon miscible, CO_2 miscible, CO_2 huff-n-puff, or immiscible), field, paper date, and whether the paper contained rate data or not. See Electronic Attachment A on the accompanying Compact Disc (CD).

Table 3 (continued on next page). Gas EOR Projects

Field	Field
Adena field, CO, USA	Flounder field, Australia
Akal reservoir, Mexico	Ford Geraldine Unit, TX. USA
Al-Huwaisah field, Oman	Fordoche field, Louisiana, USA
Alwyn field, UK North Sea	Forest Reserve and Oropouche fields, Trinidad
Ansai field, China	Gamma field, Croatia
Ante Creek, Canada	Garber field, OK, USA
B. Kozluca field, Turkey	Garzan field, Turkey
Bati Raman, Turkey	Golden Spike D3 A pool, Canada
Bay St. Elaine field, LA, USA	Goldsmith San Andres Unit, TX, USA
Bennett Ranch Unit, Wasson field, Texas, USA	Granny's Creek, W. Virginia, USA
Beryl field, North Sea	Gullfaks, Norwegian North Sea
Big Sinking field, KY, USA	Handil field, Indonesia
Block 31, TX, USA	Hanford San Andres Field, Texas, USA
Brae field, UK North Sea	Harweel Cluster, Oman
Brassey Artex B pool, Canada	Hassi Berkine South field, Algeria
Brent field, UK North Sea	Haynesville field, Louisiana, USA
Bridger Lake Unit, Wyoming, USA	Hilly Upland field, W. Virginia, USA
Burkett Unit, KS, USA	Hochleiten field, Austria
C-2 Block Unit, Seminole City Pool, OK, USA	Intisar D Reef, Libya
Cedar Creek Anticline field, ND, USA	Jatibarang field, West Java
Central Vacuum Unit,	Jay field, Florida-Alabama, USA
Charlton 30/31 field, MI, USA	Joffre Viking field, Alberta, Canada
Chihuido de la Sierra Negra field, Argentina	Kuparuk River field, AK, USA
Chunchula, AL, USA	Lake Barre field, Louisiana, USA
Clearfork Unit, Wasson field, texas, USA	Levelland, TX, USA
Cooper Basin field, Australia	Little Creek, Mississippi, USA
Cornell Unit, Wasson field, Texas, USA	Little Knife field, ND, USA
Denver Unit, Wasson field, Texas, USA	Lost Soldier Tensleep field, WY, USA
Dollarhide Devonian Unit, TX, USA	Mabee field, San Andes formation, TX, USA
Dolphin field, ND, USA	Magnus field, UK North Sea
Dulang field, Malaysia	Maljamar field, Texas, USA
East Banger field, OK, USA	Mallet Unit, TX, USA
East Vacuum Grayberg-San Andres Unit, NM, USA	McElmo Creek unit, UT, USA
El Gassi field, Algeria	McElroy and North Ward Estes fields
Fairway field, Texas, USA	Meadow Creek unit (Lakota B)

Table 3 (continued). Gas EOR Projects

Field	Field
Mead-Strawn, TX, USA	South Cowden, TX, USA
Means San Andres Unit, Texas, USA	South Swan Hills, Canada
Midland Farms (Wolfcamp), TX, USA	South Ward, Texas, USA
Midvale field, Canada	South Welch Unit, Welch San Andres Field
Millican field, Texas, USA	Spraberry Trend area, TX, USA
Milne Point Unit, Schrader Bluff form., AK, USA	St. Elaine Field, Louisiana, USA
Mitsue Gilwood Sand Unit, Canada	Statfjord field, North Sea
Neale field, Louisiana, USA	Strasshof Tief field, Austria
No. Bolsa Strip, Huntington Beach field, CA, USA	Sundown Slaughter, Texas, USA
North Cowden, TX, USA; Goldsmith, TX, USA	Teague-Blinebry field, NM, USA
North Cross Unit in Crossett field, TX, USA	Thistle field, UK North Sea
Northeast Purdy Springer "A" reservoir, OK, USA	Timbalier Bay reservoir, LA, USA
Pakenham field, Wolcamp formation, TX, USA	Twofreds field, TX, USA
Paradis field; Bay St. Elaine field; LA, USA	Wasson field, Denver unit, TX, USA
Pembina field, Alberta, Canada	Wasson field, Robertson Unit, TX, USA
Phegley unit in Muddy D reservoir, CO, USA	Wasson, Willard Unit, Texas, USA
Prudhoe Bay, AK, USA	Weeks Island, LA, USA
Rainbow Keg River AA field, Canada	Wellman field, Texas, USA
Raleigh field, Mississippi, USA,	Wertz Tensleep field, WY, USA
Rangely Weber Sand Unit, CO, USA	West Carney field, OK, USA
RFK field, Berkine basin, Algeria	West Sak, AK, USA
Rhourde El Baguel, Algeria	West Sussex unit, Wyoming
Rienecke field, TX, USA	Willard Unit in Wasson field, TX, USA
Rock Creek-Big Injun field, WVA, USA	Wizard Lake, Canada
SACROC field, TX, USA	Wolfcamp, Tx
Safah field, Oman	
Salt Creek field, TX, USA	
Seegilson Zone, Texas, USA	
Siri field, Danish North Sea	
Slaughter Estate Unit, pilot	
Slaughter Estate Unit, Texas, USA	
Slaughter field, Central Mallet Unit, TX, USA	
Slaughter field, TX, USA	
Smorbukk field, Norwegian North Sea	
Snorre field, Norwegian North Sea	

The papers included over 130 different gas EOR projects, ranging from large-scale commercial projects to small-scale pilot projects, including immiscible and miscible projects. Table 3 lists most of the projects.

The papers are in the Paper Archive, Electronic Attachment B on the accompanying Compact Disc (CD). The papers are in Portable Document Format (PDF) and can be read by the Adobe Acrobat Reader software. The paper archive is over 340 megabytes (MB) in size.

The overall purpose the literature search was to identify useful field data for model development work. Specifically, we sought to locate as many solvent flood oil-rate histories as possible. The next section describes the process of transforming the literature search into a useable database of case histories.

DATABASE OF CASE HISTORIES

The process of reviewing, analyzing, and cataloging the papers went through several steps or rounds of elimination before identifying useable case histories. In this section, we describe the method used to arrive at the final database.

In the first round, we eliminated papers that contained no oil-rate history data. This step left about 59 papers.

In the second round, we began scrutinizing the rate data. We eliminated some projects on relatively obvious grounds. For instance, secondary miscible projects were omitted because North Sea applications would likely be tertiary projects. This criterion removed some notable projects such as Crossett North Cross Unit, SACROC (Phase 1), and Wizard Lake. We omitted a few floods because they started shortly after waterflooding. This group included the Hanford (CO_2 injection started after only 1 year of water injection) and the Wasson Willard Unit (CO_2 flood started after only 30% of a pore volume of injected water) floods. The Willard Unit flood also had other limitations.

Heavy oil or immiscible projects were eliminated, as were gas-cycling or gravity-drainage projects. Also, CO_2 huff-n-puff projects were eliminated. Some older projects from the 1950's and early 1960's were eliminated because they involved such inordinately small solvent slug sizes that they performed poorly. Also, some projects were eliminated because the reports were illegible or overly ambiguous.

None of the references to North Sea projects contained useful data. Most of the references dealt with immiscible projects. Some of these immiscible projects, such as the foam-assisted WAG projects, were designed to only reduce gas production or improve sweep efficiency.

After the first two rounds of elimination, about 22 projects remained. Most of these projects are shown in Table 4. This group represented cases special interest.

To screen these projects further, a data checklist was created to extract desirable data from papers for each solvent flood. Most of the checklist items were closely connected to model parameters to be discussed later. Some of the items, however, were selected because they might be correlating parameters, such reservoir permeability and well spacing. The data checklist actually evolved over time. Items were added and deleted as our modeling work progressed. Table 5 is the final checklist.

Table 4. Catalogue of Miscible-Flood Oil-Rate Histories

Field/Reservoir/Project	Wasson Denver Unit	Rangely Weber Sand Unit	Salt Creek	Wasson Denver Unit Continuous Area
Operator	Shell Western	Chevron	ExxonMobil	Shell Western
Commercial or pilot	Commercial	Commercial	Commercial	Pilot
Injectant	CO_2	CO_2	CO_2	CO_2
Country	USA	USA	USA	USA
State/province	Texas	Colorado	Texas	Texas
Lithology	Dolomite	Sandstone	Limestone	Dolomite
Injection date	1984	1986	1993	1984
History date	1992	1994	2002	1992
Percent completed*	55	50	55	55
Supporting information	Unacceptable	Unacceptable	Good	Unacceptable
Co-mingled production	Yes	Yes	Yes	No
Permeability, md	5	Not reported	Not reported	Not reported
Area, acres	Not reported	Not reported	Not reported	Not reported
OOIP, STB	Not reported	Not reported	Not reported	Not reported
Staggered development	Yes	Yes	Yes	No
Percent OOIP recovered	Not reported	Not reported	Not reported	Not reported
Pre-flood oil rate, STB/day	55,000	30,000	19,000	20,000
Peak oil rate, STB/day	Not reported	33,000	30,000	25,000

Field/Reservoir/Project	Means San Andres Unit	Slaughter Estate Unit	Wertz Tensleep	Sundown Slaughter Unit
Operator	Exxon	Amoco	Amoco	Texaco
Commercial or pilot	Commercial	Commercial	Commercial	Commercial
Injectant	CO_2	CO_2	CO_2	CO_2
Country	USA	USA	USA	USA
State/province	Texas	Texas	Wyoming	Texas
Lithology	Dolomite	Dolomite	Sandstone	Dolomite
Injection date	1983	1984	Nov., 1986	Jan., 1994
History date	1987	1987	1995	1996
Percent completed*	25	20	60	17
Supporting information	Moderate	Moderate	Good	Unacceptable
Co-mingled production	Yes	No	No	No
Permeability, md	9-25	4.9	13	5
Area, acres	14,328	5,703	Not reported	8700
OOIP, STB	Not reported	283 million	172 million	440 million
Staggered development	No	No	No	No
Percent OOIP recovered	Not reported	Not reported	10.1	Not reported
Pre-flood oil rate, STB/day	7,500	7,000	4,000	3,000
Peak oil rate, STB/day	NA	Not reported	11,700	Not reported

* based on 15-year history if data not available

Table 4 (continued). Catalogue of Miscible-Flood Oil-Rate Histories

Field/Reservoir/Project	Lost Soldier	SACROC 4PA	SACROC 17PA	Ford Geraldine Unit
Operator	Amoco	Chevron	Chevron	Conoco
Commercial or pilot	Commercial	Commercial	Commercial	Commercial
Injectant	CO_2	CO_2	CO_2	CO_2
Country	USA	USA	USA	USA
State/province	Wyoming	Texas	Texas	Texas
Lithology	Sandstone	Limestone	Limestone	Sandstone
Injection date	July, 1989	June, 1981	May, 1981	Feb., 1981
History date	1995	1988	1988	1989
Percent completed*	50	70%	55%	55
Supporting information	Good	Good	Good	Marginal
Co-mingled production	No	No	No	Yes
Permeability, md	31	3	3	Not reported
Area, acres	Not reported	600	2700	3850
OOIP, STB	240 million	27,900,000	79,100,000	Not reported
Staggered development	No	No	No	Yes
Percent OOIP recovered	12.2	14%	10%	Not reported
Pre-flood oil rate, STB/day	2,500	800	1,400	400
Peak oil rate, STB/day	11,000	3,400	3,200	1600

Field/Reservoir/Project	East Twofreds	Goldsmith San Andres	Little Creek Field	Slaughter Estate Unit Pilot
Operator	Transpetco/Murphy	Chevon	Shell	Amoco
Commercial or pilot	Commercial	Pilot	Pilot	Pilot
Injectant	CO_2	CO_2	CO_2	CO_2
Country	USA	USA	USA	USA
State/province	Texas	Texas	Mississippi	Texas
Lithology	Sandstone	Dolomite	Sandstone	Dolomite
Injection date	Feb, 1974	1997	Feb., 1974	Sept., 1976
History date	1993	1999	1980	1985
Percent completed*	100	13	100%	70
Supporting information	Good	Unacceptable	Good	Good
Co-mingled production	No	No	No	No
Permeability, md	28	Not reported	33	3-8
Area, acres	Not reported	320	31	12
OOIP, STB	15.4 million	Not reported	200,000	642,400
Staggered development	No	No	No	No
Percent OOIP recovered	15.8%	Not reported	31.7	30.8
Pre-flood oil rate, STB/day	26	27	Near 0	50
Peak oil rate, STB/day	754	200	190	159

Field/Reservoir/Project	West Sussex Unit	Maljamar Ninth Massive Zone	Maljamar Sixth Zone	Granny's Creek Field
Operator	Conoco	Conoco	Conoco	US DOE
Commercial or pilot	Pilot	Pilot	Pilot	Pilot
Injectant	CO_2	CO_2	CO_2	CO_2
Country	USA	USA	USA	USA
State/province	Wyoming	Texas	Texas	W. Virginia
Lithology	Sandstone	Dolomite/Sand.	Dolomite/Sand.	Sandstone
Injection date	December, 1982	May, 1983	May, 1983	June, 1976
History date	1985	1992	1992	1980
Percent completed*	75	100	100	100
Supporting information	Good	Unacceptable	Unacceptable	Unacceptable
Co-mingled production	No	No	No	No
Permeability, md	28	18	18	7
Area, acres	9.6	5	5	6.7
OOIP, STB	280,000	Not reported	Not reported	Not reported
Staggered development	No	No	No	No
Percent OOIP recovered	7.0	10.1	17.6	Not reported
Pre-flood oil rate, STB/day	5	5	8	7
Peak oil rate, STB/day	79	25	20	Never increased

Table 5. Data checklist

- Tertiary solvent-flood oil rate history, preferably including waterflood rate history *
- Date of solvent injection *
- Date of oilbank breakthrough *
- Date of peak oil rate *
- Pore volume, RB *
- OOIP, STB *
- Ave. reservoir pressure, psia *
- Ave reservoir temperature, F *
- Solvent injection rate, MSCF/day *
- Water injection rate, STB/day *
- Peak oil rate, STB/day *
- Well spacing, acres
- Ultimate incremental recovery, % OOIP *
- Pre-flood recovery, %OOIP
- Waterflood recovery, %OOIP
- Incremental EOR above waterflood, %OOIP
- Average permeability, md
- Initial water saturation, %PV *
- Initial oil formation volume factor *
- Oil viscosity at reservoir conditions, cp
- Pre-flood oil rate, STB/day
- WAG ratio

* Denotes critical item

The checklist data items were divided into critical (an asterisk in Table 5) and non-critical groups. A checklist was completed for each solvent flood, paying special attention to the critical items. If the accumulated references for a subject flood did not ultimately provide the critical items, the flood was not considered further. For instance, if the flood references did not provide information about the project's injection rate, pore volume, or original oil in place (or this information could not be reasonably estimated), the flood was eliminated from further consideration.

Several prominent floods were eliminated because a lack of data or anomalies. The following describes some of our experiences.

The literature for some projects furnished rate data but failed to provide supporting critical data. This group included the Rangely Weber Sand Unit and Dollarhide. A majority of projects, also for instance, provided only very preliminary production data, such as production for only 1 or 2 years after solvent injection. The production history data was often terminated shortly after an initial oil response and before a peak oil rate was observed. This group of floods included the Sundown Slaughter Unit, Goldsmith, Hanford San Andres, and Weyburn. Though most of these floods have been completed or are very nearly completed, the public literature does not contain a complete record.

Also, just having a field's complete rate history is not enough. It is critical to know certain operational aspects as will be illustrated below.

Some of the larger floods were staged in their development. In a staged development one segment of the field would be flooded before another. Instead of reporting the production history for individual sections, operators would lump together all the production data and only report the performance of the entire field. The commingling of production data made meaningful analysis of the Salt Creek, Rangely Weber Sand, and Wasson Denver Unit difficult.

Another complication occurred with the Means Unit miscible flood. This was a promising case with considerable information, but the operators implemented a large infill-drilling program coinciding with the miscible flood. It was impossible to distinguish the rate response to miscible flooding and infill drilling.

The Ford Geraldine Unit flood was plagued by severe solvent supply deficiencies. Occasionally, the flood almost had to be shut down. This greatly affected the history and complicated interpretation. For instance, most tertiary miscible floods initially respond within a few months. At the Ford Geraldine Unit, however, the initial response was delayed over six years. While the flood was ultimately very successful, certain aspects of the rate history were anomalous. Consequently, the flood was eliminated from consideration.

Another anomaly was the Rangely Weber Sand Unit. This prominent CO_2 flood had significant injectivity loss. While injectivity loss is common in many solvent floods, it appeared to be worse than usual at Rangely. The lost injectivity resulted in significant rate losses that contributed to an attenuated oil response. (The fact that the flood was staged over 7 years and never covered the entire field also likely contributed.)

Figure 1 shows the rate history for the Rangely flood. This history includes the produced oil and water rates. CO_2 was injected in late 1986. Notice that the oil rate increased only about 10% over pre-flood levels; however, the produced water rate decreased significantly. The net result was that the produced oil cut increased significantly but the oil rate did not. Figure 2 confirms the oil cut response, as reported by the operators. The oil cut increased from about 5.8% to a peak cut of almost 9%. This peak oil cut is typical for most successful miscible floods; however, the rate response is atypical. Without injectivity loss, the data in Fig. 2 predicts the oil rate would have increased over 55%.

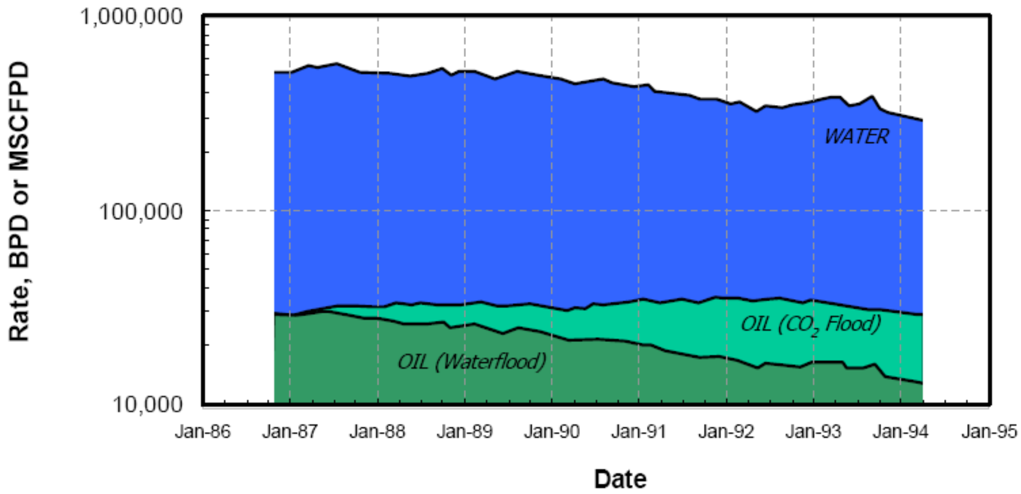

Figure 1. Rangely Weber Sand Unit miscible-flood production history. The curve above the blue area is the produced water rate history; the curve above the light green area is the produced oil rate history; the curve above the dark green curve is the expected oil rate history if waterflooding was continued.

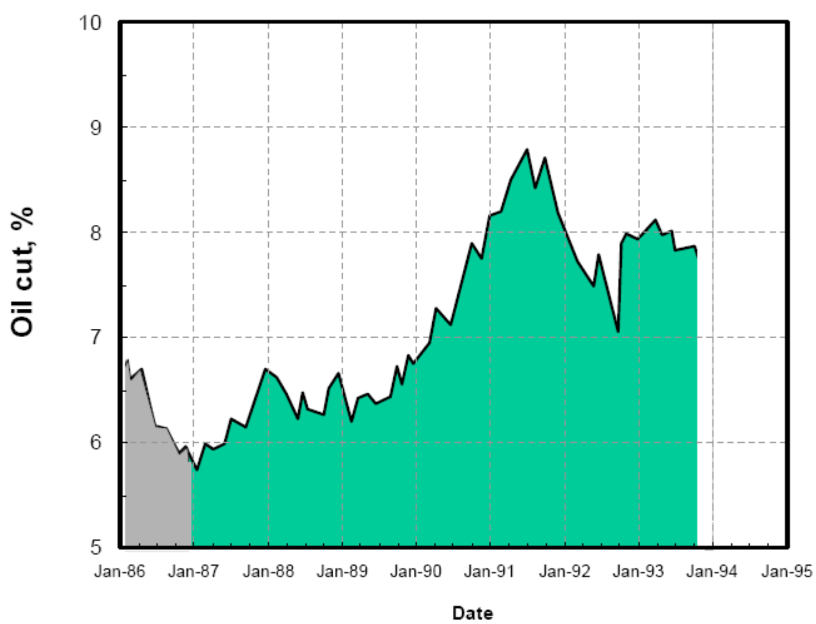

Figure 2. Rangely Weber Sand Unit oil cut history. The shaded gray region is the waterflood; the shaded green region is the CO_2 flood.

Considering the above, we were able to identify seven useable complete histories: the CO_2 flood in the east side of the Twofreds field (Thrash, 1979; Flanders and DePauw, 1993; Kirkpatrick et al., 1985), the Lost Soldier CO_2 flood (Brokmeyer et al., 1996), the Wertz CO_2 flood (Kleinsteiber, 1990), the Slaughter Estate Unit (SEU) CO_2 pilot (Rowe, 1982; Stein et al, 1992), the West Sussex Unit CO_2 pilot (Holland, et al., 1986), the SARCOC Four-Pattern Area (4PA) CO_2 flood (Langston, et al., 1988), and the SACROC Seventeen-Pattern Area (17PA) CO_2 flood (Langston, et al., 1988). Coincidentally, all of the complete histories were CO_2 floods and onshore projects. Five of the seven projects were commercial projects; the West Sussex Unit test was a pilot but used commercial-scale well spacing. Table 6 constitutes the database for the modeling work.

Table 6 (part 1 of 2). Miscible flood database

	Parameter	Twofreds	Lost Soldier	Wertz	SEU pilot
	Primary Data				
*	Time of oilbank breakthrough, months	2.0	2.0	2.0	13.0
*	Time of peak oil rate, years	6.00	1.91	1.08	2.50
	Life of miscible flood, years (estimated)	26.7	13.7	8.7	8.4
*	Pore volume, RB	33,700,000	299,000,000	222,000,000	864,000
*	OOIP, STB	15,400,000	240,000,000	172,000,000	642,400
*	Ave. reservoir pressure, psia	2,300	2,800	2,950	2,200
*	Ave reservoir temperature, ^oF	104	158	165	105
*	Solvent injection rate, MSCF/day	10,000	80,000	70,000	600
*	Water injection rate, STB/day	0	60,000	100,000	250
*	Peak oil rate, STB/day	754	11,000	11,700	159
	Well spacing, acres	40	10	10	3
*	Cum. tertiary recovery, % OOIP	15.8	11.2	10.1	30.8
	Pre-flood recovery, %OOIP	14.8	44.3	45.1	39.3
	Waterflood recovery, %OOIP	4.4	24.4		29.9
	Incremental EOR above waterflood, %OOIP	15.8	10	8.1	19.6
	Average permeability, md	28.0	31.0	13.0	6.0
	Porosity, fraction	0.18	0.10	0.10	0.12
*	Initial water saturation, %PV	46.2	10.0	10.0	8.1
*	Initial oil formation volume factor	1.18	1.12	1.16	1.23
	Oil viscosity at reservoir conditions, cp	1.5	1.38	1.28	2.00
	Pre-flood oil rate, STB/day	26	2,500	4,000	50
	WAG ratio	0.0	1.0	1.0	1.0
	D_{iEOR}, %/year	20.0	16.0	25.0	32.0
	b_{EOR}	0.3	0.2	0.1	0
	Computed Data				
	Solvent compressibility factor	0.35	0.47	0.49	0.34
	Solvent formation vol. factor, RB/Mscf	0.43	0.52	0.52	0.44
	Characteristic rate, RB/day	4,322	101,789	136,593	514
	Pre-flood oil cut, % STB/RB	0.6	2.5	2.5	9.7
	Peak oil cut, % STB/RB	17.4	10.8	7.4	30.9
	t_{D2}	0.01	0.02	0.04	0.24
	t_{D3}	0.28	0.24	0.24	0.54
	t_{D4}	1.25	1.70	1.95	1.82
	Time constant (V_p/Q_T), years	21.36	8.05	4.45	4.61
	Dimensionless decline rate constant	427	129	111	147
	Scaled rate, PVI/yr	0.047	0.124	0.225	0.217
	Scaled rate, B/D/acre-ft	0.179	0.261	0.473	0.554

* Denotes critical data

Table 6 (part 2 of 2). Miscible flood database

	Parameter	West Sussex	SACROC 4PA	SACROC 17PA	
	Primary Data				
*	Time of oilbank breakthrough, months	1.0	2.5	3.0	
*	Time of peak oil rate, years	1.10	1.25	2.20	
	Life of miscible flood, years (estimated)	5.0	9.0	13.4	
*	Pore volume, RB	320,000	53,900,000	159,300,000	
*	OOIP, STB	204,400	27,900,000	79,100,000	
*	Ave. reservoir pressure, psia	2,170	2,800	2,800	
*	Ave reservoir temperature, ^oF	104	130	130	
*	Solvent injection rate, MSCF/day	580	13,600	18,500	
*	Water injection rate, STB/day	0	21,000	41,600	
*	Peak oil rate, STB/day	79	3,400	3,200	
	Well spacing, acres	9.6	40	40	
*	Cum. tertiary recovery, % OOIP	9.5	14.4	10.0	
	Pre-flood recovery, %OOIP	42.4	52.8		
	Waterflood recovery, %OOIP	24.1	17.5		
	Incremental EOR above waterflood, %OOIP	8.3	10.2	7.5	
	Average permeability, md	28.5	3.0	3.0	
	Porosity, fraction	0.20	0.04	0.04	
*	Initial water saturation, %PV	27.0	0.22	0.22	
*	Initial oil formation volume factor	1.143	1.51	1.51	
	Oil viscosity at reservoir conditions, cp	1.4	0.35	0.35	
	Pre-flood oil rate, STB/day	5	800	1,400	
	WAG ratio	0.0	3.0	5.0	
	D_{iEOR}, %/year	135	47.0	23.0	
	b_{EOR}	0.1	0.2	0.2	
	Computed Data				
	Solvent compressibility factor	0.34	0.43	0.43	
	Solvent formation vol. factor, RB/Mscf	0.44	0.46	0.46	
	Characteristic rate, RB/day	258	27,205	50,041	
	Pre-flood oil cut, % STB/RB	1.9	2.9	2.8	
	Peak oil cut, % STB/RB	30.6	12.5	6.4	
	t_{D2}	0.03	0.04	0.03	
	t_{D3}	0.32	0.23	0.25	
	t_{D4}	1.47	1.66	1.54	
	Time constant (V_p/Q_T), years	3.40	5.43	8.72	
	Dimensionless decline rate constant	459	255	201	
	Scaled rate, PVI/yr	0.294	0.184	0.115	
	Scaled rate, B/D/acre-ft	1.220	0.153	0.097	

* Denotes critical data

The Twofreds, Wertz, and Lost Soldier floods are discussed in the Model Applications section and will not be reviewed here. The Slaughter Estate Unit and West Sussex Unit pilots and the SACROC Four Pattern and Seventeen Pattern floods are discussed briefly below.

Slaughter Estate Unit CO_2 Pilot. Discovered in 1937, the Slaughter field is in west Texas, USA. Amoco was named operator of the Slaughter Estate Unit in 1963 when waterflooding began. They conducted a CO_2 pilot test in a 12-acre double five-spot area that was not previously waterflooded. The well spacing was only 3 acres. This case was unique in that it employed much smaller well spacing than all other cases in the database. The primary recovery in the pilot area was 9.6% of the OOIP. A pilot waterflood recovered 29.9% of the OOIP. Alternate injection of acid gas (72% CO_2 and 28% H_2S) and water began in August 1976. The WAG ratio was approximately 1. The cumulative tertiary oil recovery was 30.8%. The incremental oil recovery was 19.6%.

West Sussex Unit CO_2 Pilot. Discovered in 1951, the West Sussex Shannon reservoir is located in Wyoming, USA. Full-scale waterflooding began in 1959. The cumulative recovery from primary and secondary operations was 18.1 and 24.1%, respectively.

Conoco conducted a CO_2 pilot in a previously waterflooded portion of the field. Covering 9.6 acres, the waterflood was a diagonal half of an inverted five-spot (one injector and three producers). Though a pilot test, the well spacing was 9.6 acres and representative of field-scale spacing. Continuous CO_2 injection started in December 1982. The pre-flood oil cut was 1%; the peak oil cut was 21%. The ultimate cumulative tertiary recovery was 9.5%.

SACROC Four-Pattern CO_2 Flood. Discovered in 1948, the Kelly-Snyder field is last billion-barrel field found in the continental US. Located in west Texas, the field covered over 84,000 acres. Under solution-gas drive, primary recovery was 19% of the OOIP. In March 1953, the SACROC unit was formed to improve oil recovery from water injection.

In 1968, Chevron began studying the use of CO_2 to improve recovery. The field was divided into three areas (phases). CO_2 injection began in Phase 1 in January 1972. Before CO_2 injection, Phase 1 was only marginally waterflooded; thus, this CO_2 flood was considered a secondary recovery project. Pattern waterflooding began in 1972 in Phase 2 and in 1973 in Phase 3.

In June 1981, CO_2 injection began in a 600-acre area of Phase 3. This area consisted of three 160-acre inverted 9-spot patterns and one smaller irregular pattern. This area was called the Four-Pattern Area (4PA). The 4PA contained 22 wells, including 4 injectors.

Before CO_2 injection, the 4PA was thoroughly waterflooded. Chevron estimated an ultimate waterflood recovery of 21.7% of the OOIP. Alternate CO_2 and water injection resulted in an estimated cumulative tertiary recovery of 14.4 % and an incremental recovery of 10.2%. The average WAG ratio was 3. The well spacing was 40 acres.

