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Modelling Flow along Fault Damage Zones in a Sandstone Reservoir; an Unconventional Modelling Technique Using Conventional Modelling Tools in the Douglas Field, Irish Sea, UK

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Abstract

The Douglas and West Douglas fields are part of the Liverpool Bay development in the East Irish Sea. The reservoir is a high net-to-gross, largely good quality (100-1000mD) Triassic sandstone lying in a series of fault terraces. The fields have been on production for over 10 years and whereas some wells have shown a watercut development typical for a waterflood, other wells recorded anomalous behaviour. This work addressed these anomalies as these directly influence the value of a late-life infill programme.

The subsurface team reviewed outcrops of the reservoir in NW England, addressing the possibility of vertical flow up and along damage zones of faults which may be otherwise sealing ('fault-related fractures') - a feature not previously identified in the field. The presence of fault-related fractures, observed in the outcrops, was tested in simulation models and provided a solution to the anomalous behaviour.

A novel technique was employed to pragmatically characterise the fault-related fractures in the simulator. The technique involved installing wells as 'pipes' in cells around the faults, allowing flow up and along the fault damage zones without necessarily affecting fault transmissibility across the major zones. The size and location of the pipes representing the fractures was then used as a history matching parameter in the model and resulted in the improved history match of the anomalous wells and the match in general.

Douglas Field Setting

The Douglas and Douglas West Fields are situated in the Liverpool Bay area of the Irish Sea, 30km off the west coast of the UK, with oil trapped in fault and dip-closed structures (Figure 1). The reservoir is a fluvio-aeolian Triassic clastic reservoir, locally known as the Ormskirk member of the Sherwood Sandstone formation. Core data indicate a high net-to-gross fluvial system, drying upwards into a succession of aeolian reworked fluvial sands with small dunesets and more extensive sandsheets. The sandsheets are a heterogeneous mixture of aeolian sandflats and ephemeral fluvial sandsheets. The reservoir is described more fully in Meddows (2006) and Yaliz & McKim (2003). A typical log profile for the reservoir is shown in Figure 2.

The field is highly faulted, with *ca.*150 faults mappable from 3D seismic, spread around four main fault terraces. The smaller faults are at least partially open to cross-flow, as pressure continuity is observed in the field at least along the fault terraces. The major terrace-bounding faults have traditionally been assumed to be sealing, an interpretation encouraged by the mudstone content of the reservoir, the scope for juxtaposition with the overlying mudstone seal and, crucially, the interpretation from log data of differences in fluid contacts between some of the terraces.

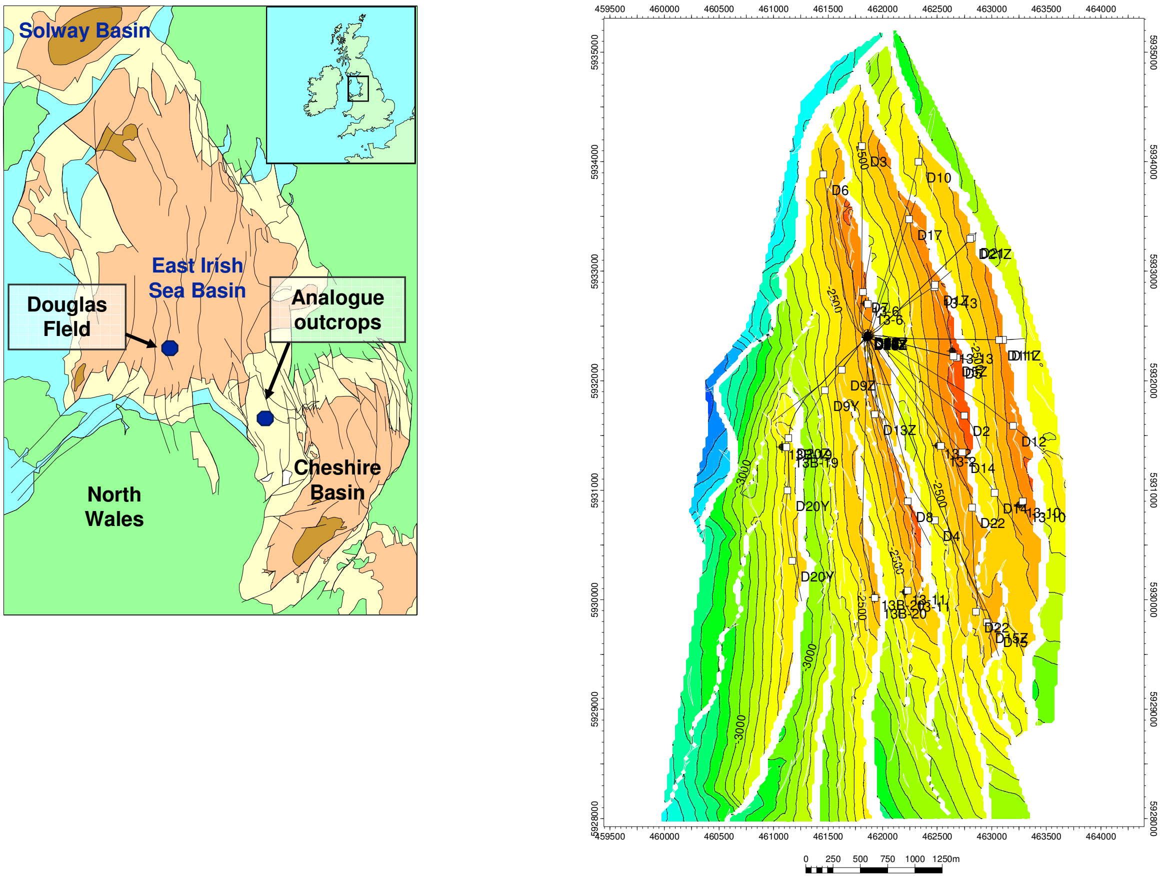


Figure 1: Left: field and outcrop locations relative to major Triassic basins (image courtesy of N. Meddows, RedRock International); right: top reservoir map for the Douglas and Douglas West fields

