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The Challenge of Producing Thin Oil Rims in Trinidad

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Abstract: *Many hydrocarbon reservoirs have water underlying an oil or gas bearing zone. When placed on production, if a wellbore draws oil or gas from an area near the water zone, the water can be drawn into the wellbore due to the phenomenon of coning. This creates problems because it results in excessive water production compared to the oil or gas production. If the water contains salts such as sodium chloride, these can corrode production facilities, and the produced fluids must be separated before transporting to the refinery. Reduced oil or gas production and increased operating expenses all lead to reduced revenue. Unfortunately, such a situation cannot be avoided if there is a thin oil-bearing layer, sandwiched between a gas cap and bottom or edge water, and in which case gas coning can also occur. Thin oil rims are found in many oil provinces around the world and are especially prominent in the prolific gas province offshore the east coast of Trinidad and Tobago. While oil, the more valuable resource is recovered before extraction of overlying gas, exploitation of these reservoirs poses a challenge for reservoir development, as early gas and water coning severely hinder maximum oil recovery. Alleviating these challenges by reservoir management involves knowing where the fluid contacts are, and optimisation of well placement and fluid withdrawal rates. This paper investigates the problems of thin oil rim reservoirs. It discusses the successful current reservoir management practices for coning carried out in Trinidad within the economic restraints of the liquefied natural gas (LNG) contracts, and demonstrates how multidisciplinary teams, using horizontal wells and good use of modern technology, have successfully exploited the fields off the east coast of Trinidad.*

Keywords: *Thin oil rim, horizontal well, coning, multilateral well, water breakthrough, water production, Trinidad*

1. Introduction

Many oil reservoirs have gas-cap and/or water support (Kromah and Dawe, 2008). The structure of the reservoir may be dome-shaped with the oil zone sandwiched between the gas cap and bottom water, or sloping with edge water (see Figure 1). If a wellbore draws oil or gas from an area near the gas or water zone, the gas and/or water can be drawn into the wellbore due to coning because gas and water are generally less viscous than oil, and thus flow more easily than oil. This phenomenon occurs particularly at high production rates where gravity effects are too small to counteract the effects of viscosity ratio, creating problems due to excessive gas or water production compared with the oil production.

If the water contains salts such as sodium chloride, these can corrode production facilities such as separators and connecting pipework. The produced fluids will also have to be separated before transporting to the refinery. The reduction in oil production and increased operating expenses all lead to reduced revenue. Unfortunately, such a situation cannot be avoided if the oil is being drawn from near the oil-water or gas-oil contacts, and particularly when the oil-bearing zone is thin.

For reservoirs with both a gas cap and an oil rim, oil, the more valuable resource, is produced before the gas from the overlying gas cap. This is because (i) if gas is produced first then reservoir pressure drops and gas will come out of solution in the oil, reducing the volume of oil that can be produced, and (ii) as the gas cap pressure is lowered, the oil can move upwards into the gas cap rock. There the saturation of oil increases from zero, but some of this oil will remain trapped and will not be recovered because of the capillary forces acting within the reservoir porous matrix, thereby reducing overall recovery. These factors also have negative financial implications.

For cases in which the oil column is thin (~ 50 ft), development and production of the oil column present additional challenges. Such reservoirs are found in many hydrocarbon provinces around the world and are prominent in the prolific gas province offshore the east coast of Trinidad and Tobago (see Figure 2).

