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POTENTIAL FROM ENHANCED OIL RECOVERY APPLICATIONS IN AUSTRALIA

NERDDP

PROJECT 976

by

D. WRIGHT, S. le POIDEVIN & G. MORRISON

and

R.G. THOMAS

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CENTRE FOR PETROLEUM ENGINEERING
UNIVERSITY OF NEW SOUTH WALES

January 1990

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FINAL REPORT

NATIONAL ENERGY RESEARCH, DEVELOPMENT AND DEMONSTRATION PROGRAM

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by

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THOMAS PETROLEUM CONSULTANTS

with assistance from

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ABSTRACT

As a result of an SPE/NERDDC meeting in Adelaide in April 1986 between oil industry and government representatives, it was decided to propose a NERDDC project on the potential from Enhanced Oil Recovery applications in Australia. The aim was to highlight to Government, industry, and the public the scope for EOR and to provide assistance in planning EOR projects and policies.

Oilfield data from 177 significant reservoirs were compiled, checked for consistency, and subjected to technical screening and preliminary economic evaluation.

For Australia's reservoirs discovered before June 1988, the "target" for EOR (oil-in-place less reserves) is estimated as 3914 million barrels. Of this, 2346 million barrels is offshore where miscible or immiscible gas processes appear to be most promising. 1568 million barrels is onshore, where miscible/immiscible gas and, in the event of technology improvements, waterflooding with polymers may be applicable. A preliminary and optimistic estimate of economically recoverable oil at current prices is about 709 million barrels.

A major issue of concern is the premature abandonment of existing wells and facilities, which can preclude future EOR opportunities. Governments and industry need to consider how to ensure that oil reserves are not lost because access is impossible due to legislative requirements.

SUMMARY

Project Objectives

- To identify the most likely field prospects for application of improved recovery, including EOR in Australia.

- To assess the additional oil which may be recovered under various improved recovery techniques at selected oil pricing levels.

Main Findings and Conclusions

- The study of EOR applications requires detailed knowledge of reservoir heterogeneity and detailed in-situ behaviour of hydrocarbons. Only general overall conclusions can be made with the limited, general information available on each field in this study, the scarcity of Australian field trials, and the early stage of research into EOR.

- The "residual" or "target" oil-in-place for EOR in discovered Australian fields is:

	Initial Oil-in-Place	Initial Reserves	"Residual" Oil-in-Place
Onshore	2085	517	1568
Offshore	6030	3684	2346
TOTAL	8114	4201	3914

- Primary and secondary recovery is thus expected to produce only 51.8% of the total oil-in-place in discovered reservoirs. Onshore, only 24.8% will be produced. This leaves 3914 million barrels of oil in place or about 20 years' production at Australia's total oil production rate.

- The major perceived scope for EOR in discovered oil fields in Australia lies in miscible gas processes. It is estimated on a very preliminary basis that about 709 million barrels of reserves could be recovered using this process at an oil price of US$20 per barrel. A graph of estimated recoverable oil versus price is shown in Figure 13. However, these results will depend heavily on the availability and cost of miscible gases. Ethane and carbon dioxide are the most readily available; flue gas or nitrogen may be suitable for some deeper reservoirs.

- Polymer and surfactant floods may have applications in some fields where reservoir conditions result in significant bypassing of oil and where waterflood operations are already in progress. Temperature limitations prevent their application in most large Australian fields.

- Because of Australian crude properties, it is unlikely that alkaline flooding or steam flooding will be of major interest in the hitherto discovered oil fields. In-situ combustion of light oils may have applications in remote areas where miscible gases are unavailable.

- Microbiological, electrical and other EOR processes are in their infancy. As research progresses, they may find widespread applications. However, no assessment of their future promise can be made based on current limited field trials.

Work Program Description

Prior to this NERDDC project, no comprehensive database existed which included the basic data relating to all Australian oil fields. Initially, basic data on all Australian oil fields were compiled at the Bureau of Mineral Resources, Geology & Geophysics (BMR) from its own resources including the BMR series "Australian Petroleum Accumulations" (Ozimic & others, 1986, 1987; Lavering & others, 1989; Miyazaki & others, 1987, and in preparation). Then, a series of meetings between the consultants (Thomas Petroleum Consultants and the Centre for Petroleum Engineering, University of New South Wales) and BMR was held to review the data and decide on an appropriate methodology.

It was decided to attempt a comprehensive study of all oil fields which would cover the subject better than a selective, detailed study of a few major, or typical fields. Following this decision, the data sheets setting out available data were sent to oil companies and/or State governments throughout Australia, for correction and updating of the basic data.

As the data were received they were inserted in coded form on a database by the Centre for Petroleum Engineering, University of New South Wales (UNSW). Screening programs based on previous US National Petroleum Council studies were set up by both BMR and UNSW staff to establish the most applicable EOR techniques for each field. Meanwhile, a set of program macros to incorporate economic data was compiled by Thomas Petroleum Consultants, Adelaide. The Centre for Petroleum Engineering tested several US Department of Energy (DOE) programs which were to be used for technical and economic evaluation. The combined technical and economic data were then run through the evaluating program, and the results were assembled by BMR using the DOE programs, spreadsheet data, and macros for spreadsheet manipulation supplied by Thomas Petroleum Consultants and BMR.

Potential for Short Term Industrial Applications

It is intended to circulate this report to oil companies and State governments to outline the perceived, broad-scale potential for EOR. Specific applications for EOR will depend on the perceived economics of EOR in a particular oil field, incorporating reservoir fluid studies and local logistic and economic factors. Wider applications of EOR may follow successful field trials. Interest in EOR has already increased following the significant Cooper Basin EOR project.

RECOMMENDATIONS

- In order to implement the first objective of the study, screening run results for individual fields will be made available to and discussed with the operating company or the government which supplied the data. For reasons of confidentiality, no individual field data are included in this report. Additional screening runs can be carried out for any additional reservoirs including new discoveries.

- Operating companies considering EOR should pursue laboratory tests of individual crudes at reservoir conditions. The results of this study are only broad and indicative, and are not based on detailed crude analyses.

- The economic effects of EOR, particularly if successfully applied in offshore fields, could be substantial. The scope for EOR only exists when wellbores and facilities are still available prior to abandonment. Consideration should be given by government and industry to ways of ensuring that premature abandonment of wellbores and facilities does not occur.

- More research, particularly of a fundamental nature, is required to properly understand and improve EOR processes. Strong support should be given to fundamental studies of the behaviour of crudes in reservoir conditions.

INTRODUCTION

Enhanced oil recovery refers to the additional oil which can be produced from a reservoir above the primary and secondary recovery. Primary recovery refers to the use of natural energy (expansion, gravity, gas or water drive) to produce oil. Secondary recovery refers to the use of additional energy (injection of water or gas) to increase production.

Enhanced oil recovery involves the use of some of the technologies shown in Figure 12.

On 4 April 1986 a workshop was held at the Australian Mineral Foundation in Adelaide under the auspices of the Society of Petroleum Engineers and NERDDC. At this meeting, attended by representatives from oil companies, CSIRO, universities and governments, a need was identified to assess the potential for EOR in Australia.

It was originally anticipated that research would:

- Screen all known Australian petroleum Accumulations to identify those fields that have potential for improving recovery through EOR
- Determine if these fields can be classified by type and if so to select a type specimen
- Describe such selected fields in terms of physical characteristics pertinent to EOR studies
- Determine the best EOR process(es) applicable to the selected fields.
- Determine pricing level at which EOR process might be viable
- Estimate additional oil recoverable through such process
- Consolidate data derived as above to enable an estimate to be made of potential, at different oil price levels, of EOR processes.

Following strong support from industry and some modifications (a type specimen was <u>not</u> used) the project was approved by NERDDC. This report represents the outcome of the project, and is intended to highlight the potential for EOR in Australia.

DATA GATHERING

Compilation of data was the most time-consuming and the most valuable part of the project. Data were received directly from State Mines Departments or oil companies, or compiled by BMR personnel from State or BMR sources. In a few cases, up-to-date data from oil companies were already available. No data were included for discoveries after June 1988, for a few small fields for which insufficient data were available, and some secondary reservoirs in major fields. The result of the compilation is the most comprehensive collection of reservoir data to date for Australian oilfields.

Data included were the minimum necessary to define the fields in the broadest sense, for input to the screening and evaluation models. For example, permeability variations, faulting, and fracturing data could not be included. The data requested is shown in Table 1.

The data are not exact; that is, in many cases values of average formation net thickness have to be altered to achieve a match with oil in place. The data are complete in the sense that all fields have an assigned value for each parameter even when fluid data, or other properties, have to be interpolated from data from similar or nearby fields in the same formation. Average oil saturation after waterflooding was back-calculated from reserves and oil-in-place data.

The compiled results are summarised in Figures 1-11 and in Table 2, which shows median values for Australia as a whole.

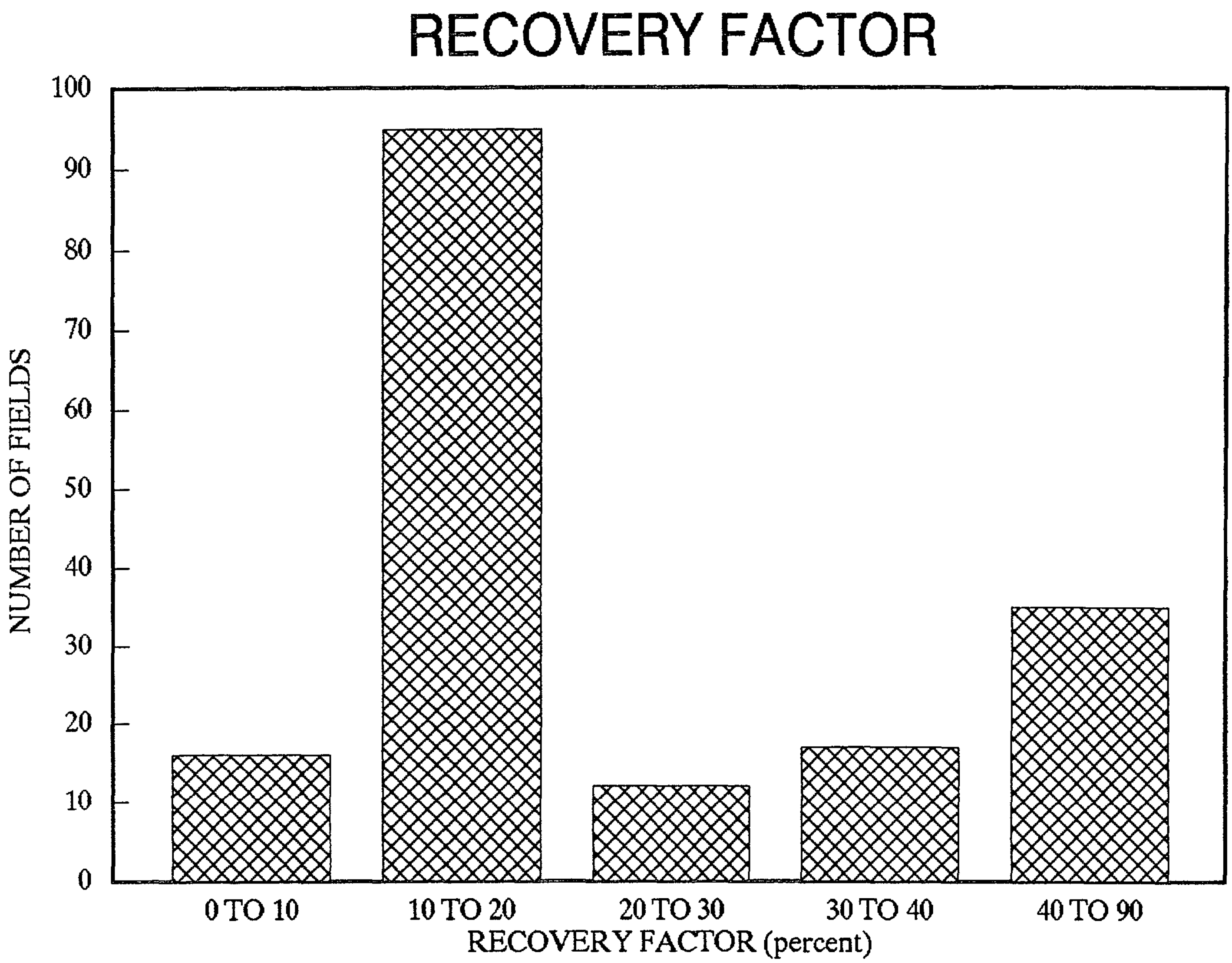


Figure 1. Recovery Factor for Australian Fields

Table 1. Example of technical data input sheet

ACCUMULATION:
STATUS:
BASIN:
FORMATION:
ELEVATION:
CLOSURE AREA:
DEPTH (TOP):
DEPTH (GOC):
DEPTH (OWC):
THICKNESS (GROSS):
THICKNESS (NET):
POROSITY:
PERMEABILITY:
WATER SATURATION:
FORMATION PRESSURE:
TEMPERATURE:
OIL TYPE:
WAX CONTENT:
BUBBLE POINT PRESSURE:
GRAVITY:
POUR POINT:
VISCOSITY:
WATER SALINITY:
WATER RESISTIVITY:
DRIVE MECHANISM:
GAS CAP (YES/NO):
FORMATION VOLUME FACTOR:
GOR:
OIL INITIALLY IN PLACE:
INITIAL RECOVERABLE RESERVES (10^6 m^3):
CUMULATIVE PRODUCTION AS OF 31/12/86 (10^6 m^3):

NOTES:

REFERENCES:

Table 2. Australian Reservoir Median Parameters

Depth	4950 ft
Area	500 acres
Thickness (gross)	33 ft
(net)	17 ft
Porosity	17.5%
Permeability	60 md
Water Saturation	40%
Pressure	2300 psia
Temperature	$195^{o}F$
Oil Gravity	44.5^{o} API
Viscosity	0.85 cp
Recovery Factor	15%

TECHNICAL EVALUATION

1. Current EOR field applications

The first objective of this study is to identify the most likely field prospects for application of improved recovery including EOR in Australia.

A full list of EOR technologies is given in Figure 12, which includes exotic processes which are in the research stage. A technical breakthrough in any of these technologies cannot be ruled out (Carroll & Linville, 1986). However, this study is focused on the currently applied technologies (called the "implemented technology" case), with an "advanced technology" case (with hypothetical future technology improvements) also being considered.

The only Australian field application of EOR as a commercial process is in the Cooper Basin by SANTOS - the very successful ethane flooding of the Tirrawarra and Moorari fields which increased reserves by 10 million barrels (Williams, 1989; Rodda, 1989). A possible EOR project in the Jackson field is also under investigation. A study of EOR possibilities in the Flounder field was carried out at Esso Australia Ltd (Younes, 1987). Cyclic LPG storage by Esso in the Barracouta M-1 oil reservoir in the Gippsland Basin has resulted in improved recovery efficiency by reducing the residual oil saturation (Williams, 1986). Field trials of microbial EOR were undertaken by TMOC in the Alton field in February 1989 (Williams, 1989; Sheehy, 1990). Williams also refers to the gas injection project at the Chookoo field.

In contrast, overseas applications of EOR are now numerous. In the USA over 1200 EOR projects were active in the period 1980-1987 (Tables 4 and 5). As at 1 January 1989, EOR currently contributed 637 000 b/d of crude (or 8% of US oil production) from 366 projects. This is an increase from just over 300 000 b/d since 1980. Other projects are active in Venezuela (216 000 b/d), Canada (148 000 b/d of which hydrocarbon miscible projects contribute 115 000 b/d), and other countries shown in Table 4. Other countries not listed, including Japan, France, West Germany, Denmark and Norway, either have active projects or pilot studies in progress.

Most of the EOR production in the US is contributed by thermal EOR, particularly in California where heavier crudes are common (the Shell Oil Bembridge project produces 101,000 b/d alone). Carbon dioxide miscible flooding predominates in the Permian Basin of Texas.

2. Potential EOR processes for Australia

Typical reservoir properties for actual field applications of EOR methods are shown in Table 3. Median Australian properties are shown for comparison.

It is significant that a wide variety of process types are in operation overseas, even in small countries, reflecting the wide variations of reservoir and fluid types and the availability of flooding agents. Details of these projects

Table 3. Typical Reservoir Properties for Field Applications of EOR methods (National Petroleum Council, 1984)

1.	**CO_2 floods (major projects)**	**Depth**	**Porosity**	**Permeabilty**	**Net-pay**	**Oil Viscosity**
		Feet	**%**	**md**	**ft**	**cp**
	Median	5250	17	12.5	87.5	0.8
	Range	2000-10750	7-23	5-75	30-213	0.4-2.0
2.	**Alkaline floods**	**Permeability**	**API**	**Viscosity**	**Temp**	**Reservoir Salinity**
		md	**Gravity**	**cp**	**^oF**	**ppm TDS**
	Median	208	24	8	120	22000
	Range	19-2470	13-43	0.5-100000	70-220	2580-190000
3.	**Surfactant floods**	**Permeability**	**API**	**Viscosity**	**Temp**	**Reservoir Salinity**
		md	**Gravity**	**cp**	**^oF**	**ppm TDS**
	Median	120	36	5	77	50000
	Range	4-2500	4-45	0.32-25	55-200	2300-160000
4.	**Polymer floods**	**Permeability**	**API**	**Viscosity**	**Temp**	**Reservoir Salinity**
		md	**Gravity**	**cp**	**^oF**	**ppm TDS**
	Median	70	34	3.7	106	94000
	Range	1-2470	16-57	0.07-172	60-234	1200-177000
5.	**Australian median values values (from Table 3)**	**Permeability**	**API**	**Viscosity**	**Temp**	**Net Pay**
		md	**Gravity**	**cp**	**^oF**	**ft**
		60	44.5	0.85	195	17

can be found in the excellent biennial EOR summaries found in the International Petroleum Encyclopedia. The screening process, described below, covers only the discovered oil in Australia, although the potential for EOR also includes oil in future extensions of discovered fields and future discoveries. However, the process types suitable for discovered oil may not extrapolate to future discoveries, which may be in fields with different properties from the trend in discovered fields.

Table 4. Some Worldwide Active EOR Projects, 1988 (International Petroleum Encyclopedia, 1989)

Country	**Types**
Austria	Caustic, steam
Canada	Alkaline, CO2, caustic, caustic-polymer, in-situ combustion, electromagnetic heating, foam, hydrocarbon, polymer, steam
Colombia	Steam
Congo	Steam
England	Micellar-polymer
France	Micellar-polymer, polymer, steam
Hungary	CO2, in-situ combustion
Indonesia	Micellar-polymer, steam
Trinidad	CO2, steam
USA	Steam, in-situ combustion, hot water, micellar-polymer, polymer, caustic/alkaline, hydrocarbon miscible, CO2, nitrogen, flue gas, carbonated waterflood
Venezuela	Gas, steam
West Germany	Hot water, polymer, steam surfactant

The screening criteria considered were as follows.

(1) National Petroleum Council, 1976 (see Bibliography and Table 6).

(2) Brashear and Kuuskraa, 1978 (see Bibliography).
(3) National Petroleum Council, 1984 (see Bibliography and Table 7) - Implemented Technology Case.

(4) National Petroleum Council, 1984 (see Bibliography and Table 8) - Advanced Technology Case.

(5) Carbon dioxide miscibility criteria (see Table 9).

It was decided to use criteria (3) and (5), with (4) (a hypothetical case with future research advances) as a sensitivity.

Table 5. US EOR Projects (Thomas & others, 1989)

Process	**Total Number (as at 1st January 1987)**	**Started 1980-1986 Inclusive**	**Production Share**
Steam	415	177	} 79%
In-situ Combustion	87	19	}
Surfactant (micellar-polymer)	87	31	} 3%
Polymer	330	259	}
Alkaline	54	25	}
Miscible/immiscible fluid displacement*	276	194	} 18%
Microbial, other	15	3	-
	1264	708	100%

*Includes carbon dioxide miscible, carbon dioxide immiscible, nitrogen, hydrocarbon gas.

Table 6. Criteria for EOR Candidates
(National Petroleum Council, 1976)

		Chemical Flooding Processes			Miscible Processes	Thermal Processes	
Screening Parameters	Units	Surfactant	Polymer	Alkaline	Carbon Dioxide	Steam	In-Situ Combustion
Oil Gravity	°API	>25	--	>35*	>27*	<25	<25
Oil Viscosity, ( )	cp	<30*~	<200	<200	<10	>20	>20
Depth (D)	Feet	--~	--	--	>2,300*	>200<5000*	>5,000*
Zone Thickness (h)	Feet	--	--	--	--	>20	>10
Temperature	°F	<250	<200	<200	<250*	--	--
Permeability, Average (K)	md	>20~	>20	--	--	--	
Transmissibility (Kh/)	md-ft/cp	--	--	--	--	>100	>20
Salinity of formation brine (TDS)	ppm	<200,000	--*	--*	--	--	--
Minimum oil saturation at start of process In water-swept zones (S_{orw})	fraction	>.20*	--	--	--	--	--
Mobile (S_{or}-S_{orw})	fraction	--	>.10				
Minimum Oil Content at start of process (S_{or})	B/AF	--	--	--	--	>500	>500
Rock Type	--	sandstone	--	sandstone	sandstone or carbonate	sandstone or carbonate	sandstone
Other	--	#	#	#	#	#	#

For footnotes see National Petroleum Council, 1976.

Table 7. Criteria for EOR Candidates - Implemented Technology Case
(National Petroleum Council, 1984)

Screening Parameters*	Units	Chemical Flooding: Surfactant	Chemical Flooding: Polymer	Chemical Flooding: Alkaline	Miscible Flooding (Carbon Dioxide)	Thermal Recovery: Steam	Thermal Recovery: In-Situ Combustion
Oil Gravity	^{o}API	--	--	< 30	>25	10 to 34	10 to 35
In Situ Oil Viscosity ( )	cp	< 40	<100	< 90	--	<15,000	< 5,000
Depth (D)	Feet	--	--	--	--	< 3,000	<11,500
Pay Zone Thickness (h)	Feet	--	--	--	--	> 20	> 20
Reservoir Temperature (T_R)	^{o}F	<200	<200	<200	--	--	--
Porosity (o)	Fraction	--	--	--	--	> 0.20#	>0.20#
Permeability,Average (k)	md	> 40	> 20	> 20	--	> 250	35
Transmissibility (kh/)	md-ft/cp	--	--	--	--	> 5	> 5
Reservoir Pressure (P_R)	psi	--	--	--	>MMP~	< 1,500	< 2,000
Minimum Oil Content at Start of Process (S_o x o)	Fraction	--	--	--	--	> 0.10	> 0.08
Salinity of Formation Brine (TDS)	ppm	<100,000	<100,000	<100,000	--	--	--
Rock Type	--	Sandstone	Sandstone or Carbonate	Sandstone	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate

For footnotes see National Petroleum Council, 1984.

Table 8. Criteria for EOR Candidates - Advanced Technology Case (National Petroleum Council, 1984)

Screening Parameters*	Units	Chemical Flooding: Surfactant	Chemical Flooding: Polymer	Chemical Flooding: Alkaline	Miscible Flooding (Carbon Dioxide)	Thermal Recovery: Steam	Thermal Recovery: In-Situ Combustion
Oil Gravity	^{o}API	--	--	< 30	> 25	--	--
In Situ Oil Viscosity ( )	cp	<100	<150	<100	--	--	<5,000
Depth (D)	Feet	--	--	--	--	<5,000	--
Pay Zone Thickness (h)	Feet	--	--	--	--	> 15	> 10
Reservoir Temperature (T_R)	^{o}F	<250	<250	<200	--	--	--
Porosity (o)	Fraction	--	--	--	--	> 0.15#	> 0.15#
Permeability, Average (k)	md	> 10	> 10	> 10	--	> 10	> 10
Transmissibility (kh/)	md-ft/cp	--	--	--	--	--	--
Reservoir Pressure (P_R)	psi	--	--	--	>MMP~	<2,000	<4,000
Minimum Oil Content at Start of Process (S_o x o)	Fraction	--	--	--	--	> 0.08	> 0.08
Salinity of Formation Brine (TDS)	ppm	<200,000	<200,000	<200,000	--	--	--
Rock Type	--	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate

For footnotes see National Petroleum Council, 1984.

3. Thermal methods

The potential for thermal recovery arises in the context of heavy crude oils which cannot be produced at the original reservoir pressure and temperature. The viscosity of the oil can be dramatically decreased by raising the reservoir temperature, thereby enabling the oil to flow more readily towards the producing well. The heat is provided by steam or hot water injection, or by burning some of the oil in place (in-situ combustion). Steam injection is the predominant form of thermal recovery.

3.1 Steam flooding

The reservoir is usually steam stimulated (by alternately injecting and producing steam in the same well) to increase injectivity before a steam drive commences. The steam drive itself consists of continuous injection into one well and production from surrounding wells. Very high recovery factors can be achieved because of the creation of a light solvent bank by the steam. However, close well spacings (of the order of five acres) are required to ensure effective heating of a large portion of the inter-well volume.

3.2 In-situ combustion

If air is injected into an oil reservoir, the oil near the wellbore can ignite (or be ignited) and burn. As more air is injected, the burning zone moves through the reservoir away from the well, distilling the oil ahead of it. The burning oil forms combustion gases and vaporises water in the reservoir to form steam. The burnt portion of the oil is mainly coke - the rest being distilled by the heat. In order to control the burning process, water injection is combined or alternated with air injection.

3.3 Applicability

In general, thermal processes are most applicable to those reservoirs which contain heavy oil. A typical criterion is an API gravity between 10 and 35^{o} API (Table 7). As almost all Australian crude oils are lighter than this (Figure 4), the process would not seem to be applicable to Australian crudes. The pay zone thickness minimum (20 feet) is also a major limitation (Figure 8), as is the porosity (minimum 20%) (Figure 5). However, the possibility of in-situ combustion of light oils has recently been proposed as an effective EOR method for remote areas, where the cost of importing chemicals could be prohibitive.

One advantage of thermal methods is that the cost of heating is tied to the cost of oil, so that when the price of oil decreases the cost of heating also decreases.

4. Chemical methods

Chemical EOR (including polymer flooding, surfactant flooding,and alkaline flooding) is used to lower the viscosity or interfacial tension of oil, or to increase the swept volume of the reservoir. In general, chemical costs can increase independently of the price of oil, so the process economics need to be carefully scrutinised.

4.1 Polymer flooding

The objective of polymer flooding is to increase the viscosity of injected water to increase the sweep efficiency during the displacement of oil by water. Water-soluble polymers, either synthetic or biologically produced, are mixed with injection water. The polymer may also have the effect of reducing the permeability of the formation to water, which also improves the sweep efficiency.

4.2 Surfactant flooding

The objective of surfactant flooding is to reduce the interfacial tension between oil and water, although the formation of emulsions is also important. Surfactants, such as sulphates and sulphonates, are mixed with polymers and the surfactant slug is injected into the reservoir followed by drive water.

4.3 Alkaline flooding

The objective of alkaline flooding is to create a reaction between injected alkaline chemicals and crude oil. The reaction forms surfactants which can reduce interfacial tension, alter the formation wettability and result in emulsification of oil.

4.4 Applicability

In general, the polymer flooding process is limited by conditions which tend to destroy the polymer, or decrease its effectiveness. Salinity reduces the mobility improvement resulting from polyacrylamide flooding. Temperature combined with divalent cations can reduce the stability of both polysaccharides and polyacrylamides. Although most Australian formation waters are very fresh the temperature maximum of 200^{o} limits the applicability of the process (Figure 3). Polymer flooding is ideally suited to reservoirs where the waterflood sweep efficiency is low. It does not decrease the residual oil saturation in the swept volume.

