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ENHANCED RECOVERY OF PETROLEUM-APPLICATIONS TO AUSTRALIA

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Summary

The recovery efficiency of oil by natural depletion from hydrocarbon reservoirs is a variable which can range from very low values (less than 1%) to over 60 percent of oil in place, depending on a number of factors.

Residual hydrocarbons left in a reservoir at depletion represent a valuable asset; with increasing oil costs and shortages, there is greater emphasis being placed by industry on enhanced recovery techniques for recovering more of this oil.

A number of processes for enhanced recovery have reached field pilot testing overseas. Amongst these are methods for lowering the viscosity of heavy oils using steam or in situ combustion, or lowering oil/water interfacial tension by micellar-surfactant displacement. Injection of hydrocarbon gas and/or carbon dioxide are also receiving increasing favour in areas of abundant gas supplies; these methods assist in displacement by re-establishing continuity and flow in the residual oil phase at depletion.

There are several possible field applications for enhanced recovery in Australia, amongst which are the Barrow Island, Moonie, Alton, Mereenie, and Tirrawarra oil fields. The prolific oil reservoirs of the Gippsland Basin are not suitable prospects for enhanced recovery because of the strong, highly efficient bottom water drive which would dissipate any injected chemicals.

The Petroleum Technology Laboratory of the BMR is currently studying enhanced recovery in core samples from the Moonie reservoir of Queensland, using a polymer displacement technique to increase water viscosity and lower its mobility. However, the application of enhanced recovery to Moonie may be difficult because of the active edge water drive.

Barrow Island may present the best domestic prospect for enhanced recovery because of its currently successful secondary waterflood and the high residual oil saturation still expected at floodout.

Introduction

Since the very early years of petroleum production, the oil industry has been striving for ways to improve recovery efficiency in hydrocarbon reservoirs; the ultimate goal has been to produce all of the hydrocarbons in place. This problem is illustrated by some common recovery factors for reservoirs producing under natural drive conditions. These vary widely from as low as zero recovery for reservoirs containing heavy viscous oil to as high as 90% for certain gas reservoirs. An approximate value of 20% to 50% of oil in place is the usual recovery at depletion for an oil reservoir producing by (natural) solution gas or water drive from an aquifer.

Recovery efficiency has taken on an even greater importance currently, with shortfalls in indigenous supplies in many countries and ever increasing demands for petroleum throughout the world. Using the United States as an example, the known in-place liquid hydrocarbon reserves in that nation exceed 300 billion barrels. This is three times greater than the combined total oil production during their oil producing history (about 110 years). On the other hand, the same nation is now the world's largest net importer of crude oil (more than 9 million B/D) simply because the productivity of their currently known recoverable reserves (about 30 billion barrels) is not sufficient to solve the US supply/demand imbalance; additionally, enhanced recovery technology is unable to economically fill the supply gap from their balance of 270 billion barrels of residual oil.

Why, then is so much oil unrecoverable by conventional techniques, and why are residual oil saturations so high in certain reservoirs? To answer these questions, we must examine reservoir drive mechanisms and the physical conditions existing in a reservoir during displacement. Considering liquid hydrocarbon reservoirs only for the moment, there are five principal natural existing production mechanisms which can exist. These are listed in Table 1 in increasing order of efficiency together with a range of approximate recoveries expected by each displacement mechanism.

Table 1

Principal oil reservoir drive mechanisms

Drive mechanism	Expected recovery
Rock and fluid expansion	2% to 10%
Solution gas drive	5% to 25%
Gas cap drive	10% to 40%
Combination drive	20% to 50%
Water drive	20% to 60%

Excepting the first, all of the drive mechanisms in Table 1 have one thing in common; liquid hydrocarbons are displaced from the reservoir by a component (either gas or water) which is generally considerably more mobile in the reservoir than the displaced oil phase, particularly when oil viscosity in the reservoir is high. It is this adverse mobility effect (permeability of a rock to a fluid divided by the fluid viscosity), causing high mobility ratios ($M = {}^{Kw}/_{Uw} / {}^{Ko}/_{Uo}$), which considerably lowers the displacement efficiency and particularly the areal sweep efficiency in a reservoir. A reservoir which contains permeable 'channels', fractures and/or lenses of tight and permeable formation, will show very poor recovery efficiency in this respect.