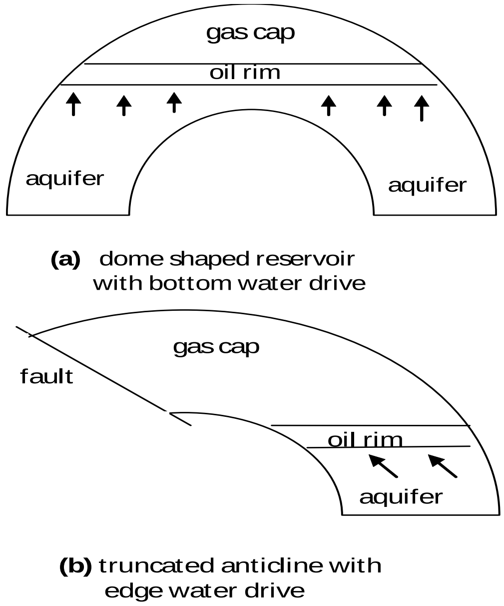

Figure 1. Bottom and edge water

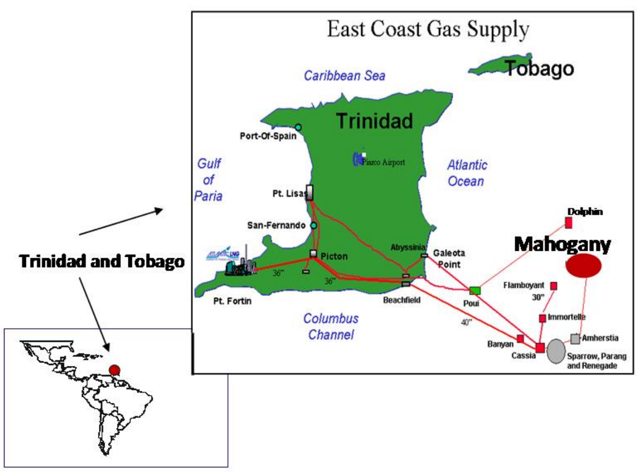

Figure 2. Location map of Trinidad and Tobago

Above the oil rims, the reservoirs contain significant volumes of gas which is being monetised by delivery to the domestic market and to the Atlantic Liquefied Natural Gas (ALNG) plant (Marcelle-De Silva et al., 2000; Mackow et al., 2003). The oil, which governments demand should be extracted first, delays the onset of gas production and further complicates the terms of the contracts between gas producer, local buyers, and ultimately the global customers.

Generally, the production of the oil rims is planned to be as rapid as possible. Unfortunately, when the oil is produced prior to the overlying gas, production is not always trouble free because of any gas and/or water coning. This paper investigates the problems of thin oil rim reservoirs and presents the successful current reservoir management practices carried out in Trinidad within the economic restraints of both the domestic and the liquefied natural gas (LNG) contracts.

2. Coning

Coning is the mechanism whereby gas or water moves toward the production interval of an oil well in a cone or crestlike form created by fluid offtake (Kromah and Dawe, 2008). It is caused by the pressure drawdown within the oil column close to the wellbore being sufficiently large to overcome viscous and gravity forces and draw the water or gas into the well. As the flow rate increases, the cone height also increases until at a critical rate, the cone becomes unstable and water, or gas, is drawn into the wellbore above the oil-water contact, or below the gas-oil contact (see Figure 3).

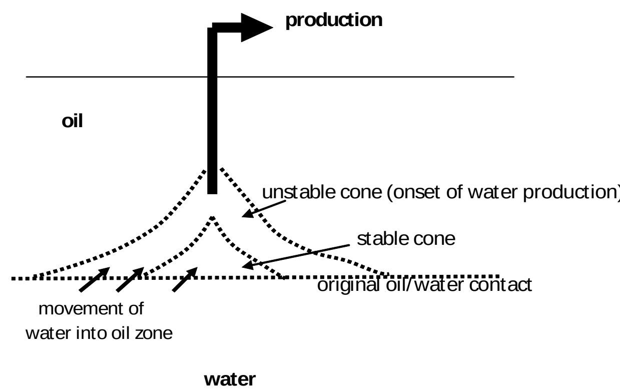

Figure 3. Stable and unstable cones

This premature water or gas breakthrough is often referred to as coning on vertical flow, or cresting on horizontal flow. As illustrated in Figure 4, while coning involves the localised movement of gas or water towards the well, cresting involves the localised movement of gas or water along a significant, if not, the entire length of a horizontal well.