SACROC Seventeen-Pattern CO_2 Flood. Chevron conducted a CO_2 flood in another area of Phase 3 of SACROC. This area covered over 2,700 acres and included 17 patterns and over 100 wells. The area was previously subject to pressure depletion and waterflooding before CO_2 injection. Alternate CO_2 and water injection began in May

1981. Chevron used an average WAG ratio of 5. The ultimate incremental recovery was projected at 7.5% of the OOIP. The well spacing was 40 acres.

The data items in the database were divided into two classes: primary and computed items. Primary items came directly from the case histories; in contrast, the computed items were derived from the primary items.

Appendix B presents a catalogue of many of the rate histories we encountered in our literature search.

Summary

The purpose of the literature search was to identify field data for model development work. Our search was very specific. We sought complete or near-complete rate histories along with some very specific supplemental information.

Initially, we identified about 59 miscible flooding projects with rate history data. This group included many projects or processes outside our scope of interest. Only 22 of these projects were significant enough for serious consideration. In the end, seven projects met our qualification criteria. Though we did not find as much useful data as we originally expected, the gathered data was sufficient for modeling. The modeling work is discussed in the next section.

EOR RATE MODEL

This section presents work to formulate, develop, and test an EOR rate model to predict the oil-rate history of a tertiary miscible flood. Our approach is intended for scoping or screening studies.

Approach

Our approach is based on hyperbolic decline curves and material balance. Figure 3 shows a schematic oil rate history from the end of a waterflood and through a solvent flood. The solid black curve shows the rate history; the shaded blue and green portions the waterflood and solvent flood, respectively. Time t_1 is the date of the start of solvent injection.

Our approach is similar to the work of Bush and Helander (1968) who investigated the problem of empirically modeling the oil rate history of a waterflood. For a reservoir previously subject to pressure depletion, they divided the waterflood history into three distinct periods: fill-up; a period of rapidly increasing oil rate; and a final period of rate decline. In the first period, the oil rate was constant and equal to the rate at the end of pressure depletion. In the second period, the oil rate increased exponentially. In the final period, the rate decreased exponentially.

The EOR history is divided into three time periods: (1) from t_1 to t_2, (2) from t_2 to t_3, and (3) from t_3 to t_4. Time t_2 is the time (date) immediately before an EOR oil response; time t_3 is the time (date) of the peak oil rate; and time t_4 is the end of the EOR process.

To model these three time periods, we use the following assumptions. Between times t_1 and t_2, the rate decreases according to an extrapolation of the decline of previous production. Usually this is a waterflood decline curve. Between times t_2 and t_3, the oil rate increases linearly with time. And after time t_3, the rate follows a hyperbolic decline curve. The dashed blue curve in Fig. 3 shows the waterflood decline curve; the dashed red curve shows the model EOR rate history.

Though an oversimplification, the model is more than adequate for screening and economic evaluations. In the following sections we present the defining equations, procedures to estimate model parameters, and model applications. An important part of the work is the development of effective empirical relationships to estimate model parameters. The empirical relationships are based upon production trends observed in published field case histories. The case histories were gathered from the literature search discussed above.

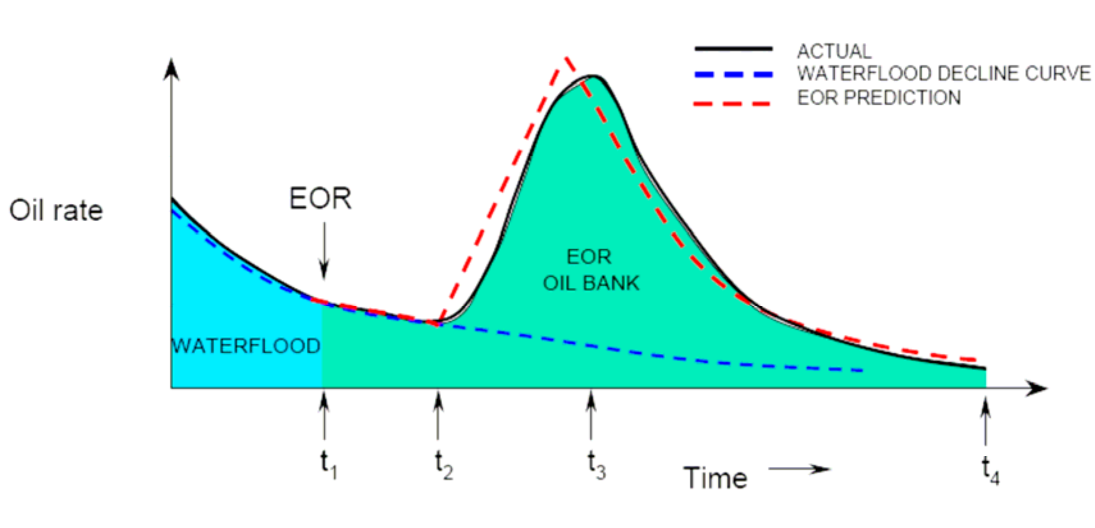

Figure 3. Oil rate history.

We first assume that ultimate recovery, expressed as a fraction of the original oil in place, for the solvent flood is known. This value changes over a fairly narrow range.

Though the rate model in Fig. 3 is applied to only tertiary miscible flooding herein, it can approximate practically any primary, secondary, or tertiary recovery process, whether onshore or offshore. Therefore, the model's range of applicability is quite wide. However, we note that the specific values of the parameters can vary widely.

Model Equations

Figure 4 defines the key oil rates and recoveries in the model. They include: (1) the peak EOR oil rate (q_{peak}), (2) the oil rate (q_1) at the time (t_1) solvent injection begins, (3) the oil rate (q_2) at the time (t_2) of the first oil response, and (4) the oil rate (q_4) at termination. The key oil recoveries include: (1) the oil recovery (N_{p2}) at the time (t_2) of the first oil response, (2) the oil recovery (N_{p3}) at the time (t_3) of the peak oil rate, and (3) the oil recovery (N_{p4}) at termination.

Oil Rates. The producing oil rate during the solvent flood is:

$$q(t) = \frac{q_{iWF}}{\left[1 + b_{WF} D_{iWF} (t - t_{iWF})\right]^{1/b_{WF}}}, \qquad \text{for } t_2 > t > t_1 \qquad (1a)$$

$$q(t) = q_{peak} \frac{(t - t_2)}{(t_3 - t_2)} - q_2 \frac{(t - t_3)}{(t_3 - t_2)}, \qquad \text{for } t_3 > t > t_2 \qquad (1b)$$

$$q(t) = \frac{q_{peak}}{\left[1 + b_{EOR} D_{iEOR} (t - t_3)\right]^{1/b_{EOR}}}, \qquad \text{for } t > t_3 \qquad (1c)$$

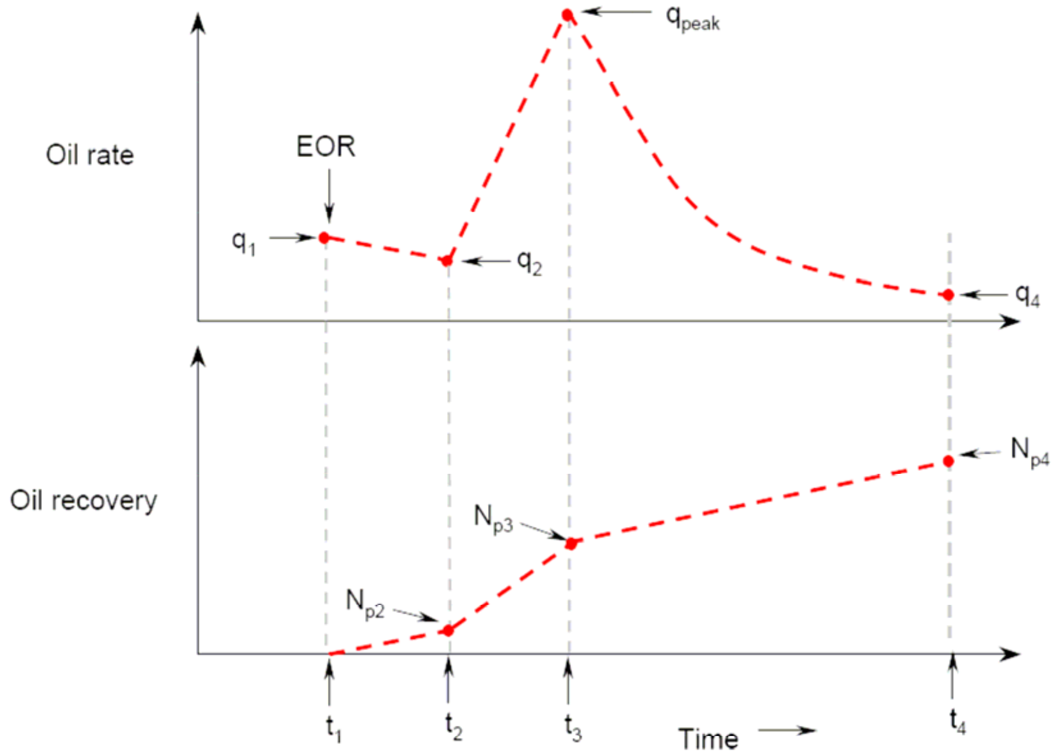

Figure 4. Key oil rates and cumulative recovery parameters inthe EOR rate model.

where b_{WF} and b_{EOR} are the decline (Arps) exponents of the decline curves for the waterflood and solvent flood, respectively; D_{iWF} and D_{iEOR} are the initial decline rates of the decline curves for the waterflood and solvent flood, respectively; q_{iWF} is the initial rate of the waterflood decline curve; and t_{iWF} is the time corresponding to q_{iWF}.

The rates q_1 and q_2 are determined from the waterflood decline curve

$$q_1 = \frac{q_{iWF}}{\left[1 + b_{WF} D_{iWF}\left(t_1 - t_{iWF}\right)\right]^{1/b_{WF}}} \tag{2}$$

$$q_2 = \frac{q_{iWF}}{\left[1 + b_{WF} D_{iWF}\left(t_2 - t_{iWF}\right)\right]^{1/b_{WF}}} \tag{3}$$

Oil Recovery. The oil recovery from the start of solvent flooding is

$$N_p(t) = \frac{q_{iWF}^{b_{WF}}}{D_{iWF}\left(1 - b_{WF}\right)} \left[\frac{1}{q_1^{(b_{WF}-1)}} - \frac{1}{q(t)^{(b_{WF}-1)}} \right], \qquad \text{for } t_2 > t > t_1 \tag{4a}$$

$$N_p(t) = N_{p2} + \frac{(t - t_2)}{2}\left(q(t) - q_2\right), \qquad \text{for } t_3 > t > t_2 \qquad (4b)$$

$$N_p(t) = N_{p3} + \frac{q_{peak}^{b_{EOR}}}{D_{iEOR}\left(1 - b_{EOR}\right)}\left[\frac{1}{q_{peak}^{(b_{EOR}-1)}} - \frac{1}{q(t)^{(b_{EOR}-1)}}\right], \qquad \text{for } t > t_3 \qquad (4c)$$

where N_{p2} and N_{p3} are

$$N_{p2} = \frac{q_{iWF}^{b_{WF}}}{D_{iWF}\left(1 - b_{WF}\right)}\left[\frac{1}{q_1^{(b_{WF}-1)}} - \frac{1}{q_2^{(b_{WF}-1)}}\right] \qquad (5)$$

$$N_{p3} = N_{p2} + \frac{(t_3 - t_2)}{2}\left(q_{peak} + q_2\right) \qquad (6)$$

The recoveries in Eqs. (4) – (6) are the cumulative oil recovered from the start of solvent injection.

Projected Waterflood Recovery. If waterflooding were hypothetically continued after t_1 instead of switching to solvent injection, the projected or hypothetical oil rate would follow an extension of waterflood decline curve. Accordingly, the oil rate would be

$$q_{WF}(t) = \frac{q_{iWF}}{\left[1 + b_{WF} D_{iWF}\left(t - t_{iWF}\right)\right]^{1/b_{WF}}}, \qquad \text{for } t > t_{iWF} \qquad (7)$$

The projected incremental oil recovery after t_1 is

$$\Delta N_{pWF}(t) = \frac{q_{iWF}^{b_{WF}}}{D_{iWF}\left(1 - b_{WF}\right)}\left[\frac{1}{q_1^{(b_{WF}-1)}} - \frac{1}{q_{WF}(t)^{(b_{WF}-1)}}\right], \qquad \text{for } t > t_1 \qquad (8)$$

Incremental Oil Recovery. The incremental oil recovery is the volume of oil recovered in excess of continued waterflooding given by

$$\Delta N_p(t) = N_p(t) - \Delta N_{pWF}(t), \qquad \text{for } t > t_1 \qquad (9)$$

For instance, if the cumulative oil recovery after solvent injection is 11 million barrels and the cumulative recovery from continued waterflooding is estimated at 1 million barrels, then incremental recovery is 10 million barrels.

Dimensionless Recovery Equation. Equation (4c) can be put in a dimensionless form with the following definitions:

$$N_{pD} = \frac{N_p}{N} \tag{10}$$

$$\Delta t_D = \frac{Q_T \Delta t}{V_p} \tag{11}$$

$$D_D = \frac{D_{iEOR} V_p}{Q_T} \tag{12}$$

$$f_{opeak} = \frac{q_{peak}}{Q_T} \tag{13}$$

$$f_{o2} = \frac{q_2}{Q_T} \tag{14}$$

where N is the OOIP, Q_T is a characteristic injection rate, Δt is an elapsed time (since the start of solvent injection), and V_p is the reservoir pore volume. D_D represents a dimensionless decline-rate constant. The characteristic rate is defined

$$Q_T = B_s Q_s + B_w Q_w \tag{11}$$

where Q_s is the field (flooded area) injected solvent rate, expressed in surface volume per unit time (e.g., scf/day or sm^3/day); Q_w is the field (flooded area) injected water rate, expressed in surface volume per unit time; B_s is the solvent formation volume factor; and B_w is the water formation volume factor. B_s is measured at the average reservoir pressure and temperature. In the absence of data, we assume $B_w = 1$. For continuous solvent injection, Q_w is zero; for alternate solvent-water injection, Q_s and Q_w are both non-zero. Q_T is injected fluid rate expressed in reservoir volume per unit time.

The variables f_{opeak} and f_{o2} represent effective oil cuts. The true oil cut is the produced oil rate normalized by the sum of the produced surface water and oil rates. In contrast, f_{opeak} and f_{o2} are produced oil rates normalized by Q_T, which is expressed as a reservoir rate. Substituting Eq. (6) into Eq. (4c) and using the definitions from Eqs. (10) – (14), Eq. (4c) becomes

$$N_{pD}(t) = N_{p2D} + \frac{(\Delta t_{D3} - \Delta t_{D2})(f_{opeak} + f_{o2})B_{oi}}{2(1 - S_{wi})} + \frac{f_{opeak} B_{oi}}{D_D (1 - S_{wi})(1 - b_{EOR})}\left[1 - \left(\frac{f_o(t)}{f_{opeak}}\right)^{1-b_{EOR}}\right] \tag{15}$$

where S_{wi} and B_{oi} are the initial (at discovery) water saturation and oil formation volume factor and f_o is the oil cut at arbitrary time t. The equation $N = V_p(1-S_{wi})/B_{oi}$ is used to help derive Eq. (15). Equation (15) also uses the following definitions:

$$\Delta t_{D3} = \frac{Q_T \Delta t_3}{V_p} \tag{16}$$

$$\Delta t_{D2} = \frac{Q_T \Delta t_2}{V_p} \tag{17}$$

$$N_{p2D} = \frac{N_{p2}}{N} \tag{18}$$

where $\Delta t_3 = t_3 - t_1$ and $\Delta t_2 = t_2 - t_1$. Equation (15) is a material balance on the produced oil. The variables Δt_{D2} and Δt_{D3} represent dimensionless times. Physically, Δt_{D2} is the pore volumes of fluid injected (PVI) at oil bank breakthrough; Δt_{D3} is the PVI at the peak oil rate. Their significance will be discussed later.

Another important dimensionless time—one corresponding to project termination is

$$\Delta t_{D4} = \frac{Q_T \Delta t_4}{V_p} \tag{19}$$

where Δt_{D4} is the PVI at termination and $\Delta t_4 = t_4 - t_1$. The variable Δt_{D4} represents the flood life expressed in PVI. Using Δt_{D4}, Eq. (15) can be put into a slightly different form. If we evaluate Eq. (1c) at $t = t_4$, cast the equation in dimensionless form, and then solve for D_D, we obtain

$$D_D = \frac{\left(\frac{f_{opeak}}{f_{o4}}\right)^{b_{EOR}} - 1}{b_{EOR}\left(\Delta t_{D4} - \Delta t_{D3}\right)}, \tag{20}$$

where f_{o4} is the oil cut at time t_4. f_{o4} is the oil cut at termination. It is a function of economic factors and is approximately 0.01-0.04. Substituting Eq. (20) into Eq. (15) gives

$$N_{p4D} = N_{p2D} + \frac{(t_{D3} - t_{D2})(f_{opeak} + f_{o2})B_{oi}}{2(1-S_{wi})} + \frac{f_{opeak} B_{oi} b_{EOR} (\Delta t_{D4} - \Delta t_{D3})}{\left[\left(\dfrac{f_{opeak}}{f_{o4}}\right)^{b_{EOR}} - 1\right](1-S_{wi})(1-b_{EOR})} \left[1 - \left(\frac{f_{o4}}{f_{opeak}}\right)^{1-b_{EOR}}\right] \tag{21}$$

where N_{p4D} is the dimensionless final cumulative recovery. N_{p4D} is sometimes referred to as the recovery factor.

Equation (21) can be solved for the peak oil cut, f_{opeak}, if the remaining parameters in the equation are known or can be estimated. This equation can easily be solved using an iterative technique, such as Newton's method. Once f_{opeak} is known, then the dimensionless decline-rate constant can be determined using Eq. (20). Then, the decline-rate constant, D_{iEOR}, can be determined using Eq. (12).

Equation (21) is a central part of the solution procedure.

Summary of Model Parameters. The key model parameters are: Δt_2, Δt_3, Δt_4, q_{peak}, q_2, D_{iEOR}, b_{EOR}, D_{iWF}, and b_{WF}. The remaining model parameters (t_{iWF}, q_{iWF}, and t_1) are either known or arbitrarily selected. In the following section, we outline the procedure to estimate the parameters.

Estimating Model Parameters

We use different approaches to estimate the model parameters. The parameters Δt_2, Δt_3, Δt_4, and b_{EOR} are estimated using empirical correlations or guidelines. The guidelines are based on production trends from actual miscible floods. See Appendix C. The parameters D_{iWF}, b_{WF}, and q_2 are estimated from a decline-curve analysis of the preceding waterflood. The model parameters q_{peak} and D_{iEOR} are estimated based on material balance. The following discusses the procedures to estimate each parameter.

Parameters b_{WF}, D_{iWF}, and q_2. The constants b_{WF} and D_{iWF} are determined from a conventional decline-curve analysis of the reservoir's waterflood rate history. This step obviously assumes that oil-rate data from the waterflood is available. Techniques to apply decline curves will not be reviewed here.

Once b_{WF} and D_{iWF} are determined, $q_2(t_2)$ can then be determined from Eq. (3) once Δt_2 is estimated. The method to estimate t_2 is discussed momentarily.

In many instances, the oil-rate history for the miscible flood will be insensitive to the values of D_{iWF} and b_{WF} because the time difference $t_2 - t_1$ is negligible compared to the overall flood life and because q_1 and q_2 are small. If this applies, curve-fitting the waterflood rate history to determine D_{iWF} and b_{WF} is unnecessary. Instead, setting $t_{iWF} = t_1$ and $q_{iWF} = q_1$ and adopting any reasonable values for D_{iWF} and b_{WF}, such as $b_{WF} = 0$

and D_{iWF} = 30%/year is quite acceptable. If this simplification is adopted, then the future incremental oil recovery predicted by the decline curve is not possible.

Peak Oil-Rate Time, Δt_3. Δt_3 is the elapsed time from the start of solvent injection until the peak oil rate. This time difference generally varies between 1 and 6 years. Appendix C shows that Δt_3 correlates well with the time constant V_p/Q_T,

$$\Delta t_3 = 0.295\left(\frac{V_p}{Q_T}\right) - 0.337 \qquad 4.5 \text{ yrs} < V_p/Q_T < 20 \text{ yrs} \qquad (22)$$

where Δt_3 and V_p/Q_T are expressed in years. The appendix shows a plot of Δt_3 versus V_p/Q_T. This equation yields a standard error of 0.17 years (2 months) and an average error of 4.2%. Equation (22) is a convenient means to quickly estimate Δt_3.

As discussed in Appendix C, Eq. (22) implies that the injected fluid volume—expressed in pore volume units—effectively determines Δt_3.

The peak rate occurs at approximately $\Delta t_{D3} \approx 0.26$ pore volumes of fluid injected (PVI). The variable Δt_{D3} is defined as the PVI at the peak rate. This can be used as an alternative means to approximate Δt_3. Accordingly, Δt_3 is

$$\Delta t_3 \approx 0.26\left(\frac{V_p}{Q_T}\right) \qquad (23)$$

where consistent units are assumed. Appendix C discusses the effect of the Δt_{D3} on the oil rate history. Equation. (23) is an acceptable approximation for the cases reviewed.

Flood Life, Δt_4. The time difference Δt_4 is the flood life. The dimensional flood life varies between approximately 8 and 27 years.

Appendix C shows that Δt_4 also correlates with the time constant according to

$$\Delta t_4 = 1.07\left(\frac{V_p}{Q_T}\right) + 4.11 \qquad 4.5 \text{ yrs} < V_p/Q_T < 20 \text{ yrs} \qquad (24)$$

where Δt_4 and V_p/Q_T are expressed in years. Appendix C shows that this equation yields a standard error of 0.91 years (11 months) and an average error of 4%. Since the time constant is invariably known, this equation gives a convenient means to quickly estimate Δt_4.

In terms of pore volumes of fluid injected, the flood life varies between approximately 1.25 and 1.95 PVI, i.e., $1.25 < \Delta t_{D4} < 1.95$, where Δt_{D4} represents the dimensionless flood life. Selecting Δt_4 based on an average value Δt_{D4} = 1.5 often yields reasonable results. Appendix C discusses this approximation, including its error, in greater detail.

The dimensionless flood life predicted by Eq. (24) is based on field data from U.S. onshore tertiary CO_2 floods. Since the expense of offshore operations is greater than onshore operations, the offshore operations will likely terminate before onshore operations, all other things equal. Thus, offshore operations may terminate at dimensionless flood life nearer to 1.25 than 1.95 PVI. The effect of operating costs on the economic limit and profitability is an economic issue and is ultimately investigated by coupling the rate model (using an approximate dimensionless flood life, e.g., 1.5 PVI) with a cash-flow projection.

The dimensionless flood life predicted by Eq. (24) is very similar to what is observed for waterfloods. For instance, Guerrero and Earlougher (1961) observed that waterflood life usually ranges between 1.25 and 1.7 PVI.

The range of scaled rates for miscible flooding approximately agrees with the range in waterflooding. Several investigators (Riley, 1964; Guerrero and Earlougher, 1961; and Bush and Helander, 1968), for instance, have reported that the scaled rate for a waterflood usually falls between 0.10 and 0.30 PVI/year, a surprisingly narrow range. The narrow range probably occurs because of economics. Rates below than the lower limit usually do not occur because they are uneconomic. Rates greater than the upper limit don't occur because they permit larger well spacing and lower drilling expenditures. Because the range for waterflooding is relatively narrow, Willhite (1986) simply recommends using a generic value of 0.28 PVI/year when only approximate estimates are required. The preceding remarks may be useful to develop quick estimates of the time constant for miscible-flood scoping studies.

Oil Bank Breakthrough Time, Δt_2. The time difference Δt_2 is the elapsed time from the start of solvent injection until oil bank breakthrough (BT). Δt_2 is very short—between 1 and 3 months, or 1 month < Δt_2 < 3 months.

This range implies a very quick oil response to solvent injection. Because Δt_2 is very short, its effect on recovery is minor. Because its range is narrow, selecting any value within the range is acceptable. Once Δt_2 is determined, t_2 is determined from $t_2 = \Delta t_2 + t_1$.

In terms of the pore volumes of fluid injected, the range of oil bank breakthrough times is $1 < \Delta t_{D2} < 4\%$.

The preceding guidelines have been validated for well spacing greater than 10 acres Therefore, they should be used carefully for well spacing less than 10 acres. Because the well spacing in most commercial projects greater than 10 acres, this is not a serious limitation. See Appendix C for a brief discussion of the performance of small pilot tests.

Decline Exponent, b_{EOR}. Based on our analysis of field data, we have observed that $0 < b_{EOR} < 0.3$.

Recall, $b_{EOR} = 0$ is an exponential decline. Many solvent floods approach or fit an exponential decline. The difference between $b_{EOR} = 0$ and $b_{EOR} = 0.3$ on the rate history is small. Thus, assuming an exponential decline is not a poor assumption. The average value of b_{EOR} for commercial floods was 0.20. Thus, selecting $b_{EOR} = 0.2$ is reasonable

The effect of increasing b_{EOR} is to increase q_{peak} and D_{iEOR}.

Peak Oil rate, q_{peak}. The peak oil rate q_{peak} is an important parameter affecting the recovery and controlling the shape of the rate history. The dimensionless peak oil cut, f_{opeak}, effectively describes q_{peak}. f_{opeak} varies between 7 and 31% for successful solvent floods, including pilots. For commercial floods, the range is narrower and lower, typically between 7 and 20%.

These ranges are not drastically smaller than for waterfloods. Bush and Helander (1968) noted that the 51% of the waterfloods experienced a peak oil rate between 12 and 31%, where the peak rate is expressed as a fraction of the water injection rate. The average for all waterfloods was 22%.

The peak oil rate is estimated using Eq. (21), the produced oil mass balance equation. This equation is first solved for f_{opeak}, and then q_{peak} is determined using Eq. (13). This approach assumes all the remaining parameters in Eq. (21) can be estimated, including the recovery factor. The recovery E_R factor is normally estimated as described in Appendix D . All of the remaining parameters can usually be estimated. For instance, f_{o4}, the oil cut at the economic limit, depends on economic factors; it typically varies between 1 and 4%.

Our approach to use material balance to estimate the peak oil rate is very similar to Willhite's (1986) approach in applying the Bush-Helander model to waterflood. Willhite showed that this approach yielded reasonable estimates of the peak rate.

Decline-Rate Constant, D_{iEOR}. The decline-rate constant D_{iEOR} is determined from Eqs. (20) and (12). Equation (20) is first used to determine the dimensionless decline-rate constant D_D. This equation is a function of the peak rate; thus, the peak rate must first be determined before using this equation. Then, Eq. (12) is used to compute D_{iEOR}.

D_{iEOR} often falls between 15 and 40% per year. This range roughly agrees with the range observed for waterfloods. For instance, Bush and Helander (1968) observed that 70% of studied waterfloods experienced a decline-rate constant between 20 and 55% per year.

Summary. In summary, b_{WF}, D_{iWF}, q_{iWF}, and t_{iWF} are determined from a decline curve analysis of the preceding waterflood. The parameters Δt_2, Δt_3, Δt_4, and b_{EOR} are determined from empirical guidelines. The parameter $q_2(\Delta t_2)$ is determined from a decline curve analysis of the waterflood after Δt_2 is determined. The parameters q_{peak} and D_{iEOR} are determined from Eq. (21), a mass balance on the produced oil.

For a quick approximation, reasonable rate predictions can often be obtained by simply assuming Δt_{D2} = 0.02, Δt_{D3} = 0.26, Δt_{D4} = 1.50, b_{EOR} = 0.2 and then computing Δt_2, Δt_3, and Δt_4 from Eqs. (16), (17), and (19). See Appendix C for a greater discussion of this approximation.

Model Applications

This section presents the results of three model applications: (1) the Twofreds CO_2 flood, (2) the Lost Soldier CO_2 flood, and (3) the Wertz CO_2 flood.

Example 1: Twofreds CO_2 Flood. The Twofreds (Delaware) field is located in west Texas, USA. Discovered in 1957, the field was produced under pressure depletion (10.4% estimated ultimate recovery) until 1963, and then under waterflood until February 1974. Then, continuous CO_2 injection began on the east side of the field. Eventually, the CO_2 was chased with alternate injection of exhaust gas (84% nitrogen) and water. The Twofreds project was the first field-scale tertiary CO_2 flood in a sandstone reservoir in Texas. The field was owned by HNG Fossil Fuels Co, Transpetco Engineering of the Southwest, and Murphy Oil Co.

The OOIP on the east side of field was 15.4 MM STB. The producing oil cut before CO_2 injection was about 1%. Within 2-4 months after CO_2 injection, the oil rate began to increase. The oil cut peaked at about 17.7% after six years. The operators reported a cumulative recovery of about 15.8% of the OOIP through June 1, 1993.

Figure 5 shows the oil rate history on semi-log coordinates. The gray region is the waterflood response; the green region denotes the CO_2 flood.

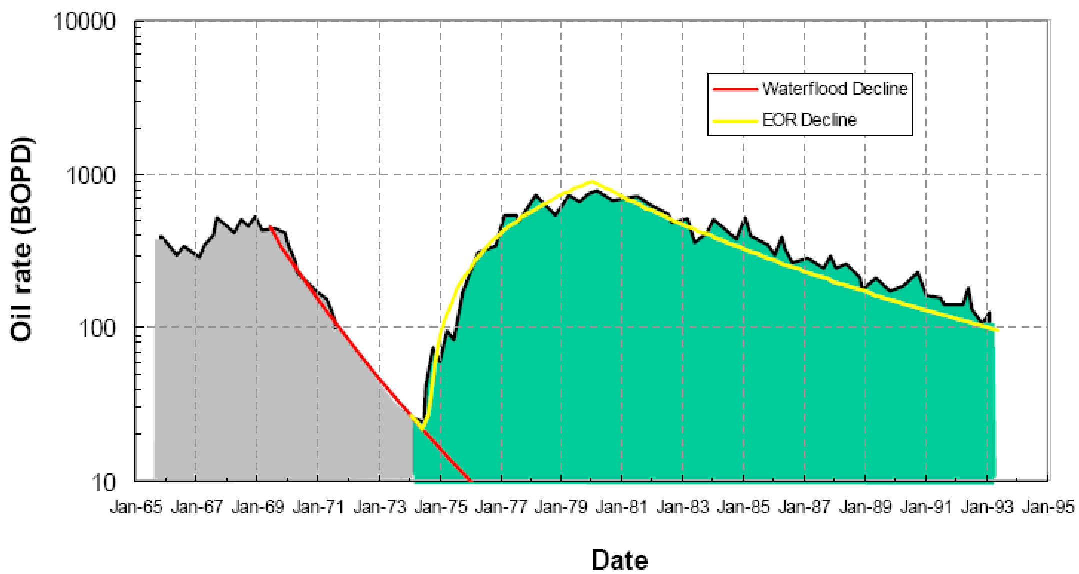

Figure 5. East side Twofreds production history, 1966-1993.