However, areal sweep efficiency and mobility ratios do not totally explain the reason for residual hydrocarbon saturations. Another aspect to consider in this respect is the (micro) pore system itself. If we examine oil displacement by water (natural or water-flood injection) as it might occur in a pore (Figure 1), certain pore configurations may allow the displacing phase (water) to move more freely through one channel than another, thus trapping a portion of the oil as discrete discontinuous globules in the second channel. This condition can occur repeatedly throughout the reservoir with the passage of the [illegible] front, further explaining residual oil saturations of 40% to 70% of oil in place. There is no way that the available differential pressure in the reservoir can overcome capillarity and dislodge these individual globules of oil.

Definitions of recovery

Historically, early petroleum explorers quickly learned that the natural energy existing in some hydrocarbon deposits was soon dissipated and wells rapidly depleted, where fluid and rock expansion may have been the principal drive mechanism. It was probably by chance that such explorers first recognised the advantages of enhanced recovery, when accidental introduction of water from other zones into such reservoirs prolonged reservoir life and considerably improved ultimate recovery. So too, poor completion techniques may have contributed to gas leakage between zones leading to a gas cap buildup in an oil producing reservoir and another form of (accidentally) induced enhanced recovery. Thus the area of water injection and often reinjection of produced gas expanded markedly in the 1930 to 1940 period. As a result, two distinct forms of terminology to describe production modes evolved at that time. These were:

(1) Primary recovery - to describe the production of hydrocarbons by natural forms of energy such as water (aquifer), gas cap drive, solution gas drive, expansion drive etc., assisted where deemed necessary by energy supply within the well bore (gas lift, mechanical pumps etc.).

(2) Secondary recovery - refers to the injection of fluids such as water or gas to stabilise or raise the natural reservoir energy and improve displacement by hydrocarbon fluids.

However, as pressure maintenance and reservoir engineering increasingly evolved, it was realised that factors such as interfacial tensions, fluid miscibility, and mobility could have a marked effect on hydrocarbon recovery. Coincidentally, experimentation was carried out using various injection fluids in water flood programs such as detergents, alcohols, etc. to improve the miscibility between the displacing/displaced phase. This was the realm of enhanced recovery sometimes called tertiary recovery, although the latter terminology generally refers to displacement after waterflooding or gas injection.

WHY RESIDUAL OIL?

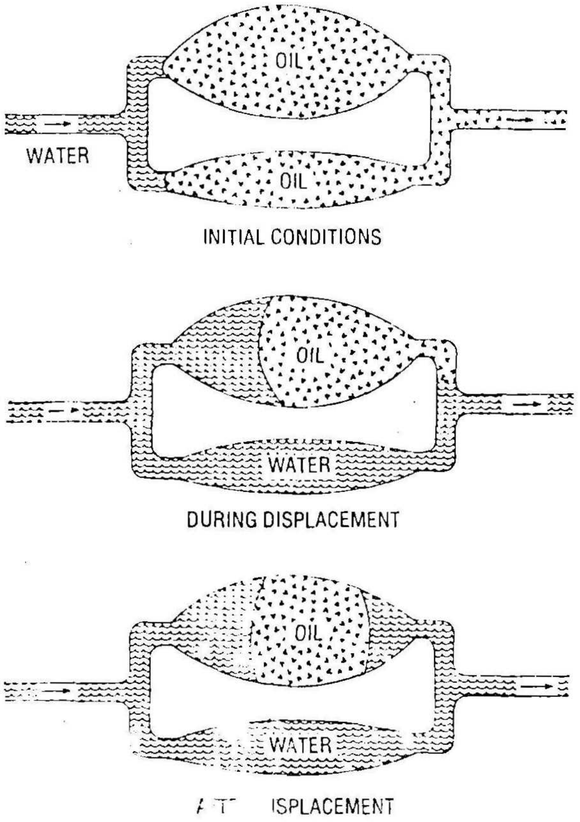

Figure 1

Courtesy Petroleum Engineer Int.