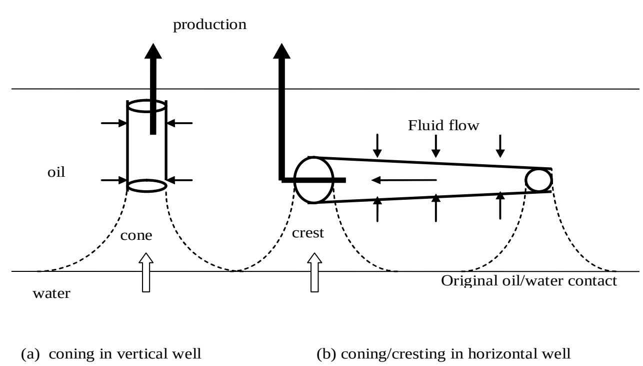

Figure 4. Coning in (a) Vertical and (b) Horizontal Wells

3. Horizontal and Multilateral wells

Horizontal and multilateral wells, as opposed to the conventional vertical wells, have proven to reduce coning problems and improve recovery in thin oil rims. Production increases of 2-5 times that of vertical wells have been observed, and horizontal wells are now accepted as the better way to improve recovery (Joshi and Ding, 1996; Vo et al., 2000). This improved performance is attributed to (i) smaller drawdowns which reduce coning effects, (ii) enlarged contact and drainage areas, and (iii) improved sweep, production rates and recovery efficiencies.

In horizontal wells, the pressure profile is fairly uniform along the horizontal portion of the wellbore, with a slightly lower pressure and hence larger pressure drawdown around the heel. In this area, this lower pressure drawdown increases the tendency for gas and/or water to cone more rapidly (Joshi, 1991). The size and shape of the cone formed is related to the magnitude and extent of the pressure drop, with vertical wells forming tall narrow cones and horizontal wells forming flat, wide cones or crests (see Figure 4). The production strategy for horizontal wells in a thin oil column is normally to place the well near the gas-oil-contact, and allow the aquifer to drive the oil upwards to minimise the loss of oil (Butler and Jiang, 1996; Joshi, 1988).

4. Geological Modelling

One of the key elements for accurate placement of horizontal wells within a thin oil rim, is the building of a detailed geological model. In addition to providing information on the areal extent of the reservoir, sand thicknesses and hydrocarbon volumes, the geological model impacts the well's location, landing point, well length and course, and completion methods, particularly if the well trajectory is to intersect several layers (Vo et al., 2000). Unfortunately, unexpected and abrupt geological uncertainties such as faults and shale-outs can occur and create challenges while drilling. Furthermore, in geologically difficult areas where there is sand thinning and shale-outs, attempts to sidetrack by drilling in a slightly different direction can be costly. The running of saturation logs such as the resistivity saturation tool (RST) can also be used to help assess the depths of the fluid contacts and as such the thicknesses of the oil rims (Samsundar et al., 2005).

5. Numerical Simulation and Reservoir Characterisation

The performance of horizontal wells has been studied using physical models in laboratories (Permadi et al., 1995) and over the years, several correlations and analytical models have been developed for production forecasting and for predicting water and gas breakthrough times (Joshi, 1998; Permadi, 1996). The building of a numerical simulation model based on the detailed geological model, is however one of the key elements for providing limits of behaviour, production optimisation and for successful well placement. This is due to the fact that the recovery of oil from thin oil rims is highly sensitive to the thickness of the oil column, formation permeability, reservoir geometry, magnitude of bed-dip, size of aquifer and gas cap, and oil viscosity (Marcelle-De Silva et al., 2000; Vo et al., 2001). These parameters vary from reservoir to reservoir and it is imperative to evaluate each reservoir separately.

