Multi-Lateral Well Modelling to Optimise Well Design and Cost
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Abstract
In prolific gas reservoirs with strong aquifer drive, water coning is often the determining factor in well productivity and ultimately, gas recovery factor. One of the main drivers in optimising the field development in these cases is to reduce the drawdown of the wells and consequently, a horizontal well design is often used. It is the case, however, that in such highly permeable gas fields extending the horizontal length beyond 1000-2000 ft often does not help to improve well productivity any further, as well bore friction becomes the constraining factor. This paper presents a cost effective and simple solution to increase well productivity by 60% compared to single horizontals at a marginal cost increase. A simple level-1 dual lateral with large bore casing-flow well design has shown to be able to deliver the additional productivity at only a 5-10% incremental increase in cost. Furthermore, we present the results of the numerical simulation study that helped to justify the well design and to deal with interference between the branches.

Introduction
Horizontal wells have become common place in oil and gas fields to increase well productivity. In the Central Luconia region 250 km offshore Sarawak, Malaysia, horizontal wells are a key element of the field development approach for a large number of gas bearing carbonate build-ups that have prolific reservoir quality (200 to >1000 mD) and a strong aquifer drive. As a consequence of the field characteristics, (fast) water encroachment and water coning play a dominant role in the field behaviour. The horizontal wells aim to reduce the drawdown and thus the effect of coning, whilst at the same time maximise the offtake per well, and the ultimate recovery.

However, in the prolific gas fields, extending the horizontal well length beyond 1000-2000 ft does not reduce drawdown any further as the well bore friction becomes the constraining factor, and the toe of the well does not contribute to the well’s production. To further enhance the productivity of our horizontal wells, a cost-effective dual lateral well design was identified to potentially increase the well productivity by some 60% compared to a single horizontal.

This paper will present the well design, the details of a numerical simulation study to justify and optimise the design concept, and finally a discussion of the simulated versus the actual well results.

Field summary
The field is a prolific carbonate build-up that has been in production since Dec 1996 at an average field offtake rate of several hundred MMscf/d. The average field permeability is in the range of several hundred mD, and the original gas column height was some 300 ft. To date the field has produced 74% of the ultimate recovery and has been experiencing water breakthrough in its deviated producer wells since mid-1998. The aquifer has risen on average some 150 to 200 ft, leaving only a relatively small gas column unswept. To maintain the field capacity and to further increase the field ultimate recovery it was decided to drill two horizontal infill wells, one according to the newly-identified well design, and one conventional 7.5/8-in tubing-flow single lateral horizontal well. In this field, coning and cusping would be a major constraint in maximising ultimate recovery as well as reducing the well capacity upon water breakthrough.

Dual-Lateral Bigbore Design
This section describes the details of the well that was designed to address two critical aspects of creating high production gas wells in prolific gas reservoirs with strong aquifers: “the dual-lateral bigbore well”. Firstly, the dual lateral element of the design aims to increase the inflow potential significantly at a low drawdown (up to 200 MMscf/D at 20 psi). The “traditional” approach of extending the horizontal well length does not work anymore at these low drawdown pressures because the well bore friction becomes the constraining factor at well length greater than 1000 ft, as shown in simulations and confirmed by well results (see below). Secondly, the big-
bore element of the design addresses the fact that once the inflow potential is increased, the outflow portion of the well to surface becomes the bottleneck. The novel application of large bore casing flow completions allows for a larger conduit for fluid flow at lower pressure loss. Together this design has the potential to replace several conventional (horizontal) wells at a marginal cost increase, driving down the total field development cost. It has the potential to change the development concept of green fields, to turn marginal developments into economically viable ones, and even can be beneficial for infill drilling campaigns.

Fig. 1 depicts the conceptual configuration of the well. The process of completing the well is as follows: (1) drill and set casing within 50ft of expected top reservoir, (2) drill 8.5-in hole into the carbonate at high angle, (3) upon confirmation of carbonate entry, build-up to 90° angle, (4) drill the 1500 ft mother bore, (5) pull back drilling assembly to top of carbonate, (6) orient the drill-bit and kick-off into a side-track, (7) drill the 1500ft child lateral, and finally (8) pull out of hole and set 7-in pre-drilled liner (PDL) into the child lateral. The PDL has a blank (solid) section above the lateral kick-off point (KOP), the reason of which will be discussed in more detail in the simulation results section below. The beauty of this well design is that it does not require a gas-tight junction at the lateral KOP since the side-track is within the reservoir unit, and as a result the complexity of the well hardly increases as reflected in the incremental cost of only some 5-10%. Using a junction to isolate the laterals, and drill two laterals kicking off far above the reservoir, would greatly increase the cost of the well, and thus reduce the benefit of such a well design.