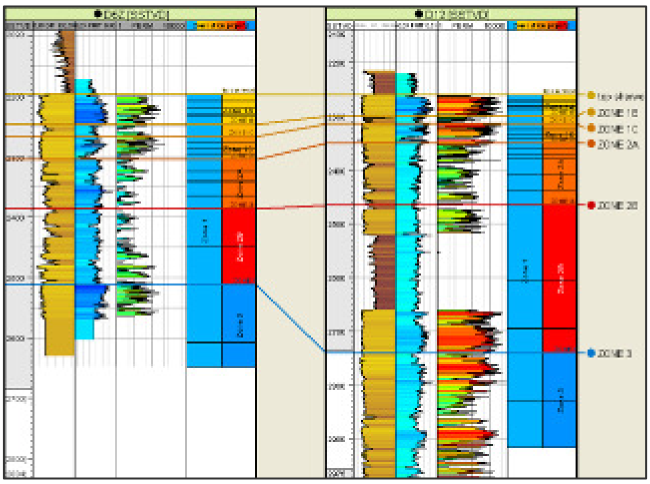


Figure 2: Triassic reservoir stratigraphy (Sherwood Sandstone Group, Ormskirk Formation)

The reservoir initially contained a 44 API dead oil with a gas-oil-ratio (GOR) of 130scf/bbl to 250scf/bbl at Douglas operating conditions. The field also contains a discrete bitumen-rich interval near the present-day OWC, tilted gently to the north (Yaliz & McKim, 2003). The bitumen layer is thought to represent an early degraded oil fill, currently tilted due to post-charge structural activity. Initial oil-in-place is estimated to be ca. 200 MMbbls.

Oil production commenced from the Douglas field in January 1996 along with water injection into all three fault terraces in the Field. Douglas West was discovered in 1997 and brought on-line in April 2003 from a long horizontal well with no water injection. The OWC in Douglas West was encountered *ca.*120ft deeper than that in the Douglas Field terraces. Primary development of the field is complete, involving 15 oil deviated or horizontal producers, 5 water injectors, 1 condensate injector and 1 gas injector.

Figure 3 shows the combined Douglas and Douglas West oil, water and gas production history. The variations in GOR over time observed from Douglas are due to the injection of gas and condensate into the Western terrace of the Douglas field for a number of years, commencing in 1996, and the subsequent reproduction of the injected gas. The gas was injected to dispose of gas with a high hydrogen sulphide (H_2S) content along with unsaleable liquids from the Liverpool Bay Development.

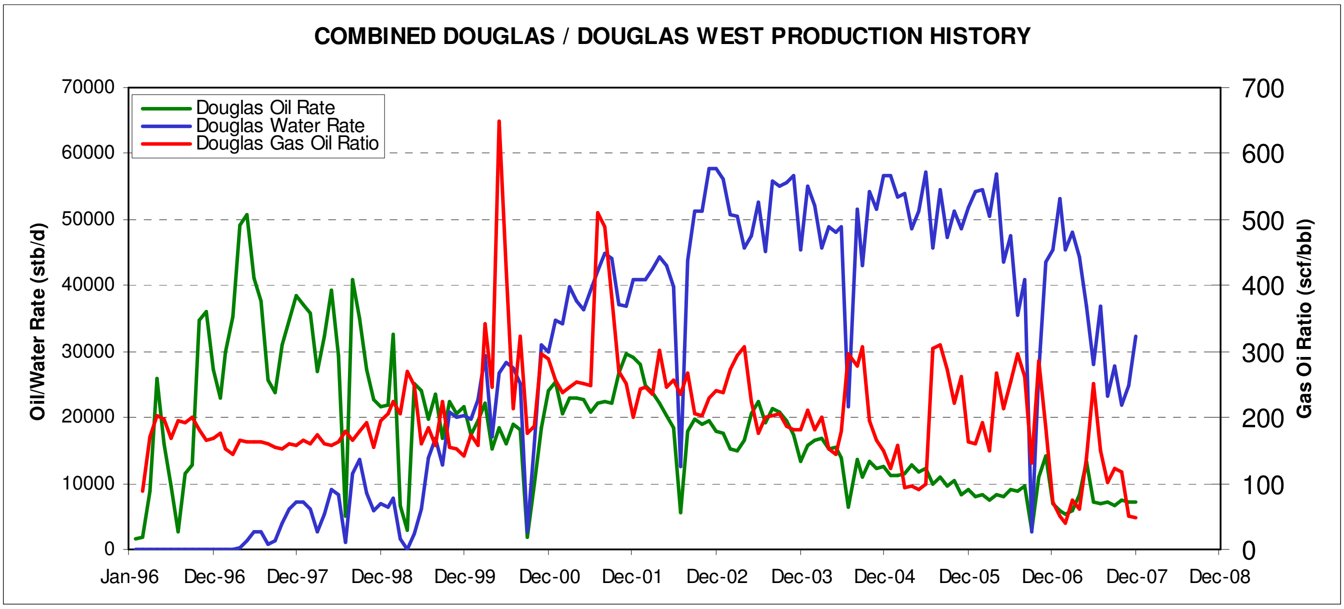


Figure 3: Combined Douglas / Douglas West production history

Reproccessing and re-interpretation of Douglas seismic data in 2005 gave an indication that there may be larger volumes of oil in place in areas of the field with little or no well coverage and also that fault patterns could be more complicated than previously mapped. This provided the opportunity to revisit the Douglas geocellular and simulation models and address not only the additional oil volumes mapped in the reservoir, but also some anomalous well behaviour, which had been difficult to explain and history match within the existing models.

Initial Reservoir Modeling

Geocellular and reservoir simulation models were constructed following the seismic reinterpretation, with the initial emphasis placed on capturing the newly-mapped structural detail.

As well as being used to assist with routine field management such as production forecasting, an additional objective of the modeling was to identify potential late-life development opportunities from unswept areas with remaining recoverable oil. A multi-deterministic scenario-based approach was adopted (Bentley & Smith, 2008), involving the identification of key uncertainties and their representation as a suite of reservoir models which could be passed through to simulation for testing against the production history. The general form of the models is illustrated in Figures 4 & 5.