Table 7. Model parameters for applications.

Parameter	Value		
	Twofreds	Lost Soldier	Wertz
OOIP, MMSTB	15.4	240	172
Pore volume, MMRB	33.7	299	222
Injection rate, RB/day	4,322	101,800	136,000
Initial formation vol. factor, RB/STB	1.18	1.12	1.16
Initial water saturation, %	46.2	10	10
E_R, %	17.2	11.2	10.1
Terminal oil cut, %	1	2.3	1.3
Δt_{D2}	0.025	0.02	0.03
Δt_{D3}	0.28	0.24	0.24
Δt_{D4}	1.25	1.7	1.95
Δt_2, mo.	6	1.9	1.6.
Δt_3, yrs	6.0	2.0	1.0
Δt_4, yrs	27.9	12.7	8.9
t_{iWF}	1/1/1969	1/1/1988	1/1/1985
q_{iWF}, STB/day	450	2900	6200
b_{WF}	0.10	0.50	0.01
$D_{iWF,}$ %/year	70	40	30
b_{iEOR}	0.30	0.20	0.10

Table 7 summarizes the model parameters. The yellow curve in Fig. 5 shows the predicted rate history. The model yields a good match of the actual history.

The operators reported an actual recovery of 15.8% OOIP through June 1, 1993. The model predicted a recovery of 16.1%.

Carbon dioxide injection into the west side of Twofreds did not begin until 1980. This example shows that the EOR rate model can effectively model cases where different areas of a field are developed at different times. The only requirement, however, is that the model must be applied sequentially rather than globally.

Example 2: Lost Soldier CO_2 Flood. The Lost Soldier Tensleep reservoir is located in Wyoming, USA. The reservoir was discovered in 1930. Primary production continued until 1962 when peripheral water injection began. Pattern waterflooding began in 1976. Alternate CO_2 and water injection began in July, 1989. The flood was operated by Amoco Production Co.

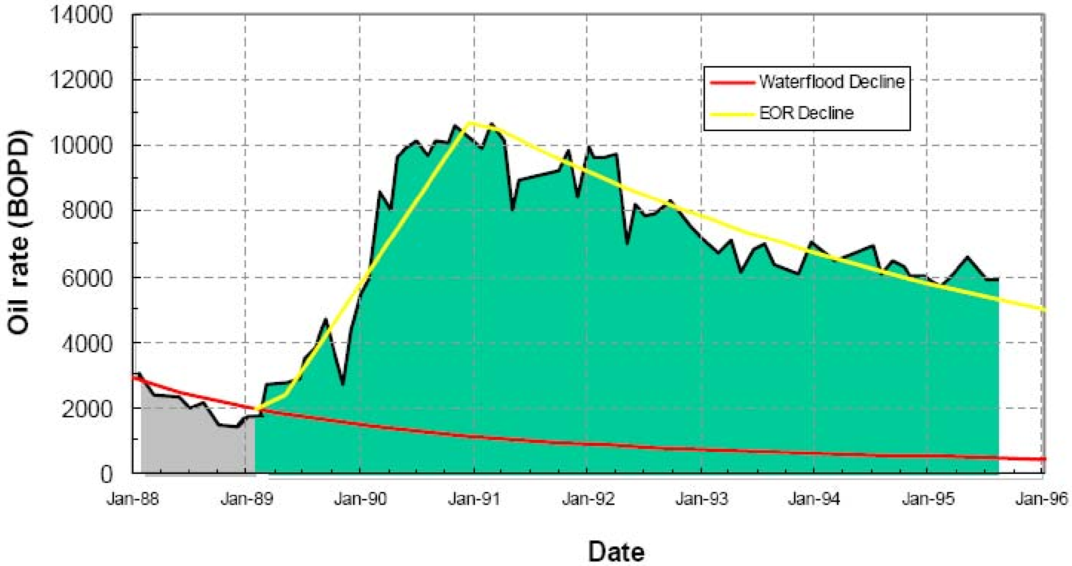

Figure 6. Lost Soldier production history, 1988-1996.

The OOIP at Lost Soldier Tensleep was 240 MM STB. The producing oil cut before CO_2 injection was approximately 2.5%. Oil bank breakthrough occurred within a few months. A peak oil cut of about 11% was realized after about 23 months. The operators reported an incremental oil recovery of 5.7% through January 1, 1996. They projected an ultimate cumulative recovery of 11.2%.

Figure 6 shows the oil rate history on Cartesian coordinates. The gray region denotes the waterflood; the green region the CO_2 flood. The waterflood was projected to recovery an additional 1% OOIP between the time of CO_2 injection and termination.

Table 7 summarizes the model parameters. The yellow curve in Fig. 6 shows the predicted rate history. The model yields a good match of the actual rate history.

The operators estimated an ultimate cumulative recovery of 11.2% OOIP. The model predicted an ultimate cumulative recovery of 10.9%.

Example 3: Wertz CO_2 Flood. The Wertz Tensleep reservoir is located in Wyoming, USA. The reservoir was discovered in 1936. Primary production was from a combination of fluid expansion and water influx. A pilot waterflood was carried out in 1978, and pattern waterflood was installed field wide in 1980. Waterflood performance was enhanced with infill drilling between 1982 and 1986. Alternate CO_2 and water injection began in November, 1986. The flood was operated by Amoco Production Co.

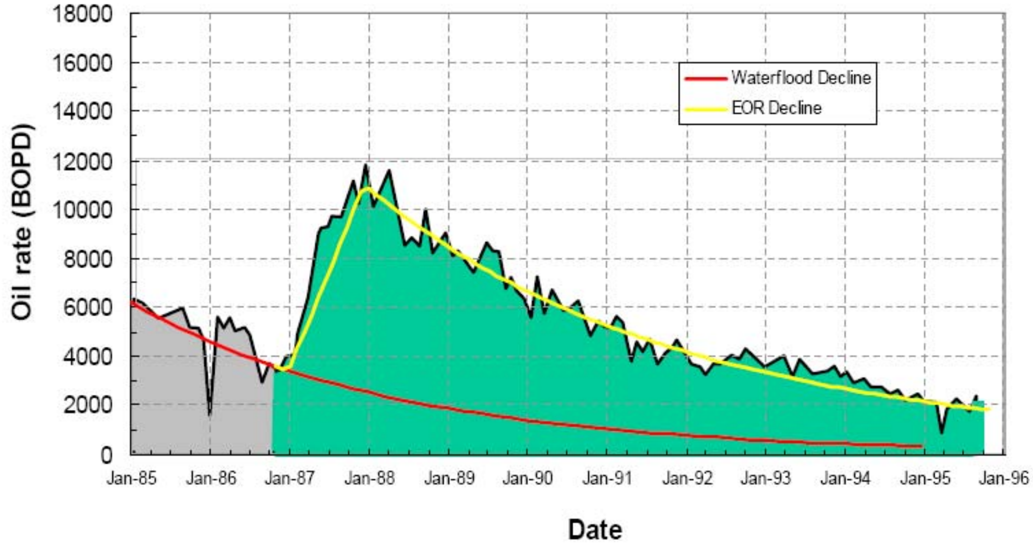

Figure 7. Wertz oil rate history, 1985-1996.

The OOIP at Wertz Tensleep was 172 MM STB. The producing oil cut prior to CO_2 injection was approximately 3.3%. Oil bank breakthrough occurred within a few months. A peak oil cut of about 10.2% was realized after about 13 months. The operators reported a cumulative recovery of 10.1% through January 1, 1996. The producing oil cut was less than 2%.

Figure 7 shows the oil rate history on Cartesian coordinates. The gray region denotes the waterflood; the green region the CO_2 flood. The red curve shows the projected waterflood decline. The waterflood was projected to recovery an additional 2.4% OOIP between the time of CO_2 injection and termination.

Table 7 summarizes the model parameters. The yellow curve in Fig. 7 shows the predicted rate history. The model matches the actual rate history.

The operators reported a cumulative recovery of 10.1% OOIP on Jan. 1, 1996. The model predicted a cumulative recovery of 10.3%.

Conclusions. The preceding examples show excellent agreement between model and actual results. Similar agreement was noted in the other commercial field cases (West Sussex, SACROC 4PA, and SACROC 17PA). These cases are not shown for the sake of brevity.

The results in the preceding examples are not a stringent test of the model inasmuch as its correlations were based on the data from these cases. The model results for the last three cases, however, are a more severe test of the model inasmuch as none of the field data from these cases was used to develop the model correlations. Thus, these latter cases truly represent model predictions.

The West Sussex results are an especially severe test of the model because its rate response was very unusual in two respects. First, its peak oil cut was 31%; substantially greater than the peak oil cut for all the other commercial cases, which varied between 6 and 17%. Second, its decline rate constant (135% per year) was much larger than that for the other cases. Despite these differences, the rate model still matched this case very well.

The repeated success of the model helps validate it. The success is largely attributed to the accuracy of the Δt_3 and Δt_4 correlations.

Model Limitations

The model proposed here is a reasonable approach to empirically estimate the oil rate history of a tertiary miscible flood. It is similar to the Bush-Helander model for waterflooding. We have illustrated the model's ability to match and predict the oil rate of tertiary miscible floods. Our success is reminiscent of Willhite's (1986) in applying the Bush-Helander model. Though we have enjoyed success with the model, we have encountered and do recognize certain limitations.

First, the correlations used to estimate model parameters Δt_3 and Δt_4—two very important parameters—are based on only six or seven field cases. On one hand, this is not very many field cases. On the other hand, the existing field data spans the entire expected range of time constants and the correlations yield very realistic predictions. Also, based on physical reasoning and our experience, we do not expect for Δt_{D3} and Δt_{D4} to fall outside of the range of existing data for new data. For example, we do not expect to find many solvent floods whose life is less than 1.25 or greater than 1.95 PVI. Nevertheless, the lack of data represents a limitation and we believe testing against more data is required.

Second, the model implicitly assumes a constant injection rate. This assumption is reasonable for many, but not all miscible floods. Some floods, such as Rangely, experience injectivity losses. This dramatic change has serious consequences on the oil rate. The current model cannot adequately treat this group of floods. The model will over-accelerate recovery and will over-estimate the producing oil rate. To treat these cases, the model must be modified for variable injection rates. It is questionable, however, whether this modification is really needed because injectivity is not reliably predictable.

Third, the model assumes the entire field is instantaneously converted to miscible flooding. In reality, a staggered development is sometimes implemented. In the Denver Unit of the Wasson field, for example, three very large portions of the unit were converted over a period of more than 8 years. The net effect of a staggered development relative to a single-stage development is to obviously expand the recovery period and diminish the peak oil rate.

Summary and Conclusions

We have successfully developed a non-simulation-based model to predict the rate history of tertiary solvent floods. The model is designed for scoping studies. The model is empirical and is based on hyperbolic decline curves and material balance. The model has been shown to closely match and predict the rate history of solvent floods. The model requires only minimal reservoir data to apply; namely, estimates of the OOIP, pore volume, cumulative EOR, injection rate, initial oil formation volume factor, and initial water saturation. Based on only this data, the model will predict the oil-rate history and cumulative recovery curve. The model is ideally suited for spreadsheet calculation and can be easily incorporated into existing cash-flow models.

SCREENING CRITERIA

Table 8 shows a summary of miscible EOR screening criteria offered by several investigators (Brashear and Kuuskraa, 1978; Goodlett, et al., 1986; Taber, et al. 1997; Klins, 1984; Taber, and Martin, 1983). This table was assembled from an analysis of papers from the literature search. Screening criteria include variables such as depth, oil viscosity, oil gravity, oil saturation prior to flooding, operating pressure, oil composition, and pay thickness. Some investigators consider criteria for miscible EOR regardless of process; other investigators adopt different criteria for different processes within miscible EOR. For instance, Goodlett, et al. (1986) give separate criteria for hydrocarbon, nitrogen or flue gas, or carbon dioxide miscible projects.

Though most investigators ignore a criterion regarding pressure, it is implied that the reservoir pressure must meet or exceed the minimum miscibility pressure if miscibility is to be attained. This criterion is sometimes implied through the depth criterion.

Though these criteria are informative, they may be misleading. The criteria limits may be very different from industry average values, where the latter is defined as the average value for past and present projects. Taber et al. (1997) addressed this problem and offered an interesting set of criteria that included average parameter values. For example, most sets of criteria dictate a maximum oil viscosity of between 10 to 20 cp. Taber et al. in contrast, added that the average oil viscosity for past and present projects was between 0.2 and 1.5 cp. This example shows that the screening criteria may be so coarse that they do not accurately reflect what is needed for a successful project.

Appendix E includes a summary of screening criteria for other EOR categories, such as chemical flooding. Copies of selected pages and tables from cited literature are reproduced.

Table 8. Miscible EOR Screening Criteria

Parameter	Brashear & Kuuskraa	Goodlett, et al. HC Miscible	Goodlett, et al. N_2, flue gas	Goodlett, et al. CO_2
Depth, ft		> 2000 for LPG > 5000 for HPG	> 4500	> 2000
Oil viscosity, cp*	< 20	< 10	< 10	< 15
Gravity, °API	> 26	> 35	> 35	> 25
Oil saturation, %PV **	> 25	> 30	> 30	> 30
Original pressure, psia	> 1500			
Operating pressure, psia				> MMP
Oil composition		High C1-C7	High C1-C7	High C5-C12
Net thickness				
Comments	Prefer thin pay, high dip, homogeneous formation, low vertical permeability	Prefer thin unless dipping;	Prefer thin unless dipping;	Prefer thin unless dipping;

Parameter	Taber, Martin, & Seright HC Miscible	Taber, Martin, & Seright N_2, flue gas	Taber, Martin, & Seright CO_2	Taber, Martin, & Seright Immiscible
Depth, ft	> 4000	> 6000	> 2500	> 1800
Oil viscosity, cp*	< 3	< 0.4	< 10	< 600
Gravity, °API	> 23	> 35	> 22	> 12
Oil saturation, %PV **	> 30	> 40	> 20	> 35
Original pressure, psia				
Operating pressure, psia				
Oil composition	High C1 – C7	High C1 – C7	High C5-C12	
Net thickness	Thin unless dipping	Thin unless dipping	Wide range	
Comments	Prefer thin unless dipping;	Prefer thin unless dipping;	Prefer thin unless dipping;	Prefer thin unless dipping;

Parameter	Klins CO_2 Flooding	Taber & Martin Miscible EOR
Depth, ft	> 3000	> 2000 for LPG > 5000 for HPG
Oil viscosity, cp*	< 12	< 10
Gravity, °API	> 30	> 35
Oil saturation, %PV **	> 25	> 30
Original pressure, psia	> 1500	
Operating pressure, psia		
Oil composition		High C2 –C7
Net thickness		Thin unless dipping
Comments		Prefer minimum fracturing; not highly heterogeneous permeability

* at reservoir conditions
** prior to flooding
HPG = high-pressure gas
LPG = liquefied petroleum gas
MMP = minimum miscibility pressure

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NOMENCLATURE

BPD	Barrels per day
B_o	Oil formation volume factor
B_s	Solvent (gas) formation volume factor
B_w	Water formation volume factor
b	Decline exponent (Arps exponent)
D	Decline rate
D_D	Dimensionless decline rate
EOR	Enhanced oil recovery
E_R	Efficiency or recovery factor
f_o	Oil cut
MSCF	Thousands of standard cubic feet
MSCFPD	Thousands of standard cubic feet per day
N_p	Cumulative produced oil
N	Original oil inplace
OOIP	Original oil inplace
Q	Injection rate
Q_T	Total injection rate
q	Production rate
RB	Reservoir barrels
S_w	Water saturation
SCF	Standard cubic feet
STB	Stock-tank barrels
t	Time
V_p	Pore volume

Greek Symbols

Δ	Operator that refers to discrete change

Subscripts

peak	Peak rate
i	Initial
WF	Waterflood
EOR	Enhanced oil recovery process
D	Dimensionless
w	Water
o	Oil
s	Solvent

CONVERSION FACTORS

1 m^3	=	35.3 ft^3
1 m^3	=	6.29 bbls
1 km^2	=	247.1 acres
1 km^2	=	100 hectares
1 atm	=	14.7 psia
6.896 MPa	=	1000 psia
1 m	=	3.28 ft
(^oF)	=	1.8(^oC) + 32

APPENDIX A: PAPER INVENTORY

The following is a listing of the paper inventory. More information about the papers can be found in Excel file "EOR_Paper_Inventory" on the accompanying Compact Disc (CD). The papers are ordered according to SPE number, from lowest to highest. This order approximately follows a chronological order, from oldest to youngest.

We began with a brief review of the Danish resource base. To familiarize ourselves with the resource base and reservoir operations, we also reviewed some papers from the SPE library. Some of these papers are listed below and included in the paper archive.

	SPE Paper No.	Title	Year
1	43-PA	Ten Years of Miscible Displacement in Block 31 Field	1961
2	66-MS	CARBONATED WATERFLOOD RESULTS--TEXAS AND OKLAHOMA	
3	256-MS	Processing of Geological and Engineering Data Multipay Fields for Evaluation	
4	333-MS	Case Histories of Carbonated Waterfloods in Dewey-Bartlesville Field	
5	341-PA	Small Propane Slug Proving Success in Slaughter Field Lease	1963
6	625-PA	LPG-Gas Injection Recovery Process Burkett Unit, Greenwood County, Kansas	1963
7	626-PA	Performance of a Miscible Flood with Alternate Gas-Water Displacement	1964
8	713-G	A Field Test of the Gas-Driven Liquid Propane Method of Oil Recovery	1957
9	824-PA	Meadow Creek Unit Lakota "B" Combination Water-Miscible Flood	1964
10	945-PA	An Efficient Gas Displacement Project Raleigh Field, Mississippi	1963
11	1126-PA	Performance of Domes Unit Carbonated Waterflood - First Stage	
12	1260-G	Pilot Propane Project Completed in West Texas Reef	1959
13	1884-PA	Performance of Seeligson Zone 20B-07 Enriched-Gas-Drive Project	1967
14	1907-MS	Success of Flue Gas Program At Neale Field	1967
15	2303-MS	Waterflood Performance Of a Shallow Channel Sandstone Reservoir Burkett Pool, Coleman County, Texas	1968
16	2418-PA	A Current Appraisal of Field Miscible Slug Projects	1970
17	2644-PA	Ante Creek - A Miscible Flood Using Separator Gas and Water Injection	1970
18	2837-PA	Case History of the University Block 9 (Wolfcamp) FieldA Gas-Water Injection Secondary Recovery Project	1970
19	2845-PA	Performance of a Propane Slug Pilot in a Watered-Out SandSouth Ward Field	1970
20	2930-PA	Prediction of Recovery in Unstable Miscible Flooding	
21	3103-PA	Carbon Dioxide Test at the Mead-Strawn Field	1971
22	3441-PA	Steam Distillation Drive-Brea Field, California	
23	3487-MS	High Pressure Miscible Gas Displacement Project, Bridger Lake Unit, Summit County	1971
24	3773-PA	Advanced Technology Improves Recovery at Fairway	1973
25	3774-PA	Propane-Gas-Water Miscible Floods In Watered-Out Areas of the Adena Field, Colorado	1972
26	3775-MS	Tertiary Miscible Flood in Phegly Unit, Washington County, Colorado	1972
27	4083-PA	Evaluation and Design of a CO2 Miscible Flood Project-SACROC Unit, Kelly-Snyder Field	1973
28	4600-PA	Performance of a Miscible Flood in the Bear Lake Cardium Unit, Pembina Field, Alberta, Canada	1975
29	4764-MS	Fosterton Northwest - A Tertiary Combustion Case History	
30	5080-PA	Miscible Flood Performance of the Intisar "D" Field, Libyan Arab Republic	1975

	SPE Paper No.	Title	Year
31	5536-PA	Reservoir Description by Simulation at SACROC - A Case History	1976
32	5539-MS	Reservoir Engineering Design of a Tertiary Miscible Gas Drive Pilot Project	1975
33	5560-PA	Status of CO2 and Hydrocarbon Miscible Oil Recovery Methods	1976
34	5821-PA	A Study of Fireflood Field Projects (includes associated paper 6504)	
35	5826-PA	Enriched-Gas Miscible Flooding: A Case History of the Levelland Unit Secondary Miscible Project	1977
36	5826-PA	Enriched-Gas Miscible Flooding: A Case History of the Levelland Unit Secondary Miscible Project	
37	5893-MS	Non-Thermal Heavy Oil Recovery Methods	
38	6117-PA	An Evaluation of Miscible CO2 Flooding in Waterflooded Sandstone Reservoirs	1977
39	6140-PA	Pool Description and Performance Analysis Leads to Understanding Golden Spike's Miscible Flood	1977
40	6350-PA	The Potential and Economics of Enhanced Oil Recovery	
41	6388-MS	A Review of the Willard (San Andres) Unit CO2 Injection Project	1977
42	6390-PA	North Cross (Devonian) Unit CO2 Flood - Review of Flood Performance and Numerical Simulation Model	1978
43	6391-MS	Corrosion and Operational Problems, CO2 Project, Sacroc Unit	1977
44	6624-MS	APPRAISAL OF MICELLAR FLOODING, CARBON DIOXIDE AND SURFACTANT FLOODING PROJECTS	
45	6626-MS	DEVELOPMENT OF A PILOT CARBON DIOXIDE FLOOD IN THE ROCK CREEK-BIG INJUN FIELD, ROANE COUNTY, WEST VIRGINIA	1977
46	6747-MS	A CO2 TERTIARY RECOVERY PILOT LITTLE CREEK FIELD, MISSISSIPPI	1977
47	6974-MS	ENHANCED OIL RECOVERY TECHNIQUES - STATE OF THE ART REVIEW	
48	7049-MS	USE OF TIME-LAPSE LOGGING TECHNIQUES IN EVALUATING THE WILLARD UNIT CO2 FLOOD MINI-TEST	1978
49	7051-MS	A METHOD FOR PROJECTING FULL-SCALE PERFORMANCE OF CO2 FLOODING IN THE WILLARD UNIT	1978
50	7090-MS	SACROC TERTIARY CO2 PILOT PROJECT	1978
51	7091-PA	Performance Review of a Large-Scale CO2-WAG Enhanced Recovery Project, SACROC Unit Kelly-Snyder Field	1979
52	7553-MS	RESERVOIR STUDY OF THE CAMP SAND, HAYNESVILLE FIELD, LOUISIANA	1978
53	8200-PA	History Match Analysis of the Little Creek CO2 Pilot Test	1980
54	8382-MS	TWOFREDS FIELD A TERTIARY OIL RECOVERY PROJECT	1979
55	8410-MS	DESIGN AND OPERATION OF THE LEVELLAND UNIT CO2 INJECTION FACILITY	1979
56	8740-MS	GRANNY'S CREEK CO2 INJECTION PROJECT, CLAY COUNTY, WEST VIRGINIA	1979
57	8830-PA	Slaughter Estate Unit CO2 Pilot - Surface and Downhole Equipment Construction and Operation in the Presence of H2S	1981
58	8831-MS	DESIGN AND IMPLEMENTATION OF A LEVELLAND UNIT CO2 TERTIARY PILOT	1980
59	8832-MS	REVIEW AND ANALYSIS OF PAST AND ONGOING CARBON DIOXIDE INJECTION FIELD TESTS	1980
60	8897-PA	Carbon Dioxide Well Stimulation: Part 2 -- Design of Aminoil's North Bolsa Strip Project (includes associated papers 11928 and 12234)	1982

	SPE Paper No.	Title	Year
61	9415-PA	Unique Enhanced Oil and Gas Recovery for Very High-Pressure Wilcox Sands Uses Cryogenic Nitrogen and Methane Mixture	1980
62	9430-PA	A Single CO2 Injection Well Minitest in a Low-Permeability Carbonate Reservoir	1980
63	9430-PA	A Single CO2 Injection Well Minitest in a Low-Permeability Carbonate Reservoir	1982
64	9719-PA	Response of North Cowden and Goldsmith Crudes to Carbon Dioxide Slugs Pushed by Nitrogen	1984
65	9786-MS	UTILIZATION OF COMPOSITION OBSERVATION WELLS IN A WEST TEXAS CO2 PILOT FLOOD	1981
66	9796-PA	Slaughter Estate Unit Tertiary Pilot Performance	1981
67	9798-MS	SAN ANDRES RESERVOIR PRESSURE CORING PROJECT FOR ENHANCED OIL RECOVERY EVALUATION, BENNETT RANCH UNIT, WASSON FIELD, WEST TEXAS	
68	9805-PA	Planning a Tertiary Oil-Recovery Project for Jay/LEC Fields Unit	1983
69	9830-MS	APPRAISING FEASIBILITY OF TERTIARY RECOVERY WITH CARBON DIOXIDE	1982
70	9976-PA	Some Aspects of the Potential Application of Surfactants or CO2 as EOR Processes in North Sea Reservoirs	1982
71	9992-PA	Status of Miscible Displacement	1982
72	10026-MS	The Wizard Lake D-3A Pool Miscible Flood	1984
73	10159-MS	Analysis and Design of a Deep Reservoir, High Volume Nitrogen Injection Project in the R-1 Sand, Lake Barre Field	
74	10160-PA	Implementation of a Gravity-Stable Miscible CO2 Flood in the 8000 Foot Sand, Bay St. Elaine Field	
75	10245-PA	Review of Miscible Flood Performance, Intisar "D" Field, Socialist People's Libyan Arab Jamahiriya	1983
76	10292-PA	CO2 Flood Performance Evaluation for the Cornell Unit, Wasson San Andres Field	
77	10547-PA	Thistle Field Development	1983
78	10693-MS	CO2 Injection for Tertiary Oil Recovery, Granny's Creek Field, Clay County, West Virginia	1983
79	10693-MS	CO2 Injection for Tertiary Oil Recovery, Granny's Creek Field, Clay County, West Virginia	
80	10695-MS	Weeks Island "S" Sand Reservoir B Gravity Stable Miscible CO2 Displacement, Iberia Parish, Louisiana	
81	10696-PA	Enhanced Oil Recovery by CO2 Miscible Displacement in the Little Knife Field, Billings County, North Dakota	1984
82	10727-PA	Slaughter Estate Unit Tertiary Miscible Gas Pilot Reservoir Description	1984
83	10731-MS	Technical Feasibility of Chemical Flooding in California Reservoirs	1984
84	10935-MS	A New Dawn for CO2 EOR	1986
85	11129-MS	Numerical Simulation of a Gravity Stable, Miscible CO2 Injection Project in a West Texas Carbonate Reef	1986
86	11162-MS	Ten Years of Handling CO2 for SACROC Unit	1986
87	11303-PA	Valuation of Supplemental and Enhanced Oil Recovery Projects With Risk Analysis	1987
88	11305-MS	Should We Continue To Explore in the North Sea?	1985
89	11506-MS	Design and Evaluation of a Gravity-Stable, Miscible CO2-Solvent Flood, Bay St. Elaine Field	
90	11902-PA	Analysis of Nitrogen-Injection Projects to Develop Screening Guides and Offshore Design Criteria	1980

	SPE Paper No.	Title	Year
91	11987-MS	Design and Operation of a CO2 Tertiary Pilot: Means San Andres Unit	1983
92	12069-MS	Technical Screening Guides for the Enhanced Recovery of Oil	
93	12197-MS	CO2 Flood: Design and Initial Operations, Ford Geraldine (Delaware Sand) Unit	1983
94	12333-MS	Danish Underground Consortium Gas Development Project Danish North Sea	
95	12637-PA	Planning and Implementing a Large-Scale Polymer Flood	
96	12664-MS	CO2 Miscible Flooding Evaluation of the South Welch Unit, Welch San Andres Field	1984
97	12665-MS	Evaluation Of CO2 Flood Performance, Springer "A" Sand, NE Purdy Unit, Garvin County, OK	
98	12666-MS	First Results From the Maljamar Carbon Dioxide Pilot	1984
99	12668-MS	CO2 Flooding a Waterflooded Shallow Pennsylvanian Sand in Oklahoma: A Case History	1984
100	12704-MS	CO2 Minitest, Little Knife Field, ND: A Case History	1984
101	13238-MS	A Simplified Predictive Model for CO2 Miscible Flooding	
102	13242-MS	The National Petroleum Council EOR Study: Thermal Processes	
103	13272-MS	Design and Implementation of a Miscible Water-Alternating-Gas Flood at Prudhoe Bay	1984
104	13989-MS	THE THISTLE FIELD - ANALYSIS OF ITS PAST PERFORMANCE AND OPTIMISATION OF ITS FUTURE DEVELOPMENT	
105	14059-MS	A Study of Nitrogen Injection for Increased Recovery From a Rich Retrograde Gas/Volatile Oil Reservoir	1986
106	14105-MS	Factors To Consider When Designing a CO2 Flood	1986
107	14287-PA	Design, Installation, and Early Operation of the Timbalier Bay S-2B(RA)SU Gravity-Stable, Miscible CO2-injection Project	1986
108	14308-PA	Investigation of Unexpectedly Low Field-Observed Fluid Mobilities During Some CO2 Tertiary Floods	1987
109	14439-MS	Performance of the Twofreds CO2 Injection Project	1985
110	14835-PA	In-Situ Combustion Appraisal and Status	
111	14934-PA	Improving Chemical Flood Efficiency With Micellar/Alkaline/Polymer Processes	
112	14939-MS	Case History of a Successful Rocky Mountain Pilot CO2 Flood	1986
113	14940-PA	The Maljamar CO2 Pilot: Review and Results	1987
114	14951-MS	The Status and Potential of Enhanced Oil Recovery	
115	14953-MS	A Progress Report on Polymer-Augmented Waterflooding in Wyoming's North Oregon Basin and Byron Fields	
116	15172-MS	The Role of Screening and Laboratory Flow Studies in EOR Process Evaluation	
117	15497-MS	Design and Implementation of Immiscible Carbon Dioxide Displacement Projects (CO2 Huff-Puff) in South Louisiana	1986
118	15569-PA	Skjold Field, Danish North Sea: Early Evaluations of Oil Recovery Through Water Imbibition in a Fractured Reservoir	
119	15591-MS	NITROGEN MANAGEMENT AT THE EAST BINGER UNIT USING AN INTEGRATED CRYOGENIC PROCESS	1986
120	15752-MS	Case Study: Enhanced Oil Recovery Potential for the Garzan Field, Turkey	1983