Alkaline flooding requires a highly acidic crude. The acid number, which measures the surface active material content of oil, is related to the crude gravity. This must be less than 30^{o} API in order to have an acid number high enough to ensure effective alkaline flooding performance. As nearly all Australian crudes are lighter than 30^{o} API (Figure 4), the apparent possibility of using alkaline floods is limited.

Surfactant flooding is also limited to fields with temperatures less than 200^{o} F, as the polymers used with the surfactant are not stable above this temperature (Figure 3).

5. Miscible and immiscible flooding

Injection of miscible gases into a reservoir can theoretically result in the recovery of essentially 100% of the contacted oil-in-place. The miscible fluid is either directly miscible with the oil in the reservoir, or extracts components from the oil which forms a bank of liquid miscible with both the reservoir and the injected fluid. The major fluids used are carbon dioxide, hydrocarbon gases and LPG, and nitrogen (for deep, high pressure reservoirs). Immiscible flooding with carbon dioxide is also used, as even without miscibility, carbon dioxide swells the oil and reduces its viscosity. Miscible floods are often alternated with water floods to improve the sweep efficiency of the process, as the miscible fluid is generally less viscous than the oil and tends to "finger" through the oil, giving a sweep efficiency much less than 100%.

5.1 Applicability

Carbon dioxide miscible flooding depends on the availability of a large volume carbon dioxide source - either a carbon dioxide reservoir, or from flue gas or separator gas or by burning oil. In addition, the reservoir temperature, pressure and oil composition must be such that the oil can be miscibly displaced. High pressures and light oils promote miscibility. Shallow reservoirs with low initial reservoir pressure may require hydrocarbon gas mixtures to achieve miscibility. Higher pressure reservoirs may allow miscibility with mixtures of carbon dioxide and nitrogen, as in flue gas, or with nitrogen alone (Figure 2).

5.2 Screening for miscible methods

Considerable research effort has been put into determining the conditions for miscibility of carbon dioxide and other fluids with oil. These conditions are normally in the form of "minimum miscibility pressures" as a function of fluid composition and reservoir temperature. As a general comment, it appears that other factors than temperature, pressure and fluid composition may play an important role in determining whether miscibility (and possible lowering of the residual oil saturation) can be achieved. All the reservoirs in the database were screened using eight the most applicable (numbers 1, 2, 3, 5, 6, 7, 8 and 11) of the eleven correlations listed in Table 9. A "majority vote" from the correlations for miscibility was used as the criterion for the suitability of miscible flooding. For further information and details of the references, contact Mr

Table 9. Carbon Dioxide Flooding Criteria (For references, contact Centre for Petroleum Engineering, UNSW)

1 : Glaso (1985)

(1) Molecular weight of C7+
(2) Temperature (deg.F)
(3) Fraction of C2 - C6 in reservoir oil

Constraints :-
no constraints given

2 : Johnson & Pollin (1981)

(1) Injection gas critical pressure (psia)
(2) Molecular weight of oil
(3) Injection gas critical temperature (Kelvin)
(4) Molecular weight of injection gas
(5) Oil API Gravity
(6) Mole fraction of diluting component (impurity) in injection gas
(7) Reservoir temperature (Kelvin)

Constraints :-
(1) 300.le.temp(K).le.410
(2) Less than 10% impurity in injection gas
(3) Impurity consisting only of c1 &/or n2

3 : Nat. Pet. Council (1976)

(1) Oil API Gravity
(2) Temperature (deg.F)

Constraints :-
Temp. < 250 deg.F

4 : Cronquist (1978)

(1) temperature (deg.K)
(2) Molecular weight of C5+
(3) Percentage of methane and nitrogen in the injection gas

Constraints :-
no constraints given

(continued...)

5 : Pet. Rec. Inst. (1979)

(1) temperature (deg.C)
(2) Oil normal boiling point (MPa)

Constraints :-
MMP < Bubble Pt of oil

6 : Alston et al (1985)

(1) Molecular weight of C5+
(2) Fraction of Volatile components (C1 & N2) in the reservoir oil
(3) Intermediate fraction (C2 - C4, CO2 & H2S) in the reservoir oil
(4) Temperature (deg.F)
(5) Psuedocritical temperature of the injection gas (weight av.) (deg.F)

Constraints :-
(1) Use Critical temperature for C2 and H2S of 585 Deg.R in psuedocritical temperature calculation.
(2) MMP < Bubble pt of oil

7 : Yellig & Metcalfe (1980)

(1) Temperature (deg.F)

Constraints :-
(1) 100 Deg.F .le. Temp .le. 190 Deg.F

8 : Holm & Josendal (1974) / Mungan (1981)

(1) Temperature (deg.F)
(2) Molecular Weight of C5+

Constraints :-
Overall - (1) 180 .le. MWC5+ .le. 340

Individual -
* MWC5+ = 340
100 deg.F .le. temp .le. 140 deg.F

* MWC5+ = 300
100 deg.F .le. temp .le. 150 deg.F

* MWC5+ = 280
100 deg.F .le. temp .le. 160 deg.F

* MWC5+ = 260
100 deg.F .le. temp .le. 160 deg.F

* MWC5+ = 240
90 deg.F .le. temp .le. 170 deg.F

* MWC5+ = 220
90 deg.F .le. temp .le. 190 deg.F

(continued...)

* MWC5+ = 200
  90 deg.F .le. temp .le. 220 deg.F

* MWC5+ = 180
  100 deg.F .le. temp .le. 240 deg.F

9 : Holm & Josendal (1982)

(1) Temperature (deg.F)
(2) Percent of C5 - C30 in C5+ fraction
(3) Density of pure Carbon Dioxide (g/cc)

Constraints :-
(1) 50% .le. (C5 - C30) / C5+ .le. 90%
(2) 65 bar .le. Pressure .le. 500 bar
(3) 290 Kelvin .le. temp .le. 440 Kelvin

10 : Orr & Silva (1985)

(1) Carbon Number
(2) Weighted partition coefficient
(3) Carbon Dioxide density (g/cc)
(4) Temperature (deg.F)

Constraints :-
(1) 65 bar .le. Pressure .le. 500 bar
(2) 290 Kelvin .le. temp .le. 440 Kelvin
(3) Require wt % for C2 to C37

11 : Enrick (1988)

(1) Temperature (deg.C)
(2) Molecular wt. of C5+ in reservoir oil

Constraints :-
(1) 5 MPa .le. Pressure .le. 30 Mpa
(2) 35 deg.C .le. temp .le. 115 deg.C
(3) 156 .le. mwc5+ .le. 256

J. Hand at the Centre for Petroleum Engineering, UNSW.

Other miscible gases and immiscible floods were not explicitly considered in this screening process. However, ethane, or ethane enriched with LPG, is a possible and available flooding agent in many parts of Australia. It was assumed the oils miscible with carbon dioxide would also be miscible with appropriately enriched ethane.

6. Comments on technical screening

The results of screening runs for each field are available only to operating oil companies or to the State Mines Department which supplied the data. Because of confidentiality requirements the data are not available to any other parties.

Table 10 shows the "target" oil in place for each process using the 1984 NPC "implemented technology" screening criteria. The "target" is the total oil-in-place remaining, after extraction of primary and secondary reserves, in reservoirs for which a given process appears applicable. Only a fraction of the "target" oil-in-place can be recovered because of the limited sweep efficiency for each process and, in the case of polymer flooding, the inability of the process to reduce residual oil saturation. Table 11 shows the same data for the 1984 NPC "advanced technology" case.

In Tables 10 and 11, in addition to the screening parameters listed, reservoirs were excluded:

(1) from the miscible flooding total, if a large gas cap existed (some exceptions were made in specific cases);

(2) from the polymer, surfactant and alkaline total, if strong or moderate water drive existed.

6.1 Miscible gas processes

Miscible processes apply to the largest "target" oil-in-place of any process. Some Australian crudes cannot achieve miscibility with carbon dioxide at reservoir temperature and pressure. However, because of the difficulty in reliably determining miscibility criteria theoretically, laboratory tests should be used to confirm or exclude miscibility.

The results of this study refer to miscibility with carbon dioxide only. Miscibility with other flooding agents (such as ethane) have not been checked.

Note that <u>immiscible</u> gas floods are also common in the United States. No estimate of the recovery from these processes, which may have considerable potential, is made in this study.

6.2 Chemical flood processes

Note that polymer and surfactant flooding have approximately the same "target oil-in-place, because of similar screening criteria. The temperature limitations result in the process being inapplicable to most offshore reservoirs, so "target" oil-in-place is smaller than for miscible flooding.

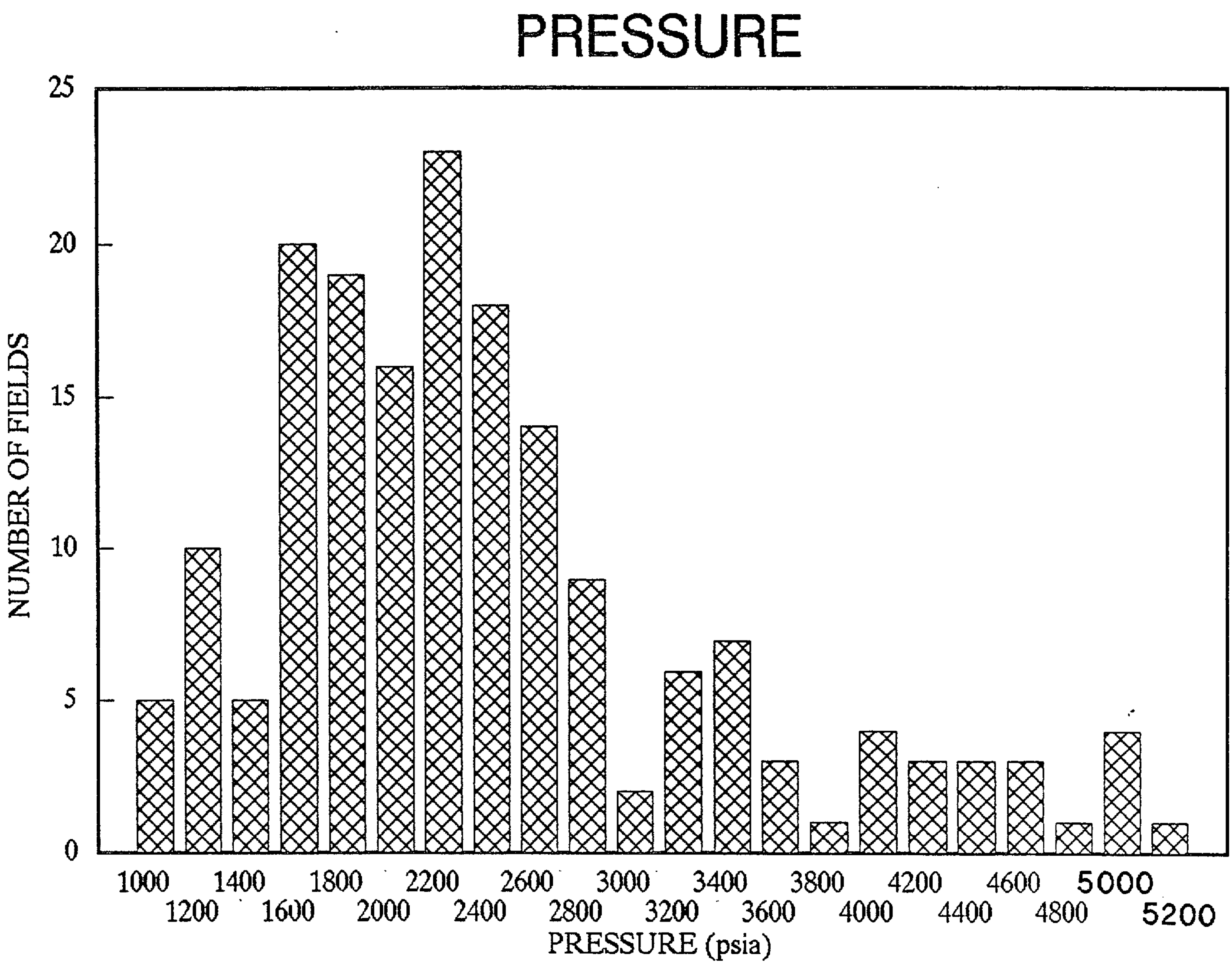
Alkaline flooding is unsuitable, based on API gravity correlations, for most Australian crudes, resulting in a low "target" oil-in-place. However, specific tests of crudes have not been carried out to check this assertion.

6.3 Thermal processes

The "target" oil-in-place for both steam and in-situ flooding applies only to a very small group of relatively heavy oil reservoirs. However, as mentioned previously, thermal EOR may not necessarily be unsuitable for light oils. It may be appropriate in the future for remote applications where other flooding agents are difficult to import.

6.4 General comments

Note that most Australian reservoir have moderate permeabilities (Figure 6) but also have very low in-situ oil viscosities (Tables 2 and 3). Most of the oil-in-place is however concentrated in very high permeability offshore reservoirs, with strong water drive. The median recovery factor is very low (15%) compared to the oil-in-place weighted average (51.8%). The reason appears to be that the drive mechanisms (Figure 11) are insufficient, in spite of the low crude viscosity, to achieve high recovery factors. As a result, additional secondary recovery (waterflooding or gas injection) combined with infill drilling may have some economic benefits. Secondary recovery is still relatively rare in Australia.

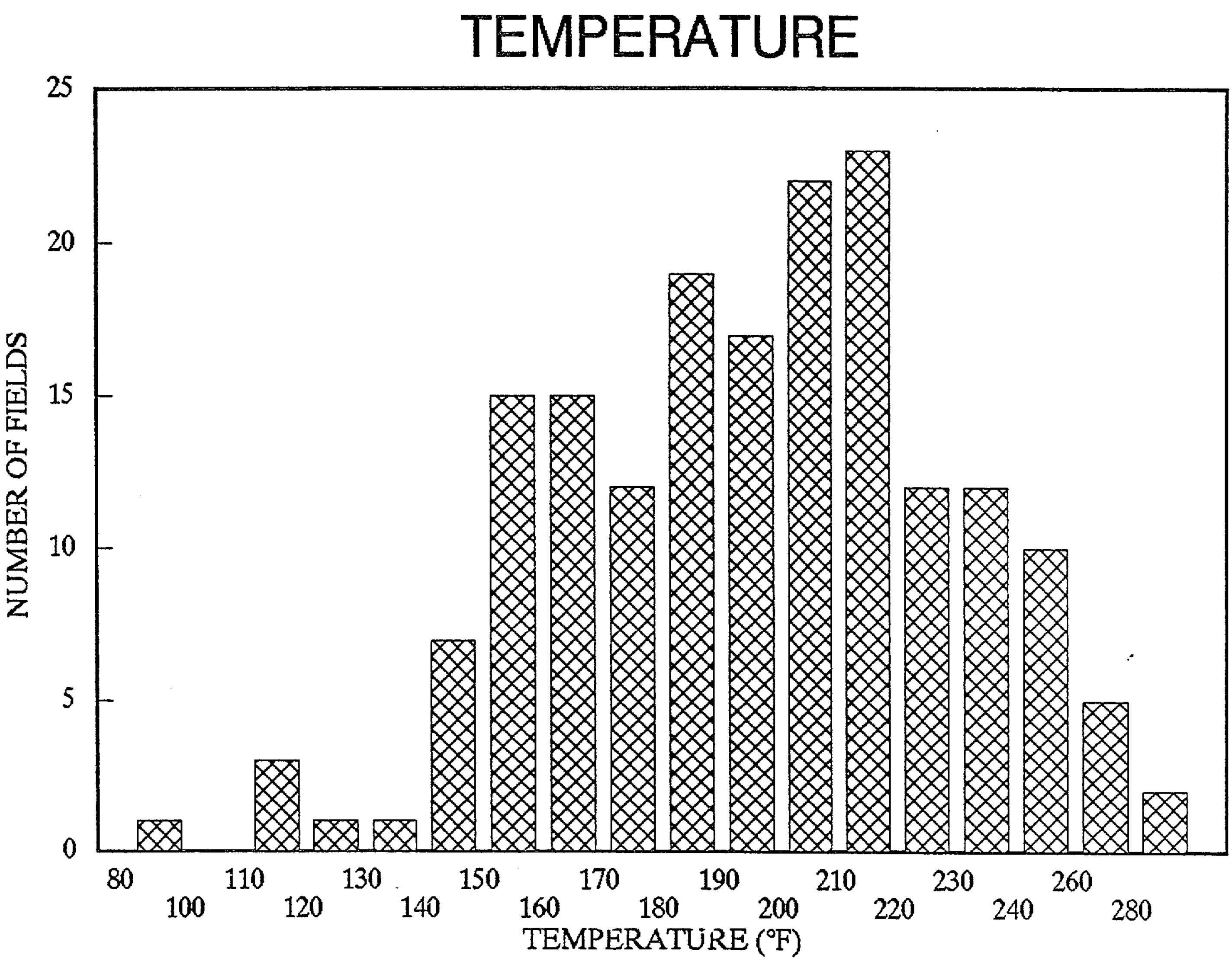


EOR Screening Criteria for Reservoir Pressure

Case	Process	Criteria
Implemented Technology	Steam	< 1500 psia
	In-situ Combustion	< 2000 psia
	(CO_2) Miscible	Minimum Miscibility Pressure*
Advanced Technology	Steam	< 2000 psia
	In-situ Combustion	< 4000 psia
	(CO_2) Miscible	Minimum Miscibility Pressure*

*Minimum miscibility pressure depends on oil composition and temperature.

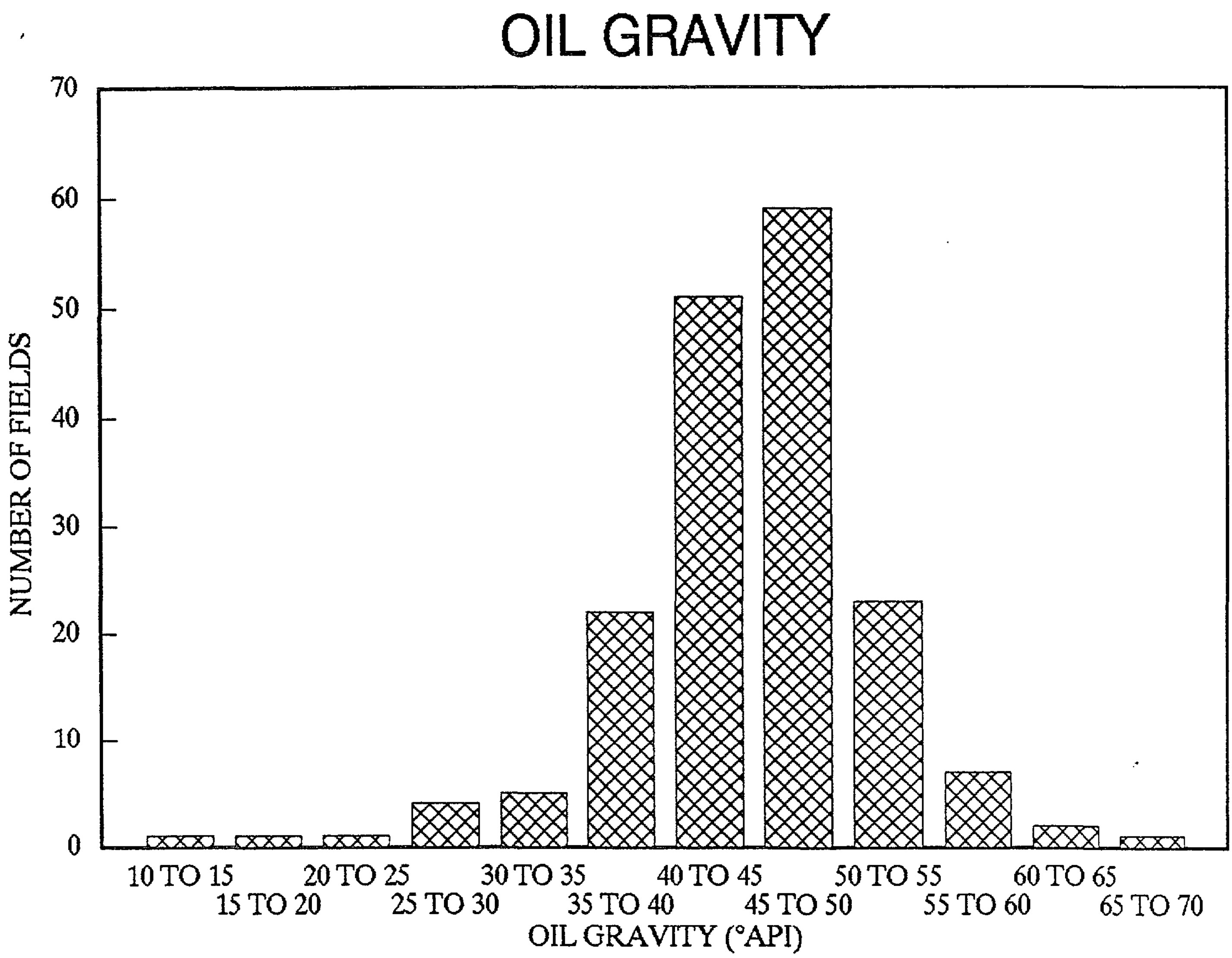
Figure 2. Reservoir Pressure.



EOR Screening Criteria for Reservoir Temperature

Case	**Process**	**Criteria**
Implemented Technology	Surfactant, Polymer, Alkaline	< 200°F
Advanced Technology	Surfactant, Polymer, Alkaline	< 250°F < 200°

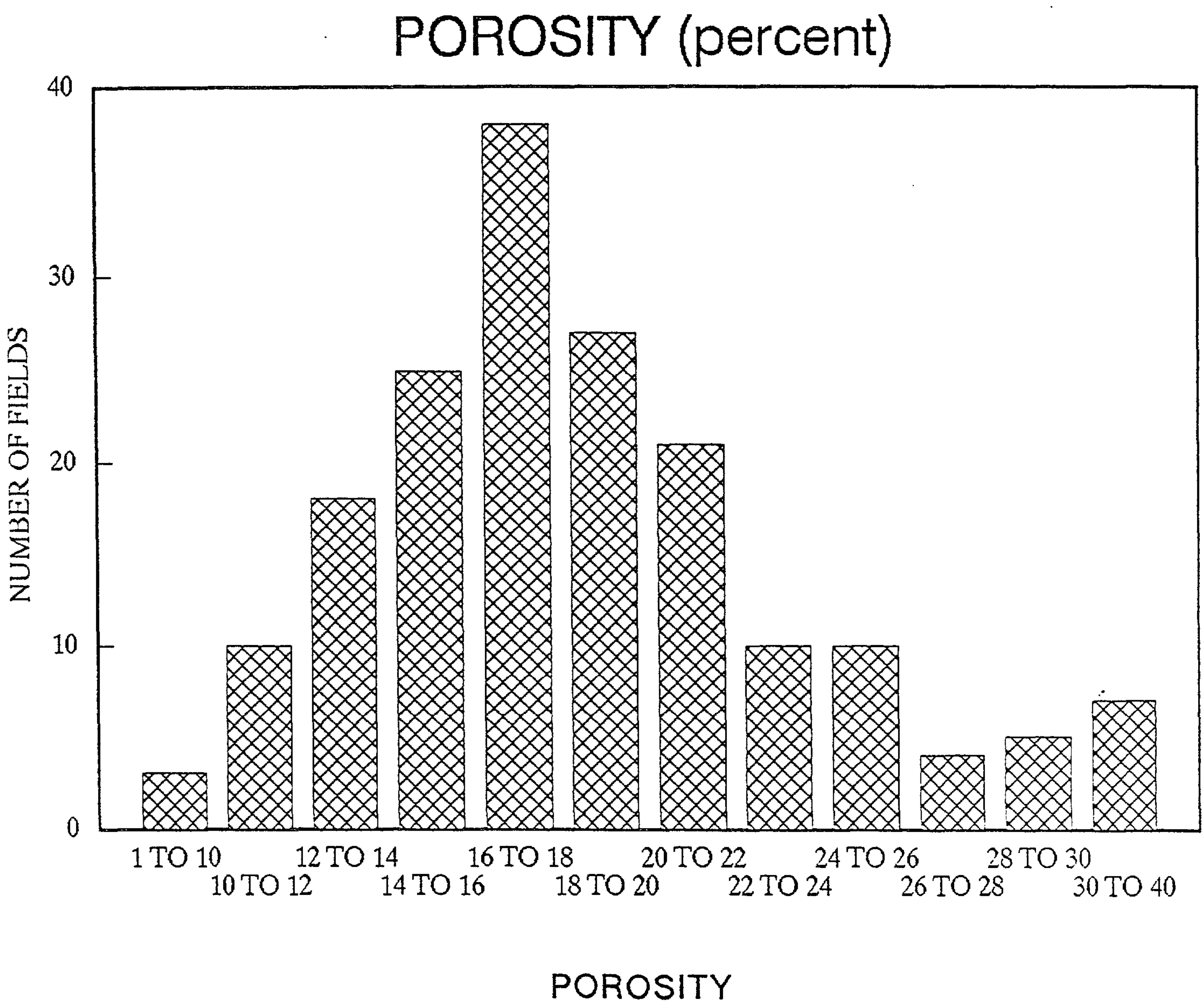
Figure 3. Reservoir Temperature.



EOR Screening Criteria for Oil Gravity

Process	**Criteria**
Alkaline	$< 30^{\circ}$ API
Miscible (CO_2)	$> 25^{\circ}$ API
Steam	10-34° API
In-situ Combustion	10-35° API

Figure 4. Oil Gravity.

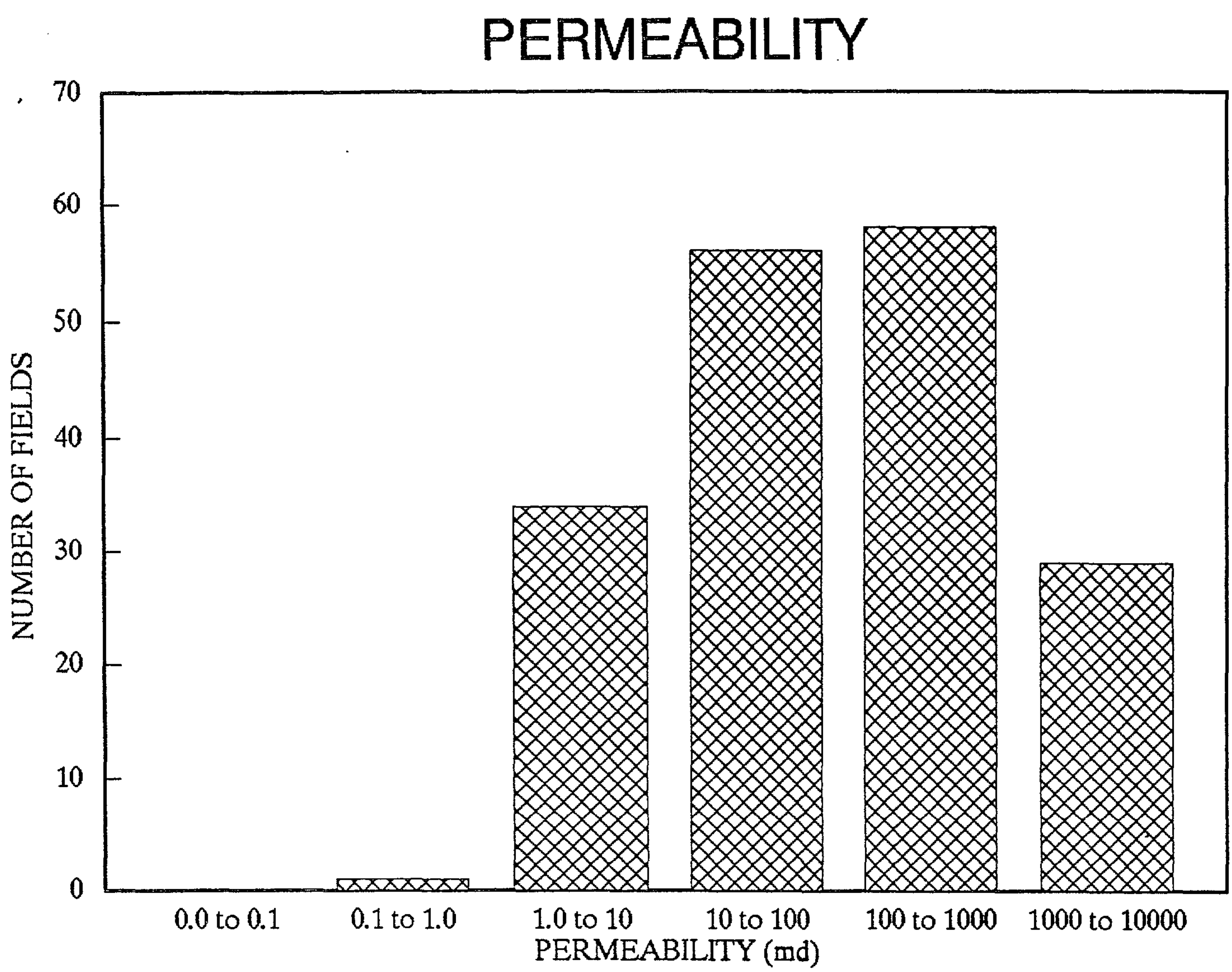


EOR Screening Criteria for Porosity*

Case	Process	Criteria
Implemented Technology	Steam In-situ Combustion	> 20%
Advanced Technology	Steam In-situ Combustion	> 15%

*These criteria are ignored if the oil saturation x porosity criteria are satisfied.