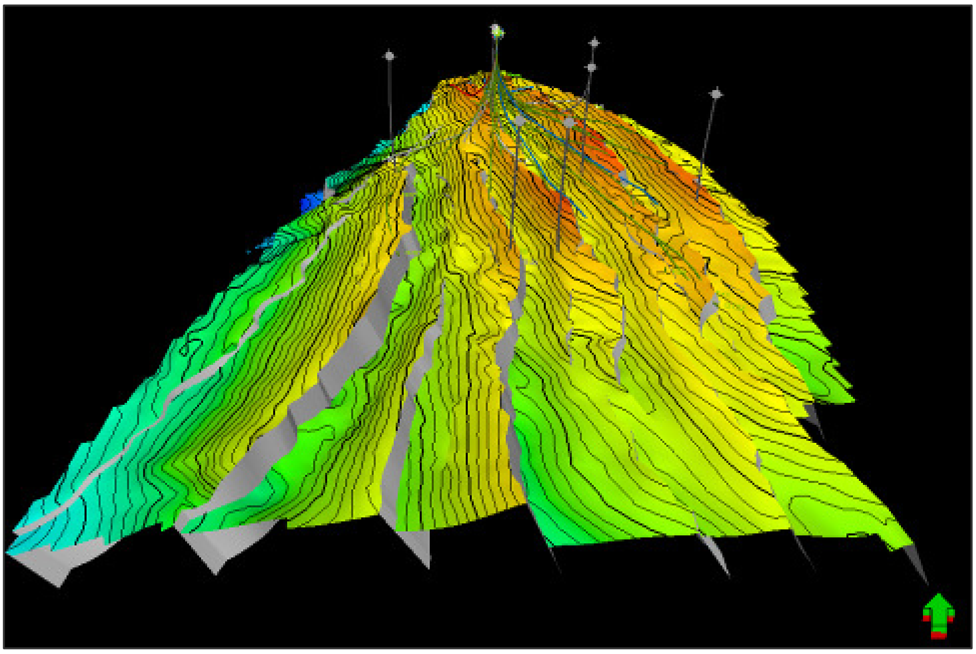


Figure 4: Overview of the geocellular model, showing the four main fault terraces and minor in-terrace faulting; the Douglas West Field lies in the westly (left-hand) terrace, with an OWC *ca.*120ft deeper than the Douglas Field terraces.

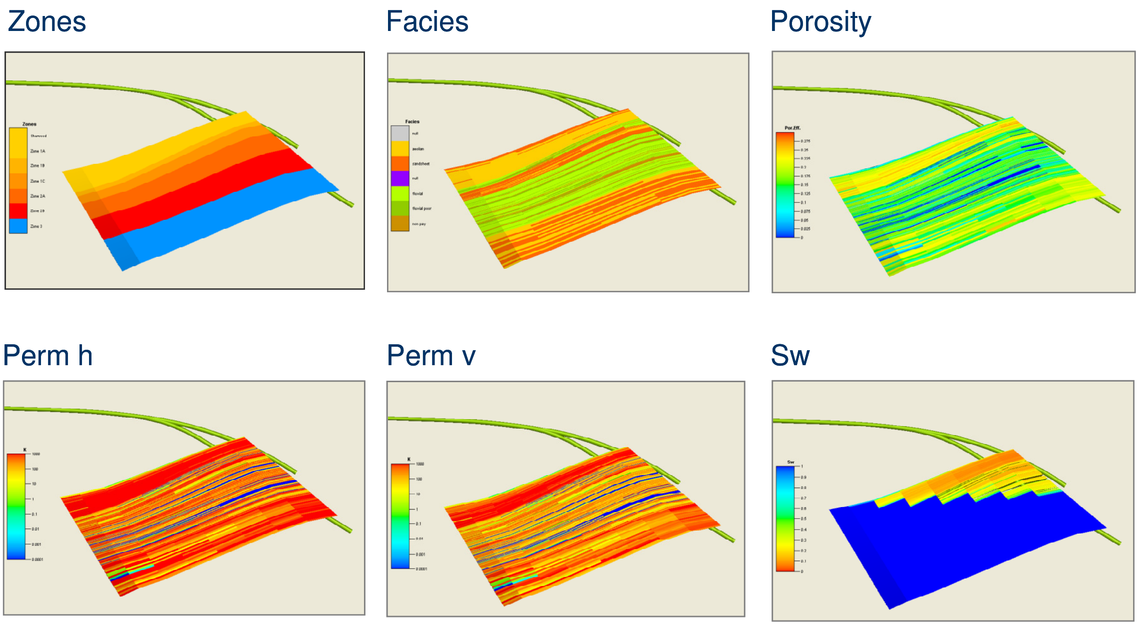


Figure 5: Cross sections through the Douglas geocellular model over one fault terrace at the location of producer D11z, showing typical facies and property distributions

Permeability is heterogeneous within layers, varying from a few milliDarcies in the tighter fluvial siltones to 1-2D in the aoelian dunesets. Eight reservoir models were built, assessing uncertainties in the lateral extent of the higher permeability reservoir elements, potential geographic anisotropy of that permeability and varying degrees of permeability baffling due to the bitumen layer. All eight models were tested to determine if one gave a significantly better match to the history data than the others. This was not the case as although the eight realizations gave a range of remaining recoverable oil, the history match for each model did not differ significantly from any other. The model chosen for further history matching was the one based on the interpreted most likely geological facies orientation (north-south). This model is the subject of further discussion in this paper.

Anomalous Well Behaviour Leading to Geological Review of Douglas

During the modeling work, a workshop was held to discuss the current Douglas models and the matches to well and geological information. A key issue was the continued anomalous behaviour of some wells and the inability to match them in the current simulation model, even when tested against the eight contrasting model realizations described above. The anomalous behaviour fell into three categories:

1. Water breakthrough not matched in wells drilled close to or through major faults.
2. Gas breakthrough not matched in wells post gas injection into a flank well in the field.
3. Flowing bottom hole pressures not matched in most wells.

An example of item 1 above is Douglas-17, drilled in 2000 in a crestal location in the central terrace, near one of the major faults. Another example is D21 & D21z (Figure 6), in which a pilot hole was drilled to tag the bounding fault and the well side-tracked to place it optimally at the crest of the footwall.

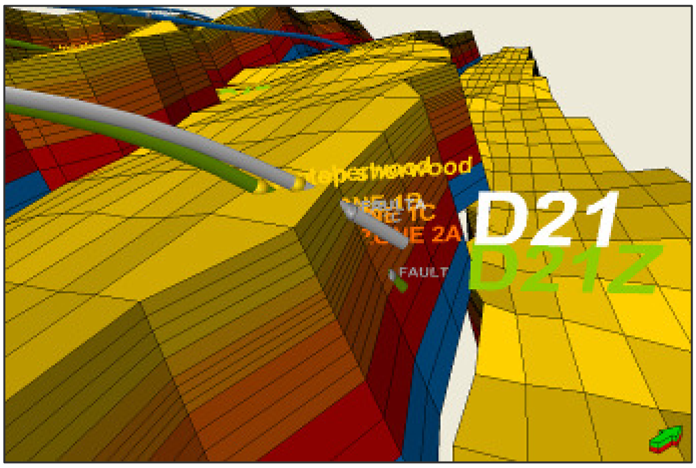


Figure 6: Structural location of Douglas producers in an optimal crestal position. Cell colouration reflects stratigraphy, as labeled in Figure 2.