As mentioned above, in order to benefit from the increased productivity of the dual-lateral, a large bore casing flow design was proposed. This design sets the 13.3/8” casing deep enough to ensure the shoe strength exceeds the maximum gas pressure, uses gas tight 13.3/8-in and 9.5/8-in casing connections, and uses corrosion resistant 9.5/8” casing material.

To establish the performance of the well, a comprehensive testing program was conducted. The test included downhole pressure measurements during a 3-rate flowing build-up test and a 2-rate Production Logging Tool (PLT) run. All downhole measurements were run on coiled tubing. Preliminary tubing head pressures were also recorded during the initial clean-up phase of the well.

The inflow potential of the dual-lateral concept was conducted with a dynamic model (see next section). The design was finalised after extensive investigation of the key factors that influence the behaviour of the dual-lateral well.

**Numerical Modelling of Multi-Laterals**

This section presents the details of the dynamic modelling work to prove up and further optimise the well design. Several factors that impact the inflow potential of the well were evaluated; i.e. (1) the lengths of the laterals, (2) the number of laterals, (3) reservoir heterogeneity, (4) lateral separation, (5) lateral build-up angles, (6) wellbore damage, and (7) hydraulic drainhole diameter. To our knowledge, there were no analytical models to describe the behaviour of a multi-lateral well until recently. Ref. 1 presents an analytical model for a multi-lateral well but it would not be able to give any indication of water breakthrough timing, which is one of the critical parameters in our well design. It was decided to use a numerical simulator to investigate the fluid flow behaviour as well as the interference between the laterals.

A sector single well model containing reservoir properties in-line with a highly permeable gas field was constructed to simulate the various well completion designs. The wellbore flow model accounts for the viscous and gravitational pressure drop along the length of the horizontal laterals. The Appendix summarises the details of the simulation model.

**Simulation Results**

The results from the dynamic modelling show two main elements that need to be considered to optimise the well design. Firstly, it is found that the length of the laterals greatly impacts on well performance. Secondly, any factor that influences the interference between the laterals, such as the number of laterals, needs to be properly addressed to maximise the benefits from the well. With respect to modelling the lateral interference, an interesting simulation aspect regarding the right grid block size was identified. Below the simulation results and their impact on the well design are discussed in more detail.

**Lateral Length.**

Table 1 shows the well productivity, the water breakthrough timing, and recovery factor for various well lengths (500-2500 ft) for single lateral and dual lateral wells. As expected, a longer well completion resulted in higher productivity and higher recovery, and delayed water break-through. However, there appears to be diminishing returns for well lengths beyond 1500 ft due to increasing frictional pressure drop along the lateral.

Another interesting result regarding the frictional pressure losses was found in the simulation study and caused us to change the original well design by adding a blank (solid) section to the 7-inch PDL to span the 170 ft between top carbonate and the lateral kick-off point. Evaluation of the flow contribution and pressures along the completion intervals, showed that in the original design (without solid section in the liner) some 17% of the flow was coming from the first 170 ft open hole section. (This section is required to cheaply drill the second lateral). At the same time this section experienced a significant (frictional) pressure drop because the total production would flow through this part of the well. Consequently the drawdown at the beginning of the laterals, and thus the flow contribution from the laterals was greatly reduced. Rather than redesigning the casing scheme and increasing well cost to isolate the initial 170ft of open carbonate section, it was found that placing a 7-in blank liner across this section cut-off the reservoir inflow contribution from that interval. This cost-effective method isolates the pressure drop over that section from the reservoir, and ensures majority of inflow from the laterals. The effect of this simple
solution was predicted to increase the well productivity by another 20%, i.e. from 140 to 160% compared to a single lateral well (see Table 1).

Different combinations of the second lateral length were studied and two tri-lateral well designs were also modelled. Table 1 summarises the performance of the dual and tri-lateral designs. The simulated results show that a shorter second lateral would result in lower production and slightly lower recovery efficiency. Even a third lateral with equivalent along-hole reservoir penetration as the dual-1500ft design does not have comparable well productivity.

Lateral Interference

One key factor in the optimum well design is the interference between the two laterals, which by virtue of the design is maximal at the KOP. Intuitively it is expected that the separating the two laterals as quickly as possible beyond the KOP, and thus drilling at high build-up angles, would generate significant benefit. Figure 2 shows, however, that increasing the angle above 3°/100 ft, which is a very drillable angle, does not improve the performance significantly. Consequently it was decided to use this build-up angle for the well design to balance well performance and drilling risks.