Figure 5. Porosity.



EOR Screening Criteria for Permeability

Case	Process	Criteria
Implemented Technology	Surfactant Polymer	> 40 md
	Alkaline	> 20 md
Advanced Technology	Surfactant Polymer	> 10 md
	Alkaline	> 10 md

Figure 6. Permeability.

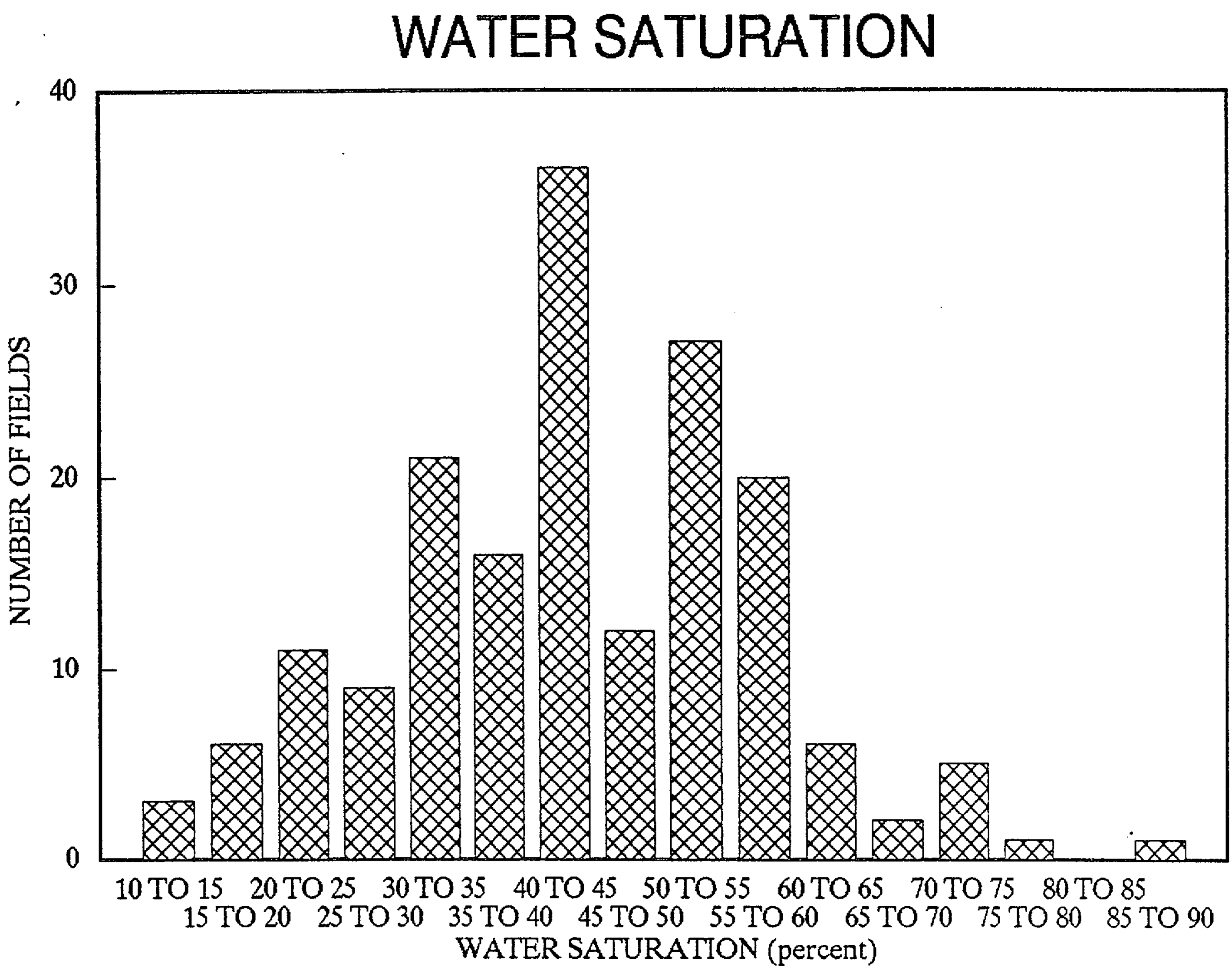
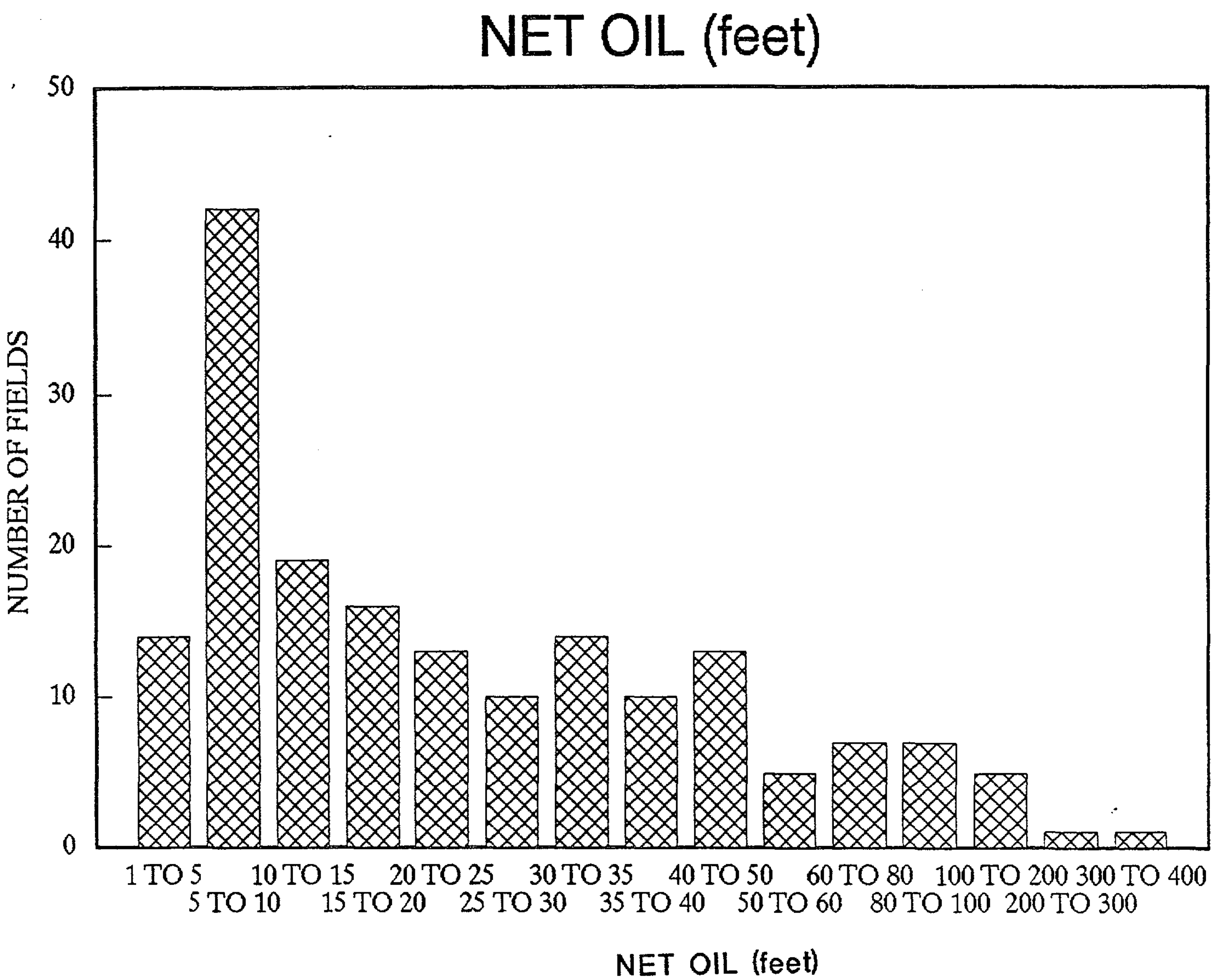


Figure 7. Water Saturation.



EOR Screening Criteria for Pay Zone Thickness

Case	Process	Criteria
Implemented Technology	Steam	> 20 ft
	In-situ Combustion	> 20 ft
Advanced Technology	Steam	> 15 ft
	In-situ Combustion	> 10 ft

Figure 8. Net Oil Sand.

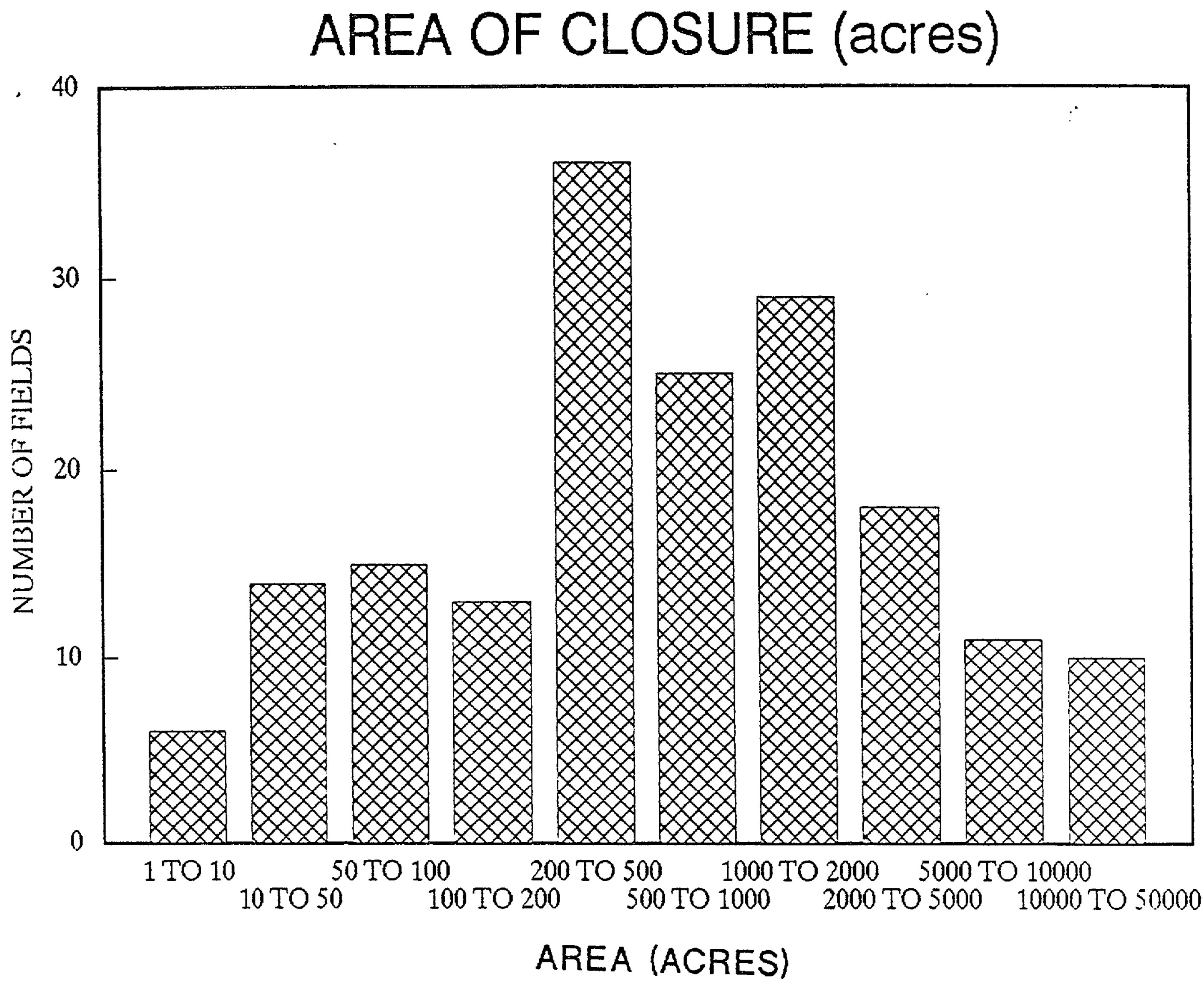
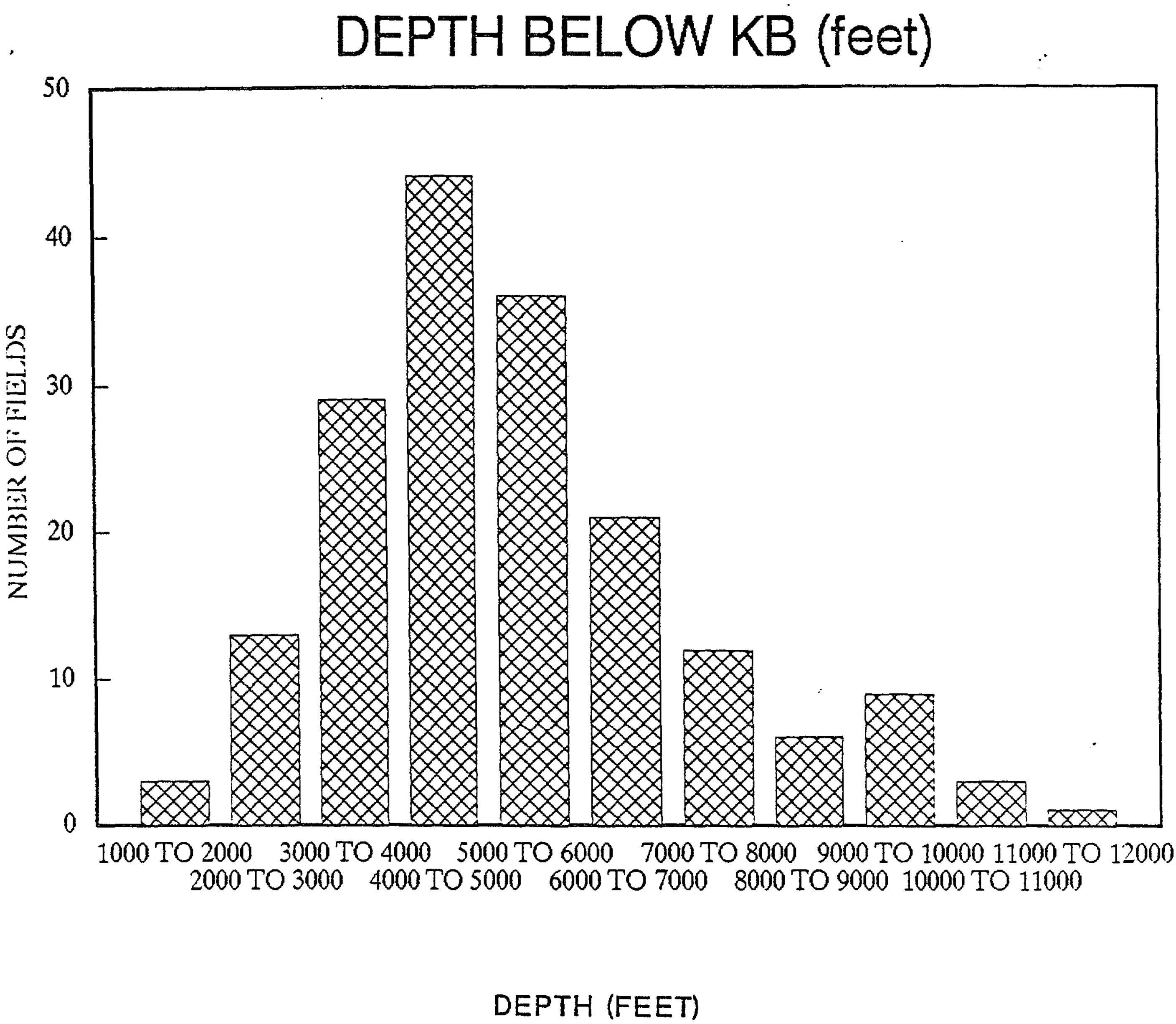


Figure 9. Area of Closure.



EOR Screening Criteria for Depth

Case	Process	Criteria
Implemented Technology	Steam	< 3000 ft
	In-situ combustion	< 11500 ft
Advanced Technology	Steam	< 5000 ft
	In-situ combustion	-

Figure 10. Reservoir Depth.

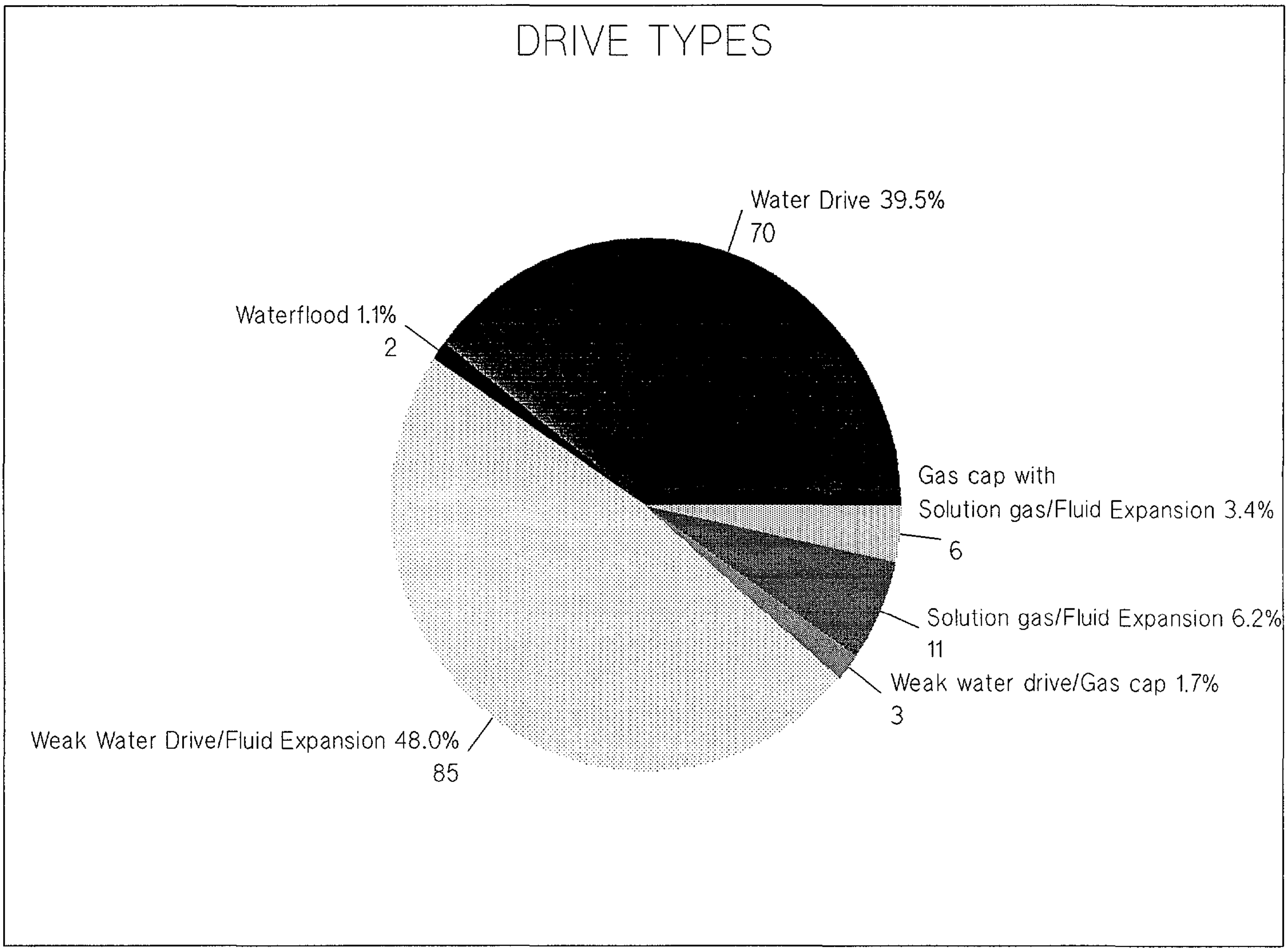

DRIVE TYPES
Water Drive 39.5%
70
Waterflood 1.1%
2
Gas cap with
Solution gas/Fluid Expansion 3.4%
6
Solution gas/Fluid Expansion 6.2%
11
Weak water drive/Gas cap 1.7%
3
Weak Water Drive/Fluid Expansion 48.0%
85

Figure 11.

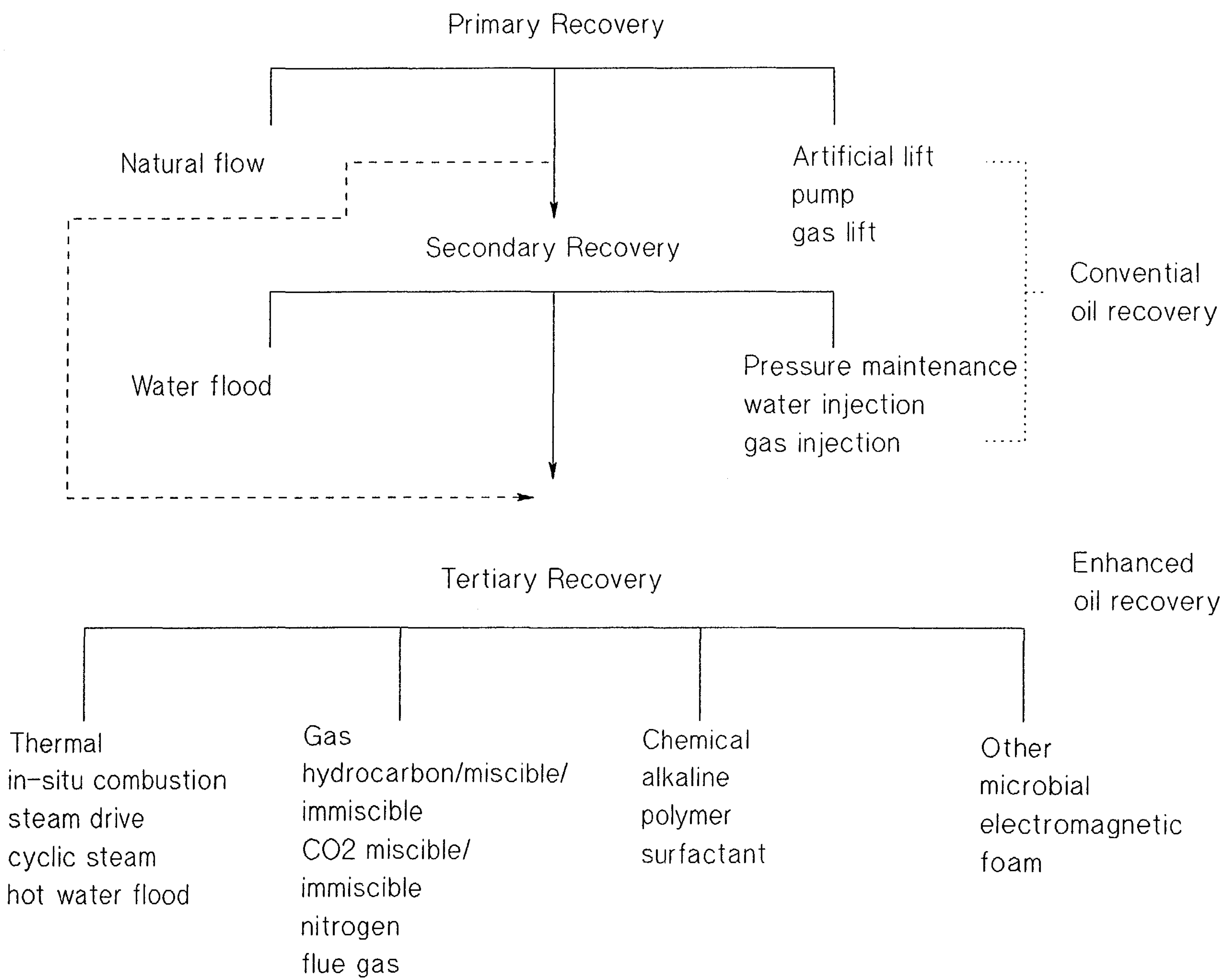


Figure 12. EOR Technologies.

Table 10. Target Oil for Implemented* Technology Case (million stock tank barrels)

Process & (number of applicable reservoirs)	**Original oil-in-place in applicable reservoirs**	**Primary/Secondary reserves in applicable reservoirs**	**"Target" oil-in place**
Miscible gas flooding** (78)	5904	3602	2302
Surfactant flooding (35)	277	358	219
Polymer flooding (39)	292	61	231
Alkaline flooding (2)	3	1	2
Steam flooding (2)	9	4	5
In-situ Combustion (2)	9	4	5
Cumulative Total Target Oil (Single process per reservoir)			
Miscible gas flooding (78)	5904	3602	2302
Polymer flooding (23)	151	12	139
Others (0)	-	-	-
No process applicable (76)	2059	587	1471
TOTAL AUSTRALIAN OIL-IN-PLACE	8114	4201	3913

* Current technology limits (see Table 6)

** Assumes carbon dioxide or equivalent miscibility

Table 11. Target Oil for Advanced* Technology Case (million stock stock tank barrels)

Process & (number of applicable reservoirs)	**Original oil-in-place in applicable reservoirs**	**Primary/secondary reserves in applicable reservoirs**	**"Target" oil-in place***
Miscible gas flooding** (78)	5904	3602	2302
Surfactant flooding (74)	560	106	454
Polymer flooding (74)	560	106	454
Alkaline flooding (2)	3	1	2
Steam flooding (25)	291	117	174
In-situ Combustion (44)	6165	3675	2490

* Hypothetical future technology advances (see Table 7)

** Assumes carbon dioxide or equivalent miscibility

ECONOMIC EVALUATION

Technical/Economic Models Used

The second objective of the study is to assess the additional oil which may be recovered under various improved recovery techniques at selected oil pricing levels. For this purpose, five predictive models were made available to BMR. These models were developed by Scientific Software-Intercomp for the US Department of Energy, and were used in the National Petroleum Council's 1984 survey of US EOR potential. These models are listed below.

(1) The Carbon Dioxide Miscible Flood Predictive Model
(2) The Chemical Flood Predictive Model
(3) The Polymer Flood Predictive Model
(4) The Steamflood Predictive Model
(5) The In-situ Combustion Predictive Model.