The dip of the reservoir bed has significant influence on the recovery depending on the operating procedure of the well since the higher the angle of dip, the larger is the effective gravitational force counteracting the viscous forces. Reservoir heterogeneities, particularly changes in permeability, play an important role in coning, thereby delaying or perhaps unfortunately enhancing early water and gas production (Marcelle-De Silva and Dawe, 2005). For example anisotropy, the ratio of the vertical to horizontal permeability, affects the shape of the cone and the rate at which the cone is formed. It is also an important factor in determining the optimal well type, whether it is a long horizontal, inclined or multi-lateral well. The presence of shaly or silty zones may act as barriers or baffles to the movement of water or gas, and may impede the formation of the cone. On the other hand, high permeability zones act as conduits for water and gas to break through to the wellbore.

Simulation studies are needed to provide details on the optimum recovery strategy, flow rates and reserves, rate control effects of simultaneous gas and water withdrawals, the effect of aquifer strength on recovery, and the effect of simultaneous gas and water injection. These studies provide information on optimal wellbore placement and distance with respect to the gas-oil-contact (GOC) and the water-oil-contact (WOC), well lengths, completion techniques, tubing size and potential workover candidates. They also assist with determining sizing of treating/production facilities and determining the need for surface facility upgrade (Vo et al., 2001; Haug et al., 1991). These numerical studies require the use of refined grids around the wellbore to properly simulate coning behaviour, breakthrough time, and post breakthrough performance. Coning is optimally simulated using a fully implicit model, which describes the multiphase flow around the well (MacDonald and Coates, 1970). However the simulation may be limited by the computing capacity available. All these different needs are dealt with by management teams where the members bring to the table all the different expertise.

6. The Practical Difficulties of Placing the Wells

In order to properly place a horizontal well, the depths to the GOC and the WOC must be known. Operators generally employ one of three techniques to land wells at the correct depth (Vo et al., 2000). The first option, and the most costly, involves drilling a vertical pilot hole to locate the GOC and the WOC. Once these depths are known, the well is side tracked and positioned at the required depth.

The second approach commonly used, particularly when the drilling of a pilot hole is rejected because of cost considerations, is to intentionally drill to the WOC. The direction of the well is then changed bringing it back up into the oil rim at the desired depth. The disadvantage of this approach is that it is sometimes difficult to steer the well back into the oil rim without loosing a significant segment of the lateral. This could also adversely affect oil production since one can have premature water breakthrough if the section of the well through the water zone is not sufficiently isolated. For reservoirs with high permeability and strong water drive, production logs indicate that water accumulation could be a problem at the lowest point in the well (i.e. the heel).

The third technique involves entering the target area with a trajectory already near horizontal, and once the GOC contact is located, the horizontal section of the well is drilled but maintaining a certain distance from the GOC.

In all options, it is important to avoid undulating well paths, as this could also lead to geological surprises, early coning of water and gas at low and high points, as well as accumulation of liquids at the low points. The optimum location for the horizontal well relative to the GOC and the WOC, will vary from reservoir to reservoir. Considerations include reservoir rock and fluid properties, size of the gas cap and aquifer, and in offshore operations, slot availability.

For the development of thin oil columns (10-20 ft), that marginally pass the economic hurdle, further cost cutting in the areas of drilling and completion are needed (Vo et al., 2000, 2001). Strategies that can be considered include (i) the use of coiled-tubing drilling, (ii) the use of multiple horizon completions where stack-pay environments exist and single-zone horizontal well may be uneconomical, and (iii) the drilling of shorter horizontal wells (600 ft) with smaller tubing and gas lifting to improve recovery efficiency.

7. Case History - Trinidad's Mahogany Field

The Mahogany Field is located 100 km offshore the southeast coast of Trinidad in 300 ft of water, and came on production in 1999 as a dedicated gas field to supply feed gas to the new liquefied natural gas (LNG) plant in Point Fortin (see Figure 2). The field has a faulted anti-clinal structure with stacked sand and shale sequences. Fifteen gas bearing reservoirs were identified to be located at depths from 6,000 to 14,000 ft sub-sea, spread across seven separate fault blocks and with gas reserves of approximately 2.6 TCF (Mackow et al., 2003; Samsundar et al., 2005). One of the main reservoirs, the 21 sand in addition to containing a 400 bcf gas cap, contained a 60-ft thin oil rim with 100 million STB of oil initially in place (OIIP). This oil rim which was underlain by an aquifer in one fault block, provided a unique development challenge since the gas reserves were designated for the LNG project.

