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Risk Management For Production Below The Bubble Point

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Abstract

This paper develops methods which provide practical guidelines for the volume of reservoir around a production well that can "safely" be dropped below the bubble point without losing reservoir energy due to excessive gas production. The methods enable a *gas production envelope* to be calculated for vertical or horizontal wells in dipping reservoirs. Within the gas production envelope for a vertical well, vertical transit times for evolving gas to reach the top of the formation (or a substantial shale) are larger than the horizontal transit times for the gas to reach the production well. Thus all mobile gas evolving within the gas production envelope will be produced together with its associated oil, rather than channel at high mobility into the well, or migrate updip in the reservoir. The gas production envelope for a horizontal well is developed by examining the gas streamlines around the well. To minimise the risk of losing reservoir energy, bottom hole pressures are managed so that field pressures outside the gas production envelope are above the bubble point.

Introduction

Most UKCS oil fields have been developed by maintaining the pressure above the bubble point, wherever pressure support by water injection is economically viable. This strategy allows high production rates without risking damage to the reservoir through gas evolution. However, waterflooding at production well pressures below the bubble point can lead to an acceleration of oil recovery by increasing field drawdowns, and may increase oil recovery if residual oil saturations are reduced as a consequence of free gas becomes trapped behind the waterfront. However, allowing free gas in the reservoir presents a number of risks; reservoir energy may be lost as a consequence of gas channelling, gas production limits may be exceeded, oil shrinkage may occur, the gas may migrate upwards and be detrimental to infill well locations, and permeability reductions may occur. Therefore, the flowing bottom hole pressure in below bubble point operations needs to be carefully managed to prevent or limit this damage.

The Gas Production Envelope Concept

The producing GOR may be reduced slightly when the pressure initially drops below the bubble point in the region around the wellbore. This is a consequence of a lower solution GOR and immobile free gas. Further reductions in pressure may lead to mobile gas being present close to the wellbore. This gas may be produced, in which case the GOR will remain close to the initial producing GOR. However, if gas becomes mobile in regions away from the immediate vicinity of wells, the high mobility of the gas may lead to gas channelling, an increasing GOR and a subsequent loss of reservoir energy. GOR monitoring is clearly vital, however, GOR monitoring is not always accurate and gives no information on the quantity of mobile gas in the reservoir that has evolved but has not been produced. Pressure monitoring is, therefore, also necessary.

Regular well testing can provide an estimate of the average reservoir pressure. However, it is necessary to decide on a "safe" operating pressure. To be sure that reservoir damage is prevented, we need to ensure that any mobile gas which appears in the reservoir is not able to accumulate undetected in the formation (for example, below shales or at the top of the formation). A simple screening procedure is proposed to identify the minimum pressure at which the reservoir can be operated without violating this condition.

The aim is to operate the field at an average pressure which will ensure that the pressure is higher than the bubble point outside a gas production envelope. Considering the volume of reservoir around a production well, the gas production envelope is defined as the boundary within which any mobile gas will be produced and will not segregate or accumulate in the formation (Figure 1). For a vertical well, this gas production envelope can be estimated by comparing the transit time for liberated gas to reach the well with the transit time for the liberated gas to segregate to the top of the reservoir. We note the gas production envelope theory assumes a homogeneous reservoir. Reservoir heterogeneity will complicate the calculation of the gas production envelope and may lead to localised gas channelling, partcularly in circumstances where there are partial barriers to vertical flow and where the gas production envelope is large.

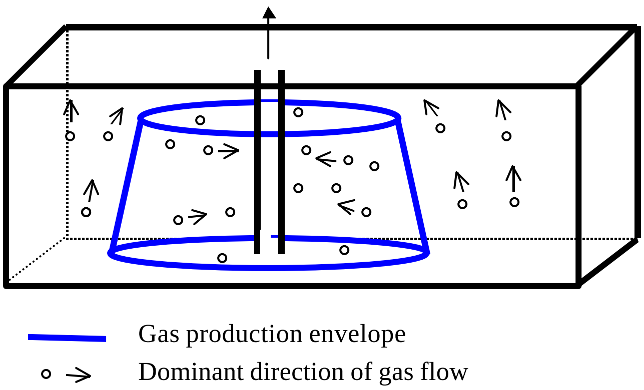

Fig 1. Gas Production Envelope

Vertical Wells

The Transit Time Method

The screening method compares the time that gas evolving at the mid height of the formation takes to travel laterally towards a producing well, with the time gas takes to segregate to the top of the formation (or laterally extensive shale). The average radius of the gas production envelope is calculated to be the distance from the well at which these two times are equal (assuming a fully penetrating well) .