In each of the models, an oil rate versus time function for a single pattern is computed using theoretical simulation techniques. The results are passed to the economic calculations. To estimate the effect of multi-pattern project behaviour on cash-flow a pattern development schedule is required. Table 12 is a generalised flowchart of the processes used by these models.

Table 12. A Generalised Flowchart for all Predictive Models

START

COMPUTE RECOVERY VERSUS TIME
FOR A SINGLE PATTERN

EXTRAPOLATE PATTERN DEVELOPMENT
OUTPUT TO FULL FIELD DEVELOPMENT

USE FIELD DEVELOPMENT RECOVERY
PROFILE TO GENERATE A BALANCE
SHEET USING ECONOMIC ALGORITHM

OUTPUT RECOVERY,
ECONOMIC AND RISK DATA

END

Details of the models, which are rather complex, are given in their accompanying reports (US DOE, 1986a-e). A brief summary of each model, as described in the reports, is given in Annex 2.

Technical and economic data input

The technical data were supplied from the spreadsheet (see Data Gathering) build up based on the input data sheets used for the technical screening runs. Macros were written to transfer the data from the spreadsheet to the input file for the evaluation models.

The economic data were supplied using the macros provided by Thomas Petroleum Consultants (see Annex 1). Because there is no established carbon dioxide supply system or other EOR infrastructure in Australia, major assumptions had to be made about the logistics, processes, and prices based on available information.It must be stressed that these assumptions make the economic results very subjective.

Oil Price

Oil prices of US$12/bbl, US$20/bbl (base case) and US$50/bbl were assumed with an exchange rate of US$0.80 = A$1.00.

Well Spacing

It was assumed that, given the existing well spacing in each field, adequate EOR could be achieved without additional drilling. Drilling of even a small number of extra wells to reduce the well spacing was found in some trial field cases to have a major adverse effect on process economics. The need for infill drilling, and its benefits and costs in Australian conditions, were impossible to check in a broad study of this kind (see Section 1.1.2 of Annex 1). The individual fields were not all checked to optimise well spacing. Conversion costs (for producers converted to injectors) were not included (see Section 1.1.2 of Annex 1). It was also generally assumed that half the wells in the field would become injectors, and the pattern area was based on a five-spot.

Offshore EOR is even more affected by the impact of infill drilling as additional platforms might be required. As a result, it was again assumed that conversion of existing wells, rather than new drilling, would provide injection facilities. This appears to be the most likely technique for offshore EOR in its early development.

Transportation

In a general study of this kind, it is assumed that oil transportation costs are similar to those of a line owner (see Section 1.1.7 of Annex 1).

Miscible gas

It is assumed that the miscible gas is supplied from either (1) a local cheap source of carbon dioxide, or (2) local sources of ethane. The costs quoted for carbon dioxide from the Moomba gas treatment plant and from flue gases (see Section 1.2.2 of Annex 1) are A$0.64/kscf and A$3.12 per kscf respectively. The higher price virtually eliminates carbon dioxide (required at approximately 10 kscf/bbl produced oil) from consideration for an oil price of US$20/barrel. The alternative is to assume a local source of suitably enriched ethane and assume that most of the ethane can be recovered from the reservoir during or after oil depletion. A price of A0.32/kscf was assumed in this case. See Annex 1 for further details. A sensitivity case for a price of $A0.64/kscf was also run.

Results

As can be seen above, some of the critical factors in the economic analysis are: (1) crude price, (2) infill drilling assumptions; and (3) availability of flooding agents.

- **Carbon dioxide miscible flooding**

  Most of the fields with reasonably large oil-in-place (more than 5 million barrels) which met the miscibility criteria, were economic at a discount rate of 15%. Because the infrastructure cost is a larger burden for small fields (less than 5 million barrels), such fields were generally very uneconomic. Grouping of small fields with common facilities is an obvious solution, but was not checked in this study, although some sharing of pipeline costs was included. For offshore fields, most of which met the miscibility criteria, economics were generally attractive. However, the availability of sufficient flood gases for large offshore reservoirs is an important issue. It should be emphasised, however, that in stratified reservoirs unit-by-unit flooding should be possible. For all reservoirs recycling of produced miscible gas will be possible. The major issue for large, unstratified reservoirs is the supply of enough gas to saturate the entire reservoir. Probably in the long term the availability of gas from coal-fired power stations or undedicated ethane production may assist in these cases. The low residual oil saturation of many offshore reservoirs is counteracted by their excellent permeability which is favourable to efficient EOR.

  Figure 13 shows the results. At US$12/barrel, 581 million barrels incremental recovery is possible. This increases to about 709 million barrels at US$20/barrel and 750 million barrels at US$50/barrel. The relative lack of sensitivity to oil price arises from the field size distribution, and the technical restrictions on EOR, which result in several fields not being candidates at any oil price. By contrast, in the US NPC study (National Petroleum Council, 1984), the number of candidate fields increases more uniformly with oil price. When the price of the miscible flooding agent was increased (to 64c/kscf) the incremental recovery for the US$20/barrel case reduced to 570 million barrels. Figure 14 shows typical gas price sensitivities for onshore and offshore fields.

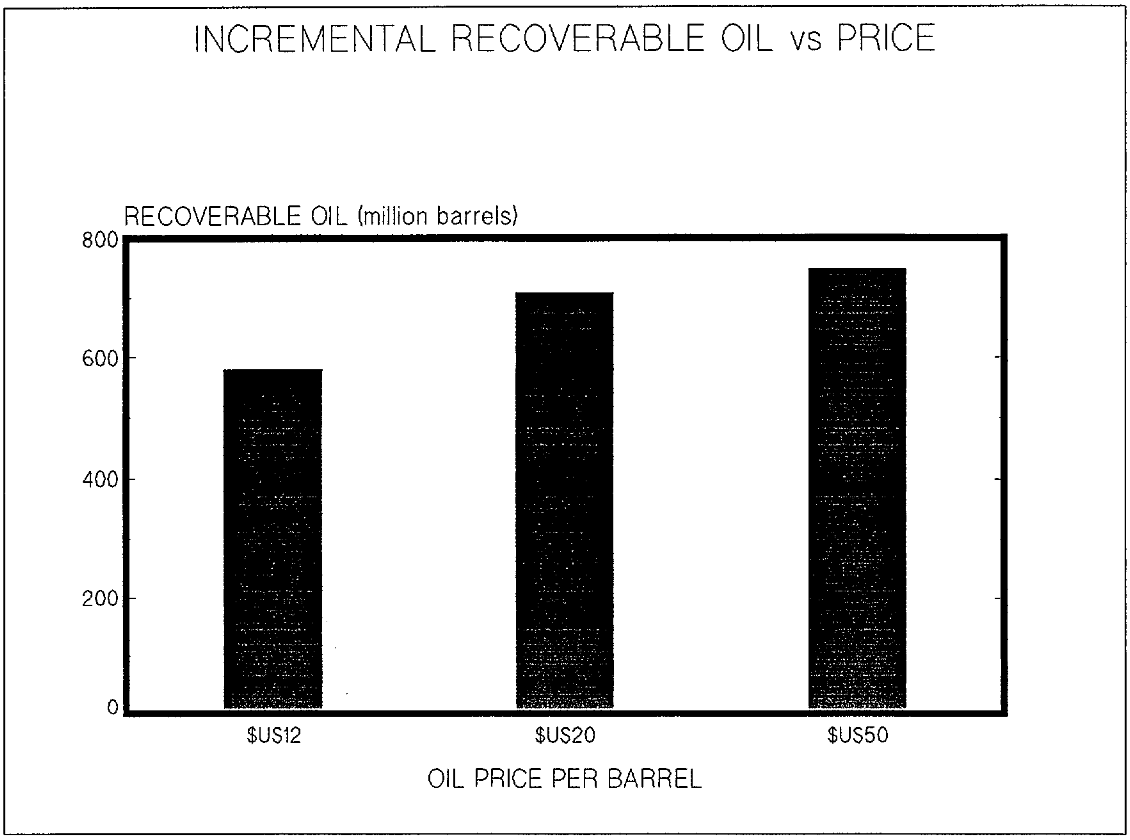
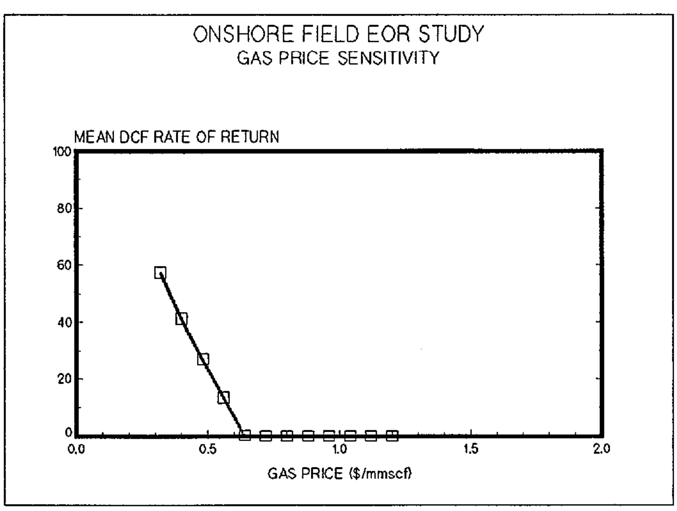


Figure 13



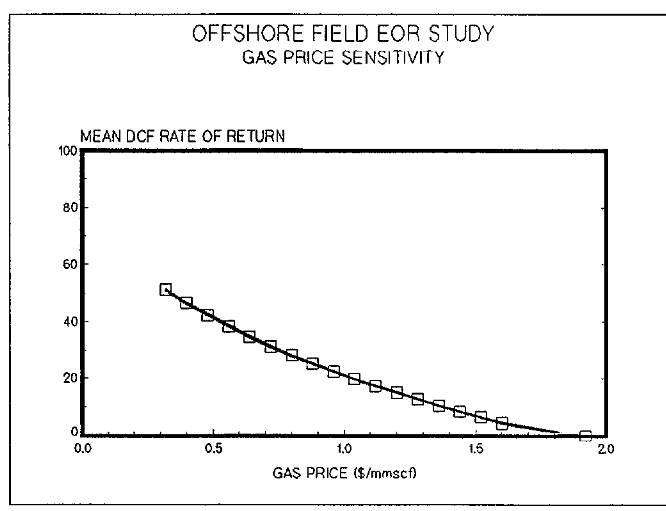


Figure 14

. **Polymer/surfactant flooding**

The polymer flooding model used gave incremental economic results which were negative. These results were also observed in the example run referred to by the US Department of Energy, 1986b. In other words, it was found to be preferable to enlarge or develop other waterfloods rather than add polymer to an existing waterflood, because the additional oil recovery did not justify the polymer cost.

However, the economics of polymer flooding (versus doing nothing) were also investigated. It was assumed that no wells were drilled, and that the reservoirs were suitable for waterflooding. At US$20/barrel, about 55 million barrels was recovered economically (secondary plus EOR recovery).

. **Other flooding agents**

No detailed economics for alkaline, steam and in-situ combustion were calculated. For the reasons given previously, these processes appear to be generally inapplicable in Australia.

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Initial data preparation was carried out by Mr Shige Miyazaki of BMR's Petroleum Resource Assessment Branch. Screening and data checking was done by Mr Steve le Poidevin. Programs from DOE were run by Mr Graeme Morrison and Mr Steve le Poidevin, with assistance from Mr Rob de Nardi. Mr Steve Davey, Mr Vel Vuckovic and Mr Len Pain of the BMR also assisted. Mrs Penny Wilkins typed the manuscript.

The cooperation of the State governments and the oil companies which provided or allowed access to data for the project was vital and is gratefully acknowledged.

The US Department of Energy provided the economic evaluation models free of charge.

ANNEX 1

ATTACHMENTS 2 AND 3 OF ANNEX 1 HAVE BEEN WITHHELD AS THEY RELATE TO CONFIDENTIAL DATA

A SYSTEM FOR

COST ESTIMATION

FOR THE

ECONOMIC EVALUATION

OF

EOR PROCESSES

IN

AUSTRALIA

Thomas Petroleum Consultants

June 1989

1.0 Costs

1.1 Process - Independent Costs

Process-independent costs are those relating to the developing and operation of oil and gas production plant, infrastructure and maintenance of both producing and injecting wells. They are tabulated for this study in Tables 1.1.1 to 1.1.7. The following notes describe the applicability of these costs to the examination of EOR prospects throughout Australia.

1.1.1 Logistic Centres and Multipliers (Refer Table No. 1.1.1)

In a country the size of Australia, distance and logistics are a major factor in the costs applicable to the development and operation of any oil or gas fields. Generally over the years since exploration for petroleum started in Australia a number of towns and/or oil fields have come to be recognised as centres for operation for the surrounding Areas/Basins. Typical examples of these centres would be Moomba and Roma for on-shore areas, Port Welshpool, Dampier and Broome for off-shore areas. At each of these places and others like them, stocks of materials necessary for the drilling and operation of oil and gas fields have been set up and transport systems exist to move such materials to their place of use. Thus the system adopted in this study for the derivation of costs at any individual on-shore field uses a base cost, for operations assumed to take place at that centre, which can then be multiplied by a Logistics Multiplier or Operations Multiplier to arrive at the cost in the specific field.

The Logistic and Operations Multipliers are dependent upon the distance of the field from the Logistic Centre. For off-shore fields the distance of the field from the Operating Shore Base is used to calculate the Logistics Costs involved in the use of work boats and helicopters. Obviously it must be recognised that for a field development of significant size and duration a logistics centre not listed within this study could be created in a suitable proximal town which is served by air and a good road system. This could have the effect of reducing the Logistic and Operating Multipliers for any given case. However, for purposes of this study using the nearest existing oil field Logistic Centre is sufficient for a first pass examination.

1.1.2 Well Costs (Refer Table No. 1.1.2)

(a) It is assumed that the well spacing during the primary or secondary phase of oil production is wider than that required for EOR and, to achieve the spacing required for application of EOR processes, further drilling will be required. Thus no costs have been developed for conversion of producing wells to injectors or vice versa. In any case, the present lack of knowledge concerning the ultimate disposition of wells within a field during the primary or secondary production process precludes any accurate assessment of what wells may in fact be suitable for conversion. Furthermore, the broad assumptions, incorporated into the analysis generally, make any attempt to forecast conversions into an exercise of false accuracy. In the event that this assumption is incorrect, for any given case, no great error will be introduced by assuming that any conversion costs are minimal or zero compared to the magnitude of the costs of the new wells that will in any case be required.

(b) Well drilling and completion costs are generalised for the Basin/Area concerned and do not take account of individual practices that may be used by any one operator in any given field. In the event that, by using the generalised costs, the application of EOR to a specific field or reservoir is considered to be borderline, it is recommended that the operator of the field be approached for more specific costs and operating data.*

(c) The cost of drilling and equipping water wells for supply of injection fluid is assumed to be the same as that for a flowing producing well. This generalisation is not too inaccurate in the case of fields in the Eromanga Basin or on Barrow Island but introduce an over-estimate of cost (if only small) to other areas where oil reservoirs are deeper than the water supply aquifers.

1.1.3 Production Plant (Refer Table No. 1.1.3)

It is assumed that the production plant existing at the end of the primary or secondary phase of oil production will be adequate to handle production of oil, gas and water from the EOR process. The costs provided here are therefore for completeness only. Unless some special case is to be studied, no capital costs for surface production facilities are included in the cost preparation worksheets described in Section 3.0.

1.1.4 On-shore Operating Costs.

On-shore operating costs are perceived to be of three principal types:

(a) The base cost necessary to run any field and to maintain the infrastructure irrespective of the number of wells in the field above a certain small number,

(b) The unit costs per well associated with the surface gathering system and manifolding etcetera,

(c) The unit costs based upon the throughput of the production facilities recognising the increased cost of maintaining and operating larger facilities.

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* Note that <u>all</u> indicated EOR candidates require full project feasibility studies.

(d) The costs pertaining to lifting oil to the surface, the cost of maintenance of the wells below ground level, i.e. well pulling, and the costs associated with reservoir management, i.e. reservoir engineering.

In this study all of these costs are taken to be identical, irrespective of the Basin or Area in which the on-shore fields are located. However, they are varied for any individual field by virtue of the Operations Multiplier which is dependent on the distance of a field from its logistics base.

1.1.5 Off-shore Capital Costs (Refer Table No. 1.1.5).

It is assumed that the existing production platform (floating production methods are not examined within this study) will be sufficient to maintain the on-going EOR production operation. Furthermore it is considered that unless the platform concerned is very close to a shore line it will not be possible to run chemical or polymer flood operations due to the size of the mixing plant required and, therefore, for off-shore EOR projects, the study has been restricted to the application of miscible CO_2 flood systems. It is assumed for this study that the production platform existing during the primary phase of production will be capable of the slight expansion necessary to carry CO_2 compression equipment. Beyond that, however, any wells which have to be drilled in order to fill in an EOR pattern will require the construction alongside the existing production platform of some form of well jacket system. In this primary examination of off-shore EOR prospects it is assumed that the well support structure is of a lightweight type which is capable of supporting a drilling mast with mud systems, power etcetera located on the existing production platform. This permits the assumption of a lighter weight structure and hence a lower cost while providing the means of being able to work over any of the wells drilled from this extension. Such structures as are assumed to be put in place for EOR projects are also assumed to be sized for a maximum of 27 well slots.

While this is a simplistic approach to what will be a very complex problem of extending the facilities for an EOR project in an off-shore field, it nevertheless provides a basis from which costing can commence. However, in the event that any individual field appears to be on the economic borderline for an EOR project when using this generalised approach it will be necessary to examine the individual circumstance of that field more closely and to develop more exact plans and costs. *

* See footnote on page 53.

1.1.6 Off-shore Operating Costs (Refer Table No. 1.1.6)

The costs of operating an off-shore production platform and wells are split into four principal groups.

(a) The direct site costs which are the costs of manning, operating and maintaining the platform and surface facilities and include the logistic costs of marine and air services which will vary significantly with distance from the logistics base,

(b) The indirect site costs which are the costs of maintaining and running the logistics shore base. These costs are concerned primarily of salaries, rentals, services, harbour dues and wharfage,

(c) The on costs and overheads which are the proportion of head office salaries, overheads, rentals and services charges which can be allocated to the particular development plus the insurances which, for the large capital investment off-shore, constitute a very significant part of the annual operating costs,

(d) The lifting costs which constitute the down hole costs of operating the wells including pressure surveys, work overs, well pulling etcetera and the costs of reservoir engineering.

In this study, the basic costs, within each of these four groups, are taken to be identical, irrespective of the location of the off-shore production platform around Australia. Annual costs for any individual field will therefore vary only with the number of wells and the distance from the appropriate shore base.

1.1.7 Oil Transportation Costs (Refer Table No. 1.1.7)

These costs consist of trucking oil from those fields too small or too remote to justify pipelines, pipeline costs from those on-shore centres such as Moomba, Jackson and Moonie and sea shipping costs. It is assumed for purposes of this study that all of the oil that is produced from EOR projects will be sold to one of the Australian refineries. The oil transportation costs contained in this study therefore are dictated for any given field by its geographical location with respect to the start of a pipeline, shipping point or refinery. Because pipelines exist as common carriers within Australia the owners of the lines must transport oil belonging to other parties provided that the line has sufficient capacity, but for doing so they are of course entitled to charge a fair tariff. Where the line owners are also oil producers in their own right obviously the cost of transporting their own oil through the line is not dictated by tariff considerations but by operating and service costs. Therefore, where appropriate, this study presents two level of costs of oil pipeline transportation but because of the confidential nature of the reserve data collected by the Bureau of Mineral Resources the choice of which transportation cost to be used for any specific field or reservoir must be made by that body.

1.1.8 General

The cost data provided within this study have been derived from published and unpublished historical and budgeted figures for field developments both on-shore and off-shore throughout Australia. They have also been supported by enquiries within the industry from drilling contractors, equipment and material supply firms and transportation companies both on-shore and off-shore. These data were collected, compiled and designed to be presented in a way that would allow their general application to conceptual development scenarios anywhere in Australia. For this reason it will be possible with detailed knowledge of any specific development to criticise their absolute accuracy. Nevertheless for purposes of the general screening of prospects for EOR such as is envisaged in this study it is believed that they provide a suitable database. This statement is by no means a disclaimer of any sort but merely a recognition that a simple set of data needed to be made available to enable examination of the very large number of known oil reservoirs within Australia in order to judge their suitability as EOR prospects. Once a bench data line can be drawn through what might be determined as the minimum viable field size for EOR in any particular Basin it will be possible to refine the costs in order to more closely examine the eligibility of field sizes lying above and below this datum.

1.2 Process Dependent Costs

Process dependent costs are those costs associated only with a particular EOR process to be applied to any particular reservoir. They include:

(a) Purchase costs of surfactants, polymers, caustic and other chemicals which may be used in a chemical flood,

(b) The cost of carbon dioxide in either liquid or gaseous form for use in a carbon dioxide flood,

(c) The costs of transportation of chemicals or carbon dioxide by either road or pipeline to the project site from the place of manufacture or purchase,

(d) The cost of preparation of such chemicals or raw material into a form for injection into the reservoir,

(e) The cost of pumping or compressing the gas or liquids for injection into the reservoir, and

(f) The cost of recycling any of the chemicals or gases recovered with the produced fluids from the reservoir.

The process dependent costs applicable to this study are provided in Tables No. 1.2.1 to 1.2.9 and the following notes describe their source and/or derivation:

1.2.1 Chemical Purchase Costs (Refer Table No. 1.2.1).

(a) The chemicals used commonly in the United States for chemical flood projects are listed in Tables G-2 and G-3 of Reference 1. This list of chemicals was presented to Glen Parkinson & Associates Pty. Ltd., a project management and engineering consultancy in Adelaide, to derive costs of purchase within Australia, either at a point of importation or a point of manufacture, and costs of transportation of the materials to the logistic centres listed in this study. The results of their investigations are given in their report, a copy of which is attached hereto as Attachment No. 1. Generally GPA found that the greater majority of the bulk polymers and surfactants required in large quantities for chemical flood processes must be imported and only those chemicals required in smaller amounts such as bactericides and oxygen scavengers etcetera might be manufactured within Australia. GPA list the points at which the various chemicals are either imported or manufactured in the appendix to their report. In this study the cost per barrel of a chemical slug to be injected into a reservoir uses only the cost of surfactant, caustic soda and polymer, where appropriate, since the amount of the other chemicals used per barrel are small enough to be ignored against the cost of the major components of the chemical slug. Thus, as an example, a surfactant slug assumes that only a broad spectrum petroleum sulphonate at a cost of $4,000 per ton at its point of purchase is used. It is an established fact that the composition of any surfactant or other chemical slug used in a chemical slug process must be carefully drawn up taking into account the chemical properties of the formation and the formation fluids into which the slug is to be injected. In the light of the broad approach made in this study and the lack of detailed knowledge of the geochemical composition of the reservoir rock and reservoir fluids, it is considered that this approximation in the costing of the chemical slugs is quite adequate. As GPA point out, some of the chemicals listed in Reference No. 1 are banned in this country because of their toxic qualities. GPA therefore established some alternatives after consultation with the chemical industry which they consider will be satisfactory.

(b) Liquid Carbon Dioxide (Refer Table No. 1.2.1)

Bulk carbon dioxide is available in liquid form in any of the capital cities in Australia where generally it is produced by the purification of flue gas from coal, oil or gas furnaces. There is also a limited amount of carbon dioxide produced from the Carolyn No. 1 well near Mt. Gambier in South Australia. GPA found that the cost of liquid carbon dioxide can range up to $220 per ton of liquid purchased in a capital city, although, dependent upon the size of the CO2 recovery and liquefaction plant this cost could be as low as $150 per ton. Since there are approximately 19 MCF of carbon dioxide to one tonne it is clear that even at this lower price of $150 per ton the cost of carbon dioxide in liquid form even before taking into account the cost of transportation, is some $8 per MCF. United States experience in the Kelly-Snyder oil field was that some 7 - 12 MCF of CO2 is required to recover one barrel of oil under a CO2 EOR process. On this basis the purchase price alone of CO2 would be some $50-60 per barrel of oil recovered. That is, without taking into account any other operating costs, return on capital required or transportation of the CO2 from the point of purchase to the point of use, a minimum price of $50 Australian per barrel of oil would be required to justify a CO2 flood using liquid CO2. For completeness however, the concept of using liquid carbon dioxide for a flood has been included as part of this study so that, in the event the cost can be reduced in real terms, the procedure will exist to allow the examination of the economics of its use in EOR processes. GPA estimated that a liquefaction plant of 30 tons per day capacity of CO2 including storage would cost some $4.5 million. Assuming that the total operating costs of such a plant would be 10% of the capital cost per annum and that a 20% rate of return before tax would be required over a 15 year life, then the cost per tonne to liquify CO2 is calculated to be approximately $112. This is in keeping with the quoted costs of $150 per ton for liquid CO2 ex capital city, if the additional cost of extraction of the pure gas from a flue gas stream is considered.

1.2.2 Carbon Dioxide in Gaseous Form

Carbon dioxide is produced in quite large quantities from major industrial installations around the country. In this study the following sources of CO2 in large quantity have been assumed.

(a) Moomba, where CO2 is produced from the Moomba gas plant and could be available for pipeline transmission to the Amadeus Basin in the West and the Eromanga Basin in the East.

(b) Loy Yang, a power station in Southern Victoria from which gas could be supplied to the Bass Strait oil fields.

(c) The Brisbane Area from which gas could be supplied to the Surat and Bowen Basins,

(d) Dampier, where it can be assumed that in the near future the LNG plant at Withnell Bay will be on stream and can supply CO2 to Barrow Island and off-shore fields, and

(e) Perth where power stations exist, which could supply gas to the Dongara/Yardarino Area.

Calculation of Gaseous CO2 costs

(a) Gas ex-Moomba (Refer Table No. 1.2.2).

Carbon dioxide saturated with water vapour is a by-product of the Moomba gas treatment plant. The only processing required to obtain pure dry carbon dioxide is to dehydrate the stream of gas coming from the top of the Moomba regeneration towers. GPA have estimated (Refer Attachment 1) that the capital cost of a Tri Ethylene Glycol plant with a capacity of 20 MMCFD of carbon dioxide would be some $9.32 million of which $9 million comprises the cost of compression. They estimate the operating costs to be 5% of the dehydration capital per year plus 7% of the compression capital per year plus fuel. Assuming, that, at Moomba, gas can be used as fuel at a cost of $2 per MMBTU and that a 20% rate of return pre-tax over a 15 year life is required, the cost of CO2 delivered into a special pipeline at 1100 psi is calculated to be 64 cents per MCF.

(b) CO2 gas ex flue gases (Refer Table No. 1.2.2).

At the other gas sources listed above it is assumed that CO2 can be produced from flue gas and this will require the removal of contaminants such as oxides of sulphur, nitrogen and water vapour. Assuming that an MEA process is used for this process GPA have estimated the cost of a plant capable of producing 19 MMCFD of pure CO2 gas to be $20 million. Operating costs are estimated to be 6% of the capital cost per year and fuel is estimated to be 6 GJ per tonne of CO2 for heating plus 100 kilowatts of electrical energy per tonne of CO2 to run the plant. It is assumed that at Loy Yang or other power stations steam can be supplied for heating at approximately $4 per GJ, which is equivalent to about 60% of the present crude oil equivalent price, and one kilowatt hour of electrical energy, supplied at industrial rates, will cost 3 cents. These costs of energy have been checked by GPA against industry sources and are considered to be reasonable.

The capital cost of compression to raise the produced CO2 to 1100 psi for insertion into a pipeline is estimated to be $8.33 million and operating costs are estimated to be 7% of capital cost per year plus fuel at 3 cents per kilowatt hour.

On the basis of above, and assuming 330 days operation per year, the cost of carbon dioxide delivered into a pipeline at 1100 psi is estimated to be $3.12 per MCF.