	SPE Paper No.	Title	Year
121	15864-MS	North Sea Field Development: Historic Costs and Future Trends	1987
122	15877-MS	Gas Injection in the Eastern Fault Block of the Thistle Field	1986
123	16721-MS	East Vacuum Grayburg-San Andres Unit CO2 Injection Project: Development and Results to Date	1987
124	16722-PA	Development and Results of the Hale/Mable Leases Cooperative Polymer EOR Injection Project, Vacuum (Grayburg-San Andres) Field, Lea County, New Mexico	
125	16830-MS	CO2 Injection and Production Field Facilities Design Evaluation and Considerations	1987
126	17134-PA	Evolution of the Carbon Dioxide Flooding Processes	1987
127	17140-PA	Polymer Flooding Review	
128	17277-MS	Evaluation and Implementation Of CO2 Injection at the Dollarhide Devonian Unit	1988
129	17321-MS	Definitive CO2 Flooding Response in the SACROC Unit	1988
130	17323-MS	History Match of the Maljamar CO2 Pilot Performance	1988
131	17326-MS	Cedar Creek Anticline Carbon Dioxide Injectivity Test: Design, Implementation, and Analysis	1988
132	17349-PA	Review of the Means San Andres Unit CO2 Tertiary Project	1990
133	17351-MS	Weeks Island Gravity Stable CO2 Pilot	1988
134	17353-PA	Chatom Gas Condensate Cycling Project	
135	17620-MS	Numerical Simulation of Gravity-Stable Hydrocarbon Solvent Flood, Wizard Lake D-3A Pool, Alberta, Canada	
136	17683-MS	Use of Compositional Simulation in the Management of Arun Gas Condensate Reservoir	
137	17791-MS	EOR Screening With an Expert System	
138	17800-MS	Enhanced Oil Recovery Model Input Program	
139	18002-MS	Performance of a Heavy-Oil Recovery Process by an immiscible CO2 Application, Bati Raman Field	1989
140	18067-PA	The Wertz Tensleep CO2 Flood: Design and Initial Performance	1990
141	18068-MS	Enhanced Oil Recovery Evaluation of the Flounder T-1.1 Reservoir	1988
142	18278-PA	Rock Compressibility, Compaction, and Subsidence in a High-Porosity Chalk Reservoir: A Case Study of Valhall Field	
143	18761-MS	Miscible Displacement of Heavy West Sak Crude by Solvents in Slim Tube	1989
144	18977-MS	Summary Results of CO2 EOR Field Tests, 1972-1987	1989
145	19020-MS	NORTH SEA ECONOMICS	
146	19023-MS	A New Approach to SACROC Injection Well Testing	1988
147	19375-PA	Slaughter Estate Unit CO2 Flood: Comparison Between Pilot and Field-Scale Performance	1992
148	19636-MS	Field-Derived Comparison of Tertiary Recovery Mechanisms for Miscible CO2 Flooding of Waterdrive and Pressure-Depleted Reservoirs in South Louisiana	1989
149	19656-MS	Reservoir Description and Performance Analysis of a Mature Miscible Flood in Rainbow Field, Canada	1989
150	19657-MS	Impact of Solvent Injection Strategy and Reservoir Description on Hydrocarbon Miscible EOR for the Prudhoe Bay Unit, Alaska	1989

	SPE Paper No.	Title	Year
151	19840-MS	Primary and Enhanced Recovery of Ekofisk Field: A Single- and Double-Porosity Numerical Simulation Study	
152	19878-MS	Improving Recovery From the Dunlin Field, U.K. Northern North Sea	
153	20120-MS	Waterflood Pattern Realignment at the McElroy Field: Section 205 Case History	
154	20156-MS	A Review of Heterogeneity Measures Used in Reservoir Characterization	
155	20224-MS	Design of a Novel Flooding System for an Oil-Wet Central Texas Carbonate Reservoir	
156	20227-MS	A Full-Field Numerical Modeling Study for the Ford Geraldine Unit CO Flood	1990
157	20229-PA	A Case History of the Hanford San Andres Miscible CO2 Project	1992
158	20234-MS	A Comparison of 31 Minnelusa Polymer Floods With 24 Minnelusa Waterfloods	
159	20255-MS	Evaluation of Unrecovered Mobile Oil in Texas, Oklahoma, and New Mexico	
160	20268-MS	Design and Results of a Shallow, Light Oilfield-Wide Application of CO2 Huff `n' Puff Process	1990
161	20938-MS	Future Trends in the North Sea : What's Ahead?	
162	20991-PA	Enhanced Recovery Under Constrained Conditions	
163	21649-MS	The Use of Selective Injection Equipment in the Rangely Weber Sand Unit	1991
164	21762-MS	An Evaluation of Carbon Dioxide Flooding	
165	22653-MS	A Laboratory and Field Injectivity Study: CO2 WAG in the San Andres Formation of West Texas	1991
166	22898-PA	Reservoir Performance of a Gravity-Stable, Vertical CO2 Miscible Flood: Wolfcamp Reef Reservoir, Wellman Unit	1993
167	22918-MS	Reservoir Gas Management in the Brae Area of the North Sea	1991
168	22930-MS	North Sea Chalk Reservoirs: An Appealing Target for Horizontal Wells?	
169	22946-PA	Waterflood and CO2 Flood of the Fractured Midale Field (includes associated paper 22947)	1993
170	23082-MS	Integrated Study of the Kraka Field	
171	23312-MS	Produced Water Management	
172	23564-PA	Carbon Dioxide Flooding	
173	23598-PA	Mobility Control Experience in the Joffre Viking Miscible CO2 Flood	1993
174	23641-PA	Ranking Reservoirs for Carbon Dioxide Flooding Processes	
175	23975-MS	A Simple Technique to Forecast CO2 Flood Performance	1992
176	24038-MS	Feasibility Study of CO2 Stimulation in the West Sak Field, Alaska	
177	24141-MS	Experimental Evaluation of a Single-Well Surfactant Tracer Test for a North Sea Oil Reservoir	1992
178	24143-MS	Evaluation of a South Louisiana CO2 Huff 'n' Puff Field Test	
179	24145-MS	Performance Review of a Large-Scale Polymer Flood	
180	24156-MS	Production Performance of the Wasson Denver Unit CO2 Flood	1992

	SPE Paper No.	Title	Year
181	24160-MS	Early CO2 Flood Experience at the South Wasson Clearfork Unit	1992
182	24163-MS	Interpretation of a CO2 WAG Injectivity Test in the San Andres Formation Using a Compositional Simulator	
183	24176-MS	CO2-Foam Field Verification Pilot Test at EVGSAU Injection Project Phase I: Project Planning and Initial Results	1992
184	24184-MS	Phase Behavior Modeling Techniques for Low-Temperature CO2 Applied to McElroy and North Ward Estes Projects	1992
185	24185-MS	CO2 Miscible Flood Simulation Study, Roberts Unit, Wasson Field, Yoakum County, Texas	1992
186	24210-MS	North Cross (Devonian) Unit CO2 Flood: Status Report	1992
187	24333-MS	Dolphin Field: A Successful Miscible Gas Flood in a Small Volatile Oil Reservoir	1992
188	24337-MS	The Feasibility of Using CO2 EOR Techniques in the Powder River Basin of Wyoming	
189	24346-MS	High-Rate Refracturing: Optimization and Performance in a CO2 Flood	1992
190	24874-MS	Brassey Field Miscible Flood Management Program Features Innovative Tracer Injection	1992
191	24928-MS	Update of Industry Experience With CO2 Injection	
192	24931-MS	Simulation of a Successful Polymer Flood in the Chateaurenard Field	
193	25058-MS	Practical Considerations of Horizontal Well Fracturing in the Danish Chalk	
194	26404-MS	A Compositional Simulation Evaluation of the Brassey Artex B Pool, British Columbia, Canada	1993
195	26614-MS	Update Case History: Performance of the Twofreds Tertiary CO2 Project	1993
196	26622-MS	WAG Process Optimization in the Rangely CO2 Miscible Flood	1993
197	26624-MS	Reservoir Management in Tertiary CO2 Floods	
198	26787-MS	Saving Thistle's Bacon: The Role of Reservoir Management in Optimising a High Watercut Field	1993
199	27660-MS	Technical Factors Useful for Screening Carbonate Reservoirs for Waterflood Infill Drilling	
200	27678-MS	North Dollarhide (Devonian) Unit: Reservoir Characterization and CO2 Feasibility Study	1994
201	27756-MS	Rangely Weber Sand Unit CO2 Project Update: Decisions and Issues Facing a Maturing EOR Project	
202	27762-MS	A Probabilistic Forecasting Method for the Huntley CO2 Projects	1994
203	27763-MS	Comparison of Actual Results of EOR Field Projects to Calculated Results of EOR Predictive Models	
204	27766-MS	A Review of IOR/EOR Opportunities for the Brent Field: Depressurisation, the Way Forward	1994
205	27767-MS	EOR by Miscible CO2 Injection in the North Sea	
206	27787-PA	CO2 Foam: Results From Four Developmental Field Trials	
207	27792-PA	Case History and Appraisal of the Medicine Pole Hills Unit Air Injection Project	
208	27825-MS	Injection Conformance Control Case Histories Using Gels at the Wertz Field CO2 Tertiary Flood in Wyoming	1994
209	28435-MS	Dipping Fluid Contacts in the Kraka Field, Danish North Sea	
210	28834-MS	Development of a Thin Oil Rim With Horizontal Wells in a Low Relief Chalk Gas Field, Tyra Field, Danish North Sea	

	SPE Paper No.	Title	Year
211	28859-MS	REGNAR - Development of a Marginal Field	
212	29115-MS	Evaluating Miscible and Immiscible Gas Injection in the Safah Field, Oman	1995
213	29116-PA	Field-Scale CO2 Flood Simulations and Their Impact on the Performance of the Wasson Denver Unit	1997
214	29145-MS	Application of Adaptive Mesh-Refinement With a New Higher-Order Method in Simulation of a North Sea Micellar/Polymer Flood	
215	29521-MS	Field Trial of Simultaneous Injection of CO2 and Water, Rangely Weber Sand Unit, Colorado	1995
216	29565-MS	Alkaline-Surfactant-Polymer Technology Potential of the Minnelusa Trend, Powder River Basin	
217	30443-MS	Reservoir Management in the Ninian Field - A Case History	
218	30645-MS	Simultaneous Water and Gas Injection Pilot at the Kuparuk River Field, Surface Line Impact	1995
219	30725-MS	Reservoir Management and Optimization of the Mitsue Gilwood Sand Unit #1 Horizontal Hydrocarbon Miscible Flood	1995
220	30726-MS	Simultaneous Water and Gas Injection Pilot at the Kuparuk River Field, Reservoir Impact	1995
221	30742-MS	Horizontal Well Applications in a Miscible CO2 Flood, Sundown Slaughter Unit, Hockley County, Texas	1996
222	30795-PA	Recovery of gas-condensate by nitrogen injection compared with methane injection	1998
223	31062-PA	The Relation Among Porosity, Permeability, and Specific Surface of Chalk From the Gorm Field, Danish North Sea	
224	35188-MS	Design and Implementation of a Grass-Roots CO2 Project for the Bennett Ranch Unit	
225	35189-MS	A Case Study of the Development of the Sundown Slaughter Unit CO2 Flood Hockley County, Texas	1996
226	35190-MS	Dollarhide Devonian CO2 Flood: Project Performance Review 10 Years Later	1996
227	35191-MS	Lost Soldier Tensleep CO2 Tertiary Project, Performance Case History; Bairoil, Wyoming	1996
228	35319-MS	On the Exploitation Conditions of the Akal Reservoir Considering Gas Cap Nitrogen Injection	1996
229	35359-PA	SACROC Unit CO2 Flood: Multidisciplinary Team Improves Reservoir Management and Decreases Operating Costs	
230	35361-MS	Evolution of Conformance Improvement Efforts in a Major CO2 WAG Injection Project	1996
231	35363-MS	Diagnosing CO2 Flood Performance Using Actual Performance Data	1996
232	35385-PA	EOR Screening Criteria Revisited - Part 1: Introduction to Screening Criteria and Enhanced Recovery Field Projects	
233	35391-MS	Analogy Procedure For The Evaluation Of CO2 Flooding Potential For Reservoirs In The Permian And Delaware Basins	
234	35395-MS	FIELD SCALE SIMULATION STUDY OF IN-SITU COMBUSTION IN HIGH PRESSURE LIGHT OIL RESERVOIRS	
235	35410-MS	Improved CO2 Flood Predictions Using 3D Geologic Description and Simulation on the Sundown Slaughter Unit	1996
236	35429-MS	Determination of Relative Permeability and Trapped Gas Saturation for Predictions of WAG Performance in the South Cowden CO2 Flood	1996
237	35431-MS	Screening Criteria for Application of Carbon Dioxide Miscible Displacement in Waterflooded Reservoirs Containing Light Oil	1996
238	35698-PA	Kuparuk Large Scale Enhanced Oil Recovery Project	1997
239	36711-MS	From Simulator to Field Management: Optimum WAG Application in a West Texas CO2 Flood - A Case History	1996
240	36844-MS	RUTH - A Comprehensive Norwegian R & D program on IOR	

	SPE Paper No.	Title	Year
241	36935-MS	Reservoir Simulation of the Planned Miscible Gas Injection Project at Rhourde El Baguel, Algeria	1996
242	37332-MS	A Geostatistical Study of a Pilot Area in the Griffithsville Oil Field	
243	37470-MS	The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO2 WAG Horizontal Injection Wells	
244	37755-MS	Alwyn North IOR Gas Injection Potential - A Case Study	1997
245	37780-MS	Stylolites Impact the Miscible Nitrogen Flood in a Mature Carbonate Oil Field	
246	37782-MS	AIR INJECTION INTO A LIGHT OIL RESERVOIR: THE HORSE CREEK PROJECT	
247	37954-MS	Development of Marginal Fields Through Technical and Commercial Innovation - A Case History from the UK North Sea	
248	38558-MS	Using 4000 ft Long Induced Fractures to Water Flood the Dan Field	
249	38848-MS	Keys to Increasing Production Via Air Injection in Gulf Coast Light Oil Reservoirs	
250	38905-MS	Laboratory Testing and Simulation Results for High Pressure Air Injection in a Waterflooded North Sea Oil Reservoir	
251	38928-MS	Making Sense of Water Injection Fractures in the Dan Field	
252	39234-PA	EOR Screening Criteria Revisited Part 2: Applications and Impact of Oil Prices	
253	39620-MS	Effect of Wettability on Oil Recovery by Near-miscible Gas Injection	
254	39778-MS	CO2 Energized and Remedial 100% CO2 Treatments Improve Productivity in Wolfcamp Intervals, Val Verde Basin, West Texas	1998
255	39787-MS	Find Grid CO2 Injection Process Simulation for Dollarhide Devonian Reservoir	1998
256	39793-MS	History Matching and Modeling the CO-Foam Pilot Test at EVGSAU	1996
257	39808-MS	West Welch CO Flood Simulation with an Equation of State and Mixed Wettability	
258	39881-MS	An Integrated Investigation for Design of a CO Pilot in the Naturally Fractured Spraberry Trend Area, West Texas	1998
259	39883-MS	Review of WAG Field Experience	1998
260	39885-MS	The Feasibility Studies of Natural Gas Flooding in Ansai Field	1998
261	48895-MS	Field Foam Applications in Enhanced Oil Recovery Projects: Screening and Design Aspects	
262	48945-MS	Goldsmith San Andres Unit CO2 Pilot - Design, Implementation, and Early Performance	1998
263	49016-MS	Evaluation of Steam Injection Process in Light Oil Reservoirs	
264	49168-MS	Simulation of a CO2 Flood in the Slaughter Field with Geostatistical Reservoir Characterization	
265	49169-MS	Field Case: Cyclic Gas Recovery for Light Oil-Using Carbon Dioxide/Nitrogen/Natural Gas	1998
266	49519-MS	Appraisal of the HORSE CREEK Air Injection Project Performance	
267	50641-MS	Brage Field, Lessons Learned After 5 Years of Production	
268	50930-MS	A Feasibility Research Method and Project Design on CO2 Miscible Flooding for a Small Complex Fault Block Field	1998
269	51087-MS	History and Potential Future of Improved Oil Recovery in the Appalachian Basin	
270	52198-MS	Coral Creek Field Study: A Comprehensive Assessment of the Potential of High-Pressure Air Injection in a Mature Waterflood Project	

	SPE Paper No.	Title	Year
271	52669-PA	Making Sense of Water Injection Fractures in the Dan Field	
272	52669-PA	Making Sense of Water Injection Fractures in the Dan Field	
273	53335-MS	Design of Action Plan and Monitoring Program: Secondary and Tertiary Gas Injection Pilots in a Limestone Reservoir	1999
274	54087-MS	The Development of Heavy Oil Fields in the United Kingdom Continental Shelf: Past, Present, and Future	
275	54429-PA	Development and Testing of a Foam-Gel Technology to Improve Conformance of the Rangely CO2 Flood	1999
276	54619-MS	Schrader Bluff CO2 EOR Evaluation	1999
277	54772-PA	Large-Volume Foam-Gel Treatments to Improve Conformance of the Rangely CO2 Flood	1999
278	55633-MS	Alkaline-Surfactant-Polymer Flooding of the Cambridge Minnelusa Field	
279	56791-MS	Yates Field Steam Pilot Applies Latest Seismic and Logging Monitoring Techniques	
280	56822-MS	Geostatistical Scaling Laws Applied to Core and Log Data	
281	56849-PA	Unconventional Miscible Enhanced Oil Recovery Experience at Prudhoe Bay	1999
282	56882-PA	Use of Full-Field Simulation to Design a Miscible CO2 Flood	
283	59363-MS	Alkali / Surfactant / Polymer at VLA 6/9/21 Field in Maracaibo Lake: Experimental Results and Pilot Project Design	
284	59550-MS	Reservoir Characterization and Laboratory Studies Assessing Improve Oil Recovery Methods for the Teague-Blinebry Field	2000
285	59717-MS	A Pulsed Neutron Analysis Model for Carbon Dioxide Floods: Application to the Reinecke Field, West Texas	2000
286	63134-MS	Dynamic Reservoir Characterization at Central Vacuum Unit	2000
287	64383-MS	Case Study of Hydraulic Fracture Completions in Horizontal Wells, South Arne Field Danish North Sea	
288	65029-MS	Mineral Scale Control in a CO2 Flooded Oilfield	
289	65124-MS	EOR Screening for Ekofisk	
290	65165-MS	SWAG Injection on the Siri Field - An Optimized Injection System for Less Cost	
291	66378-MS	Modeling Miscible WAG Injection EOR in the Magnus Field	2001
292	68285-PA	Alkaline-Surfactant-Polymer Flooding of the Cambridge Minnelusa Field	
293	70017-MS	Quantitative Analysis of Deliverability, Decline Curve, and Pressure Tests in CO2 Rich Reservoirs	2001
294	70066-MS	Horizontal Injectors Rejuvenate Mature Miscible Flood - South Swan Hills Field	2001
295	71203-PA	Review of WAG Field Experience	2001
296	71279-PA	Handil Field: Three Years of Lean-Gas Injection Into Waterflooded Reservoirs	2001
297	71322-MS	Halfdan: Developing Non-Structurally Trapped Oil in North Sea Chalk	
298	71629-MS	Applied Multisource Pressure Data Integration for Dynamic Reservoir Characterization, Reservoir, and Production Management: A Case History from the Siri Field, Offshore Denmark	
299	72103-MS	Identifying Improved Oil Recovery Potential: A New Systematic Risk Management Approach	
300	72106-MS	Evaluation of CO2 Gas Injection For Major Oil Production Fields in Malaysia - Experimental Approach Case Study: Dulang Field	2001

	SPE Paper No.	Title	Year
301	72107-MS	Unconventional Miscible EOR Experience at Prudhoe Bay: A Project Summary	2001
302	72127-MS	A Numerical Study To Evaluate The Use Of WAG As An EOR Method For Oil Production Improvement At B.Kozluca Field, Turkey	2001
303	72466-PA	Performance Evaluation of a Mature Miscible Gasflood at Prudhoe Bay	2001
304	72503-PA	Reservoir Engineering Aspects of Light-Oil Recovery by Air Injection	
305	73830-PA	A Literature Analysis of the WAG Injectivity Abnormalities in the CO2 Process	2001
306	75126-MS	SWAG Injectivity Behavior Based on Siri Field Data	2002
307	75152-MS	Field Evaluation of Different Recovery Processes in Zone 4 of the Prudhoe Bay Field	2002
308	75157-MS	Foam-Assisted WAG: Experience from the Snorre Field	2002
309	75170-MS	IOR: The Brazilian Perspective	
310	75171-MS	Improved Hydrocarbon Recovery in the United Kingdom Continental Shelf: Past, Present and Future	
311	75229-MS	Smørbukk field: Impact of Small Scale Heterogeneity on Gas Cycling Performance	2002
312	76722-MS	Hydraulic Fracture Spacing in Horizontal Chalk Producers: The South Arne Field	
313	77302-PA	Horizontal Injectors Rejuvenate Mature Miscible Flood - South Swan Hills Field	2002
314	77695-MS	FAWAG: A Breakthrough for EOR in the North Sea	2002
315	78327-MS	New Relationship Between Oil Company and Service Company Rejuvenates a Mature North Sea Gas Field	
316	78344-MS	10 Years of WAG Injection in Lower Brent at the Gullfaks Field	2002
317	78348-MS	WAG Injection at the Statfjord Field, A Success Story	2002
318	78349-MS	Tertiary Miscible Gas Injection in the Alwyn North Brent Reservoirs	2002
319	78362-MS	Full Field Tertiary Gas Injection: A Case History Offshore Abu Dhabi	2002
320	78527-MS	Jay Nitrogen Tertiary Recovery Study: Managing a Mature Field	
321	78711-MS	Mature Waterfloods Renew Oil Production by Alkaline-Surfactant-Polymer Flooding	
322	80475-MS	Improved Oil Recovery Through the Use of Horizontal Well in Thin Oil Column: A Case Study from Platong Field, Gulf of Thailand	
323	81008-MS	High Pressure Nitrogen Injection for Miscible/Immiscible Enhanced Oil Recovery	
324	81458-MS	Applying Improved Recovery Processes and Effective Reservoir Management to Maximize Oil Recovery at Salt Creek	2003
325	81461-MS	Al-Huwaisah Reservoir: The Long Journey to Improved Oil Recovery!	2003
326	81464-MS	Single Well Tests to determine the Efficiency of Alkaline-Surfactant Injection in a highly Oil-Wet Limestone Reservoir.	
327	82140-PA	Unconventional Miscible EOR Experience at Prudhoe Bay: A Project Summary	2003
328	84076-MS	WAG Pilot Design and Observation Well Data Analysis for Hassi Berkine South Field	2003
329	84904-MS	Selected U.S. Department of Energy's EOR Technology Applications	
330	86954-MS	Expanded Uses of Nitrogen, Oxygen and Rich Air for Increased Production of Both Light Oil and Heavy Oil	

	SPE Paper No.	Title	Year
331	87250-MS	A Compositional Simulation of Alternative Options of a Gas Injection Project	1980
332	88451-MS	A Technical Evaluation of a CO2 Flood for EOR Benefits in the Cooper Basin, South Australia	2000
333	88499-MS	Water-Alternating-Gas (WAG) Pilot Implementation, A First EOR Development Project in Dulang Field, Offshore Peninsular Malaysia	2004
334	88716-MS	Evaluation of IOR Potential within Kuwait	2004
335	88717-MS	Simulation Study of Miscible Gas Injection for Enhanced Oil Recovery in Low Permeable Carbonate Reservoirs in Abu Dhabi	
336	88769-MS	Maturing Field: A Case History Offshore Abu Dhabi	2004
337	88770-MS	Lessons Learned from Mature Carbonates for Application to Middle East Fields	2004
338	89338-MS	A Study of IOR by CO2 Injection in the Gullfaks Field, Offshore Norway	2004
339	89356-MS	Gas Injection Pilot in the Hochleiten Field	2004
340	89363-PA	Streamline Technology for the Evaluation of Full Field Compositional Processes; Midale, A Case Study	2004
341	89364-MS	Lessons From Trinidad's CO2 Immiscible Pilot Projects 1973-2003	2005
342	89367-MS	Application of the Novel Miscible Interpretation of RST Data and the WAG Pilot Results in Reservoir Simulation for Hassi Berkine South Field	
343	89382-MS	A Guide to Chemical Oil Recovery for the Independent Operator	2004
344	89440-MS	Three-phase Compositional Streamline Simulation and Its Application to WAG	
345	89441-MS	Analytical Model for 1-D Gas Flooding: Splitting between Hydrodynamics and Thermodynamics	2004
346	89452-MS	Selected U. S. Department of Energy EOR Technology Applications	
347	89461-MS	Production Performance Study of West Carney Field, Lincoln County, Oklahoma	
348	90307-MS	Simulation-Based EOR Evaluation of a North Sea Field	2004
349	92006-MS	Planning EOR Projects	
350	92419-MS	Reservoir Management of the Njord Field	
351	92763-MS	Beryl Field: Extracting Maximum Value from a Mature Asset Through the Evolution of Technology	
352	93364-MS	Precambrian Field Oman from Greenfield to EOR	
353	93368-MS	Applicability of Enhanced Oil Recovery techniques on mature fields - Interest of gas injection	2005
354	93472-MS	Reservoir Characterization and Simulations Studies in a Heterogeneous Pinnacle Reef for CO2 Flooding Purposes: A Case Study	
355	93606-MS	A Miscible WAG Project Using Horizontal Wells in a Mature Offshore Carbonate Middle East Reservoir	2005
356	94007-MS	Integrated Modeling of the Mature Ashtart Field, Tunisia	2005
357	94049-MS	Injection Fracturing in a Densely Spaced Line Drive Waterflood - The Halfdan Example	
358	94139-MS	APPLICATION OF TRACER TECHNOLOGY FOR OPTIMIZING RKF MISCIBLE GAS INJECTION PROJECT	
359	94637-MS	Planning EOR Projects in Offshore Oil Fields	2005
360	94682-MS	Identifying technical and economic EOR potential under conditions of limited information and time constraints	

	SPE Paper No.	Title	Year
361	97462-MS	Feasibility Study of CO2 Injection for Heavy Oil Reservoir after Cyclic Steam Stimulation: Liaohe oilfield test	2005
362	97507-MS	Gas Injection Programs in PERTAMINA West Java to Obtain Better Recovery: Field Screening, Laboratory and A Simulation Study	2005
363	97639-MS	Initial Results of WAG CO2 IOR Pilot Project Implementation in Croatia	2005
364	97650-MS	Methodology for Miscible Gas Injection EOR Screening	
365	97693-MS	Application of Improved and Enhanced Oil Recovery Strategies in the Tapis Field	
366	99546-MS	EOR Survey in the North Sea	
367	99789-MS	Development of a Correlation Between Performance of CO2 Flooding and the Past Performance of Waterflooding in Weyburn Oil Field	
368	99789-PA	Development of a Correlation Between Performance of CO2 Flooding and the Past Performance of Waterflooding in Weyburn Oil Field	
369	100021-MS	A Screening Model for CO2 Flooding and Storage in Gulf Coast Reservoirs Based on Dimensionless Groups	
370	100044-MS	Screening Criteria for CO2 Huff 'n' Puff Operations	
371	100063-MS-P	EOR Field Experiences in Carbonate Reservoirs in the United States	2006
372	100117-MS	Application of SmartWell Technology to the SACROC CO2 EOR Project: A Case Study	2006
373	100328-PA	Development of the Strasshof Tief Sour-Gas Field Including Acid-Gas Injection Into Adjacent Producing Sour-Gas Reservoirs	2007
374	101473-MS	Miscible Gas Injection Piloting and Modeling in a Giant Carbonate Reservoir	2006
375	101701-MS	Five Years of On-Going Conformance Work in the Central Mallet Unit CO2 Flood in West Texas Yields Improved Economics for Operator	2006
376	102197-MS	APPLICATION OF INTEGRATED RESERVOIR STUDIES AND PROBABILISTIC TECHNIQUES TO ESTIMATE OIL VOLUMES AND RECOVERY, TENGIZ FIELD, REPUBLIC OF KAZAKHSTAN	
377	102389-MS	Achieving the Vision in the Harweel Cluster, South Oman	2006
378	103282-MS	Seismically Driven Reservoir Characterization Using an Innovative Integrated Approach: Syd Arne Field	
379	104619-MS	Performance Evaluation of a Reservoir Under EOR REcovery: Intisar D Reef, Concession 103, Libya.	2007
380	105604-MS	Gas Blending for Miscible Gasfloods in South Oman	2007
381	105785-MS	Utilizing the Effect of Nitrogen to Implement Light Oil Air Injection in Malaysian Oil Fields	2007
382	106575-MS	Bate Raman Field Immiscible CO2 Application: Status Quo and Future Plans	2007
383	107155-MS	Modelling and early monitoring of miscible gas injection in the tight El Gassi Field, Algeria	2007
384	107886-MS	Miscible EOR Processes: Existence of Elliptic Regions in Gasflood Modeling	2007
385	107966-MS	Case Study: Application of a Viscoelastic Surfactant-Based CO2 Compatible Fracturing Fluid in the Frontier Formation, Big Horn Basin, Wyoming.	2007
386	107966-MS	Case Study: Application of a Viscoelastic Surfactant-Based CO2 Compatible Fracturing Fluid in the Frontier Formation, Big Horn Basin, Wyoming.	
387	108014-MS	Evaluating Reservoir Production Strategies in Miscible and Immiscible Gas-Injection Projects	2007
388	108031-MS	Water-Alternating-Gas Pilot in the Largest Oil Field in Argentina: Chihuido de la Sierra Negra, Neuquen Basin	2007
389	108531-MS	Seismic Observation and Verification of Line Drive Water Flood Patterns in a Chalk Reservoir, Halfdan Field, Danish North Sea	
390	108828-DL	Chemical EOR: The Past - Does It Have a Future?	
391	111223-MS	CO2 EOR From a North Michigan Silurian Reef	2007

APPENDIX B: CATALOGUE OF MISCIBLE FLOOD OIL-RATE HISTORIES

This appendix presents oil-rate histories for the following fields or units:

Rangely Weber Sand Unit
Ford Geraldine Unit
Wasson Denver Unit
Wertz Tensleep
Lost Soldier Tensleep
Means San Andres Unit
Slaughter Estate Unit
Hanford San Andres
Salt Creek
Goldsmith Pilot
Granny's Creek Pilot
Maljamar Pilot
Slaughter Estate Unit Pilot
Dollarhide
Sundown Slaughter Unit
Twofreds
West Sussex
Seminole San Andres Unit
Willard Unit, Wasson field
SACROC Unit, Kelly-Synder field, Four-Pattern Area
SACROC Unit, Kelly-Snyder field, Seventeen-Pattern Area

Field: Rangely Weber Sand Unit

Key Papers

1. Attanucci, V., et al.: “WAG Process Optimization in the Rangely CO_2 Miscible Flood,” SPE 26622, presented at the 1993 Annual Technical Conference and Exhibition, Houston, Tx (1993).
2. Masoner, L.O. and Wackowski, R.K.: Rangely Weber Sand Unit CO_2 Project Update: Decisions and Issues Facing a Maturing EOR Project,” SPE 27756, presented at the 1994 Improved Oil Recovery Symposium, Tulsa, OK (1994).