Table 2

Enhanced recovery techniques

Type	Method	Effect	Where Used
Thermal	Steam injection In situ combustion	Drastically lowers Uo	Heavy oil generally at shallow depths
LPG miscible	5% propane slug then gas and water	Improve miscibility, Improve Ko	Thin relatively shallow formation, Low Ko Low Uo
Enriched gas miscible	10% to 20% slug wet gas (high C_2 to C_6), then gas and water	As above	Light volatile oils, Low Uo, high relief reservoir
High pressure Lean gas miscible	Continuous inject and cycle dry gas	Vaporise residual hydrocarbons	Very light undersaturated volatile oils, low Ko thin formation
CO_2 miscible	Continuous inject CO_2, or 20% slug, then water and gas	Improve displacement efficiency	Less volatile oils 25° API
Surfactant - Micellar	5% to 10% slug surfactant or micellar slug, then polymer and water	Lower interfacial tension, raise Ko, Lower Kw, raise Uo	Suitable in most reservoirs where water floods have succeeded
Polymer	20% slug polymer followed by water	Lower Kw, raise Uw Improve mobility ratio	Most applicable to heterogeneous and stratified reservoirs

Uo - Viscosity to oil
Uw - Viscosity to water
Ko - Permeability to oil
Kw - Permeability to water

Most of the enhanced recovery techniques have had their origin in the United States, where extensive research and a number of field pilot studies are being carried on. The main techniques being studied are briefly listed in Table 2 and are detailed as follows.

Enhanced recovery techniques in oil reservoirs

(1) Miscible slug process The earliest enhanced recovery process took primary cognisance of the miscibility factor whereby slugs of solvents such as LPG (propane, butane), alcohols, etc. were injected into the reservoir. These additives become miscible with the residual oil in the reservoir pore systems and a 'bank' of liquid hydrocarbons is built up as production moves to a recovery well. The injected solvents are usually followed by gas and water which assist movement of the oil bank through the reservoir.

Although displacement efficiency by this process is excellent in the areas of the reservoir contacted, the main disadvantages to the technique are the poor sweep efficiency, dispersion of the miscible slug in the reservoir and (currently) greatly increasing costs of the hydrocarbon-based injection fluids.

(2) Lean gas miscible displacement: This process was derived from original research to recover condensed liquids (retrograde condensate) from wet gas reservoirs. Subsequently, the technique was adopted to oil reservoirs with some success. It was found that by injecting lean gas at high pressures, gas oil contact in certain reservoirs 'scoured' light ends from the residual oil. These light ends act like solvents and are miscible with the gas and subsequent oil contacted so that an oil bank is formed. In order to work, the process requires the oil to be high (API) gravity such that on repeated contact between residual oil and injected gas, a portion of the C_2 to C_6 fraction from the oil can be vaporised and reliquefied to form the miscible slug.

A somewhat similar process involving the injection of enriched gas into a depleted (light) oil reservoir can achieve similar effects. However, in this process the miscible slug buildup is derived from condensing C_2 to C_6 vapors in the injected (wet) gas. Both processes are highly dependent on the right type of reservoir oil (high gravity, low viscosity, highly volatile), and on favourable economic and supply conditions prevailing.

(3) <u>Carbon dioxide miscible process</u>: Carbon dioxide has certain advantages as a miscible phase enhanced recovery technique over lean and enriched gas injection; the main advantage is that CO_2 has a strong attraction to and is soluble in oil and is thus effective in displacement by vaporisation and swelling of the oil (thus reducing residual volumes).

Because of its low critical temperature ($30^{\circ}C$), CO_2 is generally in a gaseous state when injected into an oil reservoir. Although it is not directly miscible with oil, it will generate a miscible bank of oil (as with lean gas injection) after repeated contact in the reservoir. Furthermore, CO_2 can extract a much broader range of components (C_6 to C_{30}) from residual oil, thus making it more adaptable to heavier oils than lean gas techniques.

There are several techniques for using CO_2 as an enhanced recovery technique. These can range from injection of CO_2 (only) throughout the life of a project, to CO_2 followed by cyclic water and CO_2, or water and/or hydrocarbon gas. Each technique has its own merits depending upon reservoir conditions; however, the most promising consists of water followed by cycling CO_2/water injection, which method has a high capacity to replace residual oil with trapped CO_2.

Some additional advantages of CO_2 injection as an enhanced recovery mechanism are:

(a) Lowering of the oil viscosity (10 to 100 times in certain cases); crude oil viscosities from 5 cp to 90 cp are the most suitable candidates for the method.