While obviously there will be differences in flue gas composition from different plants around the country it is considered that as a first pass exercise a cost of $3.12 per MCF for pipeline carbon dioxide can be assumed at each of the sources listed above.

(c) Transportation costs of chemicals and CO2.

(i) Chemical and Liquid CO2 (Refer Tables No. 1.2.1, 1.2.7, 1.2.8, 1.2.9).

GPA through their enquiries within Australia arrived at a tabulation of costs for transportation of full loads between the capital cities and the Logistic Centres used in this study. Details of the cost of transportation of full loads of 22 tonnes per truck for chemicals and 35 tonnes for CO2, are given in the GPA report in Attachment No. 1 and are summarized in Table No. 1.2.7. In the compilation of the transport costs per ton of chemicals, purchase is assumed at the sales point closest to the relevant Logistic Centre. Transport costs between Logistics Centres and fields are computed to be $7.53 per tonne per 100 Km for chemicals and $7.43 per tonne for CO2 (Refer Table No. 1.2.8).

In the special case of Barrow Island, the onshore field in an offshore setting, transportation costs have been calculated separately, assuming that all bulk chemicals are transported ex Onslow W.A. by landing barge. (Refer Table No. 1.2.9) In the event of very large quantities of chemicals being used, and should the EOR process be economically justified, a larger, more robust system would have to be installed. The cost per tonne moved however should not vary by any order of magnitude from that calculated in Table No. 1.2.9 and any variation would be overshadowed by the purchase cost of the material itself.

(ii) Gaseous CO2 Transportation (Refer Table No. 1.2.3, 1.2.4).

Gaseous CO2 delivered from one of the sources listed above is assumed to be carried by dedicated pipeline which will be built specifically for the project concerned. Such pipelines will deliver the CO2 to the project at 1100 psi. The pipeline system is therefore designed to receive CO2 from the source plant at 1100 psi and compress it to whatever pressure is necessary (with a maximum of 2200 psi assumed) to deliver to the project at 1100 psi. Typical pipeline construction and operating costs are presented in Table No. 1.2.3.

The method of calculation of the lowest cost of transportation per MCF of carbon dioxide is illustrated in Table No. 1.2.4. For the example flow rates and pipeline lengths given, it can be seen that a pipeline of nominal diameter of 4 inches will require 7 compressor stations including the station at the head of the line. Since carbon dioxide cannot be used as a fuel then it is assumed that any pipeline system carrying carbon dioxide throughout central Australia will have no intermediate stations. (This of course is obviously true of any pipelines carrying CO2 to off-shore locations.) The minimum cost of transportation under these circumstances can therefore only be provided by the smallest possible pipeline size that requires only a compressor station at the head of the line. The cost of transportation is then calculated by assuming that a 20% rate of return is required on the line over a 15 year period. On this basis, and in the example shown in Table No. 1.2.4, the minimum cost of transportation, that is the minimum discounted weighted average tariff, (DWAT) is $1.05 per MCF in a line of 6 inches diameter.

This calculation procedure, code named CO2 TRAN, is incorporated into the cost calculation spreadsheets, described in Section 3. Table No. 1.2.4 is provided only as an example of the method used in deriving the minimum DWAT.

(d) Costs of preparation of fluids to be injected at the project.

(i) Chemical Slug Preparation Costs (Refer Table No. 1.2.5).

The capital cost of plant required to mix surfactants, caustics and polymers in the U.S.A. are provided in the U.S.A. Department of Energy reports of the EOR Predictive Models. Costing in this study is based upon conversion of the U.S.A. costs to Australian conditions in 1989.

(ii) Carbon Dioxide Preparation (Refer Table No. 1.2.6).

If liquid carbon dioxide is used in the project, it will have to be stored on site, vaporized and heated prior to being compressed for injection into the reservoir. GPA have estimated that the cost of storage of 500 tonnes of liquid CO2 plus vaporizing equipment, boilers and other ancillaries is approximately $1.6 million. Operating costs are estimated to be 7% of capital per year and fuel costs approximately $40,000 per year. With these costs, in order to obtain a rate of return of 20% pre-tax over a 15 year life, the unit cost of vaporization is 7 cents per MCF of CO2. This study assumes a rounded off number of 10 cents per MCF for this operation. This cost however assumes that the carbon dioxide is provided ex the vaporisation plant at atmospheric pressure and it must therefore be compressed to the required injection pressure by on site compressors. The calculation of the horse power required for this operation and the capital cost and operating costs of compressors for any given project are automatically calculated in the cost preparation worksheets, described in Section 3.

In projects in which CO2 is provided to the field in gaseous form by pipeline, it is assumed that the CO2 will arrive at the field at 1100 psig. The compression requirement to raise the pressure from this value to the required injection pressure is automatically calculated in the cost preparation worksheets.

(e) Injection Pumps and Compression Costs

Horse power requirement, fuel requirement and the capital and operating costs of pumps and compressors to inject the chemical slugs, carbon dioxide and water into the reservoir are calculated automatically within the cost preparation worksheets.

(f) Recycling of Produced Fluids

The United States Department of Energy Predictive Models allow the option of reclaiming carbon dioxide gas when it is produced with the natural oil and gas from the reservoir. The plant options, offered by the DOE models, range from no recovery to recovery, separation and sale of the natural gas and reinjection of the carbon dioxide. In this study the options are restricted to the flaring or blowing off of the produced gas and carbon dioxide or the reinjection of both natural gas and carbon dioxide together.

This choice can be made in the data input to the specific case under study in the cost preparation worksheets which automatically calculate the size, power and costs of the pumps and/compressors.

TABLE No. 1.1.1
PROCESS INDEPENDENT COSTS

ONSHORE LOGISTICS MULTIPLIERS (LM)

Kms to Log.Centre	100	200	300	400	500	600	700	800
BASIN/AREA								
Perth (Good Road System)	1.10	1.15	1.20	1.25	1.30	1.35	1.40	1.45
Surat,Bowen (Fair-Good Road System)	1.15	1.20	1.25	1.30	1.35	1.40	1.45	1.50
Eromanga,Cooper (Poor-Fair Road System)	1.20	1.25	1.30	1.35	1.40	1.45	1.50	1.55
Amadeus,Canning (Poor-Nil Road System)	1.25	1.30	1.35	1.40	1.45	1.50	1.55	1.60

ONSHORE OPERATIONS MULTIPLIERS (OM)

Kms to Log.Centre	100	200	300	400	500	600	700	800
BASIN/AREA								
Perth (Good Road System)	1.00	1.04	1.08	1.12	1.16	1.20	1.24	1.28
Surat,Bowen (Fair-Good Road System)	1.04	1.08	1.12	1.16	1.20	1.24	1.28	1.32
Eromanga,Cooper (Poor-Fair Road System)	1.08	1.12	1.16	1.20	1.24	1.28	1.32	1.36
Amadeus,Canning (Poor-Nil Road System)	1.12	1.16	1.20	1.24	1.28	1.32	1.36	1.40

Notes:

(1) These "Multipliers" are used to give a numerical dimension to the difficulties induced by distance and topography ,and hence cost,of development and production operations onshore Australia.

(2) They are applied to the requisite Capital or Operating Costs,which are estimated to be those costs applicable to projects taking place at a "Logistics Centre",normally a well established centre of petroleum operations.

(3) Their use permits the rapid estimation of Capital or Annual Operating Costs for any project situated at a known distance from the Logistics Centre.

TABLE No. 1.1.2
PROCESS INDEPENDENT COSTS

CAPITAL - ONSHORE DRILLING AND COMPLETION COSTS (ooo's $1988)

Completion Type	Single Nat.Flow	Add for Pump (Includes Surface)	Total for Single Pump
BASINS			
Surat			
Depth Variable/ft	0.1116	0.0030	0.1146
Fixed	105.0000	138.0000	243.0000
Eromanga			
Depth Variable/ft	0.1096	0.0030	0.1126
Fixed	110.0000	138.0000	248.0000
Cooper			
Depth Variable/ft	0.1096	0.0030	0.1126
Fixed	115.0000	138.0000	253.0000
Amadeus			
Depth Variable/ft	0.1975	0.0030	0.2005
Fixed	115.0000	138.0000	253.0000
Canning			
Depth Variable/ft	0.1516	0.0030	0.1546
Fixed	125.0000	138.0000	263.0000

TABLE No. 1.1.3
PROCESS INDEPENDENT COSTS

CAPITAL - ONSHORE SURFACE COSTS (ooo's $1988)

	Base Costs	Unit Costs Per Well Single Nat.Flow	Single Beam Pump	Unit Costs on Thruput (MSTBOD)
Gathering System		160.00	160.00	
Prod. Facilities	940.00			65.00
Water Disposal Facilities	250.00	104.00	104.00	
Infrastructure	4900.00	22.50	22.50	
Totals	6090.00	286.50	286.50	65.00

TABLE No. 1.1.4
PROCESS INDEPENDENT COSTS

OPERATING - ONSHORE FIELD FACILITIES ($ooo's per year 1988)

	Base Costs	Unit Costs per Well Single Nat.Flow	Unit Costs per Well Single Pump	Unit Costs on Thruput (MSTBOD)
Gathering System		32.50	32.50	
Prod. Facilities	29.50			3.85
Water Disposal Facilities	2.25	0.75	0.75	
Infrastructure	142.25	35.00	35.00	
Totals	174.00	68.25	68.25	3.85

OPERATING - ONSHORE WORKOVER AND LIFTING ($ooo's per year 1988)
(Includes 10% Engineering allowance)

	Unit Costs per Well		
	Single Nat.Flow	Increment for Pump	Total for Single Pump
Downhole Surveys/Logging	35.60	-18.30	17.30
Downhole Consumables	5.00	0.00	5.00
Workovers	28.00	75.00	103.00
Artificial Lift Operation		7.60	7.60
	68.60	64.30	132.90
Add 10% Engineering	6.86	6.43	13.29
Totals	75	71	146

TABLE No. 1.1.5
PROCESS INDEPENDENT COSTS

CAPITAL - OFFSHORE

WELL SUPPORT STRUCTURES (ooo's $1988)
(With Topsides for Minimum Facilities)

8 Leg Jacket (including piles) -	
Base Cost	7250
Increment per metre of Water Depth	140
Increment per Well Drilled	305

DRILLING AND COMPLETION COSTS (ooo's $1988)
WELLS DRILLED FROM PLATFORM

Increment per Well Drilled	130
Depth Variable ($ooo's per foot along hole)	0.340
Fixed Cost per Well ($ooo's)	384

TABLE No. 1.1.6
PROCESS INDEPENDENT COSTS

OPERATING - OFFSHORE FIXED PRODUCTION PLATFORM

1.0	DIRECT SITE COSTS (ooo's/year $1988)		
1.1	Typical "Fixed" Annual Costs ($ooo's/year)	5630	
1.2	Marine Logistics - assumes Supply Vessel @ $15000 per day with ONE return trip per month		
	Fixed Charges ($ooo's/year)	445	
	Distance Variable ($ooo's/Km)	1.00	
1.3	Helicopter Logistics		
	Fixed Charges ($ooo's/year)	1323	
	Distance Variable ($ooo's/Km)	1.00	
2.0	INDIRECT SITE COSTS (ooo's/year $1988)		
	Logistics Base Salaries, rentals, services, harbour dues, wharfage etc. ($ooo's/year)	1000	
3.0	ON COSTS AND OVERHEADS (ooo's/year $1988)		
3.1	Salaries/Labour Burden ($ooo's/year)	1250	
3.2	Insurances		
	3.2.1 Facilities	1000	Assumes Platform in 100 metres water, 20 wells.
	3.2.2 Public Liability ($ooo's/year)	150	50000 BBLD thruput and pipeline ashore
	3.2.3 Well Control ($/foot/well)	3.00	valued at $100 MM, with premium at 1 %/year.
4.0	LIFTING COSTS (ooo's/year/well $1988)		
	Downhole Repairs and Reservoir Management Costs ($ooo's/well/year)		
	Producing Oil Well	285	
	Injection Well	162	

SUMMARY	Downhole/Workover - Producer ($ooo's/Year/well)	285
	- Injector ($ooo's/Year/well)	162
	Total Fixed Cost per Platform ($ooo's/year)	9000
	Logistics Cost - Base ($ooo's/year)	1768
	- Variable ($ooo's/Km/Year)	2.00

TABLE No. 1.1.7
PROCESS INDEPENDENT COSTS

OIL TRANSPORTATION
Oil Pipeline/Shipping Tariffs

(Amounts payable by Non-owners)

From Pipehead/ Shipping Point	To Refinery	By Medium	Average Cost $/stbo	
Bonaparte	Perth	Ship	1.50	Note (1)
Broome	Perth	Ship	5.00	Note (2)
Dampier Area	Perth	Ship	1.00	
Gippsland(Offshore)	Westernport	Pipeline	0.40	Note (3)
Jackson	Brisbane	Pipeline	6.30	Note (4)
			3.00	Note (3)
Mereenie	Alice Springs	Pipeline	4.50	
Moomba	Pt.Bonython	Pipeline	11.00	Note (4)
			2.10	Note (3)
Moonie	Brisbane	Pipeline	2.50	

Notes :
(1) Large Tankers
(2) Small Lots
(3) Estimated Cost to Owner/Operators of Line System i.e. Operating Cost only
(4) Estimated Tariff charged to Non-owners to give to Owners a 20% per annum Rate of Return over 15 year life.
(5) The above estimates are in keeping with industry information.

Trucking Tariffs

Cost of trucking in "Doubles" (ca. 400 stbo) averages $A1.00 per STBO per 100 Kms. throughout Australia.

TABLE No. 1.2.1
PROCESS DEPENDENT COSTS

MATERIALS - CHEMICAL AND BULK LIQUID CO2 COSTS
Delivered to Logistic Centres

Chemical Type	Polymer Polyacryl	Polymer Polysacch	Alkali Caustic	Surfact Pet.Sulf	Carbon di-Oxide
Source/Point of Import	Nearest Cap.Cit.	Nearest Cap.Cit.	Adelaide/ Sydney	Nearest Cap.Cit.	Nearest Cap.Cit.
Cost at Source ($/Tonne)	3200	1500	620	4000	150
Log. Centre					
Alice Springs					
Tpt. ($/Tonne)	73	73	73	73	110
Delivered Cost ($/Tonne)	3273	1573	693	4073	260
Dampier/Onslow					
Tpt. ($/Tonne)	120	120	241	120	102
Delivered Cost ($/Tonne)	3320	1620	861	4120	252
Dongara					
Tpt. ($/Tonne)	32	32	180	32	27
Delivered Cost ($/Tonne)	3232	1532	800	4032	177
Jackson					
Tpt. ($/Tonne)	55	55	64	55	90
Delivered Cost ($/Tonne)	3255	1555	684	4055	240
Moomba					
Tpt. ($/Tonne)	86	86	86	86	N.A.
Delivered Cost ($/Tonne)	3286	1586	706	4086	N.A.
Roma					
Tpt. ($/Tonne)	23	23	77	23	37
Delivered Cost ($/Tonne)	3223	1523	697	4023	187
Welshpool					
Tpt. ($/Tonne)	27	27	51	27	14
Delivered Cost ($/Tonne)	3227	1527	671	4027	164

Notes : Costs are summarized from data provided in G.P.A. report

TABLE No. 1.2.2
PROCESS DEPENDENT COSTS

CARBON DI-OXIDE PRODUCTION COSTS

PLANT TYPE 1 - MOOMBA - DEHYDRATION AND COMPRESSION
PLANT SIZE 20 MMCFD

Data ex G.P.A. Report		
Capital Cost - Dehydration Plant	($ooo's)	320
- Compression to 1100 psig	($ooo's)	9000
Operating Cost - Dehydration @ 5 % capital/year	($ooo's/yr)	16
- Compression @ 7 % capital/year	($ooo's/yr)	630
Fuel Use - Dehydration - 20 MMBTU/day		
- Compression - 2000 MMBTU/day		
Fuel Cost - 2020 MMBTU/day @ $2.00/MMBTU - for 330 days.	($ooo's/yr)	1333
Total Direct Operating Cost	($ooo's/yr)	1979
Add 20 % Overhead	($ooo's/yr)	396
Total Operating Cost	($ooo's/yr)	2375

For 20 % per annum pre-tax R.O.R. over 15 year life,
the required charge for CO2 supplied at 1100 psig = $0.64 per MCF ($A 1989)

PLANT TYPE 2 - Loy Yang - RECOVERY ex FLUE GAS (MEA Process) and COMPRESSION
PLANT SIZE 1000 TONNES/DAY (= 19 MMCFD Equivalent)

Data ex G.P.A. Report		
Capital Cost - CO2 Extraction Plant	($ooo's)	20000
- Compression to 1100 psig	($ooo's)	8333
Operating Cost - Extraction @ 6 % capital/year	($ooo's/yr)	1200
- Compression @ 7 % capital/year	($ooo's/yr)	583
Fuel Cost - Extraction Plant		
- Heating = 6 GJ/tonne CO2 = 6000 GJ/day @ $4.00 per GJ for 330 days	($ooo's/yr)	7920
- Electrical Power = 100 KW/tonne @ 3 cents per KWhour for 330 days	($ooo's/yr)	990
- Compression = 3880 KWhour per MMCFD @ 3 cents per KWhour for 330 days	($ooo's/yr)	922
Total Direct Operating Costs	($ooo's/yr)	11615
Add 20 % Overhead	($ooo's/yr)	2323
Total Operating Costs	($ooo's/yr)	13938

For 20 % per annum pre-tax R.O.R. over 15 year life,
the required charge for CO2 supplied at 1100 psig = $3.12 per MCF ($A 1989)

TABLE No. 1.2.3
PROCESS DEPENDENT COSTS

CARBON DI-OXIDE TRANSPORTATION
PIPELINE CONSTRUCTION AND OPERATING COSTS ($1988)

ONSHORE

Capital Cost (per inch diameter per Km Length)	22500	
Operating Cost		
Maintenance (percent of Capex per year)	3.00	

OFFSHORE

Capital Cost		
Variable Costs		
Material Cost ($ooo's/inch diameter/Km length)	21	
Laying Cost ($ooo's/Km)	85	
Trenching Cost ($ooo's/Km)	100	
Fixed Costs		
Mob/Demob (around Australia) ($ooo's) - allow	1500	
Riser Installation ($ooo's) - allow	170	
Landfall approach ($ooo's) - allow	130	1800
Operating Cost		
Maintenance (per cent of Capex per Year)	3.00	

TABLE No. 1.2.4
PROCESS DEPENDENT COSTS

CO2 TRANSPORTATION TARIFFS

(1) Gasline Flow Calculations use Panhandle B Equation.
(2) For Compressor Calculations, per Stage,
BHP/MMCFD = (Ts+460)*3.03*Po/(To+460)/E*(K/(K-1))*(R^((K-1)/K)-1)+3.5
(3) Tariff calculated to provide PRE-TAX R.O.R equal to specified Discount Rate.

To = Standard Temp (deg F)	60
Po = Standard Pressure (psia)	14.650
G = Gas Gravity (Air =1.0)	1.5195
Z = Gas Compressibility	0.5000
K = Ratio of Specific Heats	1.27

PIPELINE DATA

Flow Rate (MMCFD)	20.00
Overall Pipeline Length (Kms)	200
"Standard" Pipeline Segments	
Inlet Pressure (psig)	2200
Outlet Pressure (psig)	1100
Pipeline Efficiency (Frac)	0.92
Average Temperature (deg F)	130
Pipeline Cost ($ per inch/Km)	22500
Annual Opex as % of Capex	3.00
Pipeline Life (Years)	15
Discount Rate (% per year)	20.00

"STANDARD STATION" COMPRESSION DATA

Station Inlet Pressure (psig)	1100
Station Outlet Pressure (psig	2200
Ts = Suction Temp (deg F)	100.00
E = Mechanical Efficiency	0.92
No. of Stages	1
Comp. Costs ($/BHP installed)	1600
Fixed Opex/Station ($M/year)	350
Annual Opex as % of Capex	7.00
Compressor Fuel (BTU/HP-HOUR)	8000
Fuel Cost ($/MMBTU)	2.00

Derived Data - Line Compressors

R = Stage Compression Ratio	1.987
BHP/MMCFD/Stage	41.91
Total BHP/MMCFD	41.91
Total BHP/Station	838
Capex/Station ($MM)	1.34
Station Opex($MM/yr)	0.44
Station Fuel($MM/yr)	0.12

Nominal Pipe Diameter (ins)	Distance between Stations (Kms)	Num of Stations (including pipehead)	Last P/L Sector Pressure (psig)	Last Stn Comp HP	Line Capital Cost ($MM)	Comp Capital Cost ($MM)	Total Capital Cost ($MM)	Total Annual Opex ($MM)	DWAT ($/mcf)
4.00	29	7	2142	807	18.00	10.68	28.68	5.02	1.46
6.00	231	1	2085	775	27.00	2.58	29.58	1.92	1.05
8.00	940	1	1407	330	36.00	1.87	37.87	2.07	1.30
10.00	2977	1	1205	165	45.00	1.60	46.60	2.30	1.56
12.00	7210	1	1145	111	54.00	1.52	55.52	2.56	1.84
14.00	11675	1	1128	96	63.00	1.49	64.49	2.83	2.11
16.00	23170	1	1114	83	72.00	1.47	73.47	3.09	2.39
18.00	42308	1	1108	77	81.00	1.46	82.46	3.36	2.67
20.00	72376	1	1105	74	90.00	1.46	91.46	3.63	2.94
22.00	117482	1	1103	73	99.00	1.46	100.46	3.90	3.22
24.00	177882	1	1102	72	108.00	1.46	109.46	4.17	3.50
26.00	267317	1	1101	71	117.00	1.45	118.45	4.44	3.78
30.00	541052	1	1101	71	135.00	1.45	136.45	4.98	4.33

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TABLE No. 1.2.5
PROCESS DEPENDENT COSTS

CHEMICAL TREATMENT PLANT COSTS

Calculations based on Default Cost Data given in U.S of A.
Department of Energy Fossil Energy Report III-5 (CFPM),Dec 1986

Chemical Plant Default Capital Cost (Input Card E 5) = $US500,000 * Q**0.6
where Q = Maximum plant throughput in ooo's STB/day.

Allow for,
(1) Inflation at 8 percent per year
(2) Cost Adjustment USA to Australia = 1.25
(3) Exchange Rate $US0.80 = $A1.00

Chemical Plant Cost in Australia 1989 = $A984,000 * Q**0.6

....

PROCESS DEPENDENT COSTS
POLYMER MIXING PLANT COSTS

Calculations based on Default Cost Data given in U.S of A.
Department of Energy Fossil Energy Report III-4 (PFPM),Dec 1986

Polymer Plant Default Capital Cost (Input Card E 5) = $US100,000 * Q**0.6
where Q = Maximum plant throughput in ooo's STB/day.

Allow for,
(1) Inflation at 8 percent per year,
(2) Cost Adjustment USA to Australia = 1.25
(3) Exchange Rate $US0.80 = $A1.00

Polymer Mixing Plant Cost in Australia 1989 =$A200,000 * QI**0.6

TABLE No. 1.2.6
PROCESS DEPENDENT COSTS

LIQUID CO_2 STORAGE AND VAPORIZATION

Data ex Report by G.P.A.

Capital Costs

	($ooo's)
Storage (500 Tonnes)	500
Vaporizer	400
Boilers (Unattended)	500
Ancillaries	200
	1600

Operating Costs

	($ooo's/year)
Maintenance etc @ 7 % per year	112
Fuel @ 30 MMBTU/day for 330 days @ $4.00 per MMBTU	40
Total Operating Costs	152

Throughput = 20 MMCFD per operating day

To earn 20 % per annum Rate of Return over 15 year life,

Required Tariff = $0.07 per MCF ($A 1989)

Say Vaporization Costs = $0.10 per MCF of CO_2

TABLE No. 1.2.7
PROCESS DEPENDENT COSTS

ONSHORE - BULK TRANSPORT COSTS.

DOLLARS PER TRUCK LOAD FROM SOURCE TO LOGISTIC CENTRE

Material	Polyacryl	Polysacch	Caustic	Pet.Sulf	CO2
Full Load Tonnes	22	22	22	22	35
Source	Nearest Cap.Cit.	Nearest Cap.Cit.	Adelaide/ Sydney	Nearest Cap.Cit.	Nearest Cap.Cit.
Log.Centre					
Alice	1600	1600	1600	1600	3857
Damp/Ons	2650	2650	5300	2650	3563
Dongara	700	700	3950	700	934
Jackson	1200	1200	1400	1200	3152
Moomba	1900	1900	1900	1900	N.A.
Roma	500	500	1700	500	1285
Welshpool	600	600	1125	600	507

Note : Data summarized from Report by G.P.A.

TABLE No. 1.2.8
PROCESS DEPENDENT COSTS

ONSHORE - BULK TRANSPORT COSTS - CALCULATION OF AVERAGE FREIGHT RATE

From Source	To Log.Centre	Road Truck Dist. (Kms	Cost per 22 Tonnes	$/Tonne per 100 K
Adelaide	Alice	1610	1650	4.658
Perth	Onslow	1370	2650	8.792
Perth	Dongara	359	700	8.863
Brisbane	Jackson	1212	1200	4.500
Adelaide	Moomba	966	1900	8.940
Brisbane	Roma	494	500	4.601
Melbourne	Sale	221	600	12.341

Thus, for Bulk Chemicals
Average $ per Tonne/100 Km = 7.53

Note : CO2 Tpt.Costs = $2.60/35 tonne load/Km
i.e.Equiv $ per Tonne/100 Km = 7.43

Note : Data summarized from Report by G.P.A.

TABLE No. 1.2.9
PROCESS DEPENDENT COSTS

ONSHORE - SPECIAL CASE - BARROW ISLAND BULK TRANSPORT COSTS.

(1) Barrow Island is supplied with bulk materials by Landing Barge ex Onslow W.A
For this study, it is assumed that bulk chemicals will be transported in a si

(2) Barge rental plus fuel costs = \$3000 per day
Load capability - Deck Cargo = 15 tonnes
- Liquid Cargo = 20 tonnes
Speed = 10 knots

(3) Trip Distance = 64 Kms

Return trip time = 8 hours
Allow 4 hours load/unload

Time per round trip = 12 hours

(4) Cost with 15 tonnes deck cargo = \$100 per tonne

(5) Assuming that a modified barge of the same size can carry 30 tonnes, cost per tonne = \$50, equivalent to \$78 per tonne per 100 Kms.

2.0 GEOGRAPHICAL DATA

Data appertaining to reservoir properties, fluid content, reservoir performance etcetera have been collected by the Bureau of Mineral Resources and now compiled into one large data set stored on computer file in two formats. To each reservoir for which they assembled data, the Bureau of Mineral Resources allocated a reference number of up to three digits. An additional classification has been added in the form of a single or binary alphabetic code to indicate in what Basin the reservoir is located. The data for each reservoir is stored and listed in a computer file RES14.WK1 in numerical order of field number.

After calculation by Bureau of Mineral Resources of a value for original oil in place (OOIP) for each field the total data set was re-sorted into Basins and then by descending order of OOIP. This data file is also stored on computer disk under the name RES12.WK1 and this format was chosen for easy reference of the largest fields in each of the Basins to enable economic feasibility studies of EOR processors to be addressed towards the more likely candidates first. The RES12.WK1 formats were then modified for printing to allow headings of data columns to be reprinted at the top of each page. These amended versions are stored on computer disk under the titles RES12A.WK1.

A printout of RES12A.WK1 is provided as Attachment No. 2.

In addition to the reservoir data it was necessary to accumulate geographical information relating to each field to enable the costs of development and operating logistics to be calculated for both on-shore and off-shore reservoirs. A set of files were therefore built on computer disk entitled GEOG14.WK1, GEOG12.WK1, GEOG12A.WK1, the suffix numbers having the same meaning in relation to these files as to the RES files described above.