Key rate history plots:

Paper 1

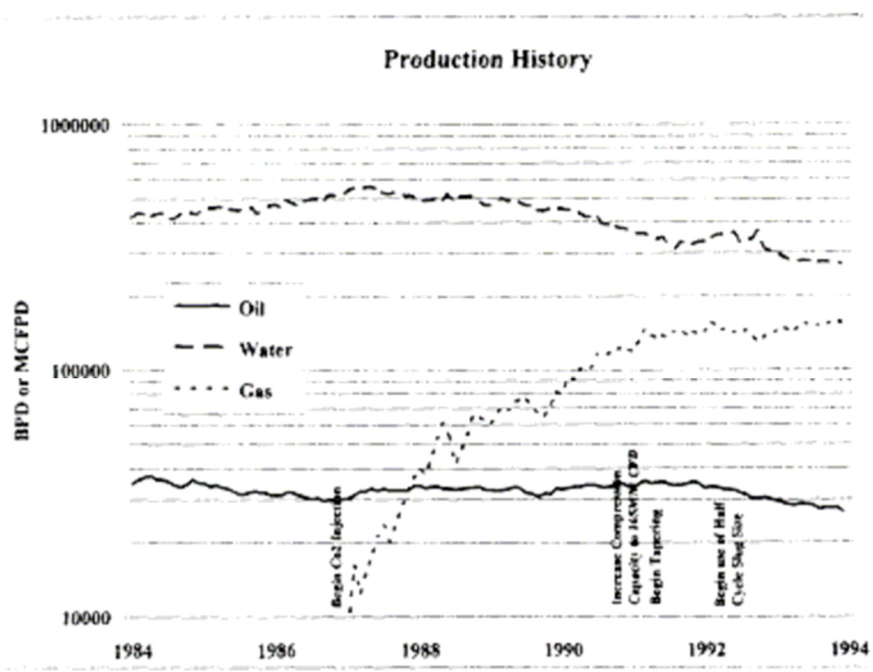


Figure 2: RWSU historical oil, water, and gas production performance.

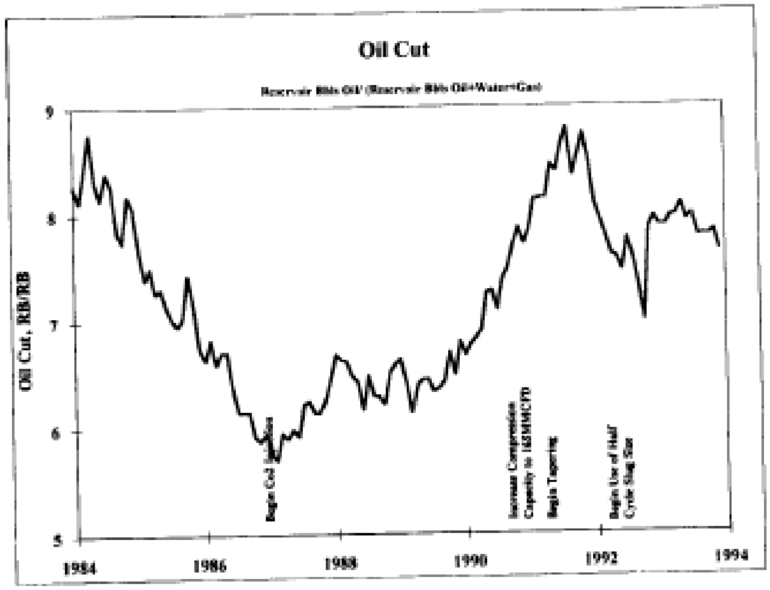
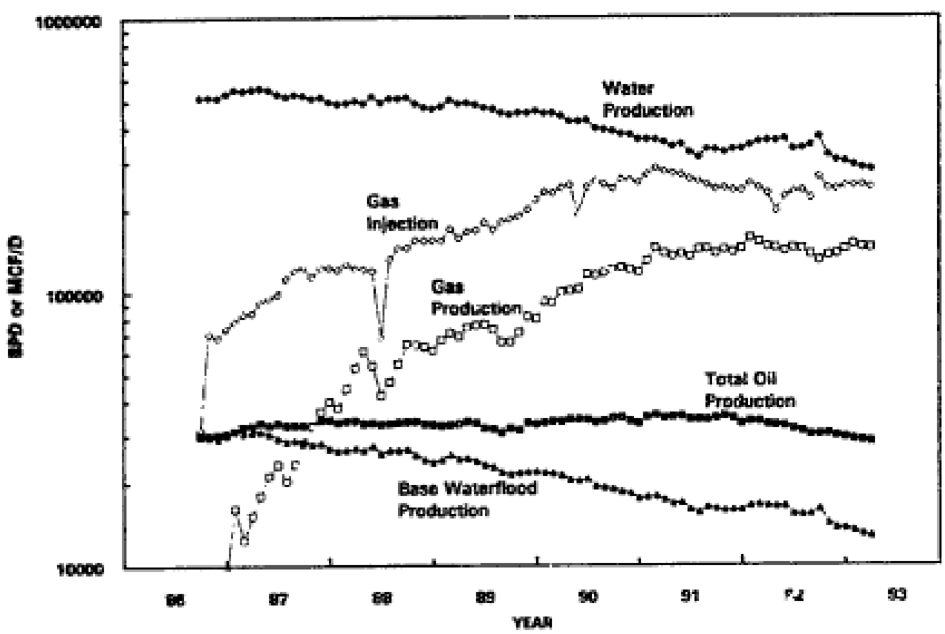


Figure 4: RWSU oil cut performance.

Paper 2



Field: Ford Geraldine Unit

Key Papers

1. Lee, K.H. and El-Saleh, M.M.: “A Full-Field Numercial Modeling Study for the Ford Geraldine Unit CO_2 Flood,” SPE 20227, presented at Enhanced Oil Recovey Symposium, Tulsa, Ok (1990).
2. Phillips, L.A., et al.: “CO_2 Flood Design: Design and Initial Operatioins, Ford Geraldine Unit,” SPE 12197, presented at the Annual Technical Conference and Exhibition, San Francisco, CA (1983).

Key rate history plots:

Paper 1

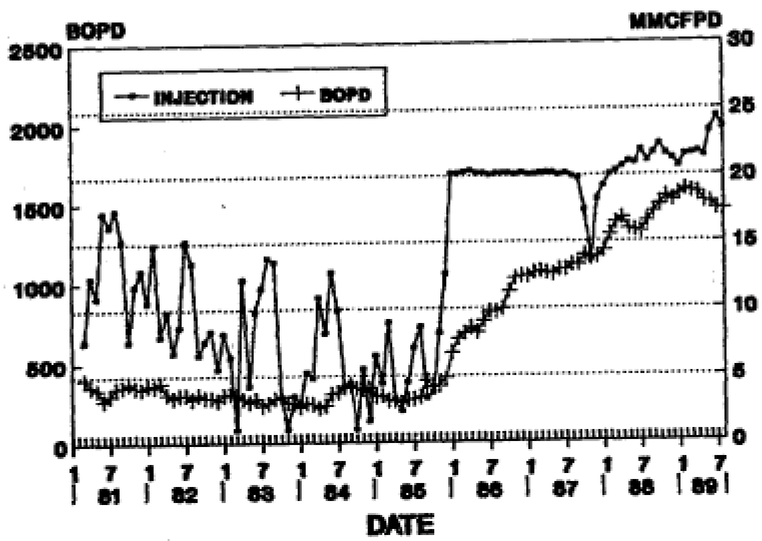


Fig. 5 – Oil production rate and CO2 injection rate of the unit.

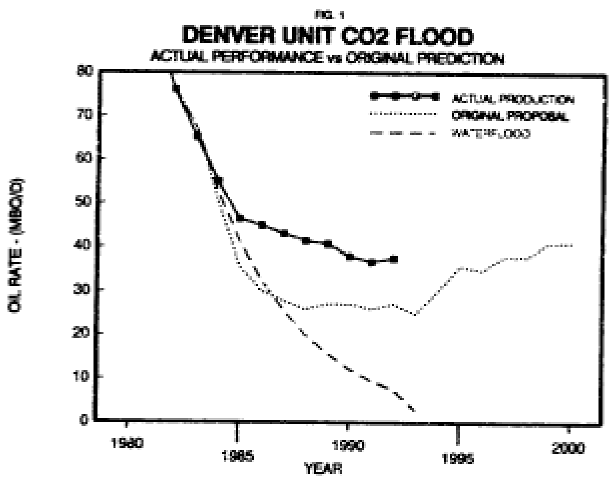
Field: Wasson Denver Unit

Key Papers

1. Tanner, C.S., et al.: “Production Performance of the Wasson Denver Unit CO_2 Flood,” SPE 24156, presented at Enhanced Oil Recovery Symposium, Tulsa, OK (1992).

Key rate history plots:

Paper 1



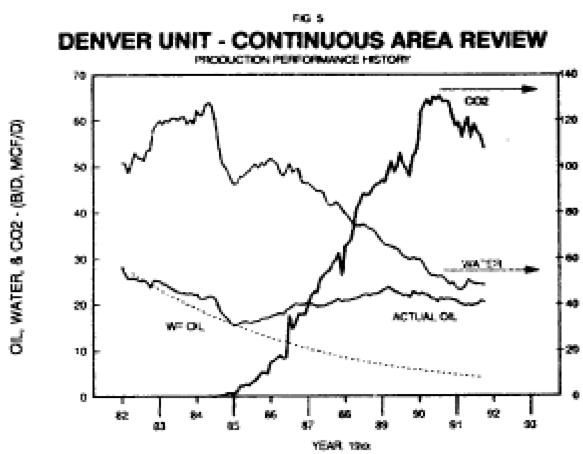
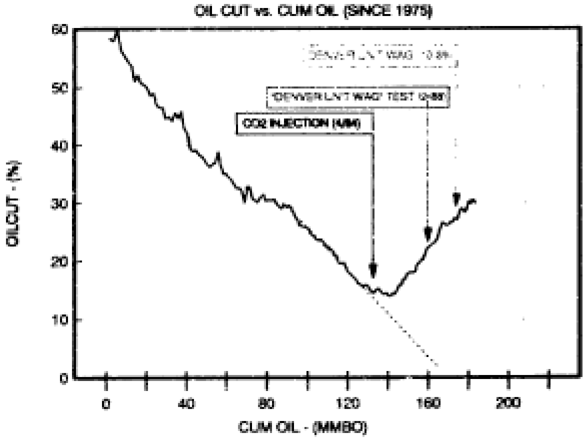


FIG. 6

DENVER UNIT - CONTINUOUS AREA REVIEW

OIL CUT vs. CUM OIL (SINCE 1975)



Field: Wertz Tensleep

Key Papers

1. Kleinsteiber, S.: "The Wertz Tensleep CO_2 Flood: Design and Initial Performance," J. Pet. Tech. (1990).
2. Brokmeyer, R.J., et al.: "Lost Soldier Tensleep CO_2 Tertiary Project, Performance Case History, Baroil, Wyoming," SPE 35191, presented at the Permian Oil and Gas Recovery Conference, Midland, TX (1996).

Key rate history plots:

Paper 1

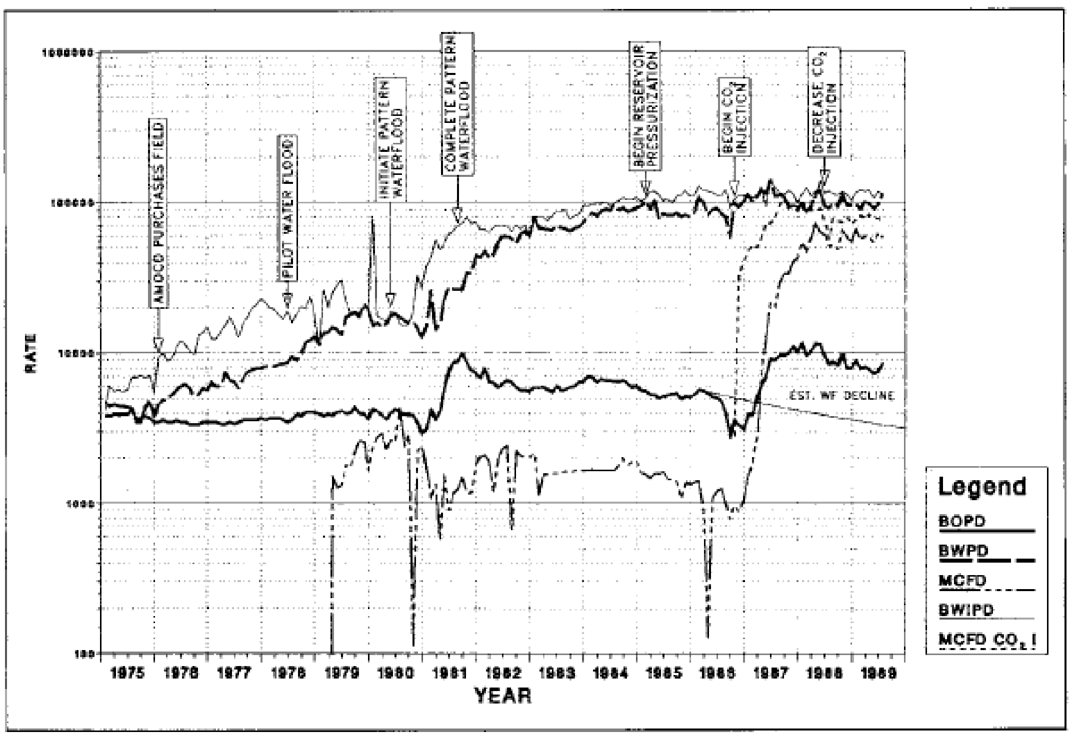


Fig. 3—Field production curve.

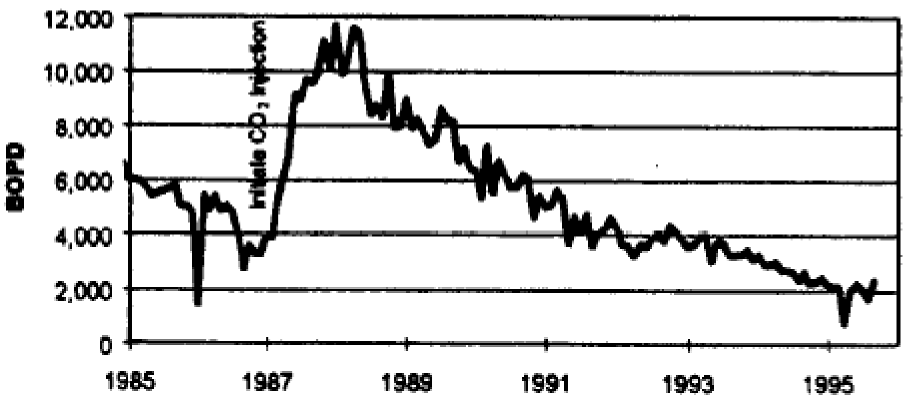


Fig. 13 - Oil production for the Wertz Tensleep CO_2 Flood

Field: Lost Soldier Tensleep

Key Papers

1. Brokmeyer, R.J., et al.: "Lost Soldier Tensleep CO_2 Tertiary Project, Performance Case History, Baroil, Wyoming," SPE 35191, presented at the Permian Oil and Gas Recovery Conference, Midland, TX (1996).

Key rate history plots:

Paper 1

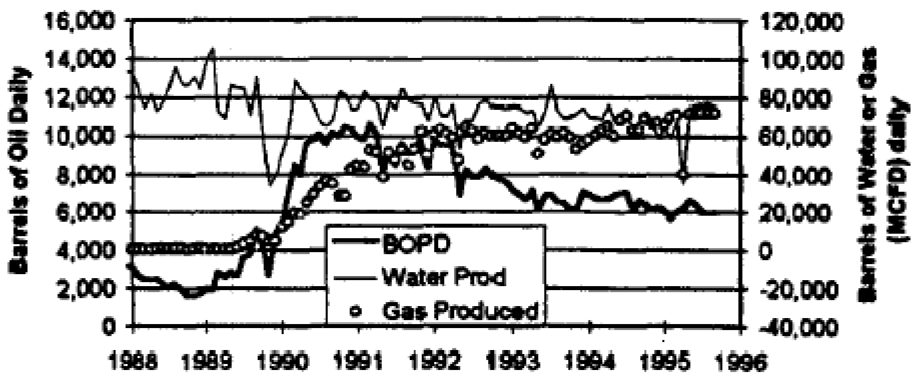


Fig. 8a - Oil, water and gas production from 1988 - 1995

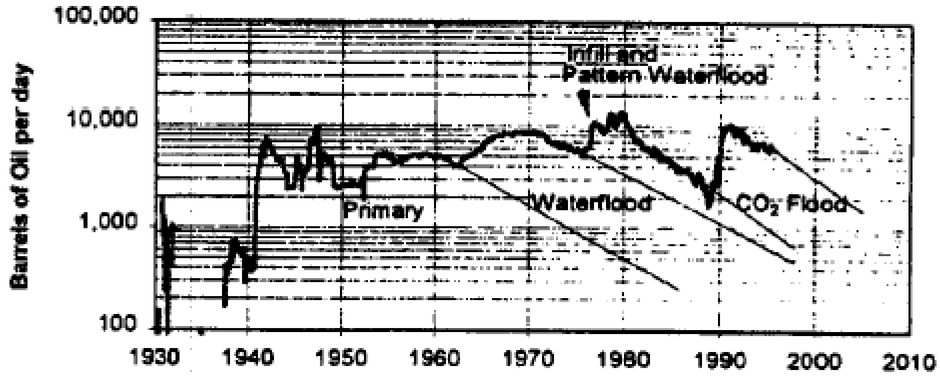


Fig. 2 - Historical Lost Soldier Tensleep oil production (1930 - 1995)

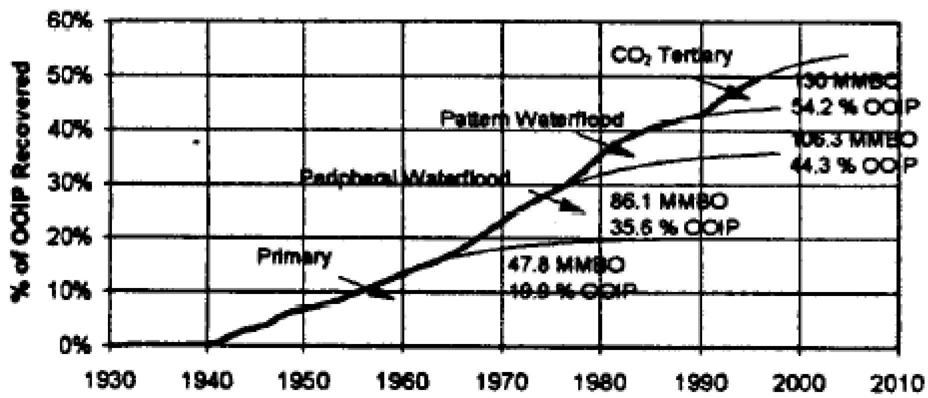


Fig. 12 - Lost Soldier Tensleep cumulative oil production since discovery (% OOIP recovered versus time)

Field: Means San Andres Unit

Key Papers

1. Magruder, J. B., et al.: "Review of the Means San Andreas Unit CO_2 Tertiary Project," J. Pet. Tech. SPE 17349 (May, 1990).

Key rate history plots:

Paper 1

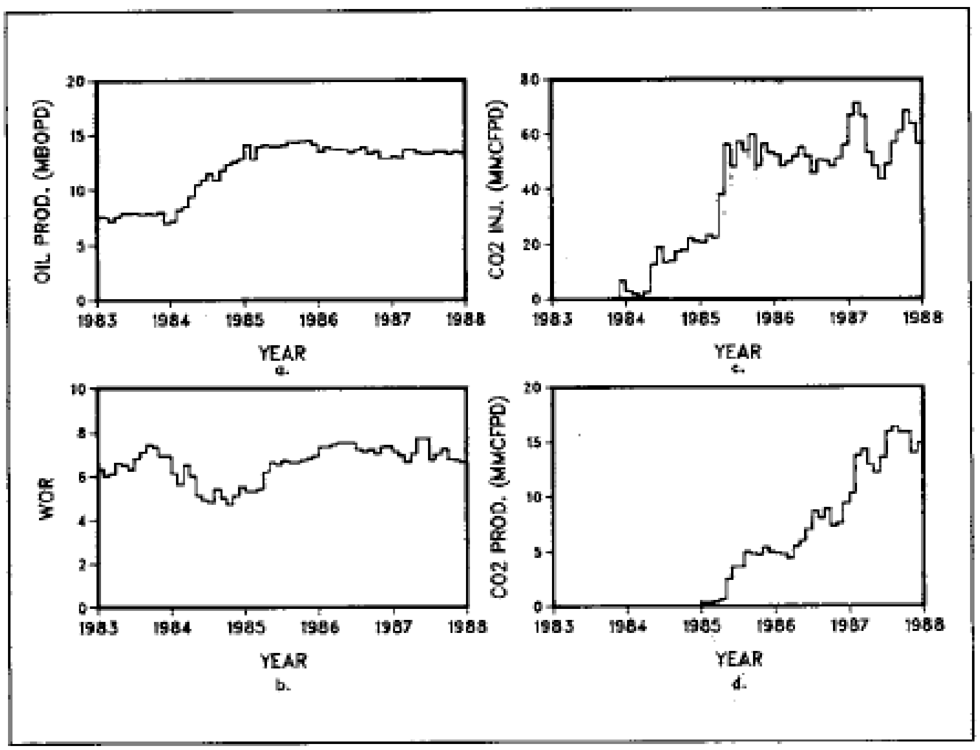


Fig. 9—Project area monthly performance data: (a) oil rate, (b) WOR, (c) CO_2 injection, and (d) CO_2 production.

Field: Slaughter Estate Unit

Key Papers

1. Stein, M.H., et al.: "Slaughter Estate Unit CO_2 Flood: Comparison Between Pilot and Field Scale Performance," SPE 19375, J. Pet. Tech. (Sept., 1992)..

Key rate history plots:

Paper 1

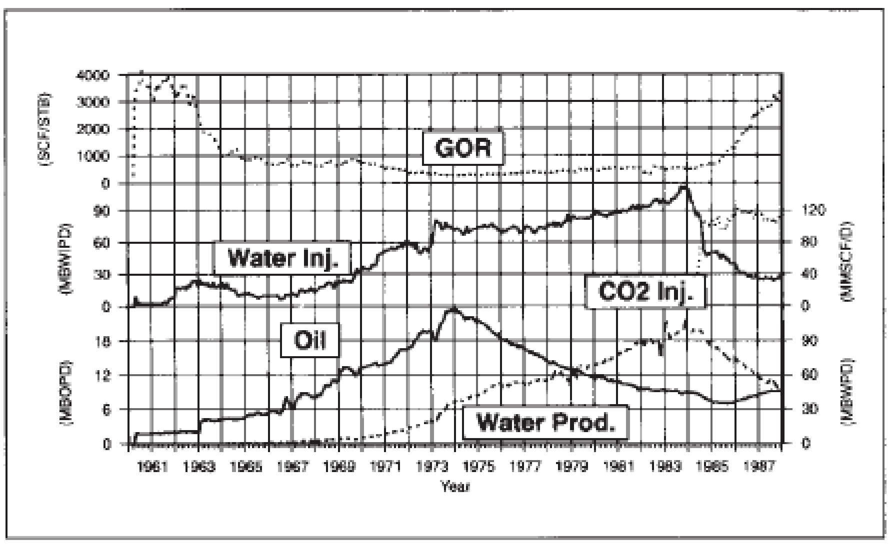


Fig. 8—Slaughter Estate Unit performance.

Field: Hanford San Andres

Key Papers

1. Merritt, M.B. and Groce, J.F.: “A Case History of the Hanford San Andres Miscible CO_2 Pilot,” SPE 20229, J. Pet. Tech. (August, 1992).

Key rate history plots:

Paper 1

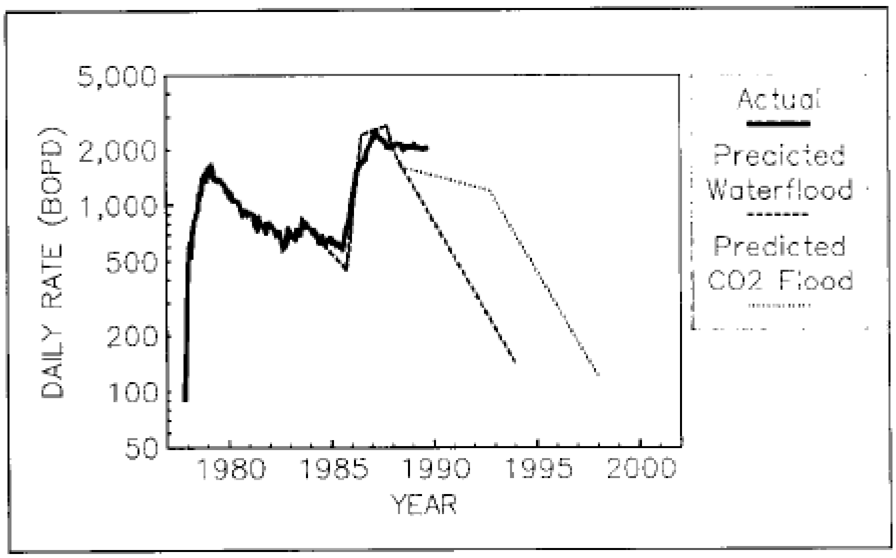


Fig. 8—Hanford Unit oil production vs. original forecast.

Field: Salt Creek

Key Papers

1. Genetti, D.B., et al.: “Applying Improve Recovery Processes and Effective Reservoir Management to Maximize Oil Recovery at Salt Creek,” SPE 81458, presented at the Middle East Show and Conference, Bahrain (2003).

Key rate history plots:

Paper 1

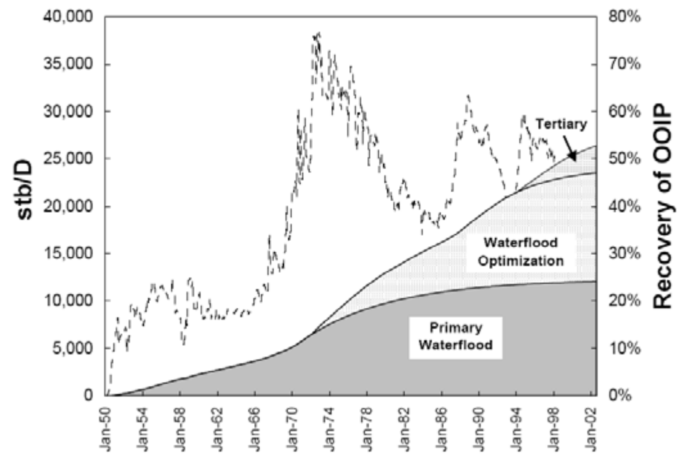


Figure 6. Salt Creek historical oil recovery as a percent of OOIP. Dashed trend shows production history in stb/D (left axis).

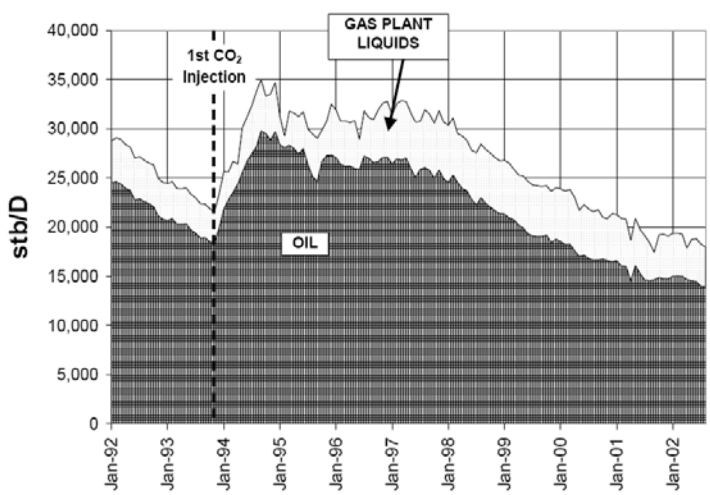


Figure 10. Salt Creek total liquid hydrocarbon production rate from 1992 to 2002.

Field: Goldsmith Pilot

Key Papers

1. Jasek, D.E., et al.: "Goldsmith San Andres Unit CO_2 Pilot—Design, Imlementation, and Easrly Performance," SPE 48945, presented at the Annual Technical Conference and Exhibition, New Orleans (1998).