In reality, gas evolves over the whole thickness of the formation. It is inevitable, therefore, that some gas evolving within the gas production envelope will migrate to the top of the reservoir before it can be produced by the well. If this effect is believed to be significant, for example in a very thick formation, it would be necessary to calculate the transit times from an alternative height in the formation.

Other assumptions used in the method are;

- Flow is radial and symmetric.
- The reservoir dip is negligible.
- The effect of drawdown on hydrocarbon properties can be ignored.
- Variations in bubble point with depth are small and can be ignored.
- Vertical movement of gas is driven by the density difference between oil and gas.
- Radial movement towards the well is driven by the pressure gradient required for oil production.

Care is required, in applying the results of this work to field situations, to ensure that these assumptions are not invalidated. For example, in a dipping reservoir, gas may migrate along dip under gravity and hydrostatic effects may lead to gas release at structurally higher locations away from the well.

Using the above assumptions the radius of the gas production envelope can be derived from Darcy's law to be;

$$r < \sqrt{\frac{326 Q_o B_o m_o}{k_v \Delta g_{og} k_{ro}}} \quad \text{in field units} \qquad (1)$$

The radius derived above is used with the radial inflow equation to determine the field average pressure which will meet the condition that the reservoir pressure is greater than the bubble point outside this boundary.

Horizontal Wells

Thin Formations

An idealised horizontal well would be perforated in one horizontal plane and its drainage area would be elliptical in that horizontal plane. The calculation of the gas production envelope for this idealised horizontal well is more complex than that for a vertical well. However, based on work by Joshi [1] or Renard [2], it can be shown that it is possible to determine an effective radius (r_{eff}) for the gas production envelope using the equation for a vertical well if r is defined as;

$$r = r_{eff} = \sqrt{ab} \qquad (2)$$

where a and b are the major and minor axes of the elliptical *gas production envelope* in the plane in which the well is located. This approach can be considered to be valid for horizontal wells which are located close enough to the top of the formation so that any gas evolving vertically above the well will be produced rather than segregate upwards.

In practice it may prove difficult to control the well at the required average pressure due to the difficulties in monitoring horizontal wells accurately and reservoir simulation may be required to help interpret any pressure measurements.

Thick formations

In thick formations when the well is not situated near the top of the formation it is necessary to define the upper boundary of the gas production envelope. A method has been developed which calculates the gas production envelope streamlines in the vertical plane perpendicular to the well. Comparison of the gas production envelope with the pressures in the reservoir enables any gas evolving outside the gas production envelope to be predicted. The method assumes;

- The reservoir is homogeneous with flow barriers above and below, and these barriers are significantly closer than any lateral barriers.
- Reservoir dip is negligible.
- The horizontal well lies in a single horizontal plane located mid-height in the zone.
- The well is long compared with distances from it, and the gas flow is relevant only for planes perpendicular to the well far from either end.
- The flow barriers are impermeable to oil, but permeable to gas. This assumption is only required if gas evolves outside the envelope within which all gas is produced.
- The effect of drawdown on hydrocarbon properties may be ignored.
- Variations in bubble point with depth are small and may be ignored.
- Critical gas saturation is zero in the region of the reservoir away from the immediate vicinity of the well.
- Variations of oil relative permeability may be ignored. That is, the gas does not affect the oil flow.

Figure 2 shows a typical gas production envelope, calculated using the complex flow potential to determine gas streamlines, and pressure isobars. It can be seen from this plot that the minimum pressure in the reservoir outside the gas production envelope is at the top directly above the well. It is therefore sufficient to ensure that the pressure at this point remains above the bubble point. Using this criterion it can be demonstrated that the size of the region below the bubble point will be significantly less than the size of the gas production envelope.