(b) 'Blowdown' recovery - oil is recovered by pressure reduction after termination of injection, also by solution gas drive.

(c) Swelling of the oil - oil volume will increase 10% to 40% with 700 s.c.f. of CO_2 in 1 barrel of crude. This means less oil per unit volume in a residual state.

(d) Changes in the interfacial tension of crude oil when carbon dioxide is dissolved in it have been reported.

(4) Thermal stimulation: The purpose of thermal stimulation is to apply heat to an oil reservoir, the intention being to lower the viscosity and thus improve the mobility of heavy reservoir crude oil. The process is primarily used in reservoirs containing low API gravity oils (12° to 35° API) which under natural depletion conditions may only produce a maximum of 15% of oil in place; often no production at all will occur without some stimulation. Tar sand oil deposits are typical examples; thermal treatment of these types of reservoirs may lower crude viscosity from several thousand centipoise to less than 100 cp, sufficient to enable production to occur. Two basic thermal treatments are used; heat injection usually in the form of steam or hot water and in situ combustion in which heat is produced in the reservoir by burning some of the heavy crude oil in place. External heat treatment of the reservoir may range from cyclic injection of steam (huff and puff method) or a steam soak and/or flooding method utilising continuous steam injection. In situ combustion may involve forward combustion of an oil zone which moves through the reservoir to a producing well; reverse combustion in which the burning front moves towards the injection of the air input; and wet combustion which combines steam displacement and in situ combustion.

Improvement in oil reservoir flow properties is primarily as a result of viscosity reduction; however thermal expansion, increased sweep efficiency (by improved oil mobility), and distillation of reservoir crude oil to lighter fractions (thus improving reservoir flow) all have a significant role to play in all thermal stimulation.

(5) Polymer displacement: It was noted previously that mobility is a critical factor in oil displacement by water drive; the higher the mobility ratio in the reservoir, the greater the dangers of 'fingering and overide' by the displacing (water) phase. This of course results in high residual oil saturations and poor recovery efficiency.

Engineers soon recognised that a partial solution to this problem, particularly in secondary recovery operations (waterfloods) was to raise the viscosity of the displacing water, thus reducing water mobility and improving sweep efficiency. Polymers, which are long-chain, high molecular weight organic compounds were found to be a simple way of effecting this viscosity increase in water. The technique is to inject an aqueous slug (20 percent of the reservoir pore volume) of polymer solution into the reservoir using about 0.06% polymer in the injection water; the 'tail' of the slug is graded to minimise fingering by the following water.

Polymer solutions also have the ability of selectively reducing the flow capacity of high-permeability channels in certain formations, thereby sidetracking some of the flow, for instance, in stratified formations. This may result in more oil contact in higher residual oil zones by the displacing medium.

There are two principal disadvantages to polymer displacement. These are the high cost of the product (up to $5.50/kg) and the mechanical degredation of polymer which may occur in the reservoir, and sometimes in the well bore injection equipment. The latter condition may cause a critical loss in the efficiency of the displacement mechanism such that a project is no longer economic. It is also important to note that enhanced recovery by polymer injection will not succeed in reservoirs in which water flooding has been uneconomic.

(6) <u>Chemical flooding</u>: The main advantages usually sought in chemical flooding is a lowering of interfacial tension between the displacing/displaced phase thus gaining greater miscibility by solubilising oil and water. The characteristics of a displacement technique using surfactants for example is a buildup of an oil bank by the lowering of interfacial tension between the residual oil and water; this is followed by the displacing medium (water and sulphonates) and is usually followed by a bank of thickened water (polymers) to develop mobility control and prevent fingering at the trailing end of the flood. Another common form of chemical flooding is to use caustic soda solutions which may form surfactants in situ with certain types of oils.

There are several problems associated with the use of surfactants in enhanced recovery. Two of these are the tendency of surfactants to channel through permeable zones, and the problem of surfactants adsorbing on rock surfaces thus causing dilution and loss of effectiveness. Operators have found techniques to resolve both these problems by using complex micelles which are composed of oil, water, and certain surfactants; micelles may essentially be defined as stable aggregated structures of soap molecules dissolved in a solvent. These molecules swell in order to accomodate unlike fluids (i.e. water and oil). Being swollen, they have the ability to give increased viscosity in the system and are not adsorbed on rock surfaces.