Key rate history plots:

Paper 1

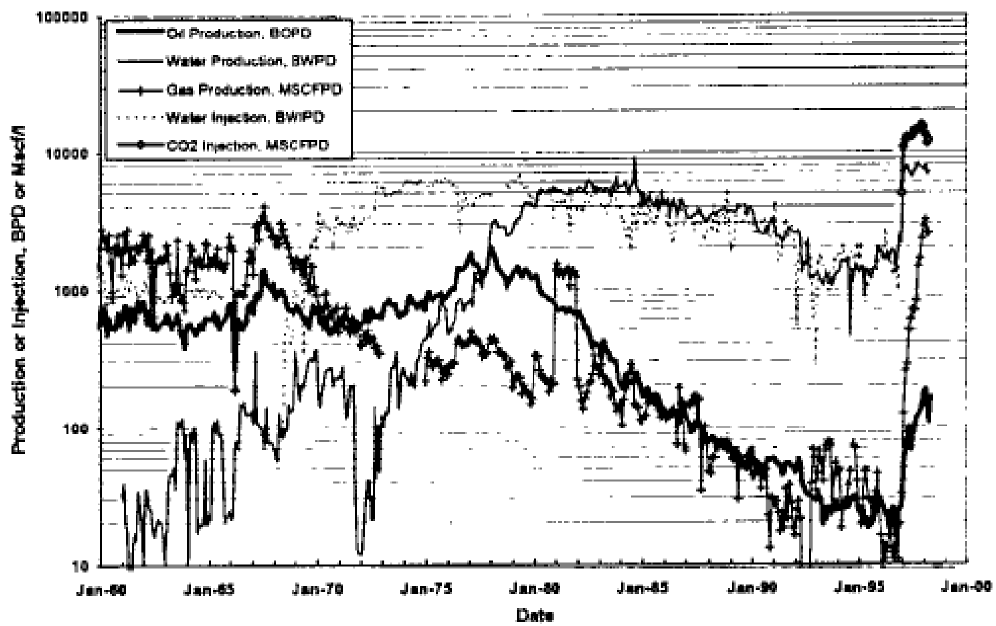


Fig. 16—GSAU CO_2 Pilot area historical (allocated) production plot showing early CO_2 response.

Field: Granny's Creek Pilot

Key Papers

1. Watts, R.J., et al.: "CO_2 Injection for Tertiary Oil Recovery, Granny's Creek Field, Clay County, West Virginia," SPE 10693, presented at the Enhanced Oil Recovery Symposium, Tulsa, OK (1982).

Key rate history plots:

Paper 1

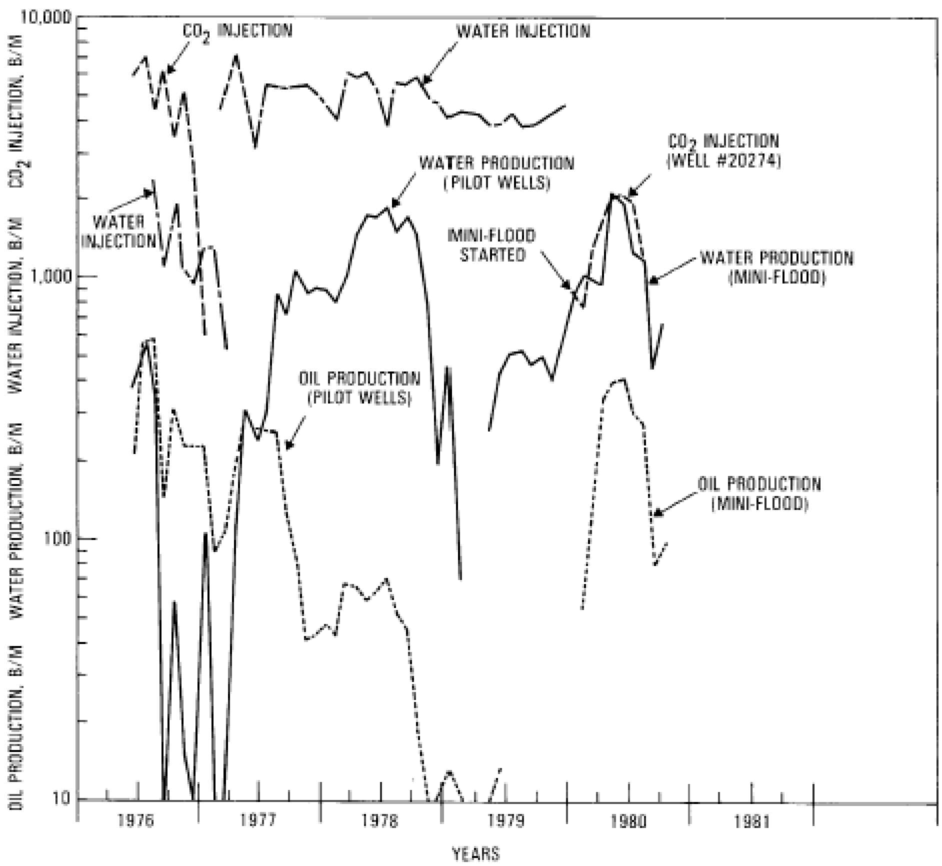


Fig. 11 — Granny's Creek CO_2 Pilot and Mini-Flood Performance History

Field: Maljamar Pilot

Key Papers

1. Pittaway, K.R., et al.: “The Maljamar CO_2 Pilot: Review and Results,” J. Pet. Tech. SPE 14940 (October, 1987).

Key rate history plots:

Paper 1

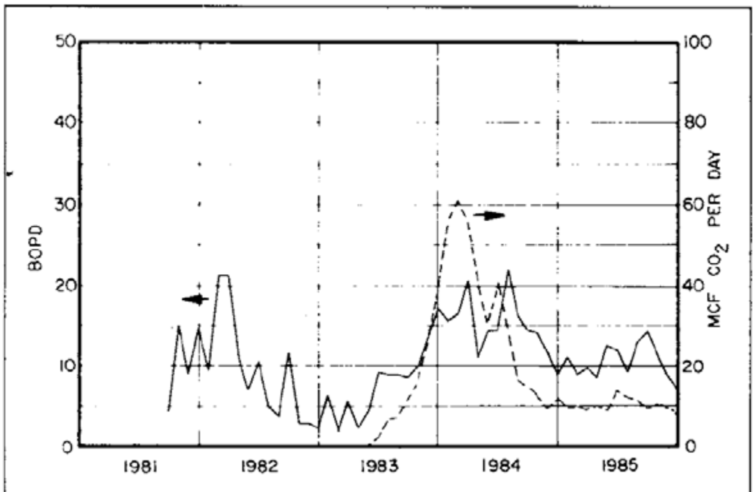


Fig. 7—Sixth zone production history.

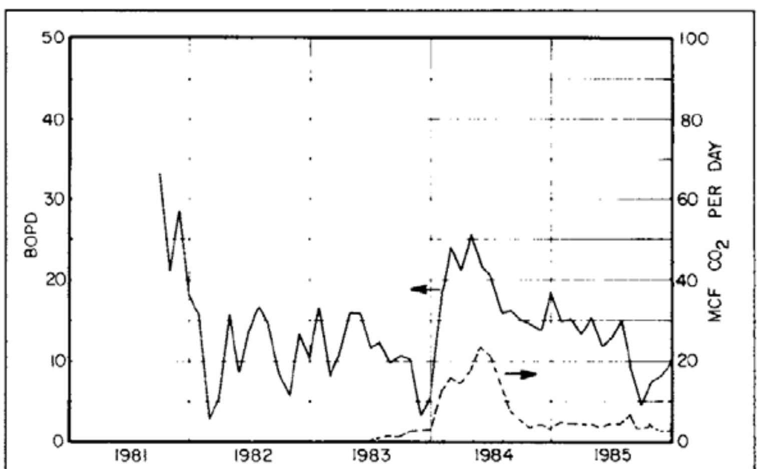


Fig. 8—Ninth Massive zone production history.

Field: Slaughter Estate Unit Pilot

Key Papers

1. Rowe, H.G.: "Slaughter Estate Unit Tertiary Pilot Performance, " J. Pet. Tech., SPE 9796 (March, 1982).

Key rate history plots:

Paper 1

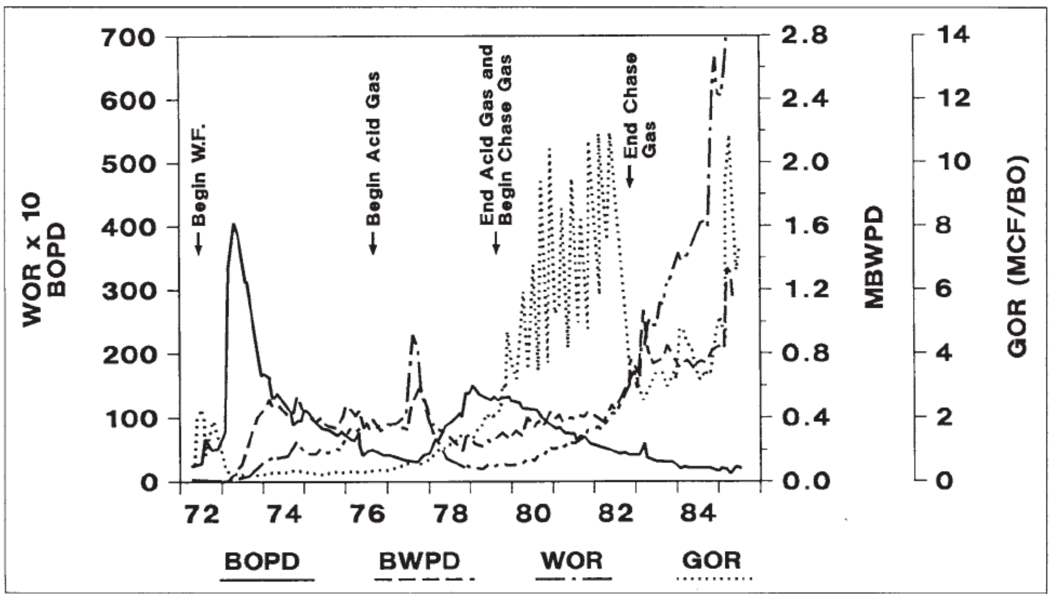


Fig. 2—Pilot performance.

Field: Dollarhide

Key Papers

1. Bellavance, J.F.R.: "Dollarhie Devonian CO_2 Flodd: Project Performance Review 10 Years Later," SPE 35190, presented at Permian Basin Oil and Gas Recovery Conference, Midland, TX (1996).

Key rate history plots:

Paper 1

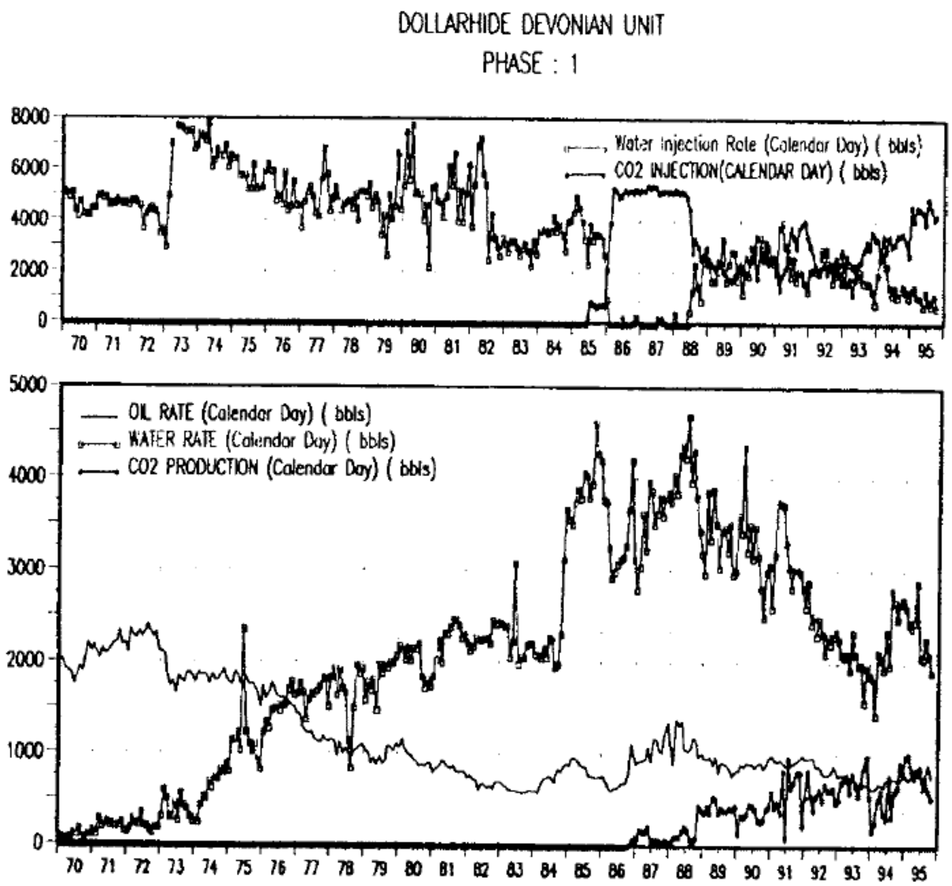


FIGURE 6

DOLLARHIDE DEVONIAN UNIT

PHASE : 2

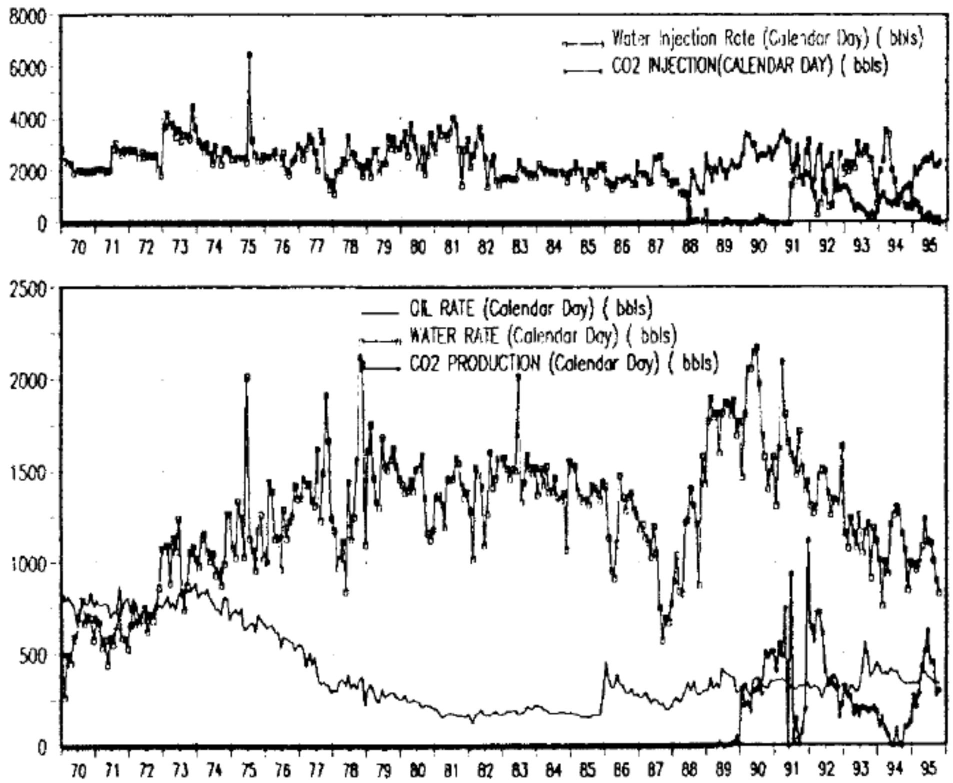


FIGURE 7

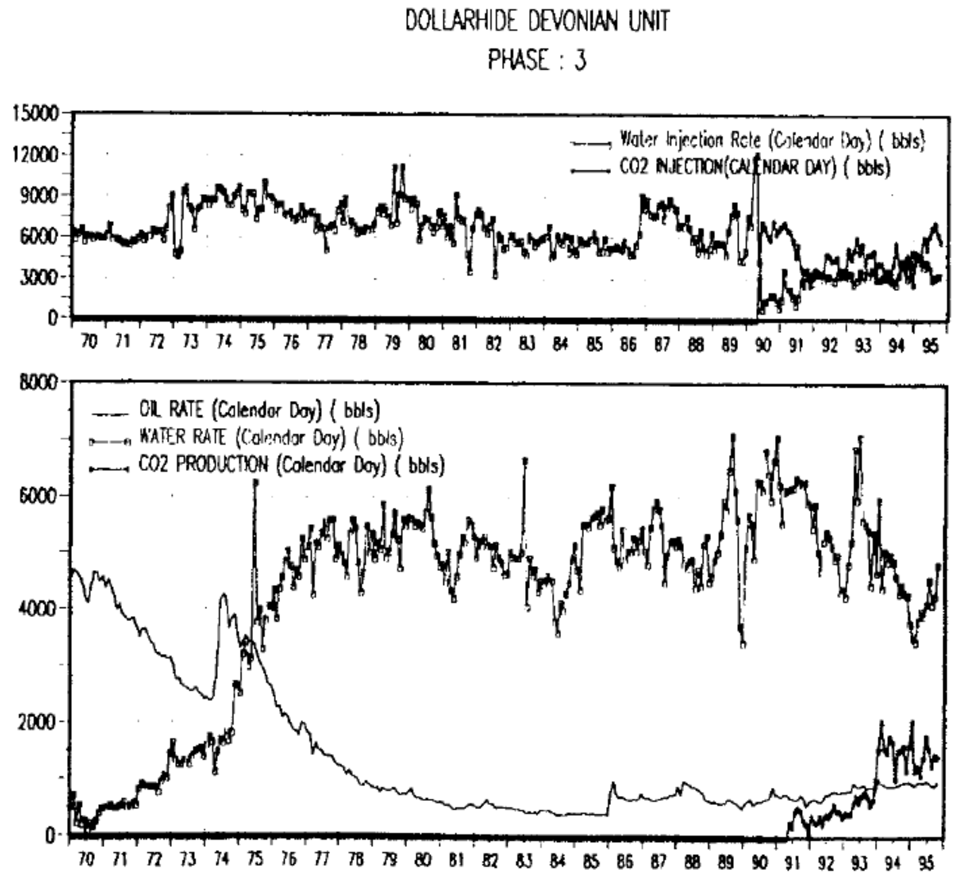

DOLLARHIDE DEVONIAN UNIT
PHASE : 3
Water Injection Rate (Calendar Day) (bbls)
CO2 INJECTION(CALENDAR DAY) (bbls)
15000
12000
9000
6000
3000
0
70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95
OIL RATE (Calendar Day) (bbls)
WATER RATE (Calendar Day) (bbls)
CO2 PRODUCTION (Calendar Day) (bbls)
8000
6000
4000
2000
0
70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95

FIGURE 8

DOLLARHIDE DEVONIAN UNIT
PHASE : 4

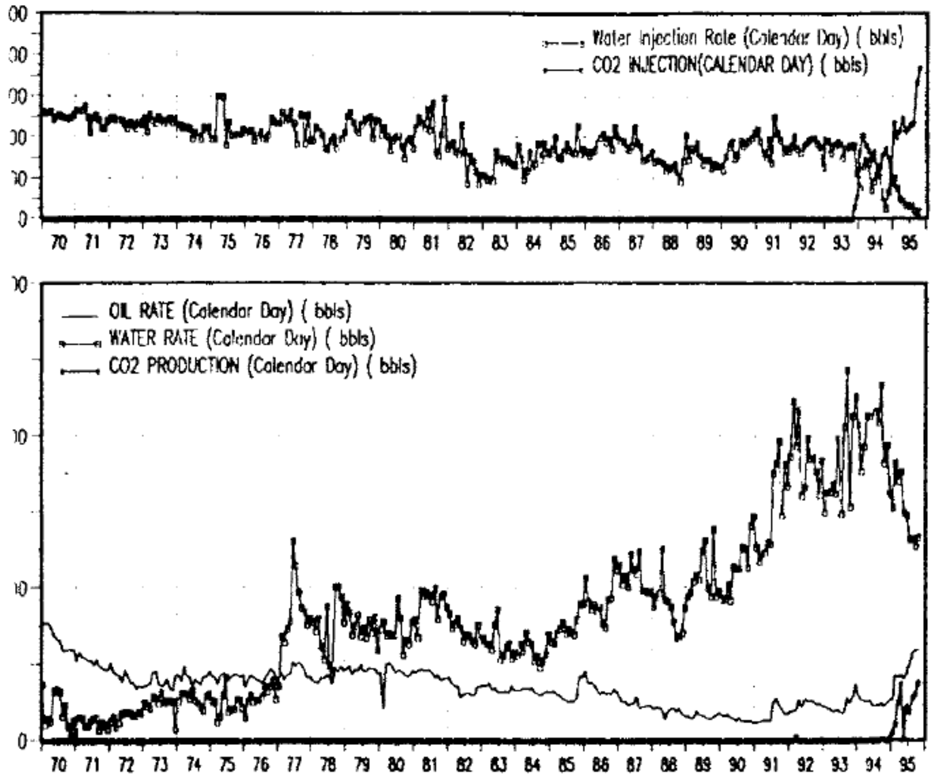


FIGURE 9

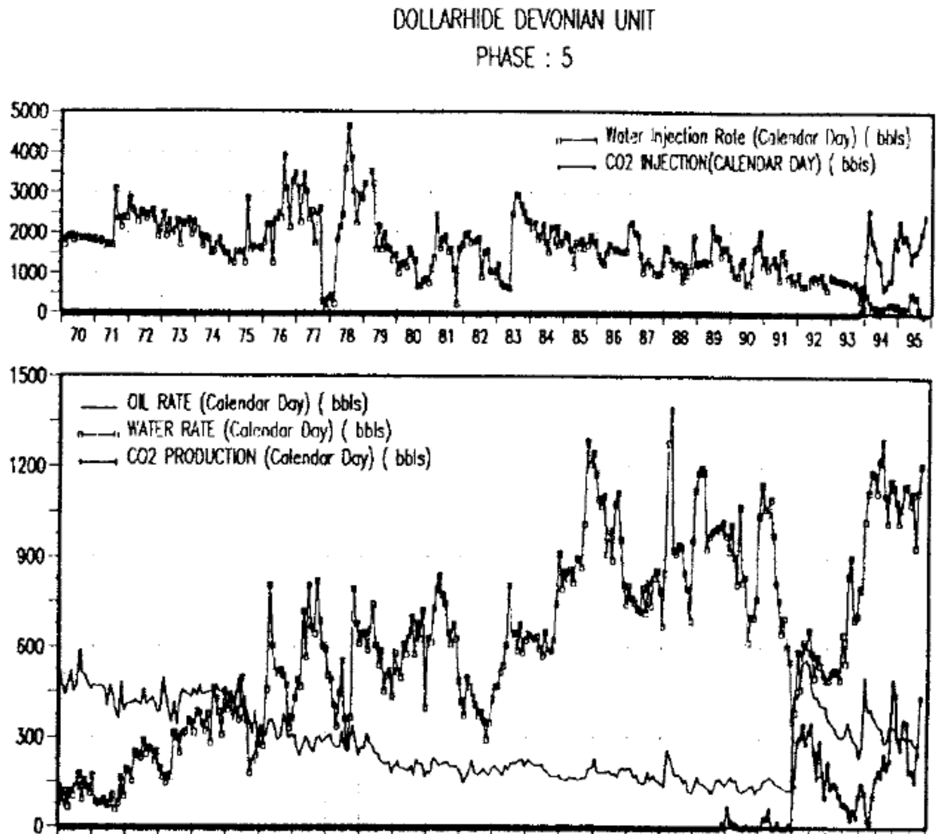

DOLLARHIDE DEVONIAN UNIT
PHASE : 5
Water Injection Rate (Calendar Day) (bbls)
CO2 INJECTION(CALENDAR DAY) (bbls)
OIL RATE (Calendar Day) (bbls)
WATER RATE (Calendar Day) (bbls)
CO2 PRODUCTION (Calendar Day) (bbls)

FIGURE 10

Field: Sundown Slaughter Unit

Key Papers

1. Fogler, L.K. and Guillot, S.N.: "A Case Stduy of the Development of the Sundown Slaughter Unit CO_2 Flood, Hockley County, TX," SPE 35189, presented at Permian Basin Oil and Gas Recovery Conference, Midland, TX (1996).

Key rate history plots:

Paper 1

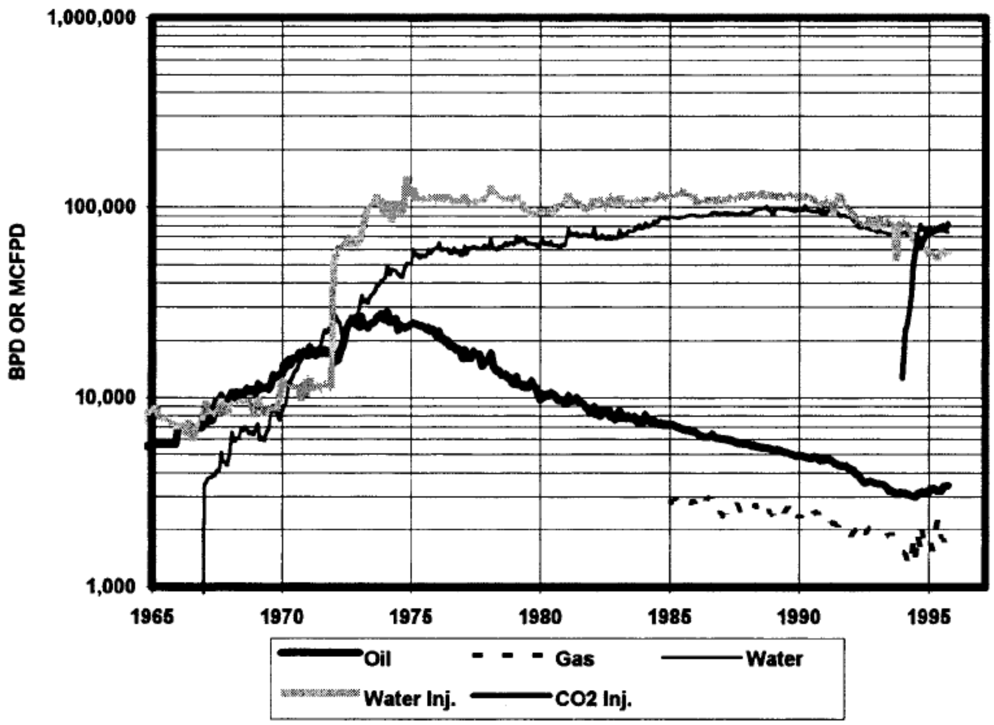


Figure 2: Production Plot of Sundown Slaughter Unit

Field: Twofreds

Key Papers

1. Flanders, W.A. and DePauw, R.M.: "Update Case History: Performance of the Twofreds Tertiary CO_2 Project," SPE 26614, presented at the Annual Technical Conference and Exhibition, Houston, TX (1993).

Key rate history plots:

Paper 1

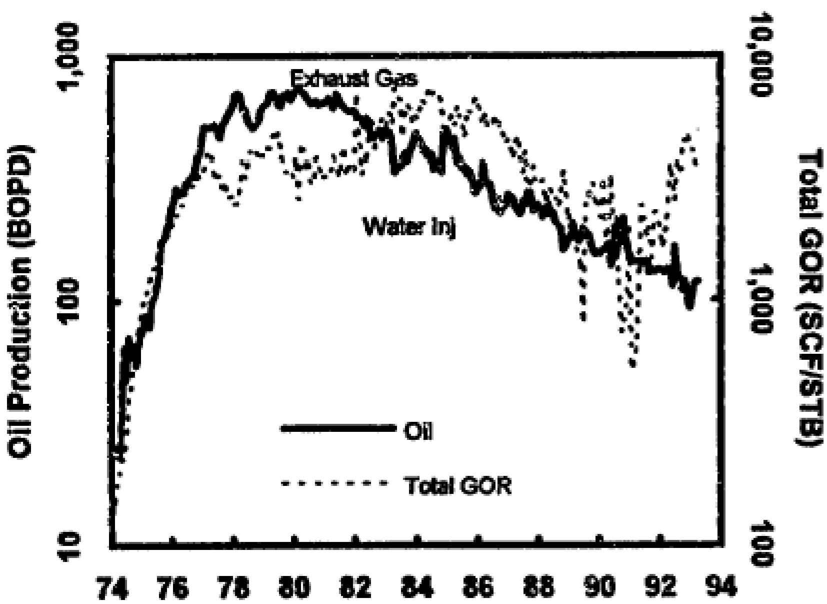


Figure 7. East side conformal area tertiary oil production

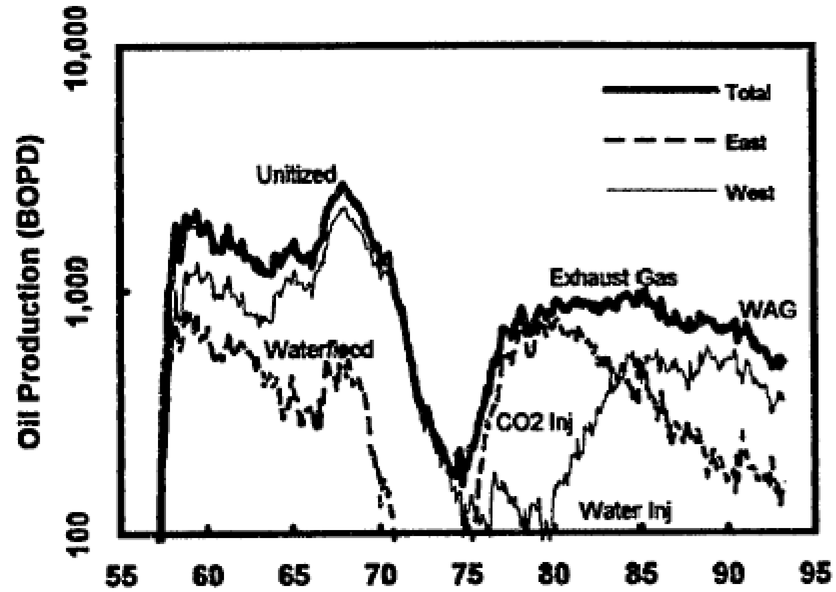


Figure 6. Oil production history since discovery

Field: West Sussex Pilot

Key Papers

1. Holland, R.C., et al.: "Case History of a Successful Rocky Mountain Pilot CO_2 Flood," SPE 14939, presented at the Symposium on Enhance Oil Recovey, Tulsa, OK (1986).