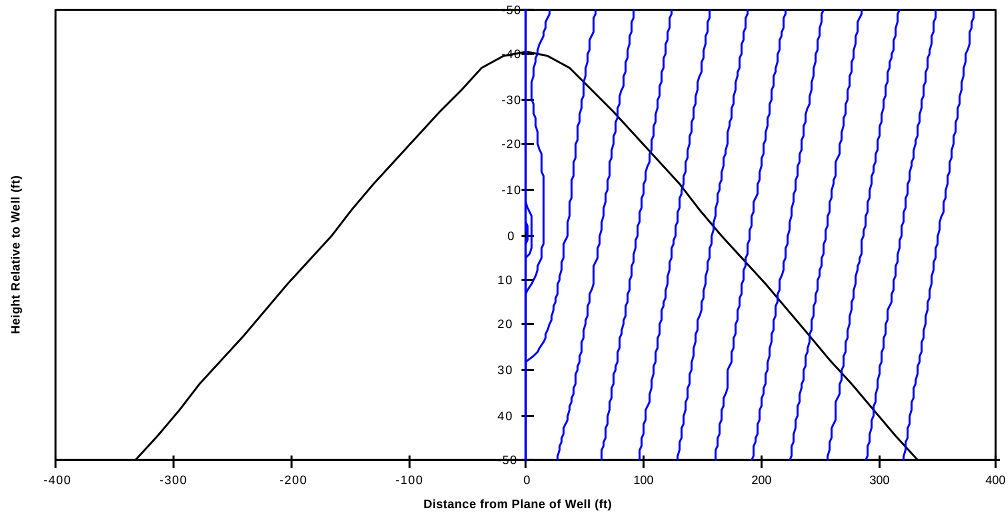

Fig 2. Gas Production Envelope and Pressure Isobars for Horizontal Well

By evaluating the pressure both at the well and at the top of the reservoir directly above the well, the pressure drop between the top of the reservoir and the well may be calculated to be

$$\Delta P = P_w - P_{top} = \frac{h\Delta rC}{288p}\ln\sin^2\left(\frac{pz_w}{h}\right) + \frac{r_o h}{288} \tag{3}$$

using reservoir units and where z_w is the position of the uppermost part of the well and C is defined to be;.

$$C = \frac{1.57x10^{-5}\sqrt{k_v k_h}\, k_{ro} h \Delta r L}{\begin{matrix} B_o Q_o \\ m_o \end{matrix}} \quad \text{(in field units)} \tag{4}$$

Consequently any evolved gas will reach the well, provided the well BHP does not fall below $BHP_{\min}$ where,

$$BHP_{\min} = P_{bub} + \frac{r_o h}{288} + \frac{\Delta r h C}{288 p} \ln \sin^2\left(\frac{p r_w}{h}\right) \tag{5}$$

The upper boundary of the gas production envelope is calculated to be;

$$z = -\frac{h}{p}\tan^{-1}\left(\frac{1}{C}\right) \tag{6}$$

Dipping Reservoirs

Extensions to the methods reported above have also been applied to account for the effect of reservoir dip on the *gas production envelope* and pressure distributions. The inclusion of dip decreases the size of the *gas production envelope* on the updip well, due to the additional influence of gravity, and decreases the pressures due to hydrostatic head differences. The presence of dip may permit mobile gas outside the *gas production envelope* to migrate updip and form gas caps.

Generic Results - Vertical Well

The *gas production envelope* and minimum operating bottom hole pressure (BHP) for a vertical well have been calculated for a range of flow rates and vertical permeabilities using typical fluid properties. Table 1 shows the calculated radius of the *gas production envelope* and the minimum bottom hole pressure for each case.

The *gas production envelope* is smallest and the pressure can be dropped the least when gas is easily able to migrate to the top of the reservoir, for example, when the vertical permeability is high or the rate is low. In these cases a small envelope is necessary to prevent gas channelling along the top of the formation (or below an extensive shale). When rates are high or vertical permeabilities are low, the *gas production envelope* is large and there is a lower risk of undetected reservoir damage.

Table 1: Radius of *Gas Production Envelope*

Rate (STB/D)	Vertical Permeability (mD)	Radius of *Gas Production Envelope* (ft)	Minimum BHP P_{bub} -BHP_{min} (psi)
25,000	20	500	658
25,000	2	1600	781
25,000	0.2	5000	-
2,500	20	160	54
2,500	2	500	66

The logarithmic distribution of pressures in the reservoir can mean that a small change in operating pressure has a large effect on the volume of the reservoir below the bubble point. Caution is therefore required, particularly when the *gas production envelope* is small, and accurate pressure monitoring is required. Also, errors in bubblepoint measurement and the vertical permeability estimate could lead to a much greater risk of reservoir damage than predicted. These risks need to be balanced against the critical gas saturation assumption. A non-zero critical gas saturation would mean that less of the gas evolving outside the *gas production envelope* would be mobile and the risk of reservoir damage would be smaller.