Early in the design phase, horizontal wells were proposed for the development of the oil rim, as these were expected to reduce coning tendencies. A detailed geological model was built and the decision taken to use a 3-dimensional numerical simulation model for the determination of optimum well placement since there was significant stratigraphic variation and structural complexity (Ali-Nandalal et al., 1999). The model incorporated data from 3-D seismic surveys, a 3-D structural software package, cores, and from the Formation Micro Imager, stratigraphic interpretation. A thin oil rim in the Immortelle/Amherstia field, which is located in close proximity to the Mahogany field, and which was previously developed using horizontal wells, was also reviewed (Mackow et al., 2000).

For the review, attention was focused on finding solutions to problems that caused the Immortelle wells to perform below expectations. The study revealed that factors which would be critical for the successful development of the 21 sand thin oil rim included (i) well placement within the oil column relative to the GOC and WOC, (ii) avoiding drilling undulating wellbores and locating the laterals in poor quality reservoir, (iii) the need to aggressively clean up the wells upon completion of drilling, and (iv) the need to understand well performance at very low drawdowns.

Based on these learnings and to reduce water coning, the initial Mahogany wells were landed at the middle or slightly above the middle of the oil column, i.e. further away from the WOC. This decision was supported by the numerical simulation studies which indicated that the optimum location for the wellbores was in the middle of the oil column (Mackow et al., 2000). The additional benefit of this design was that it allowed for late time gas coning. The gas cap could thus be produced without having to drill additional wells or even having to re-complete in the gas cap.

Particular attention was given to avoiding undulating wellbores and the associated problem of placing sand control screens to the bottom of the wells. Some of the later wells were drilled using rotary steerable drilling technology and as such extremely flat laterals were achieved (Samsundar et al., 2005). Downward movement of the well bore was avoided and as such, produced fluids naturally drained towards the heel of the well.

Management felt that pay quality was more important than well length and so to ensure that the wells were drilled in a high percentage of good pay, the wells were positioned in one layer or across a few layers of similar good quality pay. Drilling in poor quality reservoir rock was thus avoided by limiting the horizontal length of the wells to less that 2500 ft (Mackow et al., 2003). For reservoir surveillance, the decision was taken to install permanent downhole pressure gauges in each of the wells and to run the reservoir saturation tool (RST) in offset wells to monitor

GOC and OWC movements (Samsundar et al., 2005).

Finally, since the wells were to be drilled in high permeability rock (>500 md), it was anticipated that the drawdown would be very low (<20 psi). The decision was thus taken to aggressively clean up the wellbores by initially producing at high rates of up to 5,000 bpd before returning to the predetermined optimum rates with limited drawdown of 20 psi to delay coning of water or gas. This is because of the experience with the Immortelle wells which were brought on production by slowly increasing the production rates, and which were never effectively cleaned-up. As such the entire length of those laterals was not contributing to production and subsequently had to be stimulated with acid. On the other hand, wireline tractor production logs for one of the Mahogany wells however showed that the entire length of the well was contributing to production, even with a very low drawdown (Samsundar et al., 2005).

The initial Mahogany wells eventually experienced some measure of gas and/or water coning. For some of the wells, an increase in oil production rate was noted with an increase in gas production since a natural lift was created for the oil. It was observed however that wells which did not cone gas, produced more cumulative oil than those which did.

Based on the favourable performance of the initial Mahogany wells, the second phase of drilling was quickly initiated but with a few changes in the well design based on the learnings from the first drilling phase (Samsundar et al., 2005). In addition to drilling flat wells, the emphasis was now placed on drilling longer wells, with the last well achieving a producing lateral of 6,740 ft. This led to higher initial production rates from the phase 2 wells of between 3,000 to 7,000 bbl/d, as compared to the wells in phase 1 which produced at rates between 1,000 and 3,000 bbl/d.