To ensure that the simulation results were representative with respect to the lateral interference, a separate sensitivity study was carried out. The potential problem that we recognised is that simulation results could yield erroneous results, especially near the KOP where both laterals are completed within one grid block. To assess any significant numerical errors, the effect of various grid sizes around the well location was investigated. The base model had a 100ft by 100ft grid size. Several sensitivities (down to 10x10 ft) where run to determine the trend in drawdown as a result of finer gridding. The result showed, as expected, an increasing drawdown with grid refinement, but the maximum increase of only 5% was sufficiently small to consider the results of the base grid representative.

Actual well results

The dual-lateral bigbore well was drilled and completed in 26 rig-days. The actual completion design and reservoir penetration is presented in Fig. 4. As per the finalised well design, a section of 7-in blank liner was set above the lateral KOP. The actual rig-time spent on drilling the second lateral was just a single rig-day, at an incremental cost of only 4% compared to a single lateral horizontal well. This marginal cost increase was possible since the second lateral could be drilled with the same downhole assembly by just pulling back to the top of carbonate and reorienting the drill-bit to kick-off into the side-track.

Fig. 5 shows the simulated performance of the optimal dual-lateral well and a single-lateral horizontal together with the actual well data. The simulated performance assumed that there is equal mechanical skin damage of five across both laterals. No further well stimulation work was done to the well after the dynamic modelling study concluded that the impact of high mechanical damage was negligible.

Fig. 6 plots the flow contribution of the actual well in comparison with prediction from the simulation. It was expected that there would be little inflow beyond 1500ft. The actual data from the PLT, however, indicates the last 150-250 ft at the well toe did not contribute any significant flow. From the jump in production from about 50 to 100% at the KOP plot it can be concluded that both laterals contribute almost equally to the production. The mismatch between actual and simulated production in the first 300 ft of the well are discussed in the next section.

The PLT results showed an 8 psi pressure differential from the heel to the toe of the lined lateral at a flow rate of 86 MMscf/D, which is exactly half of the 16 psi total drawdown pressure observed at this gas rate. This pressure drop is slightly higher than expected from frictional pressure drop calculations, but is in line with our original hypothesis that drilling longer laterals would be wasteful.

The initial tubing head pressures recorded during the clean-up phase of the well confirmed that the bigbore design could deliver more than 180 MMscf/d at comparable THP to the current 7 5/8-inch wells flowing at 120 MMscf/d. This aspect will be studied in more detail once the well has been finally hooked up to the production system, but the initial results seem to indicate that indeed a larger outflow design is required to match the high productivity inflow of the dual-lateral design.

Discussion of Results

The availability of both simulated and the actual well performance allows for more detailed interpretation and discussion on the data. In general the actual well results match well to the predicted well performances, especially given the fact that none of the simulated results have been retroactively matched to actual results.

The placement of the blank 7-in liner above the lateral KOP achieves a lower drawdown pressure, and allows the final well design to achieve the expected increase of more than 50% in well productivity compared a single horizontal lateral of equal length. The conclusion of the simulation study was that a dual-lateral of 1500 ft each would supply the optimal balance of low drawdown pressure, higher well capacity, maximum gas recovery and drillability. The actual well results seem to confirm this prediction.

The actual well production was slightly below the simulated performance curve for the entire range of gas rates. It difficult to explain this minimal discrepancy as there could be several reasons for it such as reservoir quality, actual wellbore friction etc.

The PLT data confirmed that both laterals were contributing almost equally to the total gas flow. This also provided us with a good indication that the 8.5-in barefoot mother lateral had not collapsed, which was a slight concern, given that porosity greater than 30% was observed in several sections of the reservoir.

The mismatch seen in Figure 6 between the PLT survey and simulation result in the heel area of the well (from the KOP to 7225 ft) are explained to arise from “annular” flow
behind the 7-in pre-drilled liner. Whereas this flow behind the liner is not recorded by the PLT further down the wellbore, it will show up near the KOP as the interference from the incoming flow from the other lateral will cause all flow to be inside the liner at the KOP.

Conclusions
In summary, the main conclusions of this paper are:
1. The dual lateral big-bore well has been shown to be a very cost-effective solution to creating a high productivity gas well, which delivers some 60% extra production at only 5-10% incremental cost.
2. The actual well results were in line with the predictions from the numerical simulator.
3. Drilling very long horizontal wells in prolific gas fields is not effective since after some 1000-2000 ft (dependent on permeability) the wellbore friction prevents any further inflow from the toe of the well.
4. The low drawdown pressure of the well will alleviate the problems of gas coning and maximise the ultimate recovery.

