CHAPTER 9

Mature Fields

Inevitably, all producing fields reach maturity one day so the importance of mature field technology is set to grow as greater numbers of assets enter maturity. This chapter provides an overview of Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR), as well as several practical field applications.

Pumps, polymers and permanent seismic are just a few of the technologies used to enhance and improve production in mature assets. Mature fields are challenging as they exhibit a decline in hydrocarbon rates, increased water production as well as the responsibility of decommissioning platforms, wellheads or pipelines[1].

For our purposes, a field is defined as mature once its natural reservoir drive mechanisms—gas drive, water-drive or gravity drainage—are incapable of sustaining production. Consequently, hydrocarbons must be artificially swept from the reservoir and be able to travel through production tubing, the wellbore and to surface installations[2].

Reservoir Drive

Reservoir pressure curves correlate directly with reservoir production rate curves. As long as reservoir pressure is greater than bottom-hole pressure, the differential pressure will result in production. Pressure differentials can be created by reducing bottomhole pressure or by increasing reservoir pressure, either of which will increase hydrocarbon production[3].

Following the development of low-hanging fruit, most mature assets have traditionally been distributed onshore; however, the trend now shows extensive numbers of shelf and deepwater assets entering maturity. Already, several notable offshore fields are classified as mature assets; for example, Brent and Troll in the North Sea, and Marlim in offshore Brazil.

Figure 1 - Nodding Donkey Or Rod Pump (EPRasheed)

Pump Up Production

Primary or artificial lift methods to increase production include the nodding donkey or rod pump, Electrical Submersible Pump (ESP) or a gas-lift system. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically around 10% for oil reservoirs and 15% for gas reservoirs[4].

Secondary production (IOR) of hydrocarbons is achieved when a fluid such as water or gas is injected into the reservoir through injection wells. Injectors are carefully drilled into formations so that fluid communication or flow pathways can be made to production wells. The purpose of secondary recovery is to increase reservoir pressure and to displace hydrocarbons toward the production wellbore[5]. As a consequence of prudent reservoir management, wells may be converted from producers to injectors or new injector wells may be drilled. The trick is to consider the entire field as a 'production unit' and manage all wells with the objective of increasing overall production. This can be a very complex and contentious issue when several landowners are involved. Imagine an oil company telling a farmer that the prolific oil well on his property that is returning him a handsome revenue in royalties is about to be converted into a water injection well.

Normally, gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir. The mechanics of gas and water injection are complex and include consideration given to directional injectors and multi-phase flow. A pressure maintenance programme can begin during the primary recovery stage, but it is still considered a form of enhanced recovery. The secondary recovery stage reaches its limit when the injected fluid (water or gas) is produced in considerable amounts from the production wells and the production is no longer economical. For some fields this could be 50%, while for others it could be as high 80%. In Oman, wells are currently producing economic volumes of oil with over 90% water cut. The successive use of primary recovery and secondary recovery in an oil reservoir produces about 15% to 40% of the original oil in place[6].

Tertiary recovery (EOR) not only restores formation pressure, but also seeks to improve reservoir flow characteristics. With greater numbers of mature assets, oil companies target mature onshore and offshore oil fields worldwide in order to extract maximum value from sunk costs. Tertiary oil recovery applications are internationally recognised and this area of production engineering covers most categories of crude oil with American Petroleum Institute (API) grades varying from 13° to 41°. The industry adopted a broad ranging methodology, which enabled pilot testing to commercial/field applications using steam injection, carbon dioxide (CO_2) injection and polymer flood. EOR methods range from chemical flooding (alkaline or micellar-polymer based), biological flooding (microbial or bacterial based), miscible displacement (CO_2 injection or hydrocarbon injection), and thermal recovery (steam flood or in-situ combustion)[7].

Sometimes these methods are accompanied by additional stimulation services, such as hydraulic fracturing, or by drilling sidetrack lateral wells from the main wellbore to access stranded oil.