Key rate history plots:

Paper 1

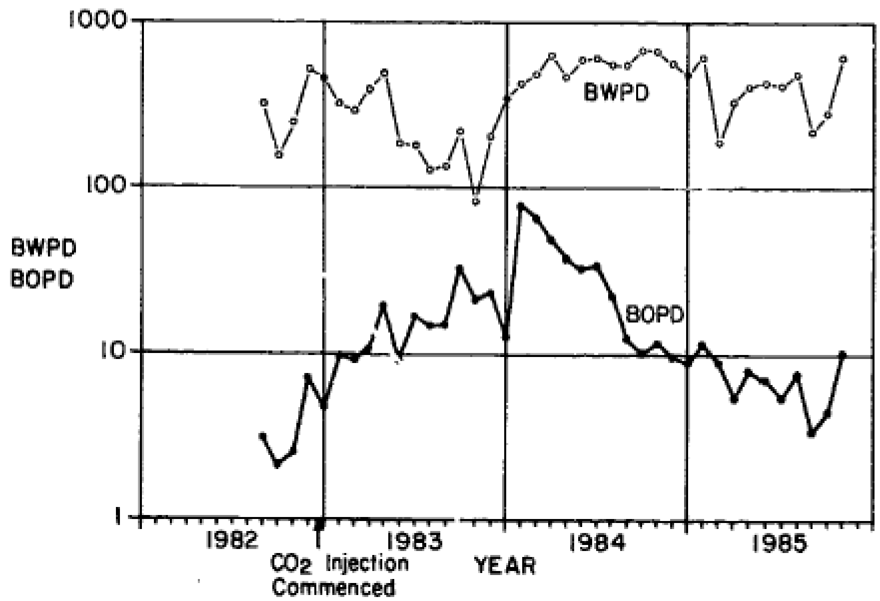


Fig. 6—Pilot oil and water production history.

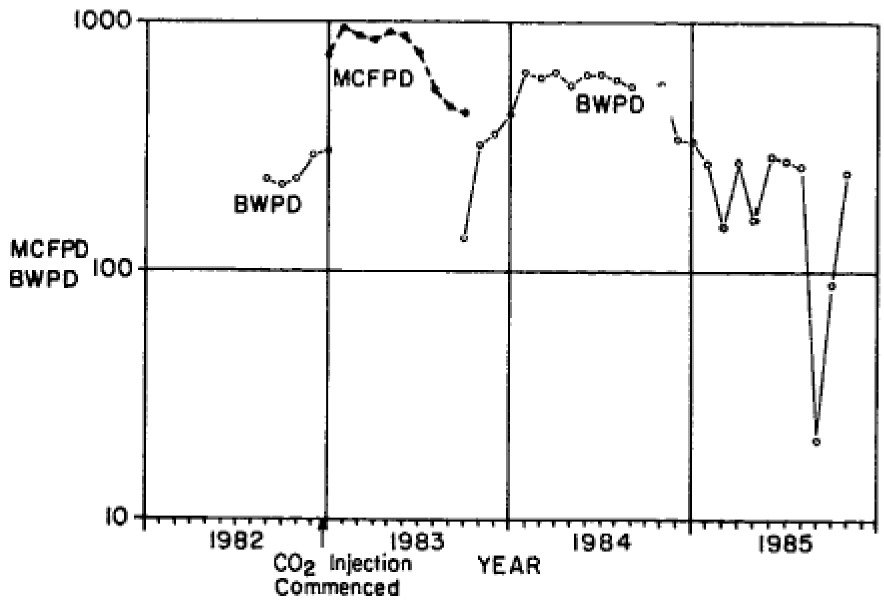


Fig. 5—Pilot water and CO_2 injection history.

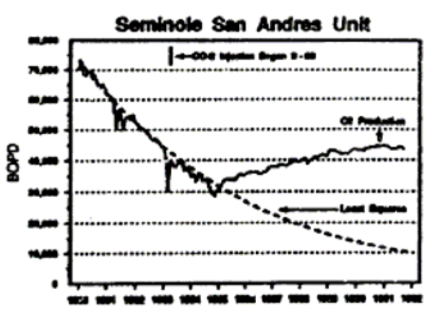
Field: Seminole San Andres Unit

Key Papers

1. Hadlow, R.E.: "Update of Industry Experience with CO_2 Injection," SPE 2498, presented at the Annual Technical Conference and Exhibition (1992).

Key rate history plots:

Paper 1



The paper contained no information about flood.

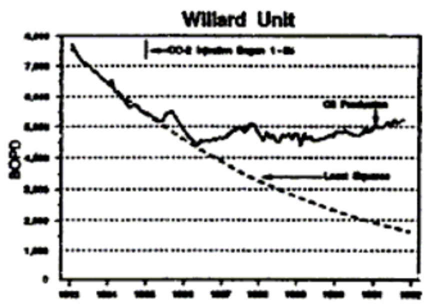
Field: Willard Unit, Wasson Field

Key Papers

1. Hadlow, R.E.: "Update of Industry Experience with CO_2 Injection," SPE 2498, presented at the Annual Technical Conference and Exhibition (1992).

Key rate history plots:

Paper 1



The paper contained no information about flood.

Field: Four-Pattern Area, SACROC Field

Key Papers

1. Langston, M.V., Hoadley, S.F., and Young, D.N.: “Definitive CO_2 Flooding Response in the SACROC Unit,” SPE 17321, presented at the 1988 SPE/DOE EOR Symposium, Tulsa, OK (1988).

Key rate history plots:

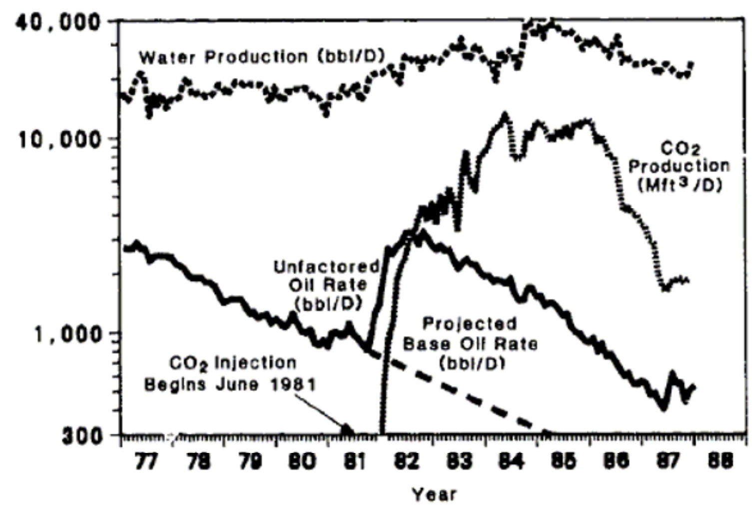


Fig. 6—Four Pattern Area performance summary.

Field: Seventeen-Pattern Area, SACROC Field

Key Papers

1. Langston, M.V., Hoadley, S.F., and Young, D.N.: "Definitive CO_2 Flooding Response in the SACROC Unit," SPE 17321, presented at the 1988 SPE/DOE EOR Symposium, Tulsa, OK (1988).

Key rate history plots:

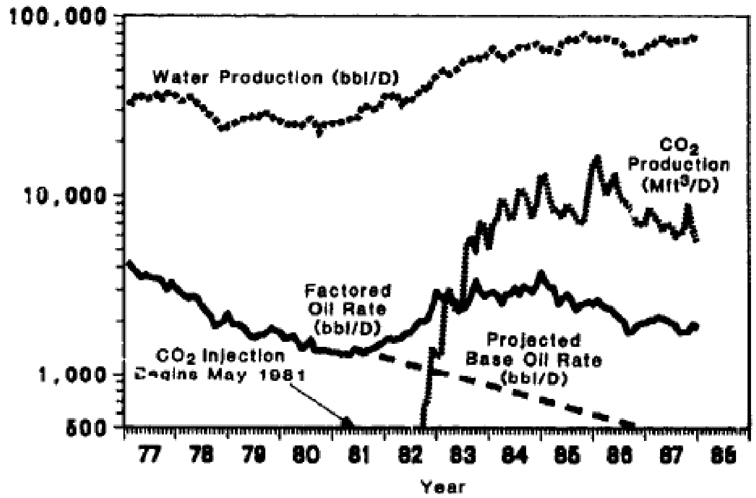


Fig. 9—Seventeen Pattern Area performance summary.

APPENDIX C: SUPPLEMENTAL EMPIRICAL CORRELATIONS

The EOR rate model requires estimating the following times: t_2, t_3, and t_4. This appendix presents development of empirical methods to estimate these times. The correlations in this appendix are based on a statistical analysis of data from the database (Table 6).

The correlations are based on field data from the Twofreds, Wertz, Lost Soldier, and SEU fields. The data from the remaining fields in the database (West Sussex, SACROC 4PA, and SACROC 17PA) were not available when correlations were first prepared. We did not update the correlations because the additional data did not appreciably change them.

Model Parameter Δt_3

The time t_3 is date of the peak oil rate. The variable Δt_3 is the elapsed time from the start of solvent injection until the peak oil rate.

Δt_3 usually falls between 1 and 6 years. We have observed that Δt_3 correlates with the time constant V_p/Q_T. Physically, this ratio is the time to inject 1 pore volume of fluid into the reservoir. The inverse of the time constant, Q_T/V_p, is a scaled measure of the solvent flood's rate. Figure C1 shows a plot of Δt_3 versus V_p/Q_T. As expected, Δt_3 increases as V_p/Q_T increases and Q_T/V_p decreases. Physically, this relationship shows that the elapsed time to reach the peak oil rate increases as the scaled flood rate decreases. Figure C1 shows a linear relationship between Δt_3 and V_p/Q_T. Linear regression yields the following relationship between Δt_3 and V_p/Q_T

$$\Delta t_3 = 0.295\left(\frac{V_p}{Q_T}\right) - 0.337 \qquad 4.5 \text{ yrs} < V_p/Q_T < 20 \text{ yrs} \qquad \text{(C1)}$$

where Δt_3 and V_p/Q_T are expressed in years. This equation has a standard error of 0.17 years (2 months) and an average error of 4.2%. Since the time constant is known for a solvent flood, this equation gives an effective way to estimate the time difference Δt_3.

Equation (C1) is fit to the data give by the black dots in Figure C1. These points correspond to field data from Twofreds, Wertz, and Lost Soldier (LS) fields. Later, data points for West Sussex, SACROC 4PA, and SACROC 17PA became available and were added (open circles), but the correlation was not updated because the trend did not appreciably change. The additional data constitute a confirmation of the correlation.

The time constant usually falls within a relatively narrow range. The time constants in Fig. C1, for example, vary between only 4.5 and 22 years/PVI. This range corresponds to a range of scaled rates between approximately 0.05 and 0.22 PVI/year. This range approximately agrees with the range for waterfloods. For instance, Riley (1964), Guerrero and Earlougher (1961), and Bush and Helander (1968) have observed that the scaled rate for most waterfloods generally falls between 0.10 and 0.30 PVI/year, a relatively narrow range. Willhite (1986) simply recommends assuming an average value of 0.29 PVI/year.

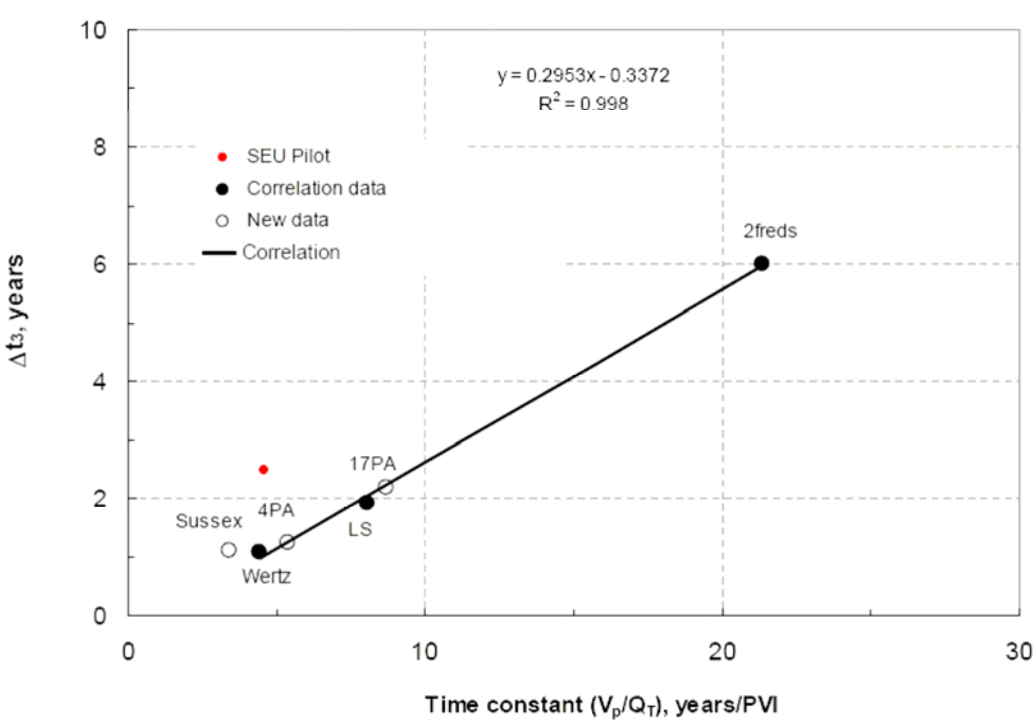


Figure C1. Time of peak oil rate (Δt_3) versus time constant.

That the y-intercept in Fig. C1 nearly passes through the origin implies that the total injected fluid volume, expressed in pore volumes units at the peak time, is approximately constant, near 0.26 PVI. The variable Δt_{D3} is defined as the pore volumes of fluid injected at the peak rate. Thus, $\Delta t_{D3} \approx 0.26$. Equation. (C1) actually predicts that Δt_{D3} falls within a narrow range, between 0.24 and 0.28 PVI, i.e., $0.24 < \Delta t_{D3} < 0.28$. This rang be used an alternate means to estimate Δt_3. First, a value for Δt_{D3} within the range is selected; then, the corresponding value of Δt_3 is computed. The field data gives an average Δt_{D3} value of 0.254. The effect of Δt_{D3} (within its range) on the resulting rate history is small. Thus, any value within the cited range is acceptable. Even values within the larger range $0.20 < \Delta t_{D3} < 0.33$ have only a weak effect on the rate history. Relative to the base case of $\Delta t_{D3} = 0.26$, for instance, the average error in the yearly oil production over a 20-year flood life is less than 0.5% of the injection rate for $\Delta t_{D3} = 0.20$ and less than 0.7% of the injection rate for $\Delta t_{D3} = 0.33$. These results are for a cumulative recovery of 10% and $b_{EOR} = 0$. These results illustrate relative insensitivity of the rate to Δt_{D3}. If we simply assume $\Delta t_{D3} = 0.254$, then the time difference Δt_3 is then computed by solving Eq. (16)

$$\Delta t_3 = \frac{\Delta t_{D3} V_p}{Q_T} \approx \frac{0.254 V_p}{Q_T} \tag{C2}$$

where Δt_3 and V_p/Q_T are expressed in years.

The correlation in Eq. (C1) and the guideline given above are valid if the well spacing is greater than 10 acres. For smaller well spacing, such as for pilot tests, solvent floods are usually much more efficient and the peak oil rate is delayed later than that predicted). In the case of the Slaughter Estate CO_2 pilot where the well spacing was only 3 acres, for example, the peak oil rate does not occur until 54% of a pore volume of fluid is injected, i.e., $\Delta t_{D3} = 0.54$. The red data point in Figure C1 shows the data point for the SEU pilot.

Clearly, the data supporting Eqs. (C1) and (C2) is sparse. Additional data would be helpful. However, because the rate history is relatively insensitive to Δt_{D3}, acquiring more data is not critical.

Our findings are qualitatively similar to the results of Bush and Helander who studied waterflooding. They tried to determine the time of the peak oil rate for a waterflood following pressure depletion. They found that the time of the peak oil rate correlated with the time constant and corresponded to a relatively narrow range of dimensionless times. For their study of 86 waterfloods, for instance, they found that the peak oil rate occurred at an average of 0.33 pore volumes of water injected.

Model Parameter Δt_4

The time t_4 is the termination date. The variable Δt_4 is the elapsed time (t_4-t_1) from the start of solvent injection until termination. It represents the flood life.

Δt_4 is between 8 and 27 years—a rather wide range. However, Δt_4 also correlates with the time constant V_p/Q_T. Figure C2 shows a plot of Δt_4 versus V_p/Q_T. As expected, Δt_4 increases as V_p/Q_T increases and Q_T/V_p decreases. Physically, this relationship shows that the flood life increases as the scaled flood rate decreases. The linear regression y relationship between Δt_3 and V_p/Q_T is

$$\Delta t_4 = 1.07\left(\frac{V_p}{Q_T}\right) + 4.11 \qquad 4.5 \text{ yrs} < V_p/Q_T < 20 \text{ yrs} \tag{C3}$$

where Δt_4 and V_p/Q_T are in years. Equation (C3) a standard error of 0.91 years (11 months) and an average error of 4%. Since V_p/Q_T is usually known, Eq. (C3) is a way to estimate Δt_{D4}.

Equation (C3) predicts Δt_4 is a sole function of the time constant. This is probably an oversimplification. Other factors, especially economic factors such as operating expenses, will also influence the flood life.

The flood life can also be described in terms of the pore volumes injected (PVI). The field data shows that the flood life ranges between 1.25 and 1.95 PVI. Δt_{D4} is a dimensionless flood life. The dimensionless life of a tertiary miscible flood is about the same as that of a waterflood. For instance, Guerrero and Earlougher (1961) observed that waterflood life usually ranges between 1.25 and 1.7 PVI.

The observed rate history is not overly sensitive to Δt_{D4} as long as an average value within its range is selected. In many cases, simply selecting Δt_4 based on a value of Δt_{D4} = 1.5 is often very reasonable. If this simplified guideline is accepted, then

$$\Delta t_4 = \frac{\Delta t_{D4} V_p}{Q_T} = \frac{1.5 V_p}{Q_T} \qquad \text{(C5)}$$

where consistent units are assumed. For example, if V_p [=] rm^3 and Q_T [=] rm^3/day (rm^3 denotes reservoir m^3), then Δt_4 [=] days. Relative to a base case of $\Delta t_{D4} = 1.5$, for instance, the average error in the yearly oil production over flood life (20 years) was only 0.83% of the injection rate for $\Delta t_{D4} = 1.75$ and was only 0.98% of the injection rate for Δt_{D4} = 1.25 PVI. This case assumed a cumulative recovery of 10% and $b_{EOR} = 0$. These results show that the error in simply assuming Δt_{D4} = 1.5 PVI is reasonably small.

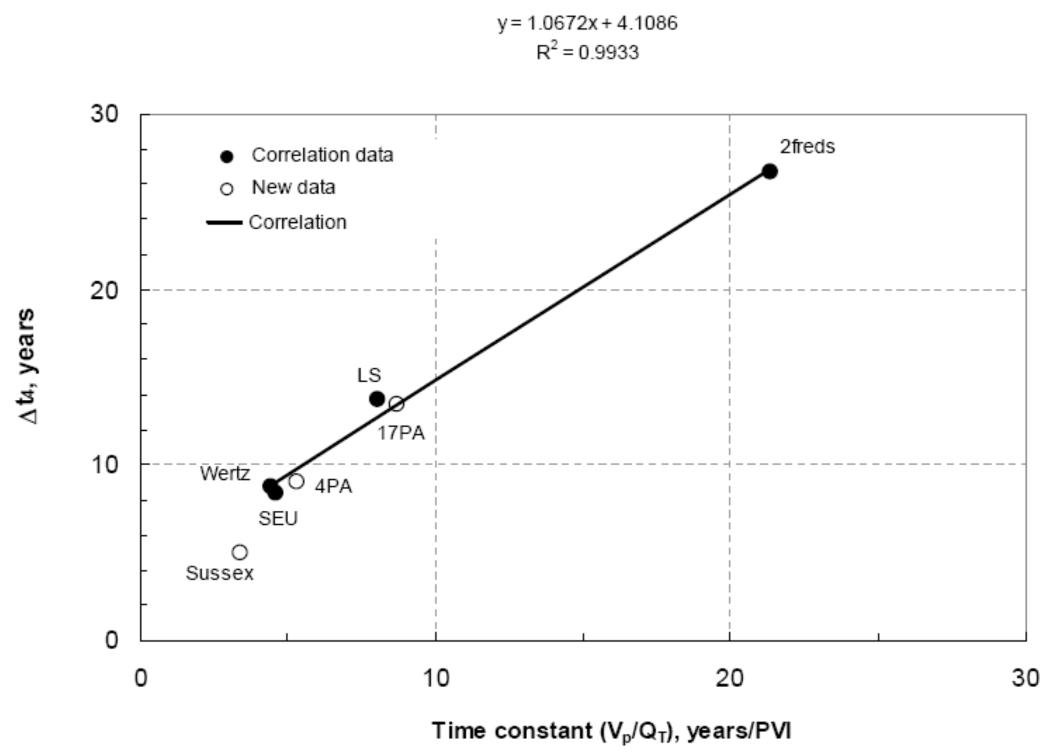


Figure C2. Flood life (Δt_4) versus time constant.

Model Parameter Δt_2

The time t_2 is date of the oil bank breakthrough. The time difference Δt_2 (= t_2 - t_1) is the time from the start of solvent injection until oil bank breakthrough.

Δt_2 is very short—usually between 1 and 3 months. Expressed as a percentage of the solvent flood's life (typically 8-27 years), Δt_2 is relatively insignificant. Therefore, the specific choice of Δt_2 within this range usually makes little difference.

Alternatively, Δt_2 can be expressed terms of pore volumes of fluid injected, Δt_{D2}. Selecting any value within the range $1 < \Delta t_{D2} < 4\%$ is acceptable and reasonable. This range is an alternative means to estimate Δt_2.

Summary

The rate model requires estimating three key time parameters: Δt_2, Δt_3, and Δt_4. These parameters can be estimated from the time constant, V_p/Q_T, which is invariably known or can be estimated. The time parameters can also be estimated from their dimensionless counterparts: Δt_{D2}, Δt_{D3}, and Δt_{D4}. The dimensionless times are observed to fall within a relatively narrow range: $0.01 < \Delta t_{D2} < 0.04$, $0.24 < \Delta t_{D3} < 0.28$, and $1.25 < \Delta t_{D4} < 1.95$. Reasonably accurate predictions can be produced if one simply assumes $\Delta t_{D2} = 0.02$, $\Delta t_{D3} = 0.26$, and $\Delta t_{D4} = 1.5$.

APPENDIX D: ESTIMATING INCREMENTAL RECOVERY

The incremental recovery of successful commercial tertiary solvent floods typically ranges between 7 and 16% of the OOIP. The incremental recovery of tertiary pilot floods is often greater and can be as much as 20% of the OOIP.

Various methods are used to estimate recovery factors for screening purposes. This Appendix presents a brief mathematical derivation of some equations that can be used as a starting point for an evaluation.

Let us define the following variables:

N_{pWF} = cumulative oil volume recovered through waterflooding
N_{pEOR} = cumulative oil volume recovered through EOR
B_{oWF} = oil formation volume factor at the end of waterflooding
B_{oEOR} = oil formation volume factor at the end of EOR

If the reservoir is initially undersaturated, then the initial oil saturation is $(1-S_{wi})$. The average oil saturation at the end of waterflooding is

$$S_{oWF} = \frac{(N - N_{pWF})B_{oWF}}{V_p} \quad \text{(D1)}$$

where $(N-N_{pWF})$ represents the oil remaining after waterflooding. If E_v is the volumetric efficiency of the EOR process and S_{om} is the remaining or residual oil saturation in the swept zone (see Figure D1), then oil remaining at the end of EOR is

$$N - N_{pEOR} = \frac{V_p}{B_{oEOR}}\left[S_{om}E_v + S_{oWF}(1 - E_v)\right] \quad \text{(D2)}$$

where the first term in the brackets accounts for the swept zone and second term accounts for the unswept zone. S_{om} is usually estimated from laboratory core tests or is a fitting parameter. The cumulative oil recovery during EOR is

$$N_p = N_{pEOR} - N_{pWF} \quad \text{(D3)}$$

Substituting Eq. (D1) into (D2), and then solving the resulting equation for N_{pEOR} and then substituting the result into Eq. (D3) gives

$$\frac{N_p}{N} = \left(1 - \frac{N_{pWF}}{N}\right)\left[1 - (1 - E_v)\frac{B_{oWF}}{B_{oEOR}}\right] - \frac{B_{oi}S_{om}}{B_{oEOR}(1 - S_{wi})}E_v \quad \text{(D4)}$$

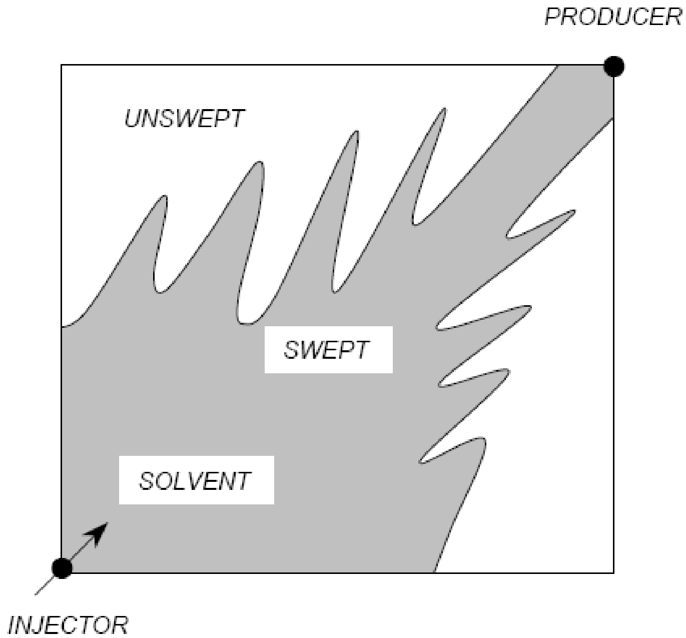


Figure D1. Swept and unswept areas during solvent flooding in a quarter 5-spot pattern.

where N_p/N is the cumulative recovery during solvent flooding expressed as a fraction of the OOIP, and we have used $NB_{oi}/(1-S_{wi})$ to replace V_p. If $B_{oWF} = B_{oEOR}$, then this equation simplifies to

$$\frac{N_p}{N} = \left(1 - \frac{N_{pWF}}{N} - \frac{B_{oi}S_{om}}{B_{oEOR}(1 - S_{wi})}\right)E_v \qquad \text{(D5)}$$

If B_{oEOR} is approximately equal to B_{oi}, then Eq. (D5) becomes

$$\frac{N_p}{N} = \left(1 - \frac{N_{pWF}}{N} - \frac{S_{om}}{(1 - S_{wi})}\right)E_v \qquad \text{(D6)}$$

If ΔN_{pWF} is the hypothetical oil recovery from continued waterflooding, then the fractional incremental oil recovery from solvent flooding is

$$\frac{\Delta N_p}{N} = \frac{N_p}{N} - \frac{\Delta N_{pWF}}{N} \qquad \text{(D7)}$$

The following example illustrates the application of Eqs. (D6) and (D7).

Example: Estimating the Incremental EOR for Slaughter Estate Unit CO_2 Pilot. Primary recovery and waterflooding recovered 9.4 and 29.9% of the OOIP, respectively, in the SEU pilot. Therefore, N_{pWF}/N = 39.3%. Continued waterflooding was projected to recover an additional 11.2% of the OOIP. Therefore, $\Delta N_{pWF}/N$ = 11.2%. The initial water saturation was 9.1%. The operators reported S_{om} = 12% from core tests. If the final areal and vertical sweep efficiencies are 90% and 70%, then E_v = 0.63. To compute the cumulative recovery during CO_2 flooding, we apply Eq. (D6):

$$\frac{N_p}{N} = \left(1 - \frac{N_{pWF}}{N} - \frac{S_{om}}{(1 - S_{wi})}\right) E_v = \left(1 - 0.393 - \frac{0.12}{(1 - 0.091)}\right)(0.63) = 30.0\%$$

To compute the incremental recovery, we apply Eq. (D7):

$$\frac{\Delta N_p}{N} = \frac{N_p}{N} - \frac{\Delta N_{pWF}}{N} = 0.30 - 0.112 = 18.8\%$$

These estimates agree closely with the actual values of 30.8 and 19.6%, respectively.

APPENDIX E: CATALOGUE OF EOR SCREENING CRITERIA

This appendix presents sets of screening criteria gathered from the literature search. This appendix consists of actual pages copied from the references. For a more detailed discussion, the reader is referred to the reference. The screening criteria are for miscible, chemical, and thermal EOR.

Screening Criteria

1. Brashear, J.P. and Kuuskraa, V.A.: The Potential and Economics of Enhanced Oil Recovery, J. Pet. Tech., SPE 06350, (Sept., 1978), 1231.

TABLE 1—CRITERIA FOR THE APPLICATION OF SELECTED EOR METHODS*

Screening Parameters	Steam Drive	In-Situ Combustion	CO_2 Miscible	Micellar/ Polymer	Improved Waterflood
Viscosity, cp at reservoir conditions	NC[1]	NC	<12	<20	<200
Gravity, °API					15
Other than California crudes	>10°	10 to 45°	>30°	>25°	>18°
California crudes	>10°	10 to 45°	>26°	>25°	>18°
Fraction of oil remaining in area to be flooded (before EOR), % PV	50[2]	50[2]	25	25	50
Oil Concentration before and after flooding (porosity × oil saturation)	>500 >0.065	>400 >0.05	NC	NC	NC
Depth, ft	<5,000	>500		NC — (8,500)[3,5]	NC — (8,500)[3,5]
Temperature, °F	NC	NC	NC	<200°F[5]	<200°F[5]
Original bottom-hole pressure, psi	NC	NC	>1,500	NC	NC
Net pay thickness, ft	>20	>10	NC	NC	NC
Permeability, md	NC	NC	NC	>20 (with polymer drive)	>20
Transmissibility, (permeability × thickness/viscosity)	>100	>20	NC	NC	NC
Natural water drive[4]	none to weak	none to weak	none to weak	none to weak	none to weak
Gas cap[4]	none to minor	none to minor	none to minor	none to minor	none to minor
Fractures	NC unless extreme	none to minor	none to minor	none to minor	none to minor
Lithology	NC	NC	NC	sandstone only[4]	NC
Salinity, ppm total dissolved solids	NC	NC	NC	<50,000 ppm[5]	NC
Hardness, ppm, calcium and magnesium	NC	NC	NC	<1,000 ppm[5]	NC
Comments	Porosity × thickness (high)	High dip preferred	Thin pay preferred	Homogeneous formation preferred	Use with or before waterflood
	10-acre spacing	Porosity × thickness high	High dip preferred	Low clay content	Low calcium and clay content
	Economic fresh water available	40-acre spacing	Homogeneous formation preferred	Porosity × thickness (high)	Porosity × thickness (high)
	Economic fuel available	Low vertical permeability preferred	Porosity × thickness low	Prefer water-flood sweep >50%	
	High net to gross pay	Preferred temperature >150°F	Natural CO_2 availability		
	Low clay content	High net to gross pay	Low vertical permeability in horizontal reservoirs		

[1]NC = Not a critical factor (for all).
[2]In portion of field to be flooded. Assuming 80% of area of reservoir contains 95% of remaining oil, the oil saturation for the total field becomes 42% PV.
[3]8,500 ft is approximately the depth at which the temperature constraint of 200°F will be reached.
[4]These criteria apply to reservoirs with substantial remaining primary recovery.
[5]Considered a constraint under current technology.
*This table is an analytic tool based on analysis of numerous EOR projects; it should not, however, be interpreted as a strict guide to the applicability of a given process to a specific reservoir.

