AN INTEGRATED STUDY OF A NATURALLY FRACTURED RESERVOIR

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ABSTRACT

The basal Carapita formations of the Orocual field in Eastern Venezuela lie at about 12,000' TVDSS, and comprise two thin sand intervals deposited in a marine barrier bar environment, with a highly stressed structural setting produced by the regional thrust. Production of 19 mmstb since 1986 has been achieved from 10 wells, but recent significant declines and asphaltene deposition problems have necessitated a better reservoir understanding.

The authors present the results of an integrated reservoir characterisation study, and the methodology used to confirm the existence of an additional reservoir drive mechanism based on natural fractures, which has been used to explain the significant discrepancies between material balance and volumetric STOIIP estimates.

A detailed core-based sedimentological study has been used to define the depositional environment and facies connectivity. Core, log, drilling, production and DST analyses have been integrated to provide information on the natural fracture network, and geomechanical interpretation has been used to prove that the fractures seen in core are natural, to explain the impact of regional stress variations on fracture properties and flow performance, and to define zones of different fracture intensity. Effective parameters for fracture orientation, permeability anisotropy and rock compressibility have been determined to represent the fracture network in the simulation model.

A non-stationary geostatistical simulation has been used to model the variations in reservoir facies distributions, and the static model has been conditioned with interpreted DST permeabilities, to correctly represent flow properties. A full field history matched simulation model has been used to confirm the drive mechanisms and to develop an exploitation strategy. The fracture network was found to be responsible for a recovery factor of 10%

INTRODUCTION

The Carapita Superior and Inferior sands of the Orocual field are situated in the Maturin basin in the east of Venezuela (figure 1), and lie between 10-13,000' TVDSS, near the base of several thousand feet of marine shale in the Lower Miocene (figure 2). Differences in initial pressures and fluids (table 1) show the reservoirs to be isolated, with both intervals being more than 4000 psi overpressured. The formations have been produced by ten wells, mostly with dual completions, since mid 1986. Due to generally poor productivity, hydraulic fracture treatments have been performed in eight wells, with mixed results. Significant production problems have also been caused by asphaltene deposition, which has required repeated chemical treatments in many wells. Seven wells were producing from eleven completed intervals at the end of 1997 and cumulative field production had reached 18.8 mmstb.

Significant production declines in recent years (figure 3) have raised serious concerns about the future viability of the reservoir, and have prompted a series of studies aimed at characterising the static model and defining reservoir fluids and production mechanisms, remaining reserves and a future exploitation scheme. These studies have been concentrated in the main Orocual and Chaguaramal blocks (figure 4).

STRUCTURAL SETTING

The Orocual field lies in the North Monagas thrust belt between the main Pirital thrust and the deformation front (figure 1), which were created by collision of the South American and Caribbean plates[1]. A recent 3-D seismic interpretation has shown the reservoir to be delineated to the north and south by a large inverse fault, with an associated back-thrust, which have been produced by this regional compressional setting; the main mapped faults and a schematic cross-section are shown in figure 4. The stresses induced by the thrusting have created a generally anticlinal structure, with the possibility of natural fracturing along the crestal area, which runs roughly NE-SW along the reservoir axis.

SEDIMENTOLOGICAL MODEL

A sedimentological model has been defined for the field based on detailed evaluations of the five cored wells (figure 4). The producing intervals comprise the Carapita Superior and Inferior reservoirs which are separated by 300 feet of shale, and each unit has been sub-divided into A, B and C sands, as shown on the type log in figure 2. The reservoir intervals were deposited in a marine barrier bar setting and comprise mainly fine to medium grain size consolidated sands, which have been severely cemented by calcites in some intervals. The sedimentary facies identified from the cores include beach foreshore and backshore deposits, channel and tidal delta sands, and lagoonal and marsh silts and shales. The sedimentological model developed from this work shows good east-west continuity over several kilometres in the main sands, however, sand body thickness becomes smaller towards the reservoir edges. The axis of the bar system is cut by tidal channels in places. Lagoonal shale deposits are interspersed between the sands. The sands were thought to be deposited from the south into an open marine environment to the north.