Field Results - Horizontal Well

Inevitably the assumptions built into the assessment methods will not fully apply to a complex field scenario. A study of a field case was performed to assess the validity of the thick reservoir, horizontal well model. Production data below the bubble point were examined for a long horizontal well located in the middle of the oil column in a faulted formation with a large basal aquifer. Analysis was performed using two different formation thicknesses contributing to field pressure depletion (the oil column only and the oil column plus aquifer) and two different reservoir intervals. Water flow was assumed to be distributed with the oil in all but one case when a segregated flow mechanism was assumed. Table 2 shows the match obtained to the measured reservoir pressure, the pressure at the top of the reservoir compared with the bubble point pressure and the radius of the gas production envelope (GPE) compared with the radius of the region below the bubble point (PBE). A large variation in results was observed depending on the assumptions made. We note that a negative number in columns 3 or 4 signifies that the reservoir is below the bubble point outside the gas production envelope.

The best match to the measured well test pressure is obtained by assuming that the smallest volume of the reservoir contributes to pressure depletion (thin formation/small reservoir interval), and that the water flows are distributed with the oil. The prediction for this scenario implies that the reservoir pressure is above the bubble point everywhere outside the gas production envelope. The gas production envelope is large and there is little risk of excessive mobile gas migration updip or into the well. This result is in line with field evidence which showed no sign of rising GORs in the horizontal well or in other wells that may signify gas channelling within the reservoir.

Table 2: Results of Field Studies

Description	% Error in Well Boundary Pressure	P_{top} - P_{bub} (Psia)	Radius of GPE - Radius of PBE (ft)	Free Gas outside GPE?
Thin Formation/Small Reservoir Interval	2	64	1000	No
Thick Formation/Small Reservoir Interval.	23	14	1000	No
Thin Formation/Large Reservoir Interval	32	-120	529	Yes
Thick Formation/Large Reservoir Interval	43	-162	-366	Yes
Thin Formation/Small Reservoir Interval /Segregated Water Flow	38	-157	-270	Yes

We note that the result is sensitive to the assumptions made regarding the volume of the reservoir contributing to pressure depletion. If the volume contributing to flow is large, a lower reservoir pressure is predicted for a given bottom hole pressure as viscous forces are smaller, gravity forces are proportionally larger and the reservoir is below the bubble point at the top of the formation. Up to 400 ft of the reservoir may also be at risk from gas channelling/cusping due to pressures below the bubble point that are outside the *gas production envelope*. This demonstrates the importance of matching the models to known pressure data before making predictions.

Conclusions

1) A set of screening methods has been developed which, in conjunction with frequent well GOR monitoring, can reduce the risks of operating below the bubblepoint.
2) Methods have been developed for both vertical and horizontal wells, and for horizontal and dipping formations.
3) An estimate of the "safe" operating condition for a field is obtained based on idealised reservoir conditions.
4) Careful choice of the model parameters can provide a valid model which closely reproduces the flow conditions in a field situation and which can, therefore, be confidently used for predictive purposes.

Symbols

a	major axis of an elliptical *gas production envelope* in horizontal well plane
b	minor axis of an elliptical *gas production envelope* in horizontal well plane
B_o	formation volume factor of oil, RB/STB
GPE	gas production envelope
h	formation thickness, ft
k_v	vertical permeability, mD
k_{ro}	oil relative permeability
L	well length, ft
P	pressure, psia
PBE	envelope within which the reservoir pressure < bubble point pressure
P_{bub}	bubble point pressure
P_{top}	pressure at top of formation
P_w	well pressure
Q_o	oil flow rate, STB/D
r	average radius of the gas production envelope, ft
r_{eff}	effective radius of the gas production envelope for a horizontal well, ft
r_w	well radius, ft
z	boundary of gas production envelope for a horizontal well
z_w	position of uppermost part of the horizontal wellbore, ft.
μ_o	oil viscosity, cp
Δg_{og}	specific gravity of oil - specific gravity of gas (at reservoir conditions)
r	density, lb/cuft

References

[1] Joshi S.D. Augmentation of Well Productivity With Slant and Horizontal Wells. JPT June 1988

[2] Renard G and Dupuy J.M. Formation Damage Effects on Horizontal-Well Flow Efficiency (Appendix A). JPT July 1991.

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