A thorough characterisation of reservoir heterogeneity and the nature of reservoir fluids is required for a mature field production strategy and only after extensive analysis of the application can a particular method be chosen. The application process can be split into three basic stages: modelling future behaviour, field data analysis and corrective correlation of the model[8].

Typically, data maybe collected from permanent seismic (time-lapse or 4D) or downhole equipment that monitors production. The objective is to draw up a reservoir management strategy that will address:

- The effect of recovery methods on reservoir fluids
- Migration and production of oil and gas
- Communication with adjacent reservoirs
- Sealing faults
- Fracturing
- Induced pathways due to modified permeability
- Scale formation
- Hydrogen Sulphide (H_2S) mitigation, and
- Water disposal.

Analysis will include:

- Reservoir temperature
- Pressure
- Depth
- Net pay
- Permeability and porosity
- Residual oil and water saturations, and
- Fluid properties such as oil, API gravity and viscosity[9,10].

Seismic

A major goal for oil companies is to improve recovery factor for mature fields. A key method is to use imaging as a way of identifying stranded hydrocarbons and improving the efficiency of water injection. This helps mitigate the problems associated with water production, such as souring and scaling, and thus decreases the lifting costs of old fields. By using 4D seismic, and examining the differences between subsequently acquired seismic images, production geophysicists can: map reservoir drainage patterns; identify flow barriers such as faults or unconformities that are below the resolution of direct seismic imaging; and, plan the location of future injector wells.

Mature Field Applications

Water Injection

Water management is a major challenge associated with mature fields. Besides handling increasing volumes of water at surface, the challenge is to increase recovery by improving the sweep or production of hydrocarbons through water injection. This requires the correct evaluation of reservoir drainage patterns. In order to meet water management and environmental needs, oil companies are shifting from water injection to water re-injection. To ensure smooth transition from lab technology to field application, oil companies run pilot programmes; for example, a pilot water re-injection programme would handle say 5% of actual water volumes produced from the reservoir and re-inject this to maintain reservoir pressures. Water injection is easily applicable offshore where the entire ocean is available, but recently land operators have had problems finding water to inject. Farmers object to the use of aquifers for obvious reasons.

Accordingly, operators have figured ways to re-inject unwanted water produced in conjunction with the oil. This recycling solves two problems at once: it is an elegant way to dispose of the unwanted saline water that is not suitable for irrigation or drinking, and it augments oil production. Now, even offshore operators are recycling produced water because it is unlawful to dump it into the sea because of its high saline content and because it contains traces of residual oil.

To get an idea of the volumes manipulated, Petrobras handles an average water injection volume of two million barrels of oil per day (MMbbl/d) half of which come from produced water. This accounts for approximately 1.87 million barrels (MMbbl) of oil which is an average water cut of 50%. Petrobras plans to construct a system for 'raw' water injection which would be placed over the seabed and used to capture and filter water prior to injection. This has a good application on mature fields or fields whose small platforms are often space-limited[11].

H_2S in Mature Fields

The term 'souring' describes various sour gas and H_2S management strategies. The Health, Safety and Environmental (HSE) implications of water injection are well understood as injection has been ongoing in certain areas since 1978. In Brazil's Offshore Campos Basin in the Marlim field, water injection begun in 1994 and a H_2S breakthrough occurred in 2003. Injecting nitrate to mitigate the problem and to simulate the reservoir behaviour of H_2S generation processes helps to define, for the fields under development, which strategy to adopt. This approach is dependent on the forecast of how much H_2S is involved and when it will be produced[12].

If only trace H_2S volumes are expected, there is no need to act; if there are medium levels, metallurgical improvements may be selected. In addition, sulphate removal for scaling treatment may help to mitigate some of the souring problems. If levels are high, nitrates must be injected. Field pilots usually test the effectiveness of nitrate injection by having one pilot re-inject reservoir water and another pilot inject seawater. It should be noted that both would be using nitrate. These technologies are developed in conjunction with service and research companies, which are performing lab tests to help determine the simulation parameters of H_2S generation in the reservoir[13].