Both Douglas-17 and Douglas-21Z came on-line at initially high oil rates, but water broke through to these wells very soon after first production. The difficulty in matching production in the simulation model related to this early water breakthrough. Figure 7 below shows the initial model predictions of water production alongside the historic water production rates. The early water breakthrough at high water rates was difficult to match in the model, given that the wells were drilled in crestal locations and there was no indication of a poor cement bond or other mechanical reason for the water production.

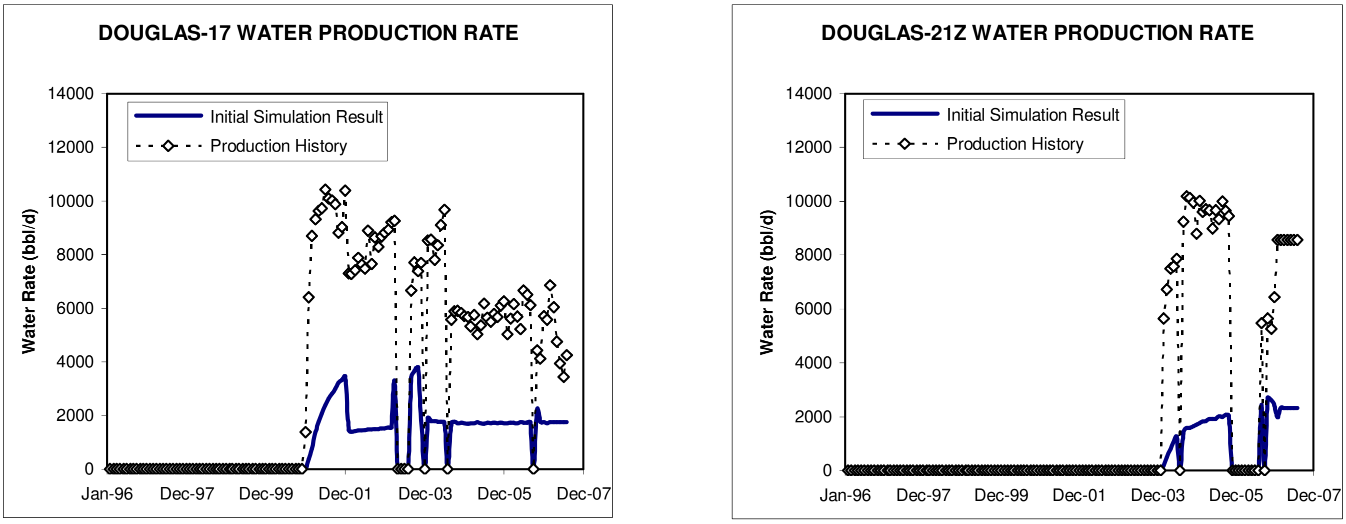


Figure 7: Douglas-17 and Douglas-21Z modelled verses actual water production

Item two is related to the injection of gas into the western fault terrace of the Douglas field over a period of approximately five years from 1997 to 2002. The gas was injected into Douglas-6 in the northern flank of the western panel and migrated upwards, reaching both Douglas-7 and Douglas-19 (see Figure 1 for location). The breakthrough of gas into these two wells was extremely difficult to match in the existing model as Douglas-19 is closest to the injector and yet the gas rates observed in this well were less than the initial model prediction. Conversely, the gas rates observed in Douglas-7 were higher than that predicted by the model (Figure 8). The previous version of the simulation model required large very high permeability streaks to be added in a corridor from Douglas-6 to Douglas-7 to match this anomalous behaviour.

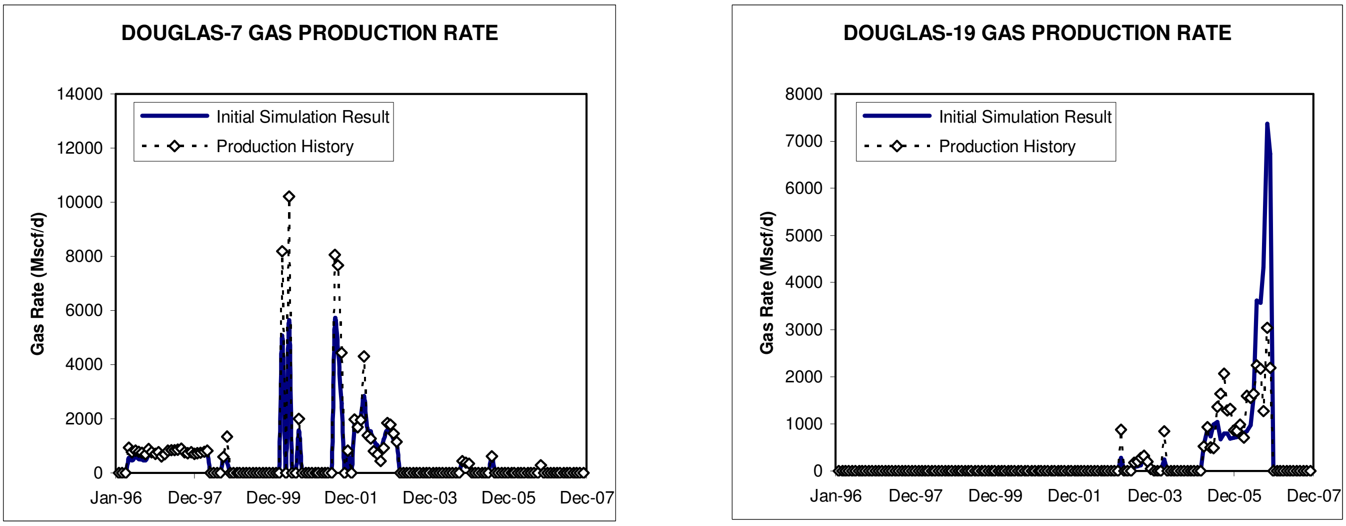
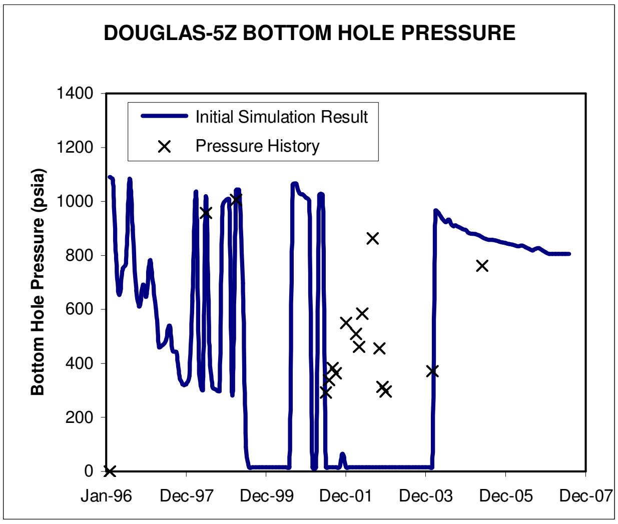