Nomenclature

- \( K_{rw} \) = Relative permeability to water end-point
- \( K_{rg} \) = Relative permeability to gas end-point
- \( N_w \) = Corey exponent for the water phase
- \( N_g \) = Corey exponent for the gas phase
- \( R_{eD} \) = Dimensionless aquifer radius
- \( K \) = permeability

Acknowledgement
We thank PETRONAS and Sarawak Shell Berhad for their support in the preparation and presentation of this paper

References

Appendix - The numerical simulator model
The following inputs were used in the dynamic simulator:
- model: 9800 ft x 8000 ft x 1800 ft
- gas column: 200 ft
- grid block size: 100 ft x 100 ft x 10 ft
- Res. Pressure: 2800 psia
- Porosity: 25%
- Horizontal K: 300 mD
- Vertical K: 200 md
- \( S_{gi} \): 0.94
- \( S_{gr} \): 0.35

SI Metric Conversion Factors

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<tr>
<th>Unit</th>
<th>Conversion Factor</th>
<th>SI Unit</th>
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<td>E – 01</td>
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* Conversion is exact.
### TABLE 1a – WELL PRODUCTIVITY FOR LATERAL LENGTHS AND NUMBER OF LATERALS

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<th>Gas Rate (MMscf/day) @ 20 psi drawdown</th>
<th>Dual Lateral</th>
<th>Tri Lateral</th>
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<td></td>
<td>Single lateral</td>
<td>no solid liner</td>
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<tr>
<td>500 ft</td>
<td>66</td>
<td>89</td>
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<tr>
<td>1000 ft</td>
<td>86</td>
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<tr>
<td>1500 ft</td>
<td>92</td>
<td>125</td>
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<tr>
<td>2500 ft</td>
<td>99</td>
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### TABLE 1b – WATER BREAKTHROUGH TIMING FOR VARIOUS LATERAL DESIGNS

<table>
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<th>Breakthrough Timing (Years)</th>
<th>Single lateral</th>
<th>Dual Lateral</th>
<th>Tri Lateral</th>
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<tr>
<td></td>
<td>no solid liner</td>
<td>solid liner</td>
<td>1500 ft + 500 ft</td>
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<tr>
<td>500 ft</td>
<td>2.6</td>
<td>4</td>
<td>5.25</td>
</tr>
<tr>
<td>1000 ft</td>
<td>3.5</td>
<td>5.25</td>
<td>5.75</td>
</tr>
<tr>
<td>1500 ft</td>
<td>4</td>
<td>5.9</td>
<td>6.1</td>
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<tr>
<td>2500 ft</td>
<td>4.5</td>
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### TABLE 1c – GAS RECOVERY FACTOR FOR VARIOUS LATERAL DESIGNS

<table>
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<th>Recovery Factor (%)</th>
<th>Single lateral</th>
<th>Dual Lateral</th>
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<td></td>
<td>no solid liner</td>
<td>solid liner</td>
<td>1500 ft + 500 ft</td>
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<tr>
<td>500 ft</td>
<td>27.7</td>
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<td>1000 ft</td>
<td>39.9</td>
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<td>53.9</td>
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<tr>
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<td>42.9</td>
<td>56.7</td>
<td>58.6</td>
</tr>
<tr>
<td>2500 ft</td>
<td>48.0</td>
<td></td>
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Table 1. Summary of the results from the simulation sensitivities
Fig 1 – Cross-section view of the original dual-lateral design. There is an 170 ft interval between the top of shale and the branching point that is open to gas flow.

Fig 2 – Plot of drawdown pressure % differential at various lateral build-up angles. 4% change equates to about 1 psi drawdown difference.

Fig 3 – Overhead XY view of the dual-lateral design as per in the dynamic model.

Fig 4 – Actual well completion diagram for dual-lateral well. The blank 7-in liner was set 50ft above the second lateral kick-off point.
Fig 5 – Plot of actual drawdown pressure versus the simulated single and dual-lateral well. The simulated well assumes there is wellbore damage skin of 5 and the reservoir is homogeneous with horizontal permeability of 300 mD.

Flow Contribution Profile for a Dual-Lateral Well
(PLT Downlog vs. Simulated Model @ 86 MMscf/d)

Fig 6 – Plot of the flow profile from the actual PLT data compared against the simulated well.