Salt and Scale

Offshore operations also create salt and scale problems. This can occur anywhere between surface and sub-surface equipment. Remote operations have been used successfully to perform interventions such as well cleaning and squeezing of scale inhibitors into the formation. Satellite wells using subsea Christmas trees are employed in all Brazilian deepwater fields, and remote handling avoids incurring high rig costs for intervention. The problems of corrosion and its effects on subsea installations need to be carefully considered[14].

Steam Onshore Fields

Onshore fields have seen good results from EOR using cyclic or continuous steam injection, as is demonstrated by the production of a total of 20,000 barrels per day (bbl/d). Applications in the Fazenda Alegre, onshore Espírito Santo Basin, have seen production rates improve in horizontal wells due to the introduction of thermal recovery methods. Several research projects are testing theories and feasibility of in-situ combustion. Petrobras is also considering variations of in-situ combustion and steam injection. The old vertical injector—vertical producer scheme—is being substituted by innovative geometries; for example, a vertical well to inject and a horizontal well to produce. Another alternative is to associate steam with solvents. This technology was recently applied in a field in the Espírito Santo Basin to mobilise oil which had not responded to steam injection alone.

Steam Assisted Gravity Drainage (SAGD) is an enhanced oil recovery technology for producing heavy oil. It involves the parallel drilling of a pair of horizontal wells spaced apart a few metres. Pressurised steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore, where it is pumped out.

In all thermal recovery processes, the cost of steam generation and the availability of water will play a major part in determining whether the cost of oil production is commercially viable.

Microbial Applications

Another EOR front uses microbial applications based on water and bacterial interaction to increase production. The water and bacteria are pumped down and this is followed by nutrients. The bacteria develop a biomass that clogs the porous medium and subsequently increases the viscosity of water and diverts flow along new pathways to increase production. Biopolymers, generated by the metabolic process of the bacteria, clog the water pathways of higher permeabilities. Continuously injected water displaces the remaining oil from the lowest permeability zones. This process has been tested by Petrobras' Carmópolis field in the Sergipe Basin[15]. Alternatively, microbes are used to 'eat' clay particles that clog pore throats, thus improving permeability. A limitation to the use of microbes is their relative temperature limit. Ongoing research seeks to breed colonies of microbes that are more temperature resistant.

Modifying Relative Permeability

A neat application is the use of chemicals to control water. Water shut-off control in more than 200 wells has been achieved with the injection of a patented polymer called Selepol, which is a relative permeability modifier. Several formulations were attempted with the more recent based on tiny pieces of hydrophilic gel[16].

Drilling in carbonates or tight sands is another area of interest where stimulation technology plays a central role. There have been five fractures in a well drilled in the Enchova field, a shallow water, low permeability, light oil-bearing carbonate.

A new exploratory approach may bring into focus a new family of reservoirs of this kind, previously thought to be marginal in Brazil[17].

A novel gas management programme was designed to characterise gas reservoirs, principally for the tight sandstone Mexilhao field in the Santos Offshore Basin. The development of a gas-producing province at the Santos Basin, south of Campos, is a major goal for Petrobras and the company is focusing on stimulating flow in low permeability porous media[18,19].

Steam Injection

In the late '70s, following the discoveries of heavy oil reservoirs in the onshore part of the Sergipe-Alagoas and Ceará-Potiguar Basins, cyclical steam injection was introduced into Brazil. These first successful projects were later expanded and commercialised[20]. Subsequently, continuous steam injection was applied to a total of 15 cyclical and continuous steam injection projects covering a broad range of oil viscosities. Steam is responsible for virtually all tertiary recovery production, estimated to be presently 3% of Brazil's total oil production. In the Fazenda Alegre field, located in the onshore Espírito Santo Basin, extremely low API grade oil is being cold-produced using steam injection and horizontal wells completed with slotted liners and stem rod pumps[21].