Figure 8: Douglas-7 and Douglas-19 modelled verses actual gas production

Most wells in the field fall into category three above with shut-in bottom hole pressures matched, but flowing bottom pressures generated by the simulation model being significantly lower than the observed pressures from downhole gauges (see Douglas-5Z and Douglas-12 examples in Figure 9 below). Most wells in the simulation model, with the exception of the western fault terrace wells, exhibited a similar initial model prediction with the bottom hole pressure drawn down to a minimum in order to withdraw the required amount of oil and water from the well. This was observed despite the productivity indices of the wells being reasonably closely matched.



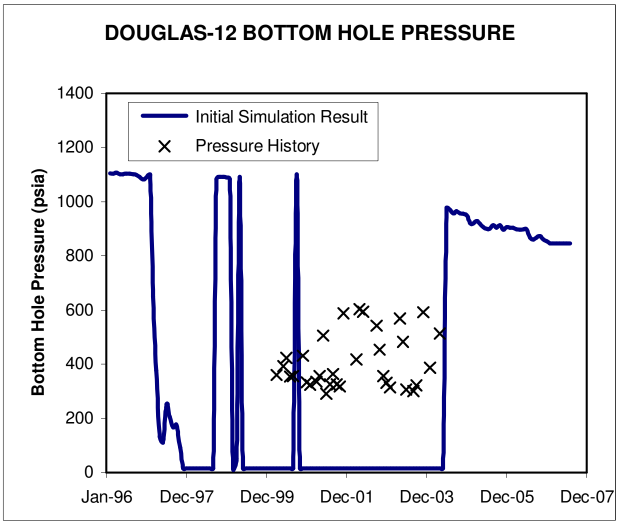


Figure 9: Douglas-5Z and Douglas-12 modelled verses actual bottom hole pressure

Use of Analogues to Improve Model Inputs

In order to address the known model issues, and better understand the reservoir prior to completing the model rebuild, a field trip was organised to view outcrops of the Sherwood Sandstone and also review core from the Douglas field. The trip focussed on understanding the nature of faulting in the outcrops, and the architecture of fault damage zones in particular.

The outcrops showed a sedimentary/stratigraphic character for the reservoir comparable to that interpreted from core descriptions and log correlations in the subsurface. The onshore outcrops are located only ca.30km Southeast of the Douglas Field, and occur in a comparable structural setting. The Sherwood Sandstone reservoirs have not had a deep burial history (current reservoir depths are around 2000-2500ftTVss) and the diagenetic history of the outcrops and the subsurface are also broadly comparable.

The outcrops showed three main structural features of interest. The first was the extent of deformation bands in the quartz-rich, typically aeolian, sandstones (Figure 10). The deformation bands tend to be zones of grain size reduction (Shipton, 2005) and are therefore likely to be permeability baffles. The deformation bands, however, are associated with discrete, polished slip surfaces, which may be preserved as open fractures.

Figure 10: Deformation bands (left) and open slip surfaces (right) in quartz-rich lithologies in the Ormskirk Sandstone

The second feature was noted in less quartz-rich intervals, where the swarms of defomation bands are less prevalent, but damage zones are nevertheless visible around fault planes, consisting of minor faults and joints. As the faults pass through silty intervals, the displacements dispersed on deformation bands and open slip surfaces become localized on more discrete fault planes (Figure 11).

Figure 11: Change in lithology prompting a change in fault damage zone style: displacement on a fault with attendant deformation bands and slip surfaces passes into a more discrete fault zone

The third observation was an exposure of a fault with more significant throw. In this case the fault juxtaposed the Sherwood Sandstone against the overlying mudstones, providing a settling comparable to the Douglas Field major terrace-bounding faults. The fault footwall showed structural damage for several feet away from the main slip plane, in the form of minor faults but also open extensional fractures (joints), (Figure 12).

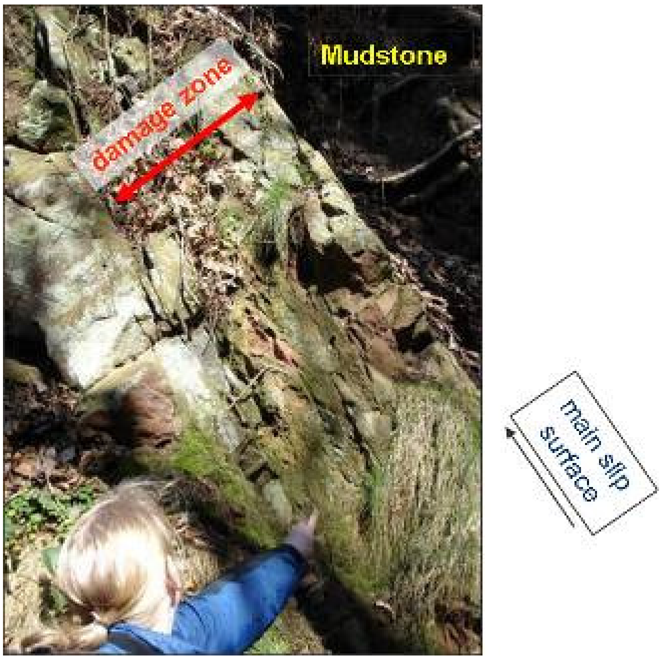


Figure 12: Footwall of a fault which juxtaposes Sherwood Sandstone reservoir against the overlying mudstone. Fault damage extends away from the main footwall in the form of minor shear and extension fractues

The picture which emerges is one of widespread faulting, but with zones of damage around faults including both permeability-reducing and permeability-increasing elements. The sealing elements are the shear fractures, distinct as deformation bands in quartz-rich layers or small faults elsewhere, and juxtaposition against mud-rich intervals. The open elements are the extensional fractures (joints) which are dispersed through the outcrops, partly due to exhumation but clearly more concentrated in the fault damage zones. These also occur around the major fault juxtaposed against mudstone, which raises the concept of faults which are clearly laterally sealing, but which contain vertically conductive fractures within their damage zones.