Also, since the sands were determined to be more consolidated than originally thought, screen only completions were used instead of gravel packs and as such development costs were lowered. For some of the wells, with the decline in reservoir pressure with production, and an increase in the density of the produced fluids due to water production, artificial gas lift was used to return wells to production after a shut-in period (Samsundar et al., 2005). Gas lifting has also allowed for production at even higher water cuts.

More recently, numerical simulation has been used to investigate coning mitigation during oil production from a thin oil rim reservoir using production cycling (Kromah and Dawe, 2008). In that study, a well was produced and shut in for periods of time. The study indicated that production cycling delayed water breakthrough with an optimum production to shut in time ratio of 2 to 1. The study also predicted that once water breakthrough occurred, getting the well to produce after periods of shut in became increasingly difficult due to liquid holdup and loading. The study however suggested that while more oil was recovered prior to breakthrough, water production was only delayed and ultimately the overall oil recovery was not improved. This technique may however be useful where water handling facilities are limited.

Analysis of production history show that the performance of the 21sand thin oil rim in the Mahogany field has exceeded initial expectations and it is now anticipated that 34% of the oil originally in place (OOIP) will be recovered (Samsundar et al., 2005). This compares favourably to the maximum recovery of 25% OOIP anticipated from the thin oil rim in the Immortelle Field.

8. Conclusion

The development of thin oil rims is challenging, with the key concern centering upon early mitigation of gas and water coning effects which can significantly reduce oil recovery. The use of horizontal wells allows for improved oil recovery and production rates as a result of less water coning, larger drained area and higher sweep efficiency.

Success demands strong multidisciplinary teamwork inclusive of geophysical and geological mapping, numerical simulation studies, and drilling and completion. Detailed geophysical and geological mapping allow for proper well planning and selection of accurate targets for drilling. Simulation studies are necessary inputs to the selection of the optimum depletion plan and well placement. Particular attention must be paid to avoiding the drilling of undulating wellbores and in poor quality reservoir. Opportunities for exchanging ideas, sharing new information and learning from previous projects are also beneficial.

Acknowledgements

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Annex-1: SI Metric Conversion Factors

bbl	x	1.589875	E-01	= m^3
ft	x	3.048	E-01	= m
mile	x	1.609344	E+00	= km
psi	x	6.894757	E+00	= kpa

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Jill Marcelle-De Silva *is a petroleum engineer by profession with 17 years experience in the energy sector at Petrotrin (Trinidad) and later BP Trinidad & Tobago LLC. She holds both B.Sc. and M.Sc. Degrees in Petroleum Engineering from the University of the West Indies (UWI), and an Engineer's Degree in Petroleum Engineering from Stanford University, California. Her professional career involved experience in numerical simulation, risk analysis, enhanced oil recovery, estimation of oil and gas reserves, preparation of long term field management plans, and predicting, monitoring, and optimising the production performance of oil and gas fields. She joined UWI as a lecturer in the Petroleum Engineering Unit in 2000, and has published technical papers on natural gas hydrates, development of thin oil rims, the evaluation of exploration prospects, development of major gas fields and the effects of permeability and wettability heterogeneities on flow in porous media.*

Richard Dawe *is the first holder of the TTMC (Trinidad and Tobago Methanol Company) Chair in Petroleum Engineering in the Department of Chemical Engineering. Professor Dawe is Head of the Petroleum Studies Unit. He joined UWI in August 1999. Richard Dawe holds a MA and DPhil in Physical Chemistry from the University of Oxford (1968), and has followed an academic career with research interests in the broad area of applied thermodynamics and petroleum engineering/geoscience. He had taken early retirement from Imperial College, UK in September 1997, after being in post there for 22 years. He had risen to become the Reader in Reservoir Physics in the Department of Earth Resources Engineering. In his career, Professor Dawe has published over 230 papers mainly on his research interests and edited the book 'Modern Petroleum Technology' (2000) with chapter contributions. In 2005, he was selected for the Vice-Chancellor's Award.*

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