In-Situ Combustion

Two in-situ combustion pilots were performed in the '80s in the Buracica and Carmópolis fields, and in the Recôncavo and Sergipe-Alagoas Basins respectively. The best results were obtained in the Buracica pilot, which was characterised by a low temperature oxidation process; however, sand production and well surface facility corrosion were major operational problems. Additionally, oxygen breakthrough interrupted the project due to the risk of well explosion. The Carmópolis pilot showed poorer results, despite the fact that it generated the best combustion efficiency. Poor reservoir characterisation was the main reason for losing control of the combustion. Electrical heating was tried in two heavy oil reservoirs in the Potiguar Basin as an alternative to steam injection. Results showed that the electrical heating process cannot replace steam, but can be useful in areas where steam is not applicable. Further electrical heating and water injection techniques have been applied in a pilot project conducted in the Canto do Amaro field[22].

Polymers

The first polymer injection project was implemented in 1969 in the Carmópolis field. After operating for some years, the project was interrupted but evaluations showed that an additional oil recovery of 5% could be credited to polymer injection. Besides the technical success of this project, the drop in the costs of polymers and the increasing ease with which polymer could be handled and prepared offered new opportunities to apply this technique. Currently, there are three polymer projects in course, one in the Carmópolis field and the other two being carried out in the Buracica field, Recôncavo Basin and in the Canto do Amaro field in the Potiguar Basin[23].

Water Management in Petrobras Fields and Treatment of Subsea Xmas Tree Wells

Water Flooding

Flooding is the main recovery method used in Brazil in both onshore and offshore fields. Offshore operations in the Campos Basin are responsible for a daily output of roughly 75% of the total country's output. The volumes of water injected exceed 800,000 bbl/d and the water production reaches values of over 350,000 bbl/d[24].

Due to the importance of water injection for the Petrobras fields, water management has become a major priority. Problems associated with water injection and production has been the focus of several important projects developed in the past few years.

It is worth emphasising that 'simple' problems in onshore fields, such as the stimulation of injector wells that have lost injectivity, become more complex offshore. Many wells located in deepwater areas are completed as satellites; therefore, workovers are extremely expensive due to the need for a floating rig. For such scenarios, remote operations are performed as a way of decreasing intervention costs.

A major factor in managing water is the rate of water injection that is required. The injection decline curve for injector wells must be precisely drawn in order to evaluate the economics of two options: to perform effective water treatment that requires fewer workovers or to inject lower quality 'water' that requires more frequent workovers.

Petrobras has been injecting seawater in offshore fields for twenty years. Water quality has been monitored using an index which covers parameters involved in water treatment such as injection and disposal volumes, corrosion risk, bacteria, solids and oxygen content. Irrespective of the quality of the injection programme, there is an ultimate loss of effectiveness over time. Some remote treatments using acid to remove damage in injection wells have been performed and have yielded very good results[25].

Remote Acidisation

This technique has been performed in the Marlim field which is a giant complex of oil fields located in water depths that vary from 1968 ft (600 m) to 3,445 ft (1050 m). It produces 600,000 bbl/d from high permeability turbidites. To maintain reservoir pressure, an equivalent amount of water is injected daily. Despite excellent reservoir properties, injector wells lose effectiveness after a few months of water injection. Conventional acid treatments cannot be performed due to high rig costs. The solution, therefore, is to pump acid from the production platform which is often several kilometres away from the subsea Xmas tree wells. Careful laboratory tests are needed before field operations can begin to ensure that the treatment does not damage subsea equipment such as injection lines, well heads and injection columns[26].

To date, only vertical or slant cased wells have been treated. The challenge is to perform remote pumping in horizontal wells completed with slotted liners.

An alternative that may help guarantee effective water injection is to inject low quality water at pressures high enough to keep fractures open. Safe water injection requires extensive modelling of reservoir sweeps, geometry and fracture propagation[27].

Flow Assurance

Flow can be interrupted or halted altogether due to inorganic scale formation caused by seawater and reservoir water mixing together; therefore, the prediction, prevention and corrective treatment of scale is fundamental to ensure the flow of oil. The Namorado field was the largest Brazilian offshore field in the '80s and suffered from scale formation. Interventions to squeeze scale inhibitors into the rock formation were performed and oil production was maintained without interruption.