2. Goodlett, G.O., Honarpour, F.T., Chung, F.T., Sarathi, P.S.: The Role of Screening and Laboratory Flow Studies in EOR Process Evaluation, SPE 15172, presented at SPE Rocky Mountain Regioinal Meeting, Billings, Montana (1986).

Table 1. Summary of Technical Screening Criteria for EOR Candidates

	Reservoir Characteristics								Fluid Properties				Reservoir Rock-Fluid Properties		
	Formation Type	Net Thickness (ft)	Depth (ft)	Temp (°F)	Average K (md)	ϕ %	Oil Saturation	P (psi)	γo (API)	μo (CP)	Oil Composition	Salinity (ppm)	Wettability	Kh/μ	ϕ So
Chemical Flooding															
Polymer	Sandstone preferred, carbonate possible	>10	<9000	<200	>20	≥20	>10% Mobile	---	>25	<100	N.C.	<100,000	W.W. preferred	—	---
Surfactant/Polymer	Sandstone preferred	N.C.	<9000	<200	>40	≥20	>30%	---	>25	<40	Light to intermediate are preferred	<140,000 <100,000	W.W. or O.W. good potential' in O.W.	--- ---	--- ---
Alkaline	Sandstone preferred	N.C.	<9000	<200	>20	≥20	>Residual	---	<30	<90	Some Organic acid				
Gas Injection															
Hydrocarbon	Sandstone or carbonate	Thin unless dipping	>2000 for LPG to >5000 high pressure gas	N.C.	N.C.	N.C.	>30%	---	>35	<10	High % of C_2-C_7	N.C.	W.W. or O.W.	---	---
Nitrogen & Flue Gas	Sandstone or carbonate	Thin unless dipping	>4500	N.C.	N.C.	N.C.	>30%	---	>24 >35 for N_2	<10	High % of C_1-C_7	N.C.	W.W. or O.W.	---	—
Carbon Dioxide	Sandstone or carbonate	Thin unless dipping	>2000	N.C.	N.C.	N.C.	>30%	≥MMP+	>25	<15	C_5-C_{12}	N.C.	W.W. or O.W.	---	---
Thermal															
In-situ Combustion	Unconsolidated sand or sandstone with high porosity or carbonate	≥20	≤11,500	>150 pre-ferred	≥35	≥20'	40-50%	≤2000	10-35	≤50,000	Some asphaltic component	N.C.	W.W. or O.W.	≥5	≥.08
Steamflooding	Unconsolidated sand or sandstone or carbonate	≥20	≤3,000	N.C.	>250	≥20'	40-50%	≤1500	10-34	≤15,000	N.C.	N.C.	W.W. or O.W. good potential in O.W.	≥5	>0.1
Microbial															
Microbial Drive and cyclic method	sandstone or carbonate	N.C.	<8,000	<140	>150	---	N.C.	<3000	>15	---	Ab' ance of toxic conc. of metals, no biocides present	<100,000	W.W. or O.W.	---	---

N.C. = Not Critical
'Ignore if saturation x porosity criteria is satisfied
+MMP = Minimum Miscibility Pressure which depends on temperature and crude oil composition

3. Taber, J.J., Martin, F.D., and Seright, R.S.: "EOR Screening Criteria Revisited—Part 1: Introduction to Screening Criteria and Enhanced Recovery Field Projects," SPE Reservoir Engineering, SPE 35385 (August, 1997).

TABLE 3—SUMMARY OF SCREENING CRITERIA FOR EOR METHODS

		Oil Properties			Reservoir Characteristics					
Detail Table in Ref. 16	EOR Method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
					Gas Injection Methods (Miscible)					
1	Nitrogen and flue gas	> 35 ↗ 48 ↗	< 0.4 ↘ 0.2 ↘	High percent of C_1 to C_7	> 40 ↗ 75 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 6,000	NC
2	Hydrocarbon	> 23 ↗ 41 ↗	< 3 ↘ 0.5 ↘	High percent of C_2 to C_7	> 30 ↗ 80 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 4,000	NC
3	CO_2	> 22 ↗ 36 ↗ [a]	< 10 ↘ 1.5 ↘	High percent of C_5 to C_{12}	> 20 ↗ 55 ↗	Sandstone or carbonate	Wide range	NC	> 2,500[a]	NC
1–3	Immiscible gases	> 12	< 600	NC	> 35 ↗ 70 ↗	NC	NC if dipping and/or good vertical permeability	NC	> 1,800	NC
					(Enhanced) Waterflooding					
4	Micellar/ Polymer, ASP, and Alkaline Flooding	> 20 ↗ 35 ↗	< 35 ↘ 13 ↘	Light, intermediate, some organic acids for alkaline floods	> 35 ↗ 53 ↗	Sandstone preferred	NC	> 10 ↗ 450 ↗	> 9,000 ↘ 3,250	> 200 ↘ 80
5	Polymer Flooding	> 15	< 150, > 10	NC	> 50 ↗ 80 ↗	Sandstone preferred	NC	> 10 ↗ 800 ↗ [b]	< 9,000	> 200 ↘ 140
					Thermal/Mechanical					
6	Combustion	> 10 ↗ 16 → ?	< 5,000 ↓ 1,200	Some asphaltic components	> 50 ↗ 72 ↗	High-porosity sand/ sandstone	> 10	> 50[c]	< 11,500 ↘ 3,500	> 100 ↗ 135
7	Steam	> 8 to 13.5 → ?	< 200,000 ↓ 4,700	NC	> 40 ↗ 66 ↗	High-porosity sand/ sandstone	> 20	> 200 ↗ 2,540 ↗ [d]	< 4,500 ↘ 1,500	NC
—	Surface mining	7 to 11	Zero cold flow	NC	> 8 wt% sand	Mineable tar sand	> 10 [e]	NC	> 3 :1 overburden to sand ratio	NC

NC = not critical.
Underlined values represent the approximate mean or average for current field projects.
[a] See Table 3 of Ref. 16.
[b] > 3md from some carbonate reservoirs if the intent is to sweep only the fracture system.
[c] Transmissibility > 20 md-ft/cp
[d] Transmissibility > 50 md-ft/cp
[e] See depth.

↗ = denotes that increasing values are better.
↘ = denotes that decreasing values are better.

4. Klins, M.A.: Carbon Dioxide Flooding, Basic Mechanisms and Project Design, International Human Resources Development Corporation, Boston, MA (1984).

TABLE 1 - KLINS CRITERIA FOR CO_2 MISCIBLE INJECTION

Screening Parameters	Values Range
Viscosity at Reservoir Conditions	<12
API Gravity	>30
Fraction of oil before EOR, [% PV]	>25
Oil Concentration, [bls/acre-ft]	NC
Depth, [ft]	>3000
Original Bottomhole Pressure, [psi]	>1500
Net Pay Thickness, [ft]	NC
Permeability, [md]	NC
Temperature, [°F]	NC
Transmissibility, [md-ft/cP]	NC

NC: Not a Critical Factor

5. Rivas, O., Embid, S., and Bolivar, F.: "Ranking Reservoirs for Carbon Dioxide Flooding Processes," SPE 23641, SPE Advanced Technology Series, Vol. 2, No. 1 (1994).

Results obtained with the three simulators compare quite well and indicate that on the average, the best reservoir for carbon dioxide injection should have an oil gravity of 36 °API, a temperature of 150 °F, a permeability of 300 mD, an oil saturation at the start of the injection of 60 %, a reservoir pressure at the time of injection of around 200 psi over minimum miscibility pressure, a porosity of 20 %, a net sand thickness of 40 ft and a reservoir dip of 20°.

Results of simulations studies indicate that the reservoir properties which most influence CO_2 flooding performance are API gravity, oil saturation and pressure. Reservoirs with an oil gravity around 37 °API, an oil saturation around 60 % and a pressure 1.3 the minimum miscibility pressure should be preferred for the process. A comparison of the simulators used here indicates that the semi-analytical predictive type model does a good job predicting CO_2 flooding performance, often in agreement with the fully compositional simulator.

TABLE 6 - PARAMETERS VALUES

Parameter	Optimum	Worst (left)	Worst (right)	Weight
Api Gravity	37	20	71	0.24
Temperature, [°F]	160	130	200^+	0.14
Permeability, [md]	300	18	2500^+	0.07
Oil Saturation, [%]	60	30	92	0.20
Pressure/PMM	1.3	0.089	1.3^+	0.19
Porosity, [%]	20	9	33	0.02
Net Oil Sand Thickness, [ft]	50	5	180	0.11
Dip, [degree]	20	5	20^+	0.03

PMM denotes the MMP

6. Mohammed-Singh, P., Singhal, A.K., and Sim, S.: "Screening Criteria for Carbon Dioxide Huff 'n' Puff Operations," SPE 100044, presented at the 2006 SPE/DOE Symposium on Improved Oil Recovery (2006).

Parameters of Successful Reservoirs	Light Oils	Medium Oils	Heavy Oils
Oil Viscosity (cp)	0.4 to 8	32 to 46	415 to 3000
Oil Gravity (°API)	23 to 38	17 to 23	11 to 14
Porosity (%)	13 to 32	25 to 32	12 to 32
Depth (feet)	1200 to 12870	2600 to 4200	1150 to 4125
Thickness (feet)	6 to 60	36 to 220	200
Permeability (mD)	10 to 3000	150 to 388	250 to 350

Factors Favorable to Huff 'n Puff Operations
High oil saturations
Thick pay intervals
Mild pressure support to production
Soak intervals 2 to 4 weeks
High injection volumes and rates
Deep reservoirs
Maximum of 3 cycles

7. Diaz, D., Bassiouni, Z., Kimbrell, W., and Wolcott, J.: "Screening Criteria for Application of Carbon Dioxide Miscible Displacement in Waterflooded Reservoirs Containing Light Oil," SPE/DOE 35431, presented 1996 SPE Improved Oil Recovery Symposium, Tulsa, OK (1996).

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

8. Taber, J.J.. and Martin, F.D.: "Technical Screening Guides for the Enhanced Recovery of Oil," SPE 12069, presented at the Annual Technical Conference and Exhibition, San Francisco, CA (1983).

Table 3

HYDROCARBON MISCIBLE FLOODING

Description

Hydrocarbon miscible flooding consists of injecting light hydrocarbons through the reservoir to form a miscible flood. Three different methods are used. One method uses about 5% PV slug of liquified petroleum gas (LPG) such as propane, followed by natural gas or gas and water. A second method, called Enriched (Condensing) Gas Drive, consists of injecting a 10-20% PV slug of natural gas that is enriched with ethane through hexane (C_2 to C_6), followed by lean gas (dry, mostly methane) and possibly water. The enriching components are transferred from the gas to the oil. The third method, called High Pressure (Vaporizing) Gas Drive, consists of injecting lean gas at high pressure to vaporize C_2 - C_6 components from the crude oil being displaced.

Mechanisms

Hydrocarbon miscible flooding recovers crude oil by:
- -- generating miscibility (in the condensing and vaporizing gas drive)
- -- increasing the oil volume (swelling)
- -- decreasing the viscosity of the oil

TECHNICAL SCREENING GUIDES

Crude Oil

Gravity	> 35° API
Viscosity	< 10 cp
Composition	High percentage of light hydrocarbons (C_2 - C_7)

Reservoir

Oil Saturation	> 30% PV
Type of Formation	Sandstone or carbonate with a minimum of fractures and high permeability streaks
Net Thickness	Relatively thin unless formation is steeply dipping
Average Permeability	Not critical if uniform
Depth	> 2000 ft (LPG) to > 5000 ft (High Pressure Gas)
Temperature	Not critical

Limitations

The minimum depth is set by the pressure needed to maintain the generated miscibility. The required pressure ranges from about 1200 psi for the LPG process to 3000-5000 psi for the High Pressure Gas Drive, depending on the oil.

A steeply dipping formation is very desirable to permit some gravity stabilization of the displacement which normally has an unfavorable mobility ratio.

Problems

Viscous fingering results in poor vertical and horizontal sweep efficiency.
Large quantities of expensive products are required.
Solvent may be trapped and not recovered.

Table 6

SURFACTANT/POLYMER FLOODING

Description

Surfactant/polymer flooding, also called micellar/polymer or microemulsion flooding, consists of injecting a slug that contains water, surfactant, electrolyte (salt), usually a cosolvent (alcohol), and possibly a hydrocarbon (oil). The size of the slug is often 5-15% PV for a high surfactant concentration system and 15-50% PV for low concentrations. The surfactant slug is followed by polymer-thickened water. Concentrations of the polymer often ranges from 500-2000 mg/L; the volume of polymer solution injected may be 50% PV, more or less, depending on the process design.

Mechanisms

Surfactant/polymer flooding recovers oil by:

-- lowering the interfacial tension between oil and water
-- solubilization of oil
-- emulsification of oil and water
-- mobility enhancement

TECHNICAL SCREENING GUIDES

Crude Oil

Gravity	> 25° API
Viscosity	< 30 cp
Composition	Light intermediates are desirable

Reservoir

Oil Saturation	> 30% PV
Type of Formation	Sandstones preferred
Net Thickness	> 10 ft
Average Permeability	> 20 md
Depth	< about 8000 ft (see Temperature)
Temperature	< 175°F

Limitations

An areal sweep of more than 50% on waterflood is desired.
Relatively homogeneous formation is preferred.
High amounts of anhydrite, gypsum, or clays are undesirable.
Available systems provide optimum behavior over a very narrow set of conditions.
With commercially available surfactants, formation water chlorides should be < 20,000 ppm and divalent ions (Ca^{++} and Mg^{++}) < 500 ppm.

Problems

Complex and expensive system.
Possibility of chromatographic separation of chemicals.
High adsorption of surfactant.
Interactions between surfactant and polymer.
Degradation of chemicals at high temperature.

Table 7

POLYMER FLOODING

Description

The objective of polymer flooding is to provide better displacement and volumetric sweep efficiencies during a waterflood. Polymer augmented waterflooding consists of adding water soluble polymers to the water before it is injected into the reservoir. Low concentrations (often 250-2000 mg/L) of certain synthetic or biopolymers are used; properly sized treatments may require 15-25% reservoir PV.

Mechanisms

Polymers improve recovery by:
- -- increasing the viscosity of water
- -- decreasing the mobility of water
- -- contacting a larger volume of the reservoir

TECHNICAL SCREENING GUIDES

Crude Oil

Gravity	> 25° API
Viscosity	< 150 cp (preferably < 100)
Composition	Not critical

Reservoir

Oil Saturation	> 10% PV mobile oil
Type of Formation	Sandstones preferred but can be used in carbonates
Net Thickness	Not critical
Average Permeability	> 10 md (as low as 3 md in some cases)
Depth	< about 9000 ft (see Temperature)
Temperature	< 200°F to minimize degradation

Limitations

If oil viscosities are high, a higher polymer concentration is needed to achieve the desired mobility control.

Results are normally better if the polymer flood is started before the water-oil ratio becomes excessively high.

Clays increase polymer adsorption.

Some heterogeneities are acceptable but, for conventional polymer flooding, reservoirs with extensive fractures should be avoided. If fractures are present, the crosslinked or gelled polymer techniques may be applicable.

Problems

Lower injectivity than with water can adversely affect oil production rate in the early stages of the polymer flood.

Acrylamide-type polymers lose viscosity due to shear degradation, or increases in salinity and divalent ions.

Xanthan gum polymers cost more, are subject to microbial degradation, and have a greater potential for wellbore plugging.

Table 8

ALKALINE FLOODING

Description

Alkaline or caustic flooding involves the injection of chemicals such as sodium hydroxide, sodium silicate or sodium carbonate. These chemicals react with organic petroleum acids in certain crudes to create surfactants in situ. They also react with reservoir rocks to change wettability. The concentration of the alkaline agent is normally 0.2 to 5%; slug size is often 10 to 50% PV, although one successful flood only used 2% PV, (but this project also included polymers for mobility control). Polymers may be added to the alkaline mixture, and polymer-thickened water can be used following the caustic slug.

Mechanisms

Alkaline flooding recovers crude oil by:
- -- a reduction of interfacial tension resulting from the produced surfactants
- -- changing wettability from oil-wet to water-wet
- -- changing wettability from water-wet to oil-wet
- -- emulsification and entrainment of oil
- -- emulsification and entrapment of oil to aid in mobility control
- -- solubilization of rigid oil films at oil-water interfaces

(Not all mechanisms are operative in each reservoir.)

TECHNICAL SCREENING GUIDES

Crude Oil

Gravity	13° to 35° API
Viscosity	< 200 cp
Composition	Some organic acids required

Reservoir

Oil Saturation	Above waterflood residual
Type of Formation	Sandstones preferred
Net Thickness	Not critical
Average Permeability	> 20 md
Depth	< about 9000 ft (see Temperature)
Temperature	< 200°F preferred

Limitations

Best results are obtained if the alkaline material reacts with the crude oil; the oil should have an acid number of more than 0.2 mg KOH/g of oil.

The interfacial tension between the alkaline solution and the crude oil should be less than 0.01 dyne/cm.

At high temperatures and in some chemical environments, excessive amounts of alkaline chemicals may be consumed by reaction with clays, minerals, or silica in the sandstone reservoir.

Carbonates are usually avoided because they often contain anhydrite or gypsum which interact adversely with the caustic chemical.

Problems

Scaling and plugging in the producing wells.
High caustic consumption.

Table 9

IN-SITU COMBUSTION

Description

In-situ combustion or fireflooding involves starting a fire in the reservoir and injecting air to sustain the burning of some of the crude oil. The most common technique is forward combustion in which the reservoir is ignited in an injection well, and air is injected to propagate the combustion front away from the well. One of the variations of this technique is a combination of forward combustion and waterflooding (COFCAW). A second technique is reverse combustion in which a fire is started in a well that will eventually become a producing well, and air injection is then switched to adjacent wells; however, no successful field trials have been completed for reverse combustion.

Mechanisms

In-situ combustion recovers crude oil by:

- -- the application of heat which is transferred downstream by conduction and convection, thus lowering the viscosity of the crude
- -- the products of steam distillation and thermal cracking which are carried forward to mix with and upgrade the crude
- -- burning coke that is produced from the heavy ends of the crude oil
- -- the pressure supplied to the reservoir by the injected air

TECHNICAL SCREENING GUIDES

Crude Oil

Gravity	< 40° API (normally 10-25°)
Viscosity	< 1000 cp
Composition	Some asphaltic components to aid coke deposition

Reservoir

Oil Saturation	> 500 bbl/acre-ft (or > 40-50% PV)
Type of Formation	Sand or sandstone with high porosity
Net Thickness	> 10 ft
Average Permeability	> 100 md
Transmissibility	> 20 md ft/cp
Depth	> 500 ft
Temperature	> 150°F preferred

Limitations

If sufficient coke is not deposited from the oil being burned, the combustion process will not be sustained.

If excessive coke is deposited, the rate of advance of the combustion zone will be slow, and the quantity of air required to sustain combustion will be high.

Oil saturation and porosity must be high to minimize heat loss to rock.

Process tends to sweep through upper part of reservoir so that sweep efficiency is poor in thick formations.

Problems

Adverse mobility ratio.

Complex process, requiring large capital investment, is difficult to control.

Produced flue gases can present environmental problems.

Operational problems such as severe corrosion caused by low pH hot water, serious oil-water emulsions, increased sand production, deposition of carbon or wax, and pipe failures in the producing wells as a result of the very high temperatures.

Table 10

STEAMFLOODING

Description

The steam drive process or steamflooding involves the continuous injection of about 80% quality steam to displace crude oil towards producing wells. Normal practice is to precede and accompany the steam drive by a cyclic steam stimulation of the producing wells (called huff and puff).

Mechanisms

Steam recovers crude oil by:
- -- heating the crude oil and reducing its viscosity
- -- supplying pressure to drive oil to the producing well

TECHNICAL SCREENING GUIDES

Crude Oil

Gravity	< 25° API (normal range is 10-25° API)
Viscosity	> 20 cp (normal range is 100-5000 cp)
Composition	Not critical but some light ends for steam distillation will help

Reservoir

Oil Saturation	> 500 bbl/acre-ft (or > 40-50% PV)
Type of Formation	Sand or sandstone with high porosity and permeability preferred
Net Thickness	> 20 feet
Average Permeability	> 200 md (see Transmissibility)
Transmissibility	> 100 md ft/cp
Depth	300-5000 ft
Temperature	Not critical

Limitations

Oil saturations must be quite high and the pay zone should be more than 20 feet thick to minimize heat losses to adjacent formations.

Lighter, less viscous crude oils can be steamflooded but normally will not be if the reservoir will respond to an ordinary waterflood.

Steamflooding is primarily applicable to viscous oils in massive, high permeability sandstones or unconsolidated sands.

Because of excessive heat losses in the wellbore, steamflooded reservoirs should be as shallow as possible as long as pressure for sufficient injection rates can be maintained.

Steamflooding is not normally used in carbonate reservoirs.

Since about one-third of the additional oil recovered is consumed to generate the required steam, the cost per incremental barrel of oil is high.

A low percentage of water-sensitive clays is desired for good injectivity.

Problems

Adverse mobility ratio and channeling of steam.

Table 11
SUMMARY OF SCREENING CRITERIA FOR ENHANCED RECOVERY METHODS

	Oil Properties			Reservoir Characteristics					
	Gravity °API	Viscosity (cp)	Composition	Oil Saturation	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods									
Hydrocarbon	> 35	< 10	High % of $C_2 - C_7$	> 30% PV	Sandstone or Carbonate	Thin unless dipping	N.C.	>2000 (LPG) to >5000 (H.P. Gas)	N.C.
Nitrogen & Flue Gas	> 24 > 35 for N_2	< 10	High % of $C_1 - C_7$	> 30% PV	Sandstone or Carbonate	Thin unless dipping	N.C.	> 4500	N.C.
Carbon Dioxide	> 26	< 15	High % of $C_5 - C_{12}$	> 30% PV	Sandstone or Carbonate	Thin unless dipping	N.C.	> 2000	N.C.
Chemical Flooding									
Surfactant/Polymer	> 25	< 30	Light intermediates desired	> 30% PV	Sandstone preferred	> 10	> 20	< 8000	< 175
Polymer	> 25	< 150	N.C.	> 10% PV Mobile oil	Sandstone preferred; Carbonate possible	N.C.	> 10 (normally)	< 9000	< 200
Alkaline	13-35	< 200	Some Organic Acids	Above Waterflood Residual	Sandstone preferred	N.C.	> 20	< 9000	< 200
Thermal									
Combustion	< 40 (10-25 normally)	< 1000	Some Asphaltic Components	>40-50% PV	Sand or Sandstone with high porosity	> 10	> 100*	> 500	> 150 preferred
Steamflooding	< 25	> 20	N.C.	>40-50% PV	Sand or Sandstone with high porosity	> 20	> 200**	300-5000	N.C.

N.C. = Not Critical
*Transmissibility > 20 md ft/cp
**Transmissibility > 100 md ft/cp

9. King, J.E., et al.: "The National Petroleum Council EOR Study: Thermal Processes," SPE 13242, presented at the Annual Technical Conference and Exhibition (1984).

TABLE 3

Thermal Recovery Screening Criteria

	Steam Injection		In Situ Combustion	
	Implemented Technology	Advanced Technology	Implemented Technology	Advanced Technology
Depth (ft)	≤ 3,000	≤ 5,000	≤ 11,500	-
Net Pay (ft)	≥ 20	≥ 15	≥ 20	≥ 10
Porosity*	≥ 0.20	≥ 0.15	≥ 0.20	≥ 0.15
Oil Saturation x Porosity	≥ 0.10	≥ 0.08	≥ 0.08	≥ 0.08
Permeability (md)	≥ 250	≥ 10	≥ 35	≥ 10
Oil Gravity (°API)	10 to 34	-	10 to 35	-
Oil Viscosity (cp)	≤ 15,000	-	≤ 5,000	≤ 5,000
Transmissibility (md-ft/cp)	≥ 5	-	≥ 5	-
Current Reservoir Pressure (psia)	≤ 1,500	≤ 2,000	≤ 2,000	≤ 4,000

*Ignored if oil saturation x porosity criteria are satisfied.

10. Awan, A.R., et al.: "EOR Survey in the North Sea," SPE 99546, presented at Improved Oil Recovery Symposium, Tulsa, Ok (2006).

Screening Criteria for MEOR Processes

Parameters	Lazar (1990)	DOE	Reviewed Projects Range	24 Norwegian fields range
Porosity, %	≥ 20		8 - 32	11 - 35
Permeability, md	≥ 150	> 50	0,1 - 5770	1 - 20000
Reservoir Temperature, oC	≤ 70	< 80	19 - 82	61 - 155
Salinity, g/l	≤ 150	≤ 150	1,4 - 104	14 - 273
Oil Viscosity, cp	5 - 50		3 - 50	0,1 - 4,83
Reservoir depth, m		< 2347	122 - 2103	1300 - 4208

Table 3: Screening criteria for MEOR / MIOR processes

11. Al-Bahar, M.A., et al.: "Evaluation Potential of IOR Within Kuwait," SPE 88716, presented at the Abu Dhabi International Petroleum Conference and Exhibition (2004).

Criteria for each EOR process are listed below.

Waterflooding
Oil mobility > 0.1 md/mPa.s.
Oil viscosity (at bubble point) < 2000 mPa.s.
Oil saturation > 50%
Current water oil ratio < 10 bbl/bbl
No active water drive
The condition of free gas/mobile water saturation:
(1-connate water saturation – current oil saturation)^2 * (oil viscosity) < 0.5
Current pressure / Initial Pressure > 0.7

Polymer Flooding
Reservoir temperature < 158F
Oil viscosity (at bubble point) < 150 mPa.s.
Horizontal permeability > 50 md
Oil saturation > 60%
Current water oil ratio < 10 bbl/bbl
No active water drive
Local or no bottom water
Local or no gas cap
Water hardness < 1000 ppm
Water salinity < 100,000 ppm

Alkaline/Polymer Flooding
Sandstone formation
Reservoir temperature < 158F
Oil gravity < 35 °API
Oil viscosity (at bubble point) < 150 mPa.s.
Horizontal permeability > 50 md
Oil saturation > 50%
No active water drive
Local or no bottom water

Local or no gas cap
Low clay content
Water hardness < 1000 ppm
Water salinity < 50,000 ppm

Surfactant/Polymer Flooding
Reservoir temperature < 158F
Oil viscosity (at bubble point) < 150 mPa.s.
Horizontal permeability > 50 md
Oil saturation > 35%
No active water drive
Local or no bottom water
Local or no gas cap
Low clay content
Water hardness < 1000 ppm
Water salinity < 50,000 ppm

Alkaline/Surfactant/Polymer Flooding
Sandstone formation
Reservoir temperature < 158F
Oil gravity < 35 °API
Oil viscosity (at bubble point) < 150 mPa.s.
Horizontal permeability > 50 md
Oil saturation > 35%
No active water drive
Local or no bottom water
Local or no gas cap
Low clay content
Water hardness < 1000 ppm
Water salinity < 50,000 ppm

Nitrogen Miscible
Depth > 1800 meter
Oil saturation > 35%
MMP (Minimum Miscibility Pressure) < (original reservoir pressure)
Oil gravity > 35 °API
Oil viscosity (at bubble point) < 2 mPa.s.
Local or no gas cap present
Initial pressure > MMP

In Situ Combustion
No fracture
Local or no bottom water
Local or no gas cap
Net pay thickness > 3 meter
Depth between 150 and 1800 meters
Permeability > 50 md
Oil transmissibility > 16 md-m/mPa.s.
Oil viscosity (at bubble point) between 2 and 5000 mPa.s.
Porosity > 18%
Oil Content (Porosity * oil Saturation) > 0.065

Steam Flooding
Depth < 1400 meters
Permeability > 200 md
Porosity > 20%
Net pay thickness > 6 meters
Current pressure < 1500 psi
Oil viscosity (at bubble point) between 50 and 5000 mPa.s.
Low clay volume
Local or no gas cap present
No fractures present
Water oil ratio < 10 bbl/bbl
Oil transmissibility > 16 md-m/mPa.s
Oil Content > 0.065

Immiscible Gas Flood
Depth > 200 meter
Oil saturation > 50%
Oil gravity > 13 °API
Oil viscosity (at bubble point) < 600 mPa.s.
No active water drive
Local or no bottom water
Local or no gas cap

Carbon Dioxide Miscible
Local or no gas cap present
Reservoir temperature > 86F
MMP (Minimum Miscibility Pressure) < (original reservoir pressure)
Oil gravity > 22 °API
Oil viscosity (at bubble point) < 10 mPa.s.
Oil saturation > 25%
Depth > 600 meters

Hydrocarbon Miscible Flood
Depth > 1200 meter
Oil saturation > 30%
Oil density < 24 °API
Oil viscosity (at bubble point) < 5 mPa.s.
Local or no gas cap present

Screening Criteria References

Al-Bahar, M.A., et al.: "Evaluation Potential of IOR Within Kuwait," SPE 88716, presented at the Abu Dhabi International Petroleum Conference and Exhibition (2004).

Awan, A.R., et al.: "EOR Survey in the North Sea," SPE 99546, presented at Improved Oil Recovery Symposium, Tulsa, OK (2006).

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