A printout of GEOG12A.WK1 is provided as Attachment No. 3.

The data presented was derived as follows:

2.1 A Logistics Centre was allocated to each of the fields/reservoirs. The geographic co-ordinates in latitude and longitude of each centre were obtained from standard geographical references and the latitude and longitude of each oil field was drawn from Reference No. 2 ("Oil and Gas Fields of Australasia" by Robertson Research). The approximate distance in kilometres on the Earth's surface for a minute of latitude and a minute of longitude at various levels of latitude throughout Australia were calculated from standard geographic references and the straight line distance each field and its Logistic Centre was calculated using Pythagoras' theorem. For on-shore fields this straight line distance was increased by 15% to allow for terrain diversions. In a similar way were calculated the distances from the nearest oil line head for on-shore fields and the nearest source of gaseous carbon dioxide. In addition the GEOG series of data contains the water depth for off-shore fields, the effective pay area of the reservoir, as calculated by Bureau of Mineral

Resources, and the number of producing oil wells and injection wells already in existence in each of the fields or reservoirs.

The cost data preparation sheets described in Section 3 have a requirement as part of their input this geographic data for the subject field. From these data are automatically calculated all relevant capital and operating costs and raw materials cost which vary with location and distance as well as oil transportation costs. In the case of off shore fields the water depth is used automatically to calculate the cost of any additional well support structures or platforms that may be required for the off-shore EOR project to be undertaken.

3.0 Project Cost Preparation

3.1 The technical/economic analyses used in this study to evaluate the commercial attractiveness of application of EOR processes to any given Australian field/reservoir are performed by use of the Predictive Models developed by the Department of Energy U.S.A.

These models were developed for economic evaluation of fields under United States fiscal conditions and cost structures. The revamping the computer source code to fit exactly these conditions within Australia was judged to be unattractive and possibly risky. Therefore, it was decided to take the more sensible step of preparing cost and fiscal data for evaluation of Australia EOR prospects in a format acceptable to the Predictive Models as they stood. This has been accomplished by the development of a set of computer spreadsheet programmes which contain all of the basic data relating to the Process Independent and Process Dependent costs.*

The spreadsheet programmes are entitled:

(a) CFON.WK1 for Chemical Flood Projects - On-shore.

(b) POLON.WK1 for Polymer Flood Projects - On-shore.

(c) CO2ON.WK1 for CO2 Miscible Flood Projects - On-shore.

(d) CO2OFF.WK1 for CO2 miscible Flood Projects - Off-shore Platforms.

3.2 Use of the spreadsheets.

3.2.1 All spreadsheets require LOTUS 1-2-3, Release 2 or later to run.

3.2.2 The spreadsheets are "menu driven" and require little or no knowledge of LOTUS operations, all commands necessary for the use of the spreadsheet being presented in a custom built menu with clear instructions as to their operation.

3.2.2 Briefly, the procedures and operations are as follows:

Once the spreadsheet has been retrieved from disk file into the active memory, the user will be prompted to supply a new file name, which may be required for a specific case. Whether or not the user changes the name, striking the enter key causes the Command Menu, illustrated in Figure 3.1 to appear.

---

* The Australian economics were checked for feasibility by comparison with field examples.

Figure No. 3.1

FILE NAME : CFON.WK1

COMMAND MENU	
Amend File Name	<ALT> F
Review Basic Cost Data	<ALT> B
Enter Project Data	<ALT> E
Print Input and Results	<ALT> P
Print Results only	<ALT> R
Save Data and Stay	<ALT> S
Save Data and Leave	<ALT> L
Quit with No Save	<ALT> Q
Return To This Menu	<ALT> M

The user then chooses the desired operation as follows:-

(a) <ALT> F — Returns the screen to the prompt for the file name change. Any new name entered is automatically presented in the spreadsheet headings and is stored for use in saving the (new) file to disk if required.

(b) <ALT> B — All of the relevant basic cost data given and described in Section 2 above, is stored in the spreadsheet. Invoking <ALT> B allows the user to review and amend these data. It is stressed that this does not need to be done to derive a set of data costs for a project but only if the base costs require updating, i.e. for inflation or as the result of a general cost review. The user will also note that certain "cells" in the cost data section are protected and, unless deliberate action is taken via LOTUS standard commands, no change can be made to the contents of these cells. Since they contain formulae for calculation the user is urged to be cautious in disturbing them.

(c) <ALT> E This is the principal command utilized in the spreadsheet and directs and prompts the user to enter the data specific to the project to be analysed. Upon invocation the following sequence occurs:

(i) The user is prompted for the:-

Basin Code number, which enables the programme to select the correct set of basic cost data,

Accumulation Number, for identification purposes.

Both these data are drawn from the GEOG files described in Section 2 above.

(ii) The next screen requests input of further geographic data, from the GEOG files, relating to distances and water depth (if appropriate). From these data, the programme calculates the Logistic and Operations Multipliers, trucking costs for chemicals and oil transportation costs. The basic cost data and these derived data are then automatically set in place for later calculation of the specific project data is entered.

(iii) The next screen requests the technical data for the project and the oil price to be used in economic evaluation and the cost of fuel.

Note that the Project Injection Rate, for liquid or CO_2, may have to be determined from a dummy run of the Predictive Model.

(iv) The next screen displays the calculated number of patterns that are required for the project, the number of production wells and the number of injection wells. It provides the user with the opportunity to change any of these factors.

Based upon the data from (iii) and (iv) the spreadsheet calculates all pressure losses in injection lines and tubing, the size of plant, the horse power of any pumps and compressors and, in the case of a CO_2 flood, the cost of CO_2 pipelines and delivered cost of CO_2.

At this stage, all of the costs related to the specific project have been computed and entered into a format suitable for reading and entry into the DOE Predictive Model.

(v) The final data entry screen permits the user to enter a Case Name, which defaults to the Basin plus Accumulation Number, a choice of Print options, the Discount Rate to be used for economic evaluation, the Royalty Rate to be paid (suggest 0 or 0.10) and the scheduling of patterns. Note that the programme defaults to placing all of the patterns to commence in the first year of the EOR project with zero patterns in each following year. The user must here use judgement as to the viability of this and amend the array input accordingly.

(vi) The final screen presents all of the economic input data in ASCII file form as it is to be input to the Predictive Model.

(d) <ALT> P Provides a printout of the project input data, derived engineering data and Predictive Model input sheet.

(e) <ALT> R Provides a printout of the Predictive Model input sheet only.

(f) <ALT> S and <ALT> L will save the spreadsheet under the current name shown above the Command Menu.

3.2.3 The form of the printout(s) and of the data description required in the Predictive Models is shown for the spreadsheets in Attachments Nos 4, 5, 6 and 7.

4.0 Notes on Economic Factors.

4.1 Predictive Models.

4.1.1 Royalty

The Predictive Models calculate Royalty, at the rate selected, on GROSS income, i.e. as per the U.S.A. custom, there are no deductions of operating costs or capital depreciation allowances from gross price to arrive at a Well Head Value, as is the Australian method. Therefore, the Royalty payments calculated by the Predictive Models, will be overstated in Australian terms, but this is not a dominant factor in the final economic outcome.

4.1.2 The Predictive Models automatically add overhead into the calculations of operating cost at some 2-4 percent. This is built in to the source code and there seems to be no way in the input procedure to change it. Fortunately the percent is small but should be realized.

4.2 Oil Price.

It was decided to run evaluations at oil prices of $US12, $20 and $50 per BBL.

I suggest we use an exchange rate of $US0.80 = $A1 (reflecting optimism in the future) and that the resultant $A price is assumed to be the same for <u>all</u> crudes at <u>all</u> refineries.

5.0 Some notes on Costs per BBL recovered.

The following are some indicative U.S.A. results of EOR, drawn from the article in Petroleum Engineer International, November 1986, entitled "EOR : What Those New Reserves Will Cost", and substituting Australian materials costs.

They demonstrate why one should not be disappointed if many of the Australian cases studied are not attractive. Don't forget, to these costs must be added capital and operating costs.

5.1 Alkaline Flood.

Typical Efficiency = 50 lb Alkali per BBL oil recovered.

NaOM costs at say Moomba = A$700/tonne
= $0.33 per lb.
Alkali Cost per BBL of oil = $A16.

5.2 Polymer Flood.

Typical Efficiency = 1.5 lb Polymer per BBL oil recovered.

Polysaccharide Costs = $1580 per tonne
= $0.72 per lb

Polymer cost per BBL of oil - $A1.08

5.3 Surfactant

Typical Efficiency = 13 - 37 lb surfactant per BBL oil recovered.

Petroleum sulfonate Cost = A$4100 per tonne
= $A1.86 per lb.

Surfactant Cost per BBL of oil = $24 - $69.

5.4 CO2 Flood.
(Kelly-Snyder Field)

Efficiency = 7-12 MCF per BBL oil recovered.

(a) Cost of CO2 ex Moomba = $0.64 per MCF
CO2 Cost per bbl = $4.48 - $7.68.

(b) Cost of CO2 ex Dampier = $3.00 per MCF
Add Pipeline to B.I. = $2.00 per MCF
Total $5.00 per MCF

CO2 Cost per bbl = $35 - $60.

REFERENCES:

(1) "Enhanced Oil Recovery" by the National Petroleum Council (U.S. of A.) June 1984.

(2) "Oil and Gas Fields of Australasia" by Robertson Research (Australia) Pty. Ltd. March 1988.

ATTACHMENT No. 1

GLEN PARKINSON & ASSOCIATES PTY LT
PROJECT MANAGEMENT • ENGINEERIN

1 East Terrace, Mile End, South Australia 503
P.O. Box 140, Hindmarsh, SA 5007 Fax (08) 43 422
Telephone (08) 352 4799

19 June 1989

Thomas Petroleum Consultants Pty Ltd
10A Saratoga Drive
NOVAR GARDENS SA 5040

ATTENTION: MR. R. THOMAS

Dear Sir

<u>CO_2 RECOVERY - LOY YANG</u>

At your request I have estimated the capital and operating costs which could be expected for a facility to extract Carbon Dioxide from flue gases at the Loy Yang Power Station in Victoria.

Throughput	20 MMSCFD of CO_2
Capital Cost $1989	$20MM
Stripping Costs	6 GJ/Tonne CO_2
Electrical Energy	100 kW Hr/Tonne CO_2
Operating Costs	6% Capital Per Annum

These costs have been based on the costs of similar facilities escalated for size increase and inflation.

These costs make no provision for compression on liquefaction and should be provided for in addition to the above figures.

I trust this meets your requirements.

Yours sincerely

Glen J. Parkinson

GLEN PARKINSON & ASSOCIATES PTY LTD
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16 May 1989

Thomas Petroleum Consultants Pty Ltd
10A Saratoga Drive
NOVAR GARDENS SA 5040

ATTENTION: MR. R. THOMAS

Dear Sir

NERDDP PROJECT 976
POTENTIAL FOR EOR IN AUSTRALIA
CARBON DIOXIDE AND CHEMICAL COSTS

As requested we have carried out the work referred to by you in your document RT:DAA/GEN266 dated 17th March 1989.

(A) CARBON DIOXIDE (CO_2) RECOVERY

We have established a conceptual design and costing for recovering waste carbon dioxide from CO_2 extraction facilities.

Most bulk CO_2 removal systems in the Australian gas industry reject the CO_2 at essentially atmospheric pressure and saturated with water vapour. We have therefore selected CO_2 at these conditions as feed material to the process.

It is necessary to remove most of the water from the CO_2 to prevent corrosion of the transport system. It is more economic to remove the water at high pressure because the specific volume of the CO_2 is lower and therefore the sizes of vessels reduces. However, when compressed to high pressures the density differential between the CO_2 and the Tri Ethylene Glycol (TEG) drying medium is reduced and may cause difficulties in processing and separation. We have therefore elected to dry the CO_2 at about 3500 kPa following staged compression, cooling and separation. The dehydration plant would be designed to operate at temperatures above about 25°C to ensure that there is no possibility of entering the two phase region, particularly in the subsequent compressors.

The dehydration facility and compression costs for the facility have been based on a nominal flow of 20 MMSCFD.

The compressor is based on an integral reciprocating compressor with 300 series stainless steel materials of construction in the appropriate areas where corrosion could be expected to be a problem with carbon steel.

The dehydration facilities have been based on a TEG system with special vessels to degas the TEG and uses 300 series stainless steel in areas susceptible to carbonic acid corrosion.

The possibility of utilizing membrane technology for the separation of CO_2 and water was investigated but is not presently applicable.

Appendix I shows the capital and marginal operating costs for a 20 MMSCFD carbon dioxide processing and compression facility.

(B) BULK CARBON DIOXIDE

Bulk CO_2 is currently supplied from several sources, one of the key sources being the CO_2 well near Mt. Gambier. At present there is an Australia wide shortage of supply of CO_2. Liquid CO_2 can be supplied in tankers (20 tonne) or ISO containers (15 tonne) which can be carried on flat top trucks to remote areas. Present delivery cost is about $1.30/km for the round trip. It is likely that by the early 1990's tankers up to 35 tonne will be available at a cost of about $1.30/km round trip.

The CO_2 is transported as a liquid at - 78 deg C and atmospheric pressure.

Storage on site will be in a vacuum insulated vessel which will have losses of up to 0.5% per day. This will be reduced if there is frequent addition of liquid CO_2 to the vessel.

The liquid CO_2 would be vaporized and compressed for injection.

A summary of costs is shown in Appendix II.

(C) PIPELINE TRANSPORTATION

Pipelines have been sized to transport various quantities of carbon dioxide over various distances.

Compression costs have been based on maintaining a minimum of 1100 psi in the pipeline to keep above the two phase region. Compressor discharge is designed to be about 2200 psi to keep within the 900# flange ratings.

A summary of pipeline and compressor station capital and operating costs is shown in Appendix III

(D) EOR CHEMICALS

We have established the costs of a broad range of chemicals used in various EOR schemes and generally in accordance with the list you supplied. These are shown in Appendix IV. When selecting actual chemicals it will be necessary to check compatibility between chemicals and polymers in each particular case. In some cases e.g. sodium pentachlorophenol the chemicals have been banned in some countries and chemical suppliers are reluctant to supply. The same applies for hydrazine. However, we have established some alternatives which we have priced and trust that this approach is satisfactory. You will also note that in some cases we have listed prices for specific products which are either the same chemical or are used as an alternative.

(E) TRANSPORTATION COSTS

We have established costs for transportation of full loads between various appropriate centres. A full load consists of 22 tonnes of palletted material or 110 x 200 litre drums.

There are some peculiarities in the costs which are due to backloading opportunities etc. In some cases we have had to estimate the costs based on similar information.

Apart from the special transportation cost outlined in Appendix II we have identified special transportation costs for:

> Bulk sodium hydroxide (caustic soda) can be delivered as a 50% solution from either Adelaide or Sydney on the basis of $11/tonne of pure sodium hydroxide/100 km i.e. about $100/tonne 100% sodium hydroxide from Adelaide to Moomba or Sydney to Jackson.

All other transportation costs are shown in Appendix V.

Yours faithfully

Glen J. Parkinson

APPENDIX I

CARBON DIOXIDE RECOVERY

BASIS: 20 MMSCFD of Carbon Dioxide.

Feed at atmospheric pressure and water saturated.

Drying using Tri Ethylene Glycol at 500 psi.

Compression in stages to 1100 psi.

Fuel and services available.

CAPITAL COSTS

(a)	Dehydration facility	\$0.32MM
(b)	Compression to 1100 psi	\$9MM installed
(c)	Compression 1100 to 2200 psi	\$2.5MM installed

OPERATING COSTS/REQUIREMENTS

(a)	Dehydration	5% capital/year + fuel
(b)	Compression	7% capital/year + fuel
(c)	Fuel for dehydration	0.02 MMSCFD
(d)	Fuel for compression	(i) 1.2 MMSCFD for 0 to 1100 psia
		(ii) 0.2 MMSCFD for 1100 to 2200 psia

APPENDIX II

BULK CARBON DIOXIDE

Purchase Price	\$220/tonne - Capital City
Delivery Cost for 35 tonne	\$1.30/km round trip

TRANSPORTATION OF BULK CARBON DIOXIDE FROM MOOMBA

Destination	Delivery \$/tonne
Sale	125
Dongara	263
Broome	410
Roma	72
Toowoomba	96
Alice Springs	112
Jackson	23
Barrow Island (Onslow)	335 + Sea

CAPITAL COSTS

Storage of liquid CO_2 (500 tonne)	\$0.5MM
Vaporizer	\$0.4MM
Boilers (unattended)	\$0.5MM
Ancillaries	\$0.2MM
	\$1.6MM
Liquifier (30 TPD)	\$4.0MM

APPENDIX III

PIPELINE - assumes fuel available

Capital Cost based on 8"/12" pipeline = $120,000/km.

Throughput with 2200 psi inlet and 1100 psi outlet.

LENGTH		FLOW (MMSCFD)	
Km	Miles	8" NB (0.6663 ft) ID	12" NB (0.9893 ft) ID
161	100	41.1	115
322	200	29.1	81.3
483	300	23.7	66.4

Marginal Operating Cost use 2% capital/year.

COMPRESSION (installed)

1100 psi to 2200 psi for 20 MMSCFD $2.5MM

Operating Cost 7% capital/year + fuel

Fuel = 0.2 MMSCFD

APPENDIX IV

	LOCATION	$ DRUM (200L)	$/TONNE
POLYMERS			
Acrylamide	A	$950	
Polyacrylamide	Cap. City		$3200
Polysaccharide	Cap. City		$1500
ALKALIS			
Sodium Carbonate (Soda Ash)	A		$350/tonne (Bulk)
Sodium Hydroxide (Caustic Soda)	A, S		$620/tonne (Bulk Soln.)
Sodium Silicate	A		$710
SURFACTANTS			
Broad Spectrum Petroleum Sulfonates	Cap. City		$4000/tonne (Bulk)
BACTERICIDE			
Sodium Dichlorophenol (Alfloc 276)	Cap. City		$12000
Corexit 7679 (Aldehyde base)	M	$1050 (212 kg)	
m-Formaldehyde	A	$182	$780
OXYGEN SCAVENGERS			
Alfloc 194 (35% Hydrazine)	P,A,M,S,B	$1600	
Corexit 7767 (Ammonium bisulphite base)	M	$420	$1600
Visco 3656 (Ammonium bisulphite base)	P,A,M,S,B	$425	
OTHERS			
Butyl Alcohol	A	$183	$1700
Isopropyl Alcohol	Cap. City	$166	$2300
Calcium Chloride	A		$535/tonne (Bulk)
Sodium Chloride	A		$100/tonne (Bulk)

A = Adelaide
M = Melbourne
P = Perth
S = Sydney

APPENDIX V

FULL LOAD TRANSPORTATION COSTS

FROM \ TO	SALE	DONGARA	BROOME	ROMA	TOOWOOMBA	ALICE SPRINGS	MOOMBA	JACKSON	BARROW IS. (ONSLOW)
MELBOURNE	600	4600	7400	2800	2700	3000	2500	2400	6300
ADELAIDE	1125	3950	6746	2650	2450	1650	1900	2450	5300
PERTH	2625	700	2450	4150	3950	3150	3400	3950	2650
BRISBANE	1200	4800		500	400	2000	1400	1200	
SYDNEY	1150	5800		1700	1500	1600	1500	1400	

ATTACHMENTS 2 AND 3 OF ANNEX 1 HAVE BEEN WITHHELD

AS THEY RELATE TO CONFIDENTIAL DATA

ATTACHMENT No. 4

Filename: CFON.WK1 10:18 PM 19-Jun-89

CHEMICAL FLOOD PROJECTS COST CALCULATION
ONSHORE FIELD

Assumes (1) Field Production Facilities exist.

Geographic Data

Basin and Accumulation Code	CW-181
Logistics Base	Onslow
Distance From Base (Kms)	64
Oil Pipeline Head	Perth
Distance from Pipeline (Kms)	1192

Accumulation and Pattern Data

Effective Area of Accumulation (acres)	21004
Number of Existing Producing Wells	400
Number of Existing Injection Wells	200
Area of New Pattern (acres)	53
Total Project Life (Years)	10

General Project Specifications

QO : Project Oil Production Rate (STBD)	20000
QI : Project Injection Rate (STBD)	20000
G : S.G.of Injected Fluid	1.00
U : Injected Fluid Viscosity (cps)	1.00
Offshore Project (1=Yes,0=No)	0
EW : Vertical Depth of Well (feet)	1919
Are Wells Deviated (1=Yes,0=No)	0
Artificial Lift (1=Yes,0=No)	1
Pr : Reservoir Pressure (psig)	1015
Pi : Sand face Injection Pressure (psig)	1265
Crude Oil Price ($A/STBO)	25.00
LL : Average Length of Well Line (feet)	4000
EL : Increase in Elevation (feet)	0
DL : Diameter of Well Line (ins)	4.000
KL : Abs. Roughness of pipe (ins)	0.0020
LW : Average Length of Tubing (feet)	1919
DW : Diameter of Well Tubing (ins)	2.991
KW : Abs. Roughness of Tubing (ins)	0.0020

Chemical Concentration Data

Surfactant Concentration (% by Wt)	5.00
Caustic Concentration (% by Wt)	0.00

Calculated Pattern Data

Total Number of Patterns	396
Total Producing Wells Required	396
Total Injection Wells Required	615
Number of New Producing Wells Required	0
Number of New Injection Wells Required	415

Calculated Pump Requirements

E : Mechanical Efficiency	0.92
Pump Fuel Rate ((BTU/HP-hr)	8000
DP : Total Net Pressure Loss (psi)	-831
P2 : Pump Discharge Pressure (psig)	434
HP : Pump Brake Horsepower Required	241
Fu : Pump Fuel Consumed (MMBTU per Day)	31

Calculated Chemical Content of Slug

Surfactant Content (LB/BBL)	17.52
Caustic Content (LB/BBL)	0.00

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Cost Data
(Refer RESLOC.WK1 for Unit Costs)

*****************************************************
Capital Costs       LM : Log. Multiplier      1.00      *
:::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::
Base Cost Facilities/Structure ($ooo's)         0       *    -- Chemical Handling Plant --
          Increment per Well ($ooo's)           0       *   (Includes recovery and treatment
-----------------------------------------------         *   of produced water and makeup)
 -- Well Costs (per well) --                            *
Drilling/Completion                                     *   Capital Cost ($ooo's) : Chembase times QI^0.6
Depth Variable ($ooo's/foot)               0.1096       *   Chembase (adjusted from DoE USA costs)      984
Fixed Cost ($ooo's)                           115       *   -----------------------------------------------
Gathering/Injection Line ($ooo's)             160       *    -- Water Wells --
                                                        *   Number of water wells (1 per 5 MSTBD
Artificial Lift Costs                                   *                    of Plant Capacity)          4
Depth Variable ($ooo's/foot)               0.0030       *
Fixed Cost ($ooo's)                           138       *   Total Water Well Costs ($ooo's)            1941
-----------------------------------------------         *   -----------------------------------------------
Total Cost per Well                                     *    -- Injection Pumps --
New Producer ($ooo's)                         629       *   Cost per HP installed ($)                  1600
Injection or Water Well ($ooo's)              485       *   Total Injection Pump Costs ($ooo's)         385
::::::::::::::::::::::::::::::::::::::::::::::::::::::::*:::::::::::::::::::::::::::::::::::::::::::::::
Total Drill/Equip Costs ($ooo's)           201409       *   Chemical Plant Costs ($ooo's)              5938
                                                        *   Water Supply/Injection Costs ($ooo's)      2326
*********************************************************************************************************
Operating Costs     OM : Ops. Multiplier      1.20
:::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::::
Downhole and Workover Costs per Well                    *   Calculated Total Production Operating Costs
Producers-  Natural Flow ($ooo's/yr)        75.00       *   Lifting/Workover Costs ($ooo's/yr)        90043
   Add for Artificial Lift ($ooo's/yr)      71.00       *   Field Facilities Costs ($ooo's/yr)        56719
Injectors ($ooo's/yr)                       28.00       *
-----------------------------------------------         *   -----------------------------------------------
Field Production Facilities                             *   Chemical Slug Costs
Base Cost ($ooo's/yr)                      174.00       *   Surfactant ($/LB on Site)                  1.89
Add Cost per Producing Well ($ooo's/yr)     68.25       *   Caustic ($/LB on Site)                     0.41
Add Cost of Throughput ($ooo's/yr/MBBLD)     3.85       *   Polymer ($/LB on Site)                     1.53
Add Cost per Injection Well ($ooo's/yr)     32.50       *   Surfactant/Caustic Slug Cost ($/BBL)      33.15
-----------------------------------------------         *   -----------------------------------------------
Costs per Barrel of Oil                                 *   Chemical Plant and Water Supply Operating Costs
Trucking Tariff ($/BBL/100 Kms)              0.00       *   Percent of Capex per year                  5.00
Pipeline/Shipping Costs ($/STBO)             1.00       *   Operating Cost ($ooo's/yr)                  473
-----------------------------------------------         *   -----------------------------------------------
Chemical Costs                                          *   Injection System Operating Costs
Surfactants ($/Tonne at Log Base)         4120.00       *   Percent of Capex per year                  5.00
Caustic ($/Tonne at Log Base)              861.00       *   Maintenance etc Cost ($ooo's/yr)          23.11
Polymer ($/Tonne at Log Base)             3320.00       *   Calorific Value of Crude Oil (MMBTU/BBL)   5.75
Transport- Base to Field ($/tonne/100Km)    78.00       *   Fuel Costs ($ooo's/yr)                    46.94
-----------------------------------------------         *   Total Operating Costs ($ooo's/yr)         70.05
Fuel Value (If Gas available use 0,                     *   -----------------------------------------------
else use Crude Price (A$/STBO)              25.00       *   Total Oil Transport Costs ($/BBL)          1.00
*********************************************************************************************************

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For Menu - Strike <Return>

CFPM - ECONOMIC DATA ENTRY
::::::::::::::::::::::::::

CARD      Entry
--------- ----------------------------------------
E-1       CW-181
E-2       10,53,0,2,1,1,1,1,1,0,1,0
E-4       0,0,0,0
E-5       5938,0,2326,0,0.000001,0.000001
E-6       0,0.0010,0
E-7       0.15,0,0.10,0,0,0,0,0
E-8       0,0,0,0,0
E-9       0,0,0,0,0,0,0,0
E-10      0,0,0
E-12      396,9*0.0
E-13      0,25.00,0
E-14      0,0.000001,0
E-15      0,33.15,0
E-16      0,1.53,0
E-17      0,371981,0
E-18      0,1.00,0
E-19      0,0.20,0
E-20      1.0,508608,508608,508608
E-21      1.0,0,0,0
E-22      END


Filename: CFON.WK1
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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	Entry
E1 - Title				
	Title or Case Description	TITLE	CW-181	
E2 - Case Controls				
	Project Years (for all patterns)	M	10	
		ISTATE	53	
		IDIST	0	
	Print Control (0,1 or 2)- See Manual	IOUT	2	
	Note: IOUT =0,Economic Summary only	IFIT	1	
	=1,Plus Annual Cashflows	IDAT	1	
	=2,Plus DCF and Escalation Calcs	NCT	1	
		NCI	1	
		IDISC	1	
		ISO	0	
		IPLIF	1	
		IDEBT	0	

NOTE!!!! Skip this Card if IDEBT = 0 on Card E2.