As some deepwater fields contain horizontal, uncased satellite wells, scale treatments are more difficult to perform. Nevertheless, some excellent results were achieved in the Marlim field using a special chemical process developed by Petrobras. Oil production increased by more than 13,000 bbl/d after the treatment. Again, the challenge for the next few years is the application of these treatments in horizontal uncased wells[28]. Sea floor water separation and re-injection are techniques under development[29].

Polymers

The use of polymers to control water is another potential solution and Petrobras has performed more than 170 well treatments in onshore fields. The rate of success for such treatments is in excess of 65%. The process modifies the relative permeabilities of the oil-water-sandstone system, retaining water in the wellbore vicinity. Higher seawater salinities, higher temperatures, higher permeabilities and higher produced volumes, as compared to onshore conditions, are the main challenges to be overcome offshore[30].

Water Disposal

Once large amounts of produced water cannot be avoided, disposal becomes the priority. The focus is on treating water to remove oil (this can be difficult due to space restrictions on platforms) in an environmentally acceptable manner so that re-injection into the reservoir or disposal in non-productive formations can be achieved[31].

Trends in Reservoir Geophysics

The challenge for seismic contractors is to increase the quality and resolution of seismic data, not only in exploration, but also in mature applications. New acquisition and seismic processing parameters oriented to reservoir characterisation and monitoring are helping improve seismic quality and resolution. With this new data set, reservoir geophysicists can potentially better understand external reservoir geometry, the internal heterogeneity of turbidite reservoirs and monitor the fluid flows. Historically, reservoir geophysicists have been using the same sequential process normally used in exploration. Nowadays, oil companies are applying new techniques such as 4D seismic adapted to reservoir needs[32].

Mature Field Seismic

In the following applications, we look at the benefits of seismic in brown fields owned by BP, Petrobras and StatoilHydro. These oil companies have successfully used the latest 4D and time-lapse seismic to maximise the life of the reservoir, characterise stacked and thin-bed reservoirs as well as monitor water injection in deepwater reservoirs. This has helped these companies reach bypassed payzones, extend production and even change the definition of what was once considered economic.

Reservoir Studies of BP's Mature Fields in the Columbus Basin, Trinidad

4D seismic accompanies the lifecycle of an oil and gas asset and can provide valuable production monitoring information. This is because, as with all technology, seismic is subject to constant improvement. Seismic shot 20 or 10 years ago would have had limited 'vision' and likely only located 'shallow' reservoirs. Today, opportunities exist to find deeper reservoirs in mature fields, which were once characterised by 2D (early less sophisticated seismic). This can be seen in the new frontiers or deep gas plays, which are being explored in the Gulf of Mexico (GOM) and in the Columbus Basin[33].

This has tremendous value in shaping decisions as to the peaking of production rates and decline curves. Usually, a cost-benefit analysis is conducted which measures costs and attributes the value gained. This exercise can be difficult as the value gained may often be indirect. 4D seismic is used mainly to better manage reservoir production across the lifecycle of a field. Due to the increasing number of brown fields worldwide, 4D seismic applications have increased substantially; however, as seismic is a recent technology, there are relatively few processes available to evaluate it[34].

In 2004, BP in Trinidad and Tobago faced the challenge of valuing a number of seismic survey options over the Greater Cassia Complex in the Columbus Basin, Trinidad. In Southern Greater Cassia, several trillion cubic feet (tcf) of gas reserves are located under shallow gas reservoirs, which often blur seismic visualisation. Development of these reserves is complicated by the presence of 27 stacked reservoirs with reserves trapped in over 100 separate segments[35].

BP had to identify and value the style of survey required to improve seismic visualisation over the southern half of the complex, which was affected by shallow gas imaging problems, and value the benefits that 4D seismic could offer for reservoir management and future well placement. This required consideration of expensive 4D Ocean Bottom Cable (OBC) seismic acquisition options. Additional benefits from 4D seismic for monitoring dynamic reservoir performance could be foreseen with a permanent installation. Here BP developed several research programmes to ascertain which 4D acquisition option was the best solution. The integration of these results, along with other elements, helped support decisions for a seismic strategy for the 'Life of the Cassia Complex'[36].