Micelles can also be tailored to each reservoir requirement and thus have a built-in flexibility, having both low interfacial tension and high viscosity characteristics. However, as these systems contain more (expensive) chemicals than the usual water/sulphonate displacement method, the economics of any displacement technique must be studied very closely, both in the laboratory and in field pilot studies.

Some critical considerations of micellar type floods, most of which also apply to polymer displacement, are as follows:

Good	Bad	Not Critical
Fresh water	Strong water drive	Depth
Soft water	Fractures	Thickness
Clean sand formations	Anhydrite	Well spacing
High permeability	Gas cap	Porosity
High residual oil saturation	Cross flow	Oil gravity
Low oil viscosity		
High sweep efficiency		
Recent wells		
Close to transport		

Enhanced recovery in gas reservoirs

Gas reservoirs are not usually suited to any forms of enhanced recovery which are practised in oil displacement primarily owing to the compressible nature of gas. Because of this feature, gas reservoirs producing solely by gas expansion give the greatest recovery efficiency (often up to 85% of gas in place) whereas much lower recovery will occur in a gas reservoir producing by water displacement (the same recovery, in fact, as would be expected if the reservoir were oil saturated). The large gas structures on the Rankin platform of the North West Shelf may fall within the latter category.

There is however one type of enhanced recovery which can show promise in certain wet gas reservoirs i.e. one containing substantial quantities of heavier components. Such deposits are often subject to retrograde condensation whereby some of the condensate forms in the reservoir. These condensed hydrocarbon liquid volumes are usually below the critical flow saturation in the reservoir and are trapped in the formation. If dry gas is cycled through such reservoirs during production and after depletion, a substantial amount of the retrograde condensate can be recovered by re-vaporisation.

Future applications in Australia

There are five oil fields regularly producing in Australia at the present time, the main production occurring from two fields in the Gippsland Shelf Basin of Victoria. In addition, there are additional fields which are capable of oil production; these mainly include Mackerel, Tuna, Mereenie, and Tirrawarra fields. The first two, which are located in Gippsland Shelf, will be on production in 1978-79. Mereenie and Tirrawarra, respectively located in the Amadeus and Cooper Basins are currently not programmed for production for reasons which will be detailed shortly. The critical factors of all reservoirs outside of Gippsland Shelf are listed in Table 3.

What potential do each of these fields have for enhanced recovery?

Gippsland Shelf: The Kingfish and Halibut reservoirs together currently produce about 400 000 barrels (of oil) per day which is about 88% of Australia's total production. The producing mechanism is a strong bottom water drive from underlying aquifers. Because of a number of factors including overall excellent permeability, porosity, and an even pore size distribution, the displacement efficiency of these fields is excellent. Primary recovery in both Kingfish and Halibut will be greater than 60% of oil in place which is well above world average even for a natural water drive reservoir.

However, because of this fact there are no prospects for enhanced recovery in the Gippsland Shelf reservoirs. Effective use of most enhanced recovery techniques requires confinement within the oil column. With the excellent vertical permeability in the Gippsland reservoirs combined with the highly mobile underlying water-table, it would be impossible to control emplacement of injected chemicals to improve recovery. In addition, the low residual oil saturation at natural floodout in Gippsland reservoirs combined with space problems on offshore platforms would make the economics of an enhanced recovery project in that basin very unattractive.

Surat Basin: The Moonie and Alton fields are located in this basin, and have each been producing oil for approximately 12 years. Moonie reservoir has an active edge water drive while the smaller Alton field produces principally by a solution gas drive mechanism. Both reservoirs are composed of sandstone and show good permeability. The oil is of low viscosity and residual oil saturation at depletion in both reservoirs will be high (more than 60% of oil in place). All of these factors are favourable for chemical or polymer floodings; as well there may be prospects in both reservoirs for lean or enriched gas drive to improve eventual recovery.

However, there are problems with respect to enhanced recovery in these reservoirs. The Moonie field, with its active edge water drive has shown problems with water production during much of its producing history, whereby water has channelled through high permeability streaks and fractures to producing wells. This has lead to poor sweep efficiency and ultimately to high residual oil saturation. This particular condition is rather unfavourable to enhanced recovery (particularly surfactant/micellar techniques) and may preclude its general use in this field.