Card No.	Description/Notes	Symbol	Entry	Notes
E3 - Debt Controls				
		PCTDBT	0	
		DBTINT	0	
		NYRRPY	0	
		NYPAID	0	
E4 - Drilling Data				
		WPP1	0	
		WPP2	0	
		WPP3	0	
		WPP4	0	
E5 - Operating Data				
	Project Chemical Plant Capex ($ooo's)	CCHM	5938	
	Chemical Plant Capacity (MMBBL/yr)	CSCAP	0	Note: Will Default. Refer Manual.
	Project Injection Capex ($ooo's)	CWAT	2326	
	Water Plant Capacity (MMBBL/yr)	CWCAP	0	Note: Will Default. Refer Manual.
	Annual Cost W/O per Pattern ($ooo's)	WOCOST	0.000001	Note: Entry of 0 only causes default
	Produced Water Treatment ($/BBL)	WTCOST	0.000001	to values built in to USA code.
E6 - Operating Data				
	Months of Working Capital	WCAP	0	
	Oil Volume Uncertainty (Factor)	UNCO	0.0010	Note: Default= 0.0010
	Startup Costs ($ooo's)	COSTRT	0	

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	
E7 - Taxes and Escalation				
	Monetary Discount Rate (Fraction)	XDR	0.15	Note: Use 0.15 or 0.20
	Inflation Rate	XINF	0	
	Royalty (Fraction)	XROY	0.10	Note: Run Cases at 0 , 0.10
	Severance Tax (N.A. in Aust)	XSEV	0	
	Federal Tax Rate	XFIT	0	Note: Economics run on Pre-Tax basis
	Invest. Credits (N.A.)	XTCR	0	
	Depreciation Time (N.A.)	DTIM	0	Note: Economics run on Pre-Tax basis
	State Income Tax (N.A.)	XSTX	0	
E8 - Windfall Profit Tax				
	NOT APPLICABLE IN AUSTRALIA	XWPT	0	
		WPHO	0	
		EPHO	0	
		BTIM	0	
		BPOW	0	
E9 - Escalation				
	Oil Price	ESCPO	0	Note: All Economics to be run at constant Costs and Prices.
	Gas Price	ESCPG	0	
	Chemical Price	ESCPI	0	
	Operating Costs	ESCFO	0	
	Chemical Handling Costs	ESCTR	0	
	Tangible Capex	ESCCT	0	
	Intangible Capex	ESCCI	0	
	Work over Costs	ESCWO	0	
E10 - Secondary Oil Production Data				
	1979 Base Oil Rate (MBBl/yr)	OILB	0	
	Current Non-Tertiary Oil Rate (MBBL/yr)	OILC	0	
	Annual Oil Rate Decline	DECL	0	

NOTE!!!! Skip this Card if ISO = 0 on Card E2.

E11 - Secondary Oil Production Curve				
	Secondary Oil per Pattern for each year (MBBL/yr) Entered as Array for I=1,M	VOS(I)		
E12 - Project Pattern Schedule				
	Number of Patterns initiated in each year of Project. Entered as Array for I=1,M	PATI(I)	1st Year Following Years 396 ,9*0.0	Note: This assumes all Patterns at start year 1.

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry
E13 - Oil Price Data			
	Low Oil Price ($/BBL)	POL(1)	0
	Most Likely Oil Price ($/BBL)	POM(1)	25.00
	High Oil Price ($/BBL)	POH(1)	0
E14 - Gas Price Data			
	Low Gas Price ($/MCF)	PGL(1)	0
	Most Likely Gas Price ($/MCF)	PGM(1)	0.000001
	High Gas Price ($/MCF)	PGH(1)	0
E15 - Surfactant (Caustic) Slug Price Data			
	Low Slug Price ($/BBL)	PIL(1)	0
	Most Likely Slug Price ($/BBL)	PIM(1)	33.15
	High Slug Price ($/BBL)	PIH(1)	0
E16 - Polymer Price Data			
	Low Polymer Price ($/LB)	PPL(1)	0
	Most Likely Polymer Price ($/LB)	PPM(1)	1.53
	High Polymer Price ($/LB)	PPH(1)	0
E17 - Fixed Annual Operating Cost Data	(Includes all Field Facilities Operating Costs, Lifting Costs and Workover Costs and Chemical Plant and Injection Plant Operating Costs)		
	Costs are $/year per Pattern		
	Low Fixed Operating Costs	FOCL(1)	0
	Most Likely Fixed Operating Costs	FOCM(1)	371981
	High Fixed Operating Costs	FOCH(1)	0
E18 - Variable Annual Operating Cost Data	(Includes all Operating Costs that depend on Oil Production. In Australian context these are limited to Oil Transportation Costs)		
	Low Variable Costs ($/BBL)	OPCL(1)	0
	Most Likely Operating Costs ($/BBL)	OPCM(1)	1.00
	High Variable Costs ($/BBL)	OPCH(1)	0

Note: Assume $A : $US0.8 and Oil Prices : $US/BBL 10,20,50 Low & High Prices always default to 0.8 & 1.2 * Mid Price. Therefore, separate runs must be made to cover each price case.

Note: Entry of 0 only causes default to POM(1)/6.

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	
E19 - Chemical Handling/Treatment Cost Data (Includes Filtering,Mixing,Oxygen Scavengers,Bactericides,etc)				
	Low Cost ($/BBL of Slug)	TRPL(1)	0	Note: Nominal amount = double that used in USA studies.
	Most Likely Cost ($/BBL of Slug)	TRPM(1)	0.20	
	High Cost ($/BBL of Slug)	TRPH(1)	0	
E20 - Tangible Capital Investment (Wells,Flowlines,Injection Lines Production Facilities and all Capital other than Chemical and Injection Systems)				
	Costs are in $ per Pattern			
	Indicator/Control	ICT	1.0	
	Low Costs ($)	CTPL	508608	
	Most Likely Costs ($)	CTPM	508608	
	High Costs ($)	CTPH	508608	
E21 - Intangible Capital Investment (Capital Expensed in a given year. In Australian context = 0)				
	Costs are in $ per Pattern			
	Indicator/Control	ICI	1.0	
	Low Costs ($)	CIPL	0	
	Most Likely Costs ($)	CIPM	0	
	High Costs ($)	CIPH	0	
E22 - END				
	Enter in Columns 1 - 4		END	

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ATTACHMENT No. 5

Filename: POLON.WK1 10:37 PM 19-Jun-89

POLYMER FLOOD PROJECTS COST CALCULATION
ONSHORE FIELD

Assumes (1) Field Production Facilities exist.

Geographic Data

Basin and Accumulation Code	CW-181
Logistics Base	Onslow
Distance From Base (Kms)	64
Oil Pipeline Head	Perth
Distance from Pipeline (Kms)	1303

Calculated Pattern Data

Total Number of Patterns	396
Total Producing Wells Required	396
Total Injection Wells Required	615
Number of New Producing Wells Required	0
Number of New Injection Wells Required	415

Accumulation and Pattern Data

Effective Area of Accumulation (acres)	21004
Number of Existing Producing Wells	400
Number of Existing Injection Wells	200
Area of New Pattern (acres)	53
Total Project Life (Years)	10

Calculated Pump Requirements

E : Mechanical Efficiency	0.92
Pump Fuel Rate ((BTU/HP-hr)	8000
DP : Total Net Pressure Loss (psi)	-831
P2 : Pump Discharge Pressure (psig)	419
HP : Pump Brake Horsepower Required	291
Fu : Pump Fuel Consumed (MMBTU per Day)	37

Calculated Chemical Content of Slug

Surfactant Content (LB/BBL)	0.00
Caustic Content (LB/BBL)	0.00

General Project Specifications

QO : Project Oil Production Rate (STBD)	25000
QI : Project Injection Rate (STBD)	25000
G : S.G.of Injected Fluid	1.00
U : Injected Fluid Viscosity (cps)	1.00
Offshore Project (1:Yes,0:No)	0
EW : Vertical Depth of Well (feet)	1919
Are Wells Deviated (1:Yes,0:No)	0
Artificial Lift (1:Yes,0:No)	1
Pr : Reservoir Pressure (psig)	1000
Pi : Sand face Injection Pressure (psig)	1250
Crude Oil Price ($A/STBO)	25.00
LL : Average Length of Well Line (feet)	4000
EL : Increase in Elevation (feet)	0
DL : Diameter of Well Line (ins)	4.000
KL : Abs. Roughness of pipe (ins)	0.0020
LW : Average Length of Tubing (feet)	1919
DW : Diameter of Well Tubing (ins)	2.991
KW : Abs. Roughness of Tubing (ins)	0.0020

Chemical Concentration Data

Surfactant Concentration (% by Wt)	0.00
Caustic Concentration (% by Wt)	0.00
Polymer Concentration (ppm)	0.00

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Cost Data
(Refer RESLOC.WK1 for Unit Costs)

Capital Costs LM : Log. Multiplier	1.00		
Base Cost Facilities/Structure ($ooo's)	0	-- Polymer Mixing Plant --	
Increment per Well ($ooo's)	0	(Includes recovery and treatment	
		of produced water and makeup)	
-- Well Costs (per well) --			
Drilling/Completion		Cost ($ooo's) : Polbase times QI^0.6	
Depth Variable ($ooo's/foot)	0.1096	Polbase (adjusted from DoE USA costs)	200
Fixed Cost ($ooo's)	115		
Gathering/Injection Line ($ooo's)	160	-- Water Wells --	
		Number of water wells (1 per 5 MSTBD	
Artificial Lift Costs		of Plant Capacity)	5
Depth Variable ($ooo's/foot)	0.0030		
Fixed Cost ($ooo's)	138	Total Water Well Costs ($ooo's)	2427
Total Cost per Well		-- Injection Pumps --	
New Producer ($ooo's)	629	Cost per HP installed ($)	1600
Injection or Water Well ($ooo's)	485	Total Injection Pump Costs ($ooo's)	465
Total Drill/Equip Costs ($ooo's)	201409	Polymer Mixing Plant Costs ($ooo's)	1380
		Water Supply/Injection Costs ($ooo's)	2891

Operating Costs OM : Ops. Multiplier	1.20		
Downhole and Workover Costs per Well		Calculated Total Production Operating Costs	
Producers- Natural Flow ($ooo's/yr)	75.00	Lifting/Workover Costs ($ooo's/yr)	90043
Add for Artificial Lift ($ooo's/yr)	71.00	Field Facilities Costs ($ooo's/yr)	56742
Injectors ($ooo's/yr)	28.00		
Field Production Facilities		Chemical Slug Costs	
Base Cost ($ooo's/yr)	174.00	Surfactant ($/LB on Site)	0.00
Add Cost per Producing Well ($ooo's/yr)	68.25	Caustic ($/LB on Site)	0.00
Add Cost of Throughput ($ooo's/yr/MBBLD)	3.85	Surfactant/Caustic Slug Cost ($/BBL)	0.00
Add Cost per Injection Well ($ooo's/yr)	32.50	Polymer ($/LB on Site)	1.53
Costs per Barrel of Oil		Chemical Plant and Water Supply Operating Costs	
Trucking Tariff ($/BBL/100 Kms)	0.00	Percent of Capex per year	5.00
Pipeline/Shipping Costs ($/STBO)	1.00	Operating Cost ($ooo's/yr)	228
Chemical Costs		Injection System Operating Costs	
Surfactants ($/Tonne at Log Base)	0.00	Percent of Capex per year	5.00
Caustic ($/Tonne at Log Base)	0.00	Maintenance etc Cost ($ooo's/yr)	27.89
Polymer ($/Tonne at Log Base)	3320.00	Calorific Value of Crude Oil (MMBTU/BBL)	5.75
Transport -Base to Field ($/tonne/100Km)	78.00	Fuel Costs ($ooo's/yr)	56.65
		Total Operating Costs ($ooo's/yr)	84.54
Fuel Value (If Gas available use 0,			
else use Crude Oil Price ($A/STBO)	25.00	Total Oil Transport Costs ($/BBL)	1.00

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CFPM - ECONOMIC DATA ENTRY
::::::::::::::::::::::::::

CARD	Entry
E-1	CW-181
E-2	10,53,0,2,1,1,1,1,1,0,1,0
E-4	0,0,0,0
E-5	1380,0,2891,0,0.000001,0.000001
E-6	0,0.0010,0
E-7	0.15,0,0.10,0,0,0,0,0
E-8	0,0,0,0,0
E-9	0,0,0,0,0,0,0,0
E-10	0,0,0
E-12	396,9*0.0
E-13	0,25.00,0
E-14	0,0.000001,0
E-15	0,1.53,0
E-16	0,371459,0
E-17	0,1.00,0
E-18	0,0.20,0
E-19	1.0,508608,508608,508608
E-20	1.0,0,0,0
E-21	END

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	
E1 - Title				
	Title or Case Description	TITLE	CW-181	
E2 - Case Controls				
	Project Years (for all patterns)	M	10	
		ISTATE	53	
		IDIST	0	
	Print Control (0,1 or 2)- See Manual	IOUT	2	
	Note: IOUT =0,Economic Summary only	IFIT	1	
	=1,Plus Annual Cashflows	IDAT	1	
	=2,Plus DCF and Escalation Calcs	NCT	1	
		NCI	1	
		IDISC	1	
		ISO	0	
		IPLIF	1	
		IDEBT	0	
NOTE!!!! Skip this Card if IDEBT = 0 on Card E2.				
E3 - Debt Controls				
		PCTDBT	0	
		DBTINT	0	
		NYRRPY	0	
		NYPAID	0	
E4 - Drilling Data				
		WPP1	0	
		WPP2	0	
		WPP3	0	
		WPP4	0	
E5 - Operating Data				
	Project Chemical Plant Capex ($ooo's)	CCHM	1380	
	Chemical Plant Capacity (MMBBL/yr)	CSCAP	0	Note: Will Default. Refer Manual.
	Project Injection Capex ($ooo's)	CWAT	2891	
	Water Plant Capacity (MMBBL/yr)	CWCAP	0	Note: Will Default. Refer Manual.
	Annual Cost W/O per Pattern ($ooo's)	WOCOST	0.000001	Note: Entry of 0 only causes default
	Produced Water Treatment ($/BBL)	WTCOST	0.000001	to values built in to USA code.
E6 - Operating Data				
	Months of Working Capital	WCAP	0	
	Oil Volume Uncertainty (Factor)	UNCO	0.0010	Note: Default= 0.0010
	Startup Costs ($ooo's)	COSTRT	0	

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	
E7 - Taxes and Escalation				
	Monetary Discount Rate (Fraction)	XDR	0.15	Note: Use 0.15 or 0.20
	Inflation Rate	XINF	0	
	Royalty (Fraction)	XROY	0.10	Note: Run Cases at 0 , 0.10
	Severance Tax (N.A. in Aust)	XSEV	0	
	Federal Tax Rate	XFIT	0	Note: Economics run on Pre-Tax basis
	Invest. Credits (N.A.)	XTCR	0	
	Depreciation Time (N.A.)	DTIM	0	Note: Economics run on Pre-Tax basis
	State Income Tax (N.A.)	XSTX	0	
E8 - Windfall Profit Tax				
	NOT APPLICABLE IN AUSTRALIA	XWPT	0	
		WPHO	0	
		EPHO	0	
		BTIM	0	
		BPOW	0	
E9 - Escalation				
	Oil Price	ESCPO	0	Note: All Economics to be run at constant Costs and Prices.
	Gas Price	ESCPG	0	
	Chemical Price	ESCPI	0	
	Operating Costs	ESCFO	0	
	Chemical Handling Costs	ESCTR	0	
	Tangible Capex	ESCCT	0	
	Intangible Capex	ESCCI	0	
	Work over Costs	ESCWO	0	
E10 - Secondary Oil Production Data				
	1979 Base Oil Rate (MBBl/yr)	OILB	0	
	Current Non-Tertiary Oil Rate (MBBL/yr)	OILC	0	
	Annual Oil Rate Decline	DECL	0	

NOTE!!!! Skip this Card if ISO = 0 on Card E2.

Card No.	Description/Notes	Symbol	Entry	
E11 - Secondary Oil Production Curve	Secondary Oil per Pattern for each year (MBBL/yr) Entered as Array for I=1,M	VOS(I)		
E12 - Project Pattern Schedule	Number of Patterns initiated in each year of Project. Entered as Array for I=1,M	PATI(I)	396 ,9*0.0	Note: This assumes all Patterns at start year 1.

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry
E13 - Oil Price Data			
	Low Oil Price ($/BBL)	POL(1)	0
	Most Likely Oil Price ($/BBL)	POM(1)	25.00
	High Oil Price ($/BBL)	POH(1)	0
E14 - Gas Price Data			
	Low Gas Price ($/MCF)	PGL(1)	0
	Most Likely Gas Price ($/MCF)	PGM(1)	0.000001
	High Gas Price ($/MCF)	PGH(1)	0
E15 - Polymer Price Data			
	Low Polymer Price ($/LB)	PPL(1)	0
	Most Likely Polymer Price ($/LB)	PPM(1)	1.53
	High Polymer Price ($/LB)	PPH(1)	0
E16 - Fixed Annual Operating Cost Data	(Includes all Field Facilities Operating Costs, Lifting Costs and Workover Costs and Chemical Plant and Injection Plant Operating Costs)		
	Costs are $/year per Pattern		
	Low Fixed Operating Costs	FOCL(1)	0
	Most Likely Fixed Operating Costs	FOCM(1)	371459
	High Fixed Operating Costs	FOCH(1)	0
E17 - Variable Annual Operating Cost Data	(Includes all Operating Costs that depend on Oil Production. In Australian context these are limited to Oil Transportation Costs)		
	Low Variable Costs ($/BBL)	OPCL(1)	0
	Most Likely Operating Costs ($/BBL)	OPCM(1)	1.00
	High Variable Costs ($/BBL)	OPCH(1)	0

Note: Assume $A : $US0.8 and Oil Prices : $US/BBL 10,20,50 Low & High Prices always default to 0.8 & 1.2 * Mid Price. Therefore, separate runs must be made to cover each price case.

Note: Entry of 0 only causes default to POM(1)/6.

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	
E18 - Chemical Handling/Treatment Cost Data (Includes Filtering,Mixing,Oxygen Scavengers,Bactericides,etc)				
	Low Cost ($/BBL of Poly Soln)	TRPL(1)	0	Note: Nominal amount : double that used in USA studies.
	Most Likely Cost ($/BBL of Poly Soln)	TRPM(1)	0.20	
	High Cost ($/BBL of Poly Soln)	TRPH(1)	0	
E19 - Tangible Capital Investment (Wells,Flowlines,Injection Lines Production Facilities and all Capital other than Chemical and Injection Systems)				
	Costs are in $ per Pattern			
	Indicator/Control	ICT	1.0	
	Low Costs ($)	CTPL	508608	
	Most Likely Costs ($)	CTPM	508608	
	High Costs ($)	CTPH	508608	
E22 - Intangible Capital Investment (Capital Expensed in a given year. In Australian context : 0)				
	Costs are in $ per Pattern			
	Indicator/Control	ICI	1.0	
	Low Costs ($)	CIPL	0	
	Most Likely Costs ($)	CIPM	0	
	High Costs ($)	CIPH	0	
E21 - END				
	Enter in Columns 1 - 4		END	

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CO2 FLOOD PROJECTS COSTS CALCULATION
ONSHORE

Assumes (1) Field Production Facilities exist.

Geographic Data			
Basin and Accumulation Code	CW-181	Total Number of Patterns	396
Logistics Base	Onslow	Total Producing Wells Required	396
Distance From Base (Kms)	64	Total Injection Wells Required	615
Oil Pipeline Head	Perth	Number of New Producing Wells Required	0
Distance from Oil Head (Kms)	1192	Number of New Injection Wells Required	415
CO2 Pipeline Distance (Kms)	169		

Accumulation and Pattern Data		Calculated Field Compression Requirements for NEW Gas.	
Effective Area of Accumulation (acres)	21004		
Number of Existing Producing Wells	400	NR : No. of Compression Stages	1
Number of Existing Injection Wells	200	Ps : Comp. Suction Pressure (psig)	1100
Area of New Pattern (acres)	53	Pd : Comp. Discharge Pressure (psig)	1058
Total Project Life (years)	10	Ts : Comp. Suction Temp (deg F)	70
		E : Mechanical Efficiency	0.92
General Project Specifications		Fuel Usage Rate (BTU/HP-hr)	8000
		R : Stage Compression Ratio	0.96
QO : Project Oil Production Rate (STBD)	20000	BHP/MMCFD/Stage	0.00
QI : Project Gas Injection Rate (MMCFD)	13.00	Total BHP/MMCFD	0.00
G : Gravity of Gas (Air=1)	1.5195	Total BHP Required	0
Z : Gas Compressibility	0.5000	Fu : Comp Fuel Consumed (MMBTU per Day)	0
K : Ratio of Specific Heats	1.27		
CO2 Supply (Liquid : 1,Gas : 2)	2	Calculated Field Compression Requirements	
WAG Ratio (For No Water,enter 0)	2.00	for RECYCLED Gas.	
Recycle Produced CO2 (1=Yes,0=No)	0	NR : No. of Compression Stages	3
Ratio Produced/Injected Gas	0.75	Ps : Comp. Suction Pressure (psig)	60
Oil/Gas Separator Pressure (psig)	60	Pd : Comp. Discharge Pressure (psig)	1058
Offshore Operation (1=Yes,0=No)	0	Ts : Comp. Suction Temp (deg F)	100
EW : Vertical Depth of Well (feet)	1919	E : Mechanical Efficiency	0.92
Are Wells Deviated (1=Yes,0=No)	0	Fuel Usage Rate ((BTU/HP-hr)	8000
Artificial Lift (1=Yes,0=No)	1	R : Stage Compression Ratio	2.43
Pr : Reservoir Pressure (psig)	1115	BHP/MMCFD/Stage	0.00
Pi : Sand face Injection Pressure (psig)	1265	Total BHP/MMCFD	0.00
		Total BHP Required	0
Crude Oil Price ($A/STBO)	25.00	Fu : Comp Fuel Consumed (MMBTU per Day)	0
LL : Average Length of Well Line (feet)	4000	Pump Requirements for Water Injection (WAG)	
EL : Increase in Elevation (feet)	0		
DL : Diameter of Well Line (ins)	4.000	E : Mechanical Efficiency	0.92
KL : Abs. Roughness of pipe (ins)	0.0020	Fuel Usage Rate ((BTU/HP-hr)	8000
TL : Temperature of Line (deg F)	120	Total Water Injection Rate (STBD)	30025
LW : Average Length of Tubing (feet)	1919	Total Net Pressure Loss (psi)	-831
DW : Diameter of Well Tubing (ins)	2.991	Pump Discharge Pressure (psig)	434
KW : Abs. Roughness of Tubing (ins)	0.0020	Pump BHP Required	241
TW : Temperature of Tubing (deg F)	160	Pump Fuel Consumed (MMBTU per Day)	31

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Cost Data
(Refer RESLOC.WK1 for Unit Costs)

Capital Costs	LM : Log. Multiplier	1.00

Base Facilities/Structure Cost ($ooo's)	0
Increment per Well Drilled ($ooo's)	0
-- Well Costs (per well) --	
Drilling/Completion	
Depth Variable ($ooo's/foot)	0.1096
Fixed Cost ($ooo's)	115
Gathering/Injection Line ($ooo's)	160
Artificial Lift Costs	
Depth Variable ($ooo's/foot)	0.0030
Fixed Cost ($ooo's)	138
Total Cost per Well	
New Producer ($ooo's)	629
Injection or Water Well ($ooo's)	485
Total Drill/Equip Costs ($ooo's)	201409

-- CO2 Recycle/Injection Plant --	
(Includes compression of NEW CO2 and recompression of produced CO2 and Gas.	
Compressor Costs ($ per BHP installed)	1600
Total Cost Compression/Plant ($ooo's)	0
-- Water Wells --	
WAG Water Requirement (STBD)	30420
No. of water wells (1 per 5 MSTBD WAG)	6
Total Water Well Costs ($ooo's)	2953
-- Water Injection Pumps --	
Cost per HP installed ($)	1600
Total Injection Pump Costs ($ooo's)	385
Total Capex for Recycle Plant,Compression Water Supply and Injection ($ooo's)	3338

Operating Costs	OM : Ops. Multiplier	1.20

Downhole and Workover Costs per Well	
Producers- Natural Flow ($ooo's/yr)	75.00
Add for Artificial Lift ($ooo's/yr)	71.00
Injectors ($ooo's/yr)	28.00
Field Production Facilities	
Base Cost ($ooo's/yr)	174.00
Add Cost per Producing Well ($ooo's/yr)	68.25
Add Cost of Throughput ($ooo's/yr/MBBLD)	3.85
Add Cost per Injection Well ($ooo's/yr)	32.50
Costs per Barrel of Oil	
Trucking Tariff ($/BBL/100 Kms)	0.00
Pipeline/Shipping Costs ($/STBO)	1.00
Liquid CO2 ($/Tonne at Log Base)	0
Trucking Base to Field ($/Tonne/100 Kms)	0.00
Liquid CO2 Vaporisation ($ per MCF)	0.00
Gaseous CO2 Cost ($/MCF ex Supply Point)	3.12
CO2 Pipeline Tariff ($/MCF)	2.02
Fuel Value (If Gas available=0, else use Crude Price ($/STBO)	25.00

Total Prod and Well Operating Costs	
Lifting/Workover Costs ($ooo's/yr)	90043
Field Facilities Costs ($ooo's/yr)	56719
CO2 Plant and Gas/Water Injection Operating Costs	
Percent of Capex per year	5.00
Maintenance etc Cost ($ooo's/yr)	200
Calorific Value of Crude Oil (MMBTU/BBL)	5.75
Fuel Costs ($ooo's/yr)	47
Total Plant Operating Costs ($ooo's/yr)	247
Total Production,Well and Plant Operating Costs ($ooo's/Year)	147009
CO2 Costs	
Liquid CO2 Delivered Cost ($ per MCF)	0.00
Store/Vaporise ($ per MCF)	0.00
Total Cost Liquid CO2 ($ per MCF)	0.00
Gaseous CO2 Delivered Cost ($ per MCF)	5.14
CO2 Cost as used ($ per MCF)	5.14
Total Oil Transport Costs ($/BBL)	1.00

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For Menu - Strike <RETURN>

CO2PM - ECONOMIC DATA ENTRY
:::::::::::::::::::::::::::

CARD      Entry
--------- -------------------------------------------------
E-1       CW-181
E-2       10,53,0,2,1,1,1,1,1,0,3,1,1,1,0
E-4       0,0,0,0
E-5       3338,0,0.000001,0.000001
E-6       0,0.0010,0
E-7       0.000001,0.000001,0.000001,0.000001,0.000001
E-8       0,0,0
E-10      0.15,0,0.10,0,0,0,0,0
E-11      0,0,0,0,0
E-12      0,0,0,0,0,0,0,0
E-13      396,9*0.0
E-14      0,25.00,0
E-15      0,0.000001,0
E-16      0,5.14,0
E-17      0,371235,0
E-18      0,1.00,0
E-19      0.000001,0.000001,0.000001
E-20      1.0,508608,508608,508608
E-21      1.0,0,0,0
E-22      END

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	Entry
E1 - Title				
	Title or Case Description	TITLE	CW-181	
E2 - Case Controls				
	Project Years (for all patterns)	M	10	
		ISTATE	53	
		IDIST	0	
	Print Control (0,1 or 2)- See Manual	IOUT2	2	
	Note: IOUT2=0,Economic Summary only	IFIT	1	
	=1,Cash Flows	IDAT	1	
	=2,DCF Calcs. and Escalated Data	NCT	1	
		NCI	1	
		IDISC	1	
		ISO	0	
	Type of CO2 Recycle Plant (0,1,2 or 3)	ICO2	3	
		IPLIF	1	
	Year of Pipeline Capex	IYPL	1	
	Year of CO2 Plant Capex	IYCS	1	
		IDEBT	0	

Note: For Recompression of Produced gas, ICO2=2,else no CO2 Plant assumed and ICO2=3.Entry shown here for ICO2 is dictated by choice made in data entry on Page 1 above.