Figure 13: Open fractures associated with deformation bands in Ormskirk Sandstone core from the Douglas Field

Evidence of fracturing in the core material is sparse, as the core was taken in vertical appraisal wells. Fracturing is nevertheless observed (Figure 13) in the form of deformation bands and small faulted intervals. One fault plane in particular is well preserved in core, is not cemented and, crucially, is hydrocarbon stained. Although the core material is limited, the structural features seen extensively at outcrop can be observed, and there is an indication that at least some of the fault zones have been open to hydrocarbons.

The structural concept which emerged from the field and core review is summarised in Figure 14. Although faults may be sealing to lateral cross-flow, either through juxtaposition or cataclasis and formation of a sealing fault gouge, the damage zones around the faults may include open fractures, either joints or slip surfaces. The joints will tend to be stratigraphically sensitive and bed-limited to the more clay-poor intervals, but the slip surfaces will be through-going. The major faults may combine both the greatest tendency to seal to lateral cross-flow and, with more extensive damage zones, the greatest tendency to allow vertical flow along those damage zones.

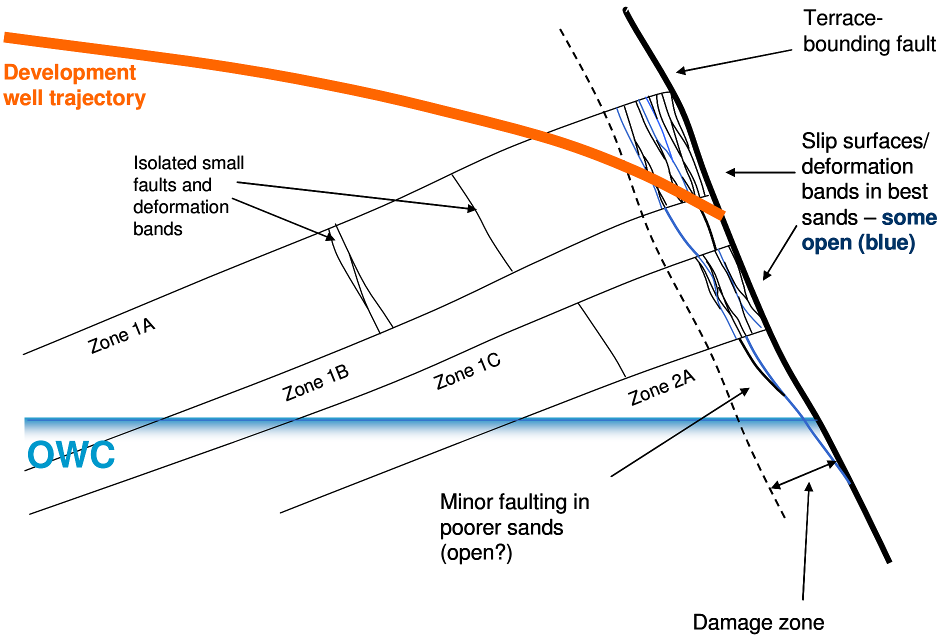


Figure 14: Structural concept for the major fault terraces

In the Douglas Field development plan, many producers are located in crestal footwall positions and penetrate the damage zones of the main faults. These wells may therefore be susceptible to vertical fluid flow through these damage zones, which potentially offers an explanation for the anomalous well behaviour. What was required was a simple, practical method of representing this effect in the existing reservoir simulation models and testing the concept against the production history.

Technique Employed to Model the Fault Damage Zones

The technique of adding pseudo fractures throughout the model was utilised only after exhausting other means of introducing water to the wells. In addition to testing against the eight static model realizations, the following variables were explored:

- Relative permeability modifiers – without going to pseudo relative permeability curves with straight line water curves, a match could not be achieved by modifying the oil and water relative permeability curves. This method was used in a previous version of the simulation model and although the use of pseudo relative permeabilty curves does improve the water production match, the bottom hole pressures remained unmatched.

- High permeability streaks – this was tested around D17, which had the poorest match to water rate. A match could only be achieved when a high perm streak was introduced in addition to a large reduction in the permeability in the surrounding area. This is geologically unrealistic and was discarded as a method of achieving a water rate match, although hinting at the previously unmodelled permeability increases required to honour the production history.

- Faulted corridors connecting injection wells to producers – again this was tested on D17 and the fault geometry required was difficult to justify as the corridor required was very narrow and the match required the well to only access hydrocarbons through this corridor. This method was also discarded as the geometry required was geologically extreme, and inconsistent with the structural history of the field.

- Permeability modifiers – I, J and K permeability modifiers were tested and global increases did not produce the rapid water influx observed in D17 and D21Z and could not increase the water rates sufficiently in other wells to achieve a reasonable match. This was even the case where sandstone permeability was increased to the maximum known permeabilities from core.

- Aquifer size, strength and connectivity – the most influential aquifer on water rate for central and northern wells was found to be the basal aquifer and even large changes to size and strength had minimal impact. Connectivity was tested by using a minimum value for permeabilility in the model to ensure access to the aquifers and although this did increase the water rate for a number of wells, it failed to improve the bottom hole pressure matches.

Each of the above variables were able to improve the simulation match in certain areas, but no combination of the above was found to match well oil, water and gas rates as well as bottom hole pressures simultaneously. Attention therefore turned to major fault damage zones as the candidate for explaining anomalous well performance.

The idea of modelling open fractures in an area close to the faults and giving them a variable extent in order to use them as a history matching parameter presented an interesting modelling challenge. Initial tests on the model indicated that a single vertical dummy well could be used to model an open fracture near a producing well. The well was given completions in every simulation grid block it passed through and the open/shut flag for the well was set to shut the well off above the formation, with the well allowed to crossflow within the formation. By altering the location and/or wellbore radius of this dummy well the rapid onset of water production could be matched.