Because of the more confined drive mechanism (solution gas) at Alton, prospects for enhanced recovery there may be more favourable, although remaining oil resources at depletion will be small and are concentrated in several sand lenses.

Carnarvon Basin: Barrow Island is the only oil field currently producing in this basin. The field is large, having in place reserves of more than 700 million barrels. However, partly because of low permeability, well productivity in Barrow is rather poor; this has been partly offset by 'tight' drilling patterns and also by a pressure maintenance water injection project. The latter work has more than doubled oil recovery over primary production, although residual saturation at depletion is still expected to be about 75% of oil in place. Barrow Island can be regarded as the only oilfield in Australia which is already undergoing enhanced recovery, for water flooding (secondary recovery) has been carried out there for 10 years.

Because of the success of this flooding program, there is every reason to believe that, with the right economic incentives, further enhanced recovery techniques (in this case, tertiary recovery) may also succeed. Processes which might be regarded as prospective for Barrow would include surfactant/micellar techniques as well as miscible slug processes and (possibly) CO_2 injection.

The main drawback in Barrow to the surfactant/micellar process is the low formation permeability, while the low formation pressures of the shallow Windalia Sandstone may be detrimental to the CO_2 miscible process (which requires pressures in excess of 1500 psi). If a ready source of light miscible hydrocarbons were available (such as LPG products from other gas fields in the basin) there would seem to be a reasonable possibility that the miscible slug technique could have promise at Barrow, if gravity segregation is not a detrimental factor in the Barrow reservoir.

Amadeus Basin: The Mereenie field, which lies in the northern part of the Amadeus Basin is an oilfield of significant proportions, having in place reserves of about 300 million barrels. However, because of the remote location, and low productivity of the reservoir and some other factors, the economics of oil production at Mereenie, for the moment, are marginal. Also, the Mereenie reservoir is in effect a large gas field partly underlain by the oil producing zone. It would therefore be imperative that oil production be initiated before or contiguous with the production of gas, to avoid migration (and loss) of oil into the gas horizon on pressure drawdown, a factor which may further complicate the marketing picture. Mereenie appears to be subject to a partial water drive, and it is likely this would need to be supplemented during production in order to sustain formation pressure and assist in good displacement efficiency. Possible enhanced recovery techniques could include displacement by water flooding or some form of miscible gas drive using gas and/or LPG products from overlying wet gas reservoirs. The main problem of course with any enhanced recovery process at Mereenie would hinge on product outlets and ultimately economics.

Cooper Basin: The Tirrawarra oil field is the centre of three other smaller adjacent oil fields discovered in the Cooper Basin. Although the estimated in place reserves of Tirrawarra are about 115 million barrels the high residual water saturation (50% pore volume) combined with the poor reservoir productivity and remote location suggest very marginal prospects for any enhanced recovery in the near future for this field.

Table 3

Some critical factors of main oil productive reservoirs in Australia

Field	Metres	Average Porosity (% Bulk volume)	Average Permeability (Md.)	Estimated oil in place ($Bbls \times 10^6$)	Water Saturation (%P.V.)	Type of drive mechanism	Estimated primary oil recovery (% Hcv)	Residual oil Saturation (% Hcv)	Reservoir temp. (^{o}C)	Reservoir pressure (psia)	Oil viscosity at reservoir conditions (cp)	Formatio Water Salinity (ppm)
Moonie	1908	18	290	54.8	47	Edge water	36	64	68	2501	0.89	2000
Alton	1993	17	260	5.3	47	Solution gas	40	60	70	2770	0.34	1500
Barrow Island	657	27	6	758	50	Solution gas	12	88	65	900	0.65	40 000
						Secondary water flood	25	75				
Mereenie	1508	6	10	300	30	Gas expansion & Water drive	50	50	69	1700	2.05 @ 37°C*	40 000
Tirrawarra	3098	14	20	115	50	Solution gas	20	80	153	4200	.095	17 000

* Not reservoir conditions

Research Required:

As noted in Table 2, there are approximately 7 main enhanced recovery techniques which are being extensively used throughout the world, most often as tertiary mechanisms. This of course does not include the most widely used enhanced recovery process, which is water-flooding. Numerous other techniques for increasing oil production are being investigated. Some of these are commonly known (e.g. ultra sonic energy to change the size and shape of discontinuous residual oil globules to overcome capillary pressure). Others are strictly proprietary as a result of major research by various oil companies. The eventual goal is of course to try and duplicate Nature's conditions of nearly 100% water saturation directly below the oil column in a reservoir; the problem is how to establish these same displacement conditions within the economic limits of petroleum production (approximately 20 yrs).