NOTE!!!! Skip this Card if IDEBT = 0 on Card E2.

Card No.	Description/Notes	Symbol	Entry	Entry
E3 - Debt Controls				
		PCTDBT	0	
		DBTINT	0	
		NYRRPY	0	
		NYPAID	0	
E4 - Drilling Data				
		WPP1	0	
		WPP2	0	
		WPP3	0	
		WPP4	0	
E5 - Operating Data				
	Project CO2 Recycle Plant Capex ($ooo's)	CSEP	3338	
	CO2 Recycle Plant Capacity (MMCFD)	CSCAP	0	
	Annual Cost W/O per Pattern ($ooo's)	WOCOST	0.000001	
	Produced Water Treatment ($/BBL)	WTCOST	0.000001	
E6 - Operating Data				
	Months of Working Capital	WCAP	0	
	Oil Volume Uncertainty (Factor)	UNCO	0.0010	
	Startup Costs ($ooo's)	COSTRT	0	

Note: Will Default. Refer Manual.
Note: Entry of 0 only causes default to values built in to USA code. These costs are included below.

Note: Default= 0.0010

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	
E7 - Pipeline Data				
	Pipeline Capex ($ooo's)	CPIPL	0.000001	
	Length (Miles)	PIPEL	0.000001	Note: Must NOT enter 0 or will Default to USA values.Pipeline costs are included in cost of CO2 delivered in Card E16.
	Capacity (MMMCFD)	PCAP	0.000001	
	Unit Cost ($ooo's/Mile)	PDPM	0.000001	
	Fixed Opex ($ooo's/mile/yr)	PFOC	0.000001	
E8 - Released Oil Data				
	1979 Base Oil Rate (MBBl/yr)	OILB	0	
	Current Non-Tertiary Oil Rate (MBBL/yr)	OILC	0	
	Annual Oil Rate Decline	DECL	0	
NOTE!!!! Skip this Card if ISO = 0 on Card E2.				
E9 - Secondary Oil Production Curve				
	Secondary Oil per Pattern for each year (MBBL/yr) Entered as Array for I=1,M	VOS(I)		
E10 - Taxes and Monetary Data				
	Monetary Discount Rate (Fraction)	XDR	0.15	Note: Use 0.15 or 0.20
	Inflation Rate	XINF	0	
	Royalty (Fraction)	XROY	0.10	Note: Run Cases at 0 , 0.10
	Severance Tax (N.A. in Aust)	XSEV	0	
	Federal Tax Rate	XFIT	0	Note: Economics run on Pre-Tax basis
	Invest. Credits (N.A.)	XTCR	0	
	Depreciation Time (N.A.)	DTIM	0	Note: Economics run on Pre-Tax basis
	State Income Tax (N.A.)	XSTX	0	
E11- Windfall Profit Tax				
	NOT APPLICABLE IN AUSTRALIA	XWPT	0	
		WPHO	0	
		EPHO	0	
		BTIM	0	
		BPOW	0	
E12- Escalation				
	Oil Price	ESCPO	0	Note: All Economics to be run at constant Costs and Prices.
	Gas Price	ESCPG	0	
	Chemical Price	ESCPI	0	
	Operating Costs	ESCFO	0	
	Chemical Handling Costs	ESCTR	0	
	Tangible Capex	ESCCT	0	
	Intangible Capex	ESCCI	0	
	Work over Costs	ESCWO	0	

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	
E13 - Project Pattern Schedule				
	Number of Patterns initiated in each year of Project. Entered as Array for I=1,M	PATI(I)	396 ,9*0.0	Note: This assumes all Patterns at start year 1.
E14 - Oil Price Data				Note: Assume $A = $US0.8 and Oil Prices = $US/BBL 10,20,50 Low & High Prices always default to 0.8 & 1.2 * Mid Price. Therefore, separate runs must be made to cover each price case.
	Low Oil Price ($/BBL)	POL(1)	0	
	Most Likely Oil Price ($/BBL)	POM(1)	25.00	
	High Oil Price ($/BBL)	POH(1)	0	
E15 - Gas Price Data				
	Low Gas Price ($/MCF)	PGL(1)	0	
	Most Likely Gas Price ($/MCF)	PGM(1)	0.000001	Note: Entry of 0 only causes default to POM(1)/6.
	High Gas Price ($/MCF)	PGH(1)	0	
E16 - CO2 Price Data				
	Low CO2 Price ($/MCF)	PIL(1)	0	
	Most Likely CO2 Price ($/MCF)	PIM(1)	5.14	
	High CO2 Price ($/MCF)	PIH(1)	0	
E17 - Fixed Annual Operating Cost Data				
	(Includes all Field Facilities Operating Costs, Lifting Costs and Workover Costs and CO2 Plant and Injection Plant Operating Costs)			
	Costs are $/year per Pattern			
	Low Fixed Operating Costs	FOCL(1)	0	
	Most Likely Fixed Operating Costs	FOCM(1)	371235	
	High Fixed Operating Costs	FOCH(1)	0	

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry
E18 - Variable Annual Operating Cost Data	(Includes all Operating Costs that depend on Oil Production. In Australian context these are limited to Oil Transportation Costs)		
	Low Variable Costs ($/BBL)	OPCL(1)	0
	Most Likely Operating Costs ($/BBL)	OPCM(1)	1.00
	High Variable Costs ($/BBL)	OPCH(1)	0
E19 - CO2 Treating/Recycling Cost Data			
	Low Cost ($/MCF)	TRPL(1)	0.000001
	Most Likely Cost ($/MCF)	TRPM(1)	0.000001
	High Cost ($/MCF)	TRPH(1)	0.000001
E20 - Tangible Capital Investment	(Wells,Flowlines,Injection Lines Production Facilities and all Capital other than CO2 Plant and Injection Systems)		
	Costs are in $ per Pattern		
	Indicator/Control	ICT	1.0
	Low Costs ($)	CTPL	508608
	Most Likely Costs ($)	CTPM	508608
	High Costs ($)	CTPH	508608
E21 - Intangible Capital Investment	(Capital Expensed in a given year. In Australian context : 0)		
	Costs are in $ per Pattern		
	Indicator/Control	ICI	1.0
	Low Costs ($)	CIPL	0
	Most Likely Costs ($)	CIPM	0
	High Costs ($)	CIPH	0
E22 - END			
	Enter in Columns 1 - 4		END

Note: Must NOT enter 0 or will Default to USA values.These costs are included in Opex on Card E17

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Filename: CO2OFF.WK1 10:26 PM 19-Jun-89

CO2 FLOOD PROJECTS COSTS CALCULATION
OFFSHORE FIELD

Assumes (1) Field Production Facilities exist
(2) Process applicable only to fields developed from platforms.
(3) CO2 delivered to platform(s) by new pipeline

Geographic Data	
Basin and Accumulation Code	G-25
Logistics Base	W'Pool
Distance From Base (Kms)	182
Oil Pipeline Head	W'Port
Distance from Pipeline (Kms)	0
Distance from CO2 Plant (Kms)	204
Water Depth (metres)	73

Calculated Pattern Data	
Total Number of Patterns	92
Total Producing Wells Required	92
Total Injection Wells Required	149
Number of New Producing Wells Required	50
Number of New Injection Wells Required	149

Accumulation and Pattern Data	
Effective Area of Accumulation (acres)	18409
Number of Existing Producing Wells	42
Number of Existing Injection Wells	0
Area of New Pattern (acres)	200
Total Project Life (years)	20

General Project Specifications	
QO : Project Oil Production Rate (STBD)	20000
QI : Project Gas Injection Rate (MMCFD)	13.00
G : Gravity of Gas (Air=1)	1.5195
Z : Gas Compressibility	0.5000
K : Ratio of Specific Heats	1.27
CO2 Supply (Liquid = 1,Gas = 2)	2
WAG Ratio (For No Water,enter 0)	0.00
Recycle Produced CO2 (1=Yes,0=No)	1
Ratio Produced/Injected Gas	0.75
Oil/Gas Separator Pressure (psig)	60
Offshore Operation (1=Yes,0=No)	1
EW : Vertical Depth of Wells (feet)	7327
Are Wells Deviated (1=Yes,0=No)	1
Artificial Lift (1=Yes,0=No)	0
Pr : Reservoir Pressure (psig)	3318
Pi : Sand face Injection Pressure (psig)	3600
Crude Oil Price ($/STBO)	25.00
LL : Average Length of Well Line (feet)	0
EL : Increase in Elevation (feet)	0
DL : Diameter of Well Line (ins)	4.000
KL : Abs. Roughness of pipe (ins)	0.0020
TL : Temperature of Line (deg F)	160
LW : Average Length of Tubing (feet)	9085
DW : Diameter of Well Tubing (ins)	2.991
KW : Abs. Roughness of Tubing (ins)	0.0020
TW : Temperature of Tubing (deg F)	120

Calculated Field Compression Requirements for NEW Gas.	
NR : No. of Compression Stages	1
Ps : Comp. Suction Pressure (psig)	1100
Pd : Comp. Discharge Pressure (psig)	1745
Ts : Comp. Suction Temp (deg F)	70
E : Mechanical Efficiency	0.92
Fuel Usage Rate (BTU/HP-hr)	8000
R : Stage Compression Ratio	1.58
BHP/MMCFD/Stage	27.08
Total BHP/MMCFD	27.08
Total BHP Required	352
Fu : Comp Fuel Consumed (MMBTU per Day)	68

Calculated Field Compression Requirements for RECYCLED Gas.	
NR : No. of Compression Stages	3
Ps : Comp. Suction Pressure (psig)	60
Pd : Comp. Discharge Pressure (psig)	1745
Ts : Comp. Suction Temp (deg F)	100
E : Mechanical Efficiency	0.92
Fuel Usage Rate ((BTU/HP-hr)	8000
R : Stage Compression Ratio	2.87
BHP/MMCFD/Stage	64.85
Total BHP/MMCFD	194.54
Total BHP Required	1897
Fu : Comp Fuel Consumed (MMBTU per Day)	364

Pump Requirements for Water Injection (WAG)	
E : Mechanical Efficiency	0.92
Fuel Usage Rate ((BTU/HP-hr)	8000
Total Water Injection Rate (STBD)	0
Total Net Pressure Loss (psi)	0
Pump Discharge Pressure (psig)	0
Pump BHP Required	0
Pump Fuel Consumed (MMBTU per Day)	0

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Cost Data
(Refer RESLOC.WK1 for Unit Costs)

Capital Costs LM : Log. Multiplier	1.00		
Base Structure (max 27 Wells) ($ooo's)	0	-- CO2 Recycle/Injection Plant --	
Increment of Water Depth ($ooo's/metre)	0	(Includes compression of NEW CO2 and	
Increment per Well Slot ($ooo's)	305	recompression of produced CO2 and Gas.	
		Compressor Costs ($ per BHP installed)	1800
-- Well Costs (per well) --		Total Cost Compression/Plant ($ooo's)	4048
Drilling/Completion			
Depth Variable ($ooo's/foot)	0.3400		
Fixed Cost ($ooo's)	384	-- Water Wells --	
Gathering/Injection Line ($ooo's)	0	WAG Water Requirement (STBD)	0
Artificial Lift Costs		No. of water wells (1 per 5 MSTBD WAG)	0
Depth Variable ($ooo's/foot)	0.0000	Total Water Well Costs ($ooo's)	0
Fixed Cost ($ooo's)	0		
		-- Water Injection Pumps --	
Total Cost per Well		Cost per HP installed ($)	1800
New Producer ($ooo's)	3473	Total Injection Pump Costs ($ooo's)	0
Injection or Water Well ($ooo's)	3473		
Total Drill/Equip Costs ($ooo's)	751835	Total Capex for Recycle Plant,Compression	
		Water Supply and Injection ($ooo's)	4048
Operating Costs OM : Ops. Multiplier	1.00		
Downhole and Workover Costs per Well		Total Prod and Well Operating Costs	
Producers- Natural Flow ($ooo's/yr)	285.00	Lifting/Workover Costs ($ooo's/yr)	50358
Add for Artificial Lift ($ooo's/yr)	0.00	Field Facilities Costs ($ooo's/yr)	44934
Injectors ($ooo's/yr)	162.00		
		CO2 Plant and Gas/Water Injection Operating Costs	
Field Production Facilities		Percent of Capex per year	7.00
Base Cost ($ooo's/yr)	9000.00	Maintenance etc Cost ($ooo's/yr)	283
Add Well Control Insurance ($/Ft/Well/yr	3.00	Calorific Value of Crude Oil (MMBTU/BBL)	5.75
Logistics Cost - Base ($ooo's/yr)	1768.00	Fuel Costs ($ooo's/yr)	674
- Variable ($ooo's/Km/yr)	2.00	Total Plant Operating Costs ($ooo's/yr)	958
Costs per Barrel of Oil		Total Production,Well and Plant	
		Operating Costs ($ooo's/Year)	96250
Pipeline/Shipping Costs ($/STBO)	0.40		
Liquid CO2 ($/Tonne at Log Base)	234.00	CO2 Costs	
Shipping Base to Field ($/Tonne/100 Kms)	7.40	Liquid CO2 Delivered Cost ($ per MCF)	0.00
Liquid CO2 Vaporisation ($ per MCF)	0.40	Store/Vaporise ($ per MCF)	0.00
Gaseous CO2 Cost ($/MCF ex Supply Point)	0.50	Total Cost ($ per MCF)	0.00
CO2 Pipeline Tariff ($/MCF)	3.00	Gaseous CO2 Delivered Cost ($ per MCF)	3.50
		CO2 Cost as used ($ per MCF)	3.50
Fuel Value (If Gas Available use 0			
else use Crude Oil Price ($/STBO)	25.00	Total Oil Transport Costs ($/BBL)	0.40

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For Menu - Strike <RETURN>

CO2PM - ECONOMIC DATA ENTRY
::::::::::::::::::::::::::

CARD	Entry
E-1	6-25
E-2	20,53,0,2,1,1,1,1,1,0.2,1,1,1,0
E-4	0,0,0,0
E-5	4048,0,0.000001,0.000001
E-6	0,0.0010,0
E-7	0.000001,0.000001,0.000001,0.000001,0.000001
E-8	0,0,0
E-10	0.15,0,0.10,0,0,0,0,0
E-11	0,0,0,0,0
E-12	0,0,0,0,0,0,0,0
E-13	92,19*0.0
E-14	0,25.00,0
E-15	0,0.000001,0
E-16	0,3.50,0
E-17	0,1046191,0
E-18	0,0.40,0
E-19	0.000001,0.000001,0.000001
E-20	1.0,8172115,8172115,8172115
E-21	1.0,0,0,0
E-22	END

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	Entry	
E1 - Title					
	Title or Case Description	TITLE	G-25		
E2 - Case Controls					
	Project Years (for all patterns)	M	20		
		ISTATE	53		
		IDIST	0		
	Print Control (0,1 or 2)- See Manual	IOUT2	2		
	Note: IOUT2=0,Economic Summary only	IFIT	1		
	=1,Cash Flows	IDAT	1		
	=2,DCF Calcs. and Escalated Data	NCT	1		
		NCI	1		
		IDISC	1		
		ISO	0		
	Type of CO2 Recycle Plant (0,1,2 or 3)	ICO2	2		Note: For Recompression of Produced gas, ICO2=2,else no CO2 Plant assumed and ICO2=3.Entry shown here for ICO2 is dictated by choice made in data entry on Page 1 above.
		IPLIF	1		
	Year of Pipeline Capex	IYPL	1		
	Year of CO2 Plant Capex	IYCS	1		
		IDEBT	0		

NOTE!!!! Skip this Card if IDEBT = 0 on Card E2.

Card No.	Description/Notes	Symbol	Entry		
E3 - Debt Controls					
		PCTDBT	0		
		DBTINT	0		
		NYRRPY	0		
		NYPAID	0		
E4 - Drilling Data					
		WPP1	0		
		WPP2	0		
		WPP3	0		
		WPP4	0		
E5 - Operating Data					
	Project CO2 Recycle Plant Capex ($ooo's)	CSEP	4048		
	CO2 Recycle Plant Capacity (MMCFD)	CSCAP	0		Note: Will Default. Refer Manual.
	Annual Cost W/O per Pattern ($ooo's)	WOCOST	0.000001		Note: Entry of 0 only causes default to values built in to USA code.
	Produced Water Treatment ($/BBL)	WTCOST	0.000001		
E6 - Operating Data					
	Months of Working Capital	WCAP	0		
	Oil Volume Uncertainty (Factor)	UNCO	0.0010		Note: Default= 0.0010
	Startup Costs ($ooo's)	COSTRT	0		

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	
E7 - Taxes and Escalation				
	Monetary Discount Rate (Fraction)	XDR	0.15	Note: Use 0.15 or 0.20
	Inflation Rate	XINF	0	
	Royalty (Fraction)	XROY	0.10	Note: Run Cases at 0 , 0.10
	Severance Tax (N.A. in Aust)	XSEV	0	
	Federal Tax Rate	XFIT	0	Note: Economics run on Pre-Tax basis
	Invest. Credits (N.A.)	XTCR	0	
	Depreciation Time (N.A.)	DTIM	0	Note: Economics run on Pre-Tax basis
	State Income Tax (N.A.)	XSTX	0	
E8 - Windfall Profit Tax				
	NOT APPLICABLE IN AUSTRALIA	XWPT	0	
		WPHO	0	
		EPHO	0	
		BTIM	0	
		BPOW	0	
E9 - Escalation				
	Oil Price	ESCPO	0	Note: All Economics to be run at constant Costs and Prices.
	Gas Price	ESCPG	0	
	Chemical Price	ESCPI	0	
	Operating Costs	ESCFO	0	
	Chemical Handling Costs	ESCTR	0	
	Tangible Capex	ESCCT	0	
	Intangible Capex	ESCCI	0	
	Work over Costs	ESCWO	0	
E10 - Secondary Oil Production Data				
	1979 Base Oil Rate (MBBl/yr)	OILB	0	
	Current Non-Tertiary Oil Rate (MBBL/yr)	OILC	0	
	Annual Oil Rate Decline	DECL	0	

NOTE!!!! Skip this Card if ISO = 0 on Card E2.

Card No.	Description/Notes	Symbol	Entry	
E11 - Secondary Oil Production Curve				
	Secondary Oil per Pattern for each year (MBBL/yr) Entered as Array for I=1,M	VOS(I)		
E12 - Project Pattern Schedule				
	Number of Patterns initiated in each year of Project. Entered as Array for I=1,M	PATI(I)	1st Year Following Years 396 ,9*0.0	Note: This assumes all Patterns at start year 1.

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry	
E13 - Project Pattern Schedule				
	Number of Patterns initiated in each year of Project. Entered as Array for I=1,M	PATI(I)	92 ,19*0.0	Note: This assumes all Patterns at start year 1.
E14 - Oil Price Data				Note: Assume $A = $US0.8 and Oil Prices = $US/BBL 10,20,50 Low & High Prices always default to 0.8 & 1.2 * Mid Price. Therefore,separate runs must be made to cover each price case.
	Low Oil Price ($/BBL)	POL(1)	0	
	Most Likely Oil Price ($/BBL)	POM(1)	25.00	
	High Oil Price ($/BBL)	POH(1)	0	
E15 - Gas Price Data				
	Low Gas Price ($/MCF)	PGL(1)	0	
	Most Likely Gas Price ($/MCF)	PGM(1)	0.000001	Note: Entry of 0 only causes default to POM(1)/6.
	High Gas Price ($/MCF)	PGH(1)	0	
E16 - CO2 Price Data				
	Low CO2 Price ($/MCF)	PIL(1)	0	
	Most Likely CO2 Price ($/MCF)	PIM(1)	3.50	
	High CO2 Price ($/MCF)	PIH(1)	0	
E17 - Fixed Annual Operating Cost Data				
	(Includes all Field Facilities Operating Costs, Lifting Costs and Workover Costs and CO2 Plant and Injection Plant Operating Costs)			
	Costs are $/year per Pattern			
	Low Fixed Operating Costs	FOCL(1)	0	
	Most Likely Fixed Operating Costs	FOCM(1)	1046191	
	High Fixed Operating Costs	FOCH(1)	0	

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Simulation - Project Input Economic Data

Card No.	Description/Notes	Symbol	Entry
E18 - Variable Annual Operating Cost Data	(Includes all Operating Costs that depend on Oil Production. In Australian context these are limited to Oil Transportation Costs)		
	Low Variable Costs ($/BBL)	OPCL(1)	0
	Most Likely Operating Costs ($/BBL)	OPCM(1)	0.40
	High Variable Costs ($/BBL)	OPCH(1)	0
E19 - CO2 Treating/Recycling Cost Data			
	Low Cost ($/MCF)	TRPL(1)	0.000001
	Most Likely Cost ($/MCF)	TRPM(1)	0.000001
	High Cost ($/MCF)	TRPH(1)	0.000001
E20 - Tangible Capital Investment	(Wells,Flowlines,Injection Lines Production Facilities and all Capital other than CO2 Plant and Injection Systems)		
	Costs are in $ per Pattern		
	Indicator/Control	ICT	1.0
	Low Costs ($)	CTPL	8172115
	Most Likely Costs ($)	CTPM	8172115
	High Costs ($)	CTPH	8172115
E21 - Intangible Capital Investment	(Capital Expensed in a given year. In Australian context : 0)		
	Costs are in $ per Pattern		
	Indicator/Control	ICI	1.0
	Low Costs ($)	CIPL	0
	Most Likely Costs ($)	CIPM	0
	High Costs ($)	CIPH	0
E22 - END			
	Enter in Columns 1 - 4		END

Note: Must NOT enter 0 or will Default to USA values.These costs are included in Opex on Card E17

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ANNEX 2

EOR PREDICTIVE MODELS - DESCRIPTIONS (US DOE, 1986)

1. The CO_2 Miscible Flood Predictive Model (CO2PM)

This model has been described in a paper published by the Society of Petroleum Engineers which is entitled: A Simplified Predictive Model for carbon dioxide Miscible Flooding, by G.W. Paul (SPE 13238, 1984). The CO2PM is applicable to both secondary (mobile oil) and tertiary (residual oil) floods, and to either continuous carbon dioxide injection or water-alternating-gas (WAG) process.

As part of CO2PM's reservoir assessment, a three-dimensional (layered, five-spot) , two-phase (aqueous and oleic), three component (oil, water and carbon dioxide) model is used to compute: oil and carbon dioxide breakthrough time, fluid recovery, and areal sweep efficiency. In this model, one-dimensional fractional flow theory is applied to first-contact miscible displacements in the presence of a second immiscible phase (water). The program may be used, with some minor restrictions, for multiple-contact miscible floods.

The CO2PM economic calculations are used to convert predicted performance data from the oil recovery algorithm into a cash flow analysis extending over the life of the project. This analysis combines forecasts of revenue, costs, expenses, and taxes into an annual balance sheet. The model also permits an evaluation of the uncertainty of future earnings as a result of changes in key variables and thus an evaluation of project risk.

From extensive testing, the model is claimed to reproduce the results of numerical simulations, laboratory experiments, and field floods reasonably well. The model may therefore be used to determine the limits on carbon dioxide miscible flood profitability as a function of reservoir (petrophysical) and operating parameters.

2. The Chemical Flood Predictive Model (CFPM)

This model has been described in a paper published by the Society of Petroleum Engineers which is entitled: A Simplified Predictive Model for Micellar-Polymer Flooding, by G.W. Paul (SPE, 10733, 1982). The CFPM models micellar (surfactant)-polymer (MP) floods in reservoirs which have been previously waterflooded to residual oil saturation. Thus only true tertiary floods are considered. An option is available in a model which allows a rough estimate of oil recovery by caustic (alkaline) or caustic-polymer processes. This option however is not modelled as a separate process, rather it hinges upon the outcome of MP computations.

This overall oil recovery efficiency is the product of the efficiencies for: one-dimensional displacement, vertical sweep of surfactant, and polymer sweep. The displacement efficiency is determined from the permeability, depth of the sweep of surfactant, and polymer sweep. The displacement efficiency is determined from the permeability, depth of the reservoir, and well spacing. Correlations derived from the results of numerical simulation are used to express vertical sweep efficiency as a function of surfactant slug size, surfactant adsorption and reservoir heterogeneity. The polymer sweep efficiency is an empirical factor developed from numerical simulation and is a function of the polymer slug size and vertical sweep efficiency.

Project economics and risk are determined by CFPM in the same manner as the CO2PM program described previously.

Based on comparisons with field floods and other field results, the CFPM program tends to be optimistic for oil breakthrough and peak rate.

3. The Polymer Flood Predictive Model (PFPM)

The PFPM may be used to model either polymer or water flooding, and additionally there is also an option that allows the calculation of the incremental oil recovery and economics of polymer relative to waterflooding. The architecture of the PFPM is similar to that of the other predictive models in the series which have been described above. That is, an oil rate versus time function for a single pattern is computed and is then passed to the economic calculations. Data for reservoir and process development, operating costs, and a pattern schedule (if multiple patterns are desired) allow the computation of discounted cash flow and other measures of profitability.

The PFPM is a three-dimensional (stratified, five-spot), two-phase (water and oil) model which computes water front breakthrough and oil recovery using fractional flow theory. A correlation based on numerical simulation results is used to model the polymer slug size effect.

During its development, the PFPM was found to yield excellent performance predictions (oil recovery, injectivity) when compared with the results of analytical, steamtube, and finite difference models. When compared with a field example, the PFPM yielded a fairly good match to observed data for both the water and polymer flood.

4. The Steamflood Predictive Model (SFPM)

This model has been described in a paper published by the Society of Petroleum Engineers which is entitled: A Simplified Predictive Model for Steamdrive Performance, by S.R. Aydelott (SPE 10748, 1982). The SFPM is applicable to the steam drive processes, but not to cyclic steam injection (steam soak) processes. The architecture of the SFPM is similar to the other models described previously.

There are four separate oil recovery predictive algorithms in the SFPM. However, all of these make use of calculations for heat losses in surface pipe and in the wellbore. The most severe restriction of the model is the assumption that the reservoir is horizontal, homogeneous, isotropic, and incrompressible. An additional limitation is that only five-spot sweep corrections are currently included. Project economics and risk are determined by SFPM in the same manner as the programs described previously.

This model has been demonstrated to match three field case histories. Good agreement between the model and case histories was obtained without arbitrary adjustments.

5. The In-situ Combustion Predictive Model (ICPM)

The ICPM oil recovery algorithm is based on a correlation of the major variables in the combustion process to the results of 12 field pilot tests. The correlation relates oil burned and oil produced to the amount of air injected and the reservoir volume, and is for dry gas combustion only. A method to predict wet combustions was added by the National Petroleum Council based on laboratory data.

The assumptions and limitations of the ICPM are:

(a) no free gas saturation
(b) empirical sweep efficiency based on pattern size
(c) constant air-to-fuel ratio of 70 000 cubic feet of air burned per barrel of oil burned
(d) produced water is determined from a material balance relationship
(e) water saturation in burned volume is 20% for wet combustion and zero for dry combustion
(f) produced gas is determined from a material balance relationship
(g) the amount of reaction gases is two-thirds of injected oxygen
(h) gas saturation in burned volume is 80% for wet combustion and zero for dry combustion
(i) air injection rate is based on a ten-year pattern life
(j) the air injection rate after the first year of the project is constant
(k) the ratio of the number of production wells to injection wells is 2:1

As for the models described previously, the architecture of the ICPM entails that an oil rate versus time function for a single pattern is computed, the results of which are passed to the algorithm that computes the economic calculations. The economic calculations are used to convert predicted performance data into a cash flow analysis extending over the life of the project. This analysis combines forecasts of revenue, costs, expenses, and taxes into an annual balance sheet. The model also permits an evaluation of the uncertainty of future earnings as a result of changes in key variables and thus an evaluation of project risk.