GEOSTATISTICAL MODELLING

A geostatistical methodology has been used in the static modelling to allow the integration of geological and petrophysical parameters and trends.

Stochastic sedimentological model. Three facies types, sand, silt and shale, were interpreted from log data (foot by toot interpretation) which had been calibrated with the cores. Lateral changes in the distribution of the sand bodies were seen in the Carapita Inferior AB unit, with the proportion of shale increasing towards the eastern and western ends of the model area. This was modelled using local vertical proportion curves which had been separately defined in these areas (figure 5). The curves were kriged over the whole reservoir, resulting in an areal matrix of vertical proportion curves, ensuring a gradual facies transition between the zones (figure 6). The facies distributions were subsequently simulated using a non-stationary truncated gaussian simulation method[2]. Single vertical proportion curves were used in the other units, so facies distributions were assigned using stationary truncated gaussian simulation. The P_{50} cases of the fifty realisations run were retained, using the volume of connected sand as a ranking criteria, after validation by reference to the sedimentological model. Figure 7 shows a section of a facies realisation which has been simulated by the non-stationary truncated gaussian method.

Petrophysical parameters. Water saturation, porosity and permeability data from log interpretations were used as inputs for the modelling. These properties were conditioned to both the wells and the facies; shale facies were assumed to have zero porosity and permeability and 100% water saturation, and parameter distributions were obtained by kriging. The values were upscaled using arithmetic, power law and porosity weighted averaging for the porosity, permeability and water saturation respectively. The water saturation was found to have a bimodal distribution (figure 8), allowing good quality sand to be separated from poorer quality rock using a cut-off of 35%, and two saturation regions were defined for the simulation model.

RESERVOIR STOIIP

Comparison between the STOIIP derived from mapping and geostatistical modelling, and that from material balance analysis revealed a large discrepancy. The static modelling produced a STOIIP of 118 mmstb for the two reservoir units, whilst material balance showed a requirement for around 300 mmstb, using measured rock compressibility of $2e^{-6}$ psi^{-1}. As core-calibrated well petrophysical interpretations show similar porosity distributions and a predictable variation in net pay, it is unreasonable to more than double these parameters to increase the reservoir oil in place. The logical explanations for the discrepancy are either due to reservoir influx across the boundaries, or an increased effective rock compressibility due to fracturing.

Reservoir limits. As inflow across the northern, eastern and southern boundaries is highly unlikely, due to large fault displacements, production from the block to the east, and virgin reservoir pressures measured in exploration wells to the south and dry wells to the north. Any significant reservoir inflow could only come from the west, where the reservoir boundary is not well defined. Due to sealing faults within the reservoir, the considerable distance to the western limit of Chaguaramal and the increasing shale volume towards the edges of the reservoir, it is unlikely that sufficient influx could occur to support the production from the Orocual area wells by this mechanism. However; this has been confirmed by numerical simulation sensitivity analysis, which showed the requirement for additional energy support within the well drainage areas.

Rock compressibility. Additional evidence in favour of enhanced rock compressibility due to fracturing comes from the form of the material balance plot for Orocual Superior (figure 9), where it may be seen that the initial drainage from 1986-88 produced little pressure decline. As the Chaguaramal area had virgin reservoir pressures in 1991, this could not be due to inflow from the west, and can only be matched using a varying rock compressibility in the material balance, which has been rationalised as the closing of natural fractures. Increasing the rock compressibility by an order of magnitude produces agreement between the material balance and volumetric studies; this is in line with Jones' results[3] from laboratory measurements of fractured reservoir properties.

EVIDENCE FOR NATURAL FRACTURING

The existence of fractures in the Carapita cores had been noted during the sedimentological study (core descriptions), and following the STOIIP discrepancies, other information was also sought to confirm the presence of an active natural fracture network.

Core descriptions. The Carapita cores gave generally good coverage of the main A and B producing sands, although some non-recovered sections in two wells are thought to be indicative of extensive fracturing. Analysis of the fractures was made to try to estimate fracture parameters.