Mature Field Seismic Application in Petrobras' Deepwater Campos Basin, Brazil

Petrobras acquired its first 4D seismic in the Marlim field in 1997. In 1999, Petrobras started several 3D, reservoir-oriented seismic acquisition programmes covering former 3D surveys. These occurred in the South Marlim, Barracuda and Caratinga, Espadarte, Marimbá, and Pampo-Linguado fields in the Campos Basin.

Common seismic processing techniques were used to map reservoir turbidite systems and to reduce appraisal and production risk. Visualisation techniques were applied in 3D views of exploration and development projects[37]. From its initial evaluation of the 4D interpretation, Petrobras was able to re-locate the trajectories of 11 development wells planned for the Marlim Complex. In addition, the company was able to identify the need for nine additional wells to improve reservoir drainage efficiency. In short, the company realised a Return on Investment (ROI) of more than 40 times by saving US $1.6 billion by not drilling wells in the wrong place. It remains to be seen how much additional revenue the company will gain from drilling its development wells in the right place.

Geosciences

Oil companies commonly apply dual geoscience programmes of seismic for reservoir characterisation and also 3D geological modelling. Seismic for reservoir characterisation is a main issue. An acquisition project was started in 2005 with the objective of acquiring base 4D timelapse data of the whole Marlim Complex (Marlim, Marlim Sul and Marlim Leste fields). Petrobras has a '4D-room' where geologists and engineers can visualise geological phenomena[38,39]. At the time, Marlim was the largest seismic acquisition ever acquired both in terms of area and the amount of data acquired. The data amounted to 157 terabytes and required the continuous application of 12,000 processing units (9000 of which were located in Houston and 3,000 in Gatwick, UK).

Regarding the specific challenges that reservoirs create, modelling reveals such things as key depositional features and reservoir geometry which can help explain the gross size, volumes and channels of the reservoir[40].

Figure 2 - Offshore Vessel in the Troll Field

Mature Field Application of 3D Seismic and Multilaterals in Norway's Troll Field

The Troll field is located approximately 50 miles (80 km) off the west coast of Norway in shallow seawaters. Troll's reserves are mainly gas (at one time it was considered to be a gas play only), but it also contains sizeable oil reserves and has produced more than one billion barrels of oil.

This oil, however, was distributed in hard-to-reach thin oil-bearing layers that were just 13 ft to 85 ft (4 to 26 m) thick and spread out over an area of approximately 173 square miles (450 sq km)[41,42].

A combination of multi-laterals and state-of-the-art geosteering drilling technology was required to drain the thinly dispersed pockets of oil. This included the latest rotary steerable systems in conjunction with reservoir imaging tools, which allowed the oil company to place the well in the best parts of the reservoir. This, however, was only half the story as state-of-the-art completion and production technology was required due to challenges such as Subsea sand and water separation.

In the late 1980s, it was the belief that the development of Troll oil would 'never' be economically feasible because its oil reserves were so thinly layered and the price of oil was US $10 per barrel; however, with the creative use of technology, Troll became one of the largest oil producing fields in the North Sea. The success of this drilling and production approach led to its application in even thinner oil layers measuring just 23 ft to 46 ft (7 to 14 m) thick[43].

The Troll story is one of realising the potential of the field by: applying modern drilling technology; placing well trajectories within a very difficult and challenging reservoir; and keeping sand and water production to a minimum to achieve maximum production.

These successful field applications illustrate the immense financial and technical risks faced by the oil companies in reaching their prize, and show how challenges can be overcome to realise added profit and extended reservoir life.

We have seen how technology in Extreme E & P and mature field applications has extended Hubbert's peak into a plateau. With the powerful combination of technology and knowledge we are producing from reservoirs once thought to be unproduceable and improving overall recovery rates.

But how does the oil and gas from wells reach consumers?