It is probably not practical for technology in this country to try and develop new processes of enhanced recovery, but rather to investigate the use of proven techniques to suitable situations. For instance, Barrow Island has been shown to be a good example of an enhanced recovery prospect. This would require extensive laboratory work with cores and formation fluids to discern which of the available suitable processes was most favourable; this could be followed by field pilot testing if laboratory results warranted.

It is interesting to note that primary oil recovery at Barrow (12%) would recover 96 million barrels; this will be increased to about 190 million barrels (25%) recoverable oil with the secondary waterflood now in use. If some enhanced (tertiary) process could be economically adapted to this field to increase recovery an additional 5% to 10%, this could mean added recoverable reserves of 37 to 74 million barrels. At the "new" oil price for Barrow crude this represents a gross value of 470 million to 940 million dollars - a considerable saving in foreign exchange.

The Petroleum Technology Laboratory of the Bureau of Mineral Resources is already investigating the Moonie oilfield in Queensland for improved recovery techniques. Polymer displacement is currently being studied as a possible candidate in this regard; that work has involved core samples from six wells whereby oil displacement by (edge) water drive is being followed by polymer injection/displacement. Factors to be studied will be improvements to recovery as well as mobility control and study of polymer retention by the core samples. Field pilot testing could follow if the laboratory work shows promise.

There are also possible projects for enhanced recovery in the gas productive reservoirs of the Cooper Basin. Most of these fields are 'wet gas' prospects and contain substantial amounts of hydrocarbon liquids (approximately C_2 to C_6 range) some of which is almost certainly being lost by retrograde condensation in the reservoir during production.

Experimentation to determine the amount of retrograde condensation by reservoir fluid analysis (PVT) combined with laboratory dry gas cycling through long core 'tubes' needs examining as a possible technique for recovering additional liquids in these reservoirs. Such techniques may also have application on the North West Shelf gas reservoirs depending on mobility of the underlying water-tables.

Liquid hydrocarbon production associated with gas producing operations in the Cooper Basin may necessitate eventual construction of a liquids pipeline from the area to southern markets. If this ensues, prospects for production and perhaps some form of enhanced recovery in the Tirrawarra field may improve and require additional research in that region.

Recommendations and conclusions:

The use of enhanced recovery to improve recovery efficiency from oil reservoirs will undoubtedly have some application in Australia. The Barrow Island field in Western Australia is probably the most prospective reservoir in this regard because of its currently successful secondary waterflood and the high residual oil saturation expected at floodout (75% OIP). Other prospects may include the Alton reservoir in Queensland, the Mereenie field in the Northern Territory, and possibly the Tirrawarra field in South Australia's Cooper Basin. The Moonie field of Queensland is another candidate which BMR is currently studying by a polymer displacement technique; the success of this particular process is doubtful because of Moonie's edge water drive. Similarly, the prolific Gippsland Shelf Basin has no prospect for enhanced recovery owing to the underlying very strong water drive.

The application of suitable enhanced recovery techniques to any particular domestic reservoir will entail laboratory and subsequently field pilot testing if a particular process appears to have merit. BMR should continue a program of laboratory study in this respect, subsequent to the current work on Moonie. This should entail feasibility studies on prospective reservoirs as well as discussions and planning with authorities concerned. It is possible, for instance, that because of the remote location and multi-national backing in the Barrow Island field, it may be more suitable for studies to be conducted by the company itself, if such work is not already underway.

However, with the ever-increasing supply gap in Australia's indigenous liquid petroleum production, the prospect of substantially reducing our imbalance by enhanced recovery is very unlikely, particularly considering the current limited applications. The only alternative for a more viable energy supply is to increase activity in exploration drilling which has dropped to extremely low levels in recent years. Good drilling targets still exist, particularly on the continental shelves and slopes such as the North West Shelf and Exmouth Plateau. However, this is a high-cost and tecnhologically difficult drilling/production area and every encouragement is needed for such operations; Australia's future in self-sufficiency of liquid hydrocarbon fuels is most dependent on it.