As the model would be required for forecasting away from the wells to test development options, it was important to emplace pseudo open fractures throughout the model in line with the underlying geological concept. To achieve this end the tool was initially used to achieve individual well matches and then applied globally by infilling the model with a large number of dummy wells away from the existing production and injection wells. This would ensure that the field performance captured not just the local well matches but would allow the field-wide impact of the open damage zone concept to be assessed. The wellbore radius of the dummy wells located away from well control was generally chosen to represent the average wellbore radius required to match production in each fault terrace. In the Douglas West terrace however, dummy wells were not required to match production, so the wellbore radius used is significantly lower than in the other fault terraces. Figure 15 shows the final history-matched model with both vertical and horizontal dummy wells added to represent the fracture network along the major terrace-bounding faults.

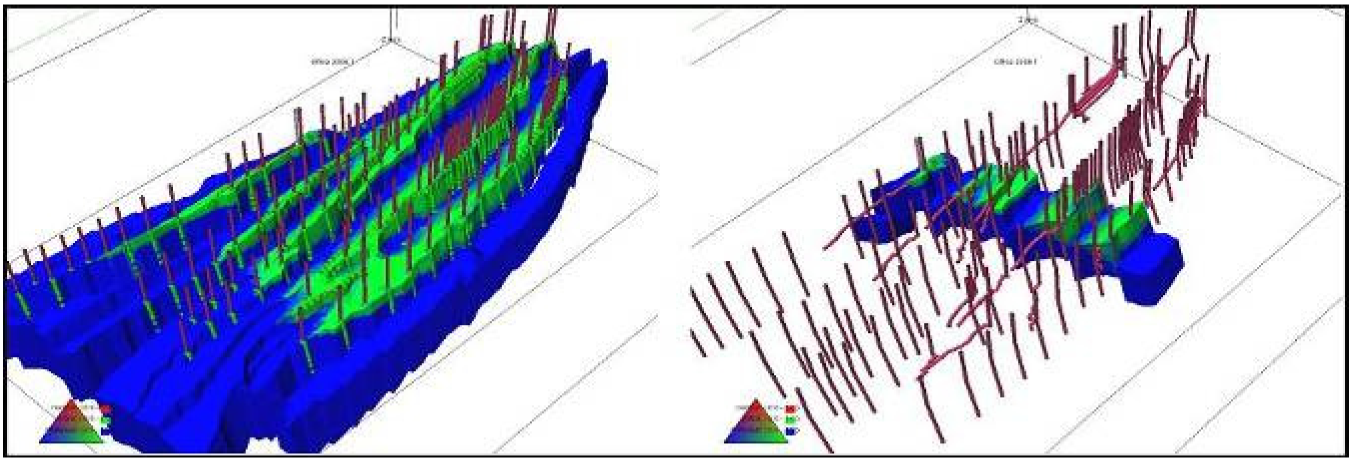


Figure 15: Location of dummy wells in simulation model (used to model fracture flow along fault damage zones)

Improvements in the History Match

The technique described above to model the fault damage zones in the Douglas and Douglas West field allowed each of the three main production anomalies to be addressed and made a marked improvement to the history match of almost every well in the field.

Figures 16 to 18 compare the simulation model results before and after the addition of dummy wells to represent the fault damage zones with historic data for the three categories of anomalous well behaviour described above. The introduction of open fractures in the model allowed the early water breakthough in Douglas-17 and Douglas-21Z to be matched very closely (Figure 16). The Douglas-7 and Douglas-19 Gas Oil Ratio match also improved and a reasonable match was obtained for both wells (Figure 17). The most significant improvement in the model, however, was the flowing bottom hole pressure match for most wells in the field. While other history matching techniques had previously enabled a reasonable match to water, oil and gas rates as well as shut in bottom hole pressures, the flowing bottom pressures for most wells were poorly matched. The new simulation model now contains a reasonable match to all of these parameters, including flowing bottom hole pressure (refer Douglas-5Z and Douglas-12 examples shown below in Figure 18), and none of the history matching variables used exceed the bounds of what is geologically reasonable.

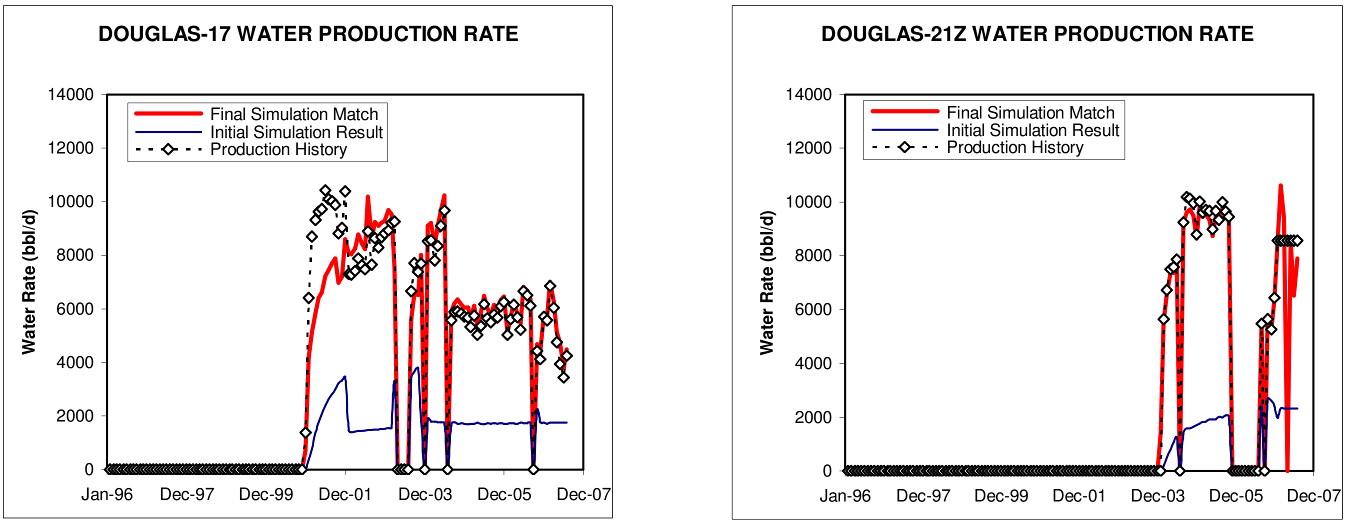


Figure 16: Douglas-17 and Douglas-21Z modelled verses actual water production

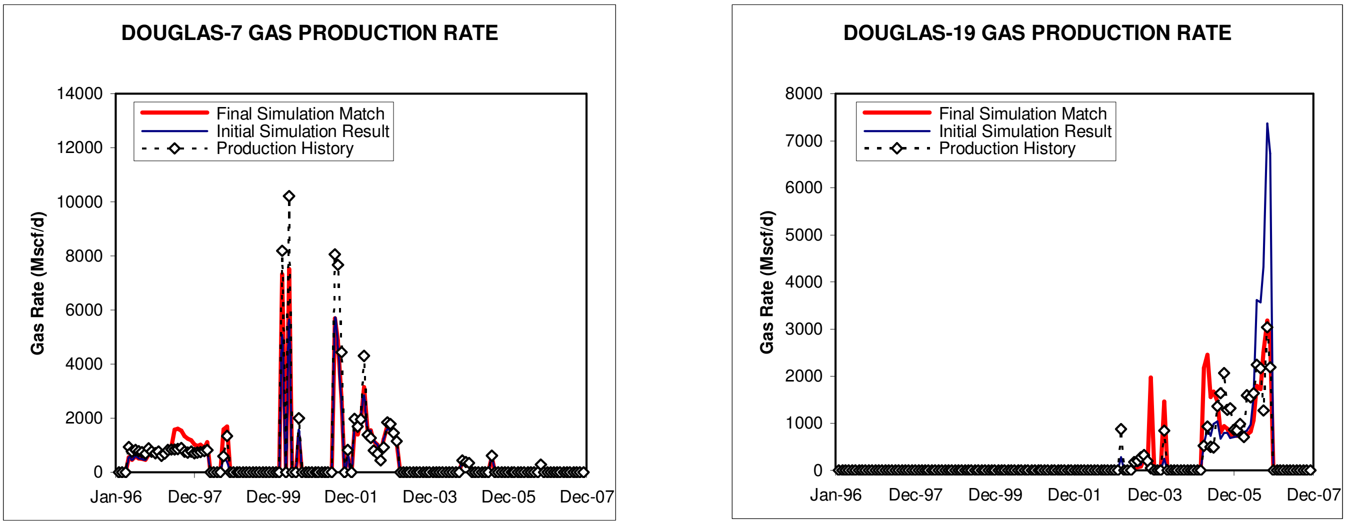


Figure 17: Douglas-7 and Douglas-19 modelled verses actual gas production

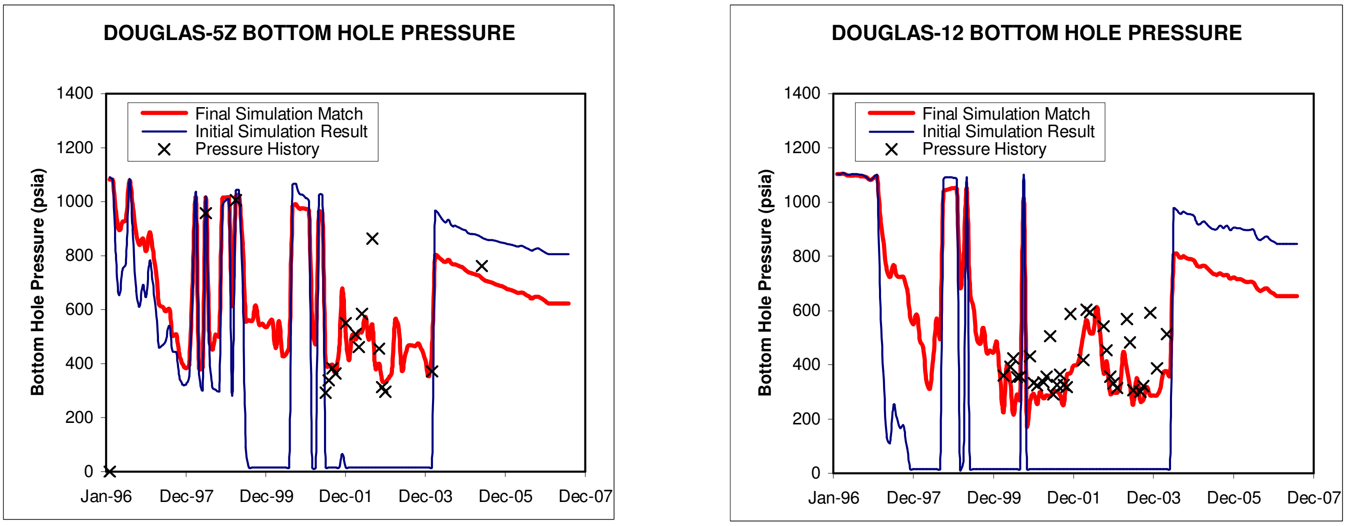


Figure 18: Douglas-5Z and Douglas-12 modelled verses actual bottom hole pressure

Lessons Learnt, Implications for Future Development and Applicability for Faulted Sandstone Reservoirs in General

The key modeling issue was the step change in the conceptual geological model for the field. It is intuitively reasonable to assume that normal faults in a clastic reservoir with a mudstone component will tend to seal, particularly in the case of the major faults and more so when OWC differences are interpreted between fault terraces. The step change, prompted by difficulties in reconciling production data with the model, was to accept that major faults can be laterally sealing, but be surrounded by damage zones which could include fractures which are vertically permeable.

As with many reservoirs which contain low density fracture systems, in the Douglas Field the change in interpretation was prompted by an accumulation of production data which was inconsistent with other interpretations. Once sense-checked against outcrop data and structural geological theory, the new model seemed not only plausible but likely.

The new interpretation underpins the modeling which will support late-life infill drilling options, and would have been more useful still if it had been available as a plausible scenario earlier in the field life.

The learning to carry forward from examples such the Douglas Field is that a breadth of reservoir realizations should be carried through the life cycle, even if these are not initially the ‘best guess’ scenarios.

This case in particular highlights the importance of understanding faults as heterogeneous damage zones, rather than single planes of offset. It also offers a practical way of implementing such concepts in a conventional reservoir simulation model.

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