Fracture distribution. All of the cores were found to contain significant numbers of natural fractures, distributed throughout the main Superior and Inferior sands. 75% of the natural fractures were found to be open, with the remainder being closed through cementation or filled with shale. The fractures tended to occur in clusters, which were separated by wider intervals with no fracturing. No systematic patterns of fracturing were evident from the cores however.

Fracture inclination. The true inclination (corrected for well deviation) for the open natural fractures in the cores has been plotted in figure 10. The fractures show a predominantly vertical orientation, with about 20 degrees scatter, which represents the general trend of *effective* fractures in Carapita; there are few open horizontal fractures.

***Conclusion*.** These results confirm the occurrence of open fractures throughout the Carapita sand intervals, albeit with some localised distributions in individual wells and intervals with no fractures. The fractures show a tendency to occur in clusters, and have a higher concentration in the poorer quality sands. Insufficient data is available to provide a good fracture characterisation however.

Drilling problems. Naturally fractured formations often have significant lost circulation problems during drilling. Figure 11 shows that many Carapita wells encountered these problems and that these wells mainly follow the crestal axis of the structure, where most fractures are likely to occur due to greater flexure.
Of the 17 wells drilled through the zones of interest, 9 reservoir intervals had lost circulation problems, with the most severe problems being encountered in WELL-3 and WELL-14. These wells had unrecovered core sections through these intervals, but adjacent recovered sections contain natural fractures. The cores provide evidence that the zones with the worst lost circulation problems are associated with intervals which contain natural fractures, and it is reasonable to suppose that the fractures are a major factor in these problems. Hence it can be considered that the drilling information provides evidence for effective fracture systems along the crestal region of the Carapita reservoirs.

Production data. Production data and pressure transient analysis can provide confirmatory evidence for fractures, either through unusually large production rates, DST average permeability values significantly exceeding matrix values or fractured welltest responses in build up tests.

Well productivity. A bubble map representing production to the end of 1997 is shown in figure 11. It may be seen that the wells with the best production follow a similar trend to the wells with lost circulation, although there is no direct correlation between these parameters. The notable exception appears to be WELL-3, where serious asphaltene problems have resulted in very poor productivity.

A combination of the production and lost circulation data points towards a zone of fracturing running along the crest of the structure, which augments the reservoir properties and allows better productivity. Wells towards the southern flank of the structure have produced very little, despite having similar petrophysical properties, which may indicate that there is poorer fracturing in these zones; limited drainage areas due to faulting, and asphaltene problems have also limited the productivity in this area however.

The production profile of the WELL-1 well also shows the presence of fractures in the reservoir. A regular pattern has been observed where very high production rates suddenly decline and after closing the well for several months, sustainable high production rates are again observed upon re-opening. DST permeabilities vary between 30 and 1 md depending upon when in the pattern the well is tested, and it has been concluded that this behaviour can be explained by the fracture system locally closing and opening during these depletion/re-charging cycles.

Dynamic Vs petrophysical permeability. Figure 12 compares DST and petrophysical permeabilities. The points with DST values far exceeding log derived permeabilities come from the pre-hydraulic fracture welltests on WELL-15 and WELL-14. Both of these wells, which are in the same part of the reservoir, show very high permeabilities coupled with very high skins (+114 to 742). These results seem to be indicative of natural fracture networks with poor communication to the wellbore. Subsequent hydraulic fractures appear to have created communication and have proved extremely productive, with cumulative production to date above 1.1 mmstb in each well interval. In the case of WELL-14 in particular, the very poor petrophysical properties wouldn't account for this volume of sustained production. These results point to a zone of enhanced fracturing in the north of the Orocual region.

Fractured welltest responses. A review of the Carapita welltests concluded that although many wells showed welltest derivative responses that could be interpreted as being due to natural fractures, probably only tests from WELL-3 and WELL-15 were due to this mechanism alone. The responses in the other wells were considered to be caused by combinations of high wellbore storage, nearby faulting, natural fractures and layering in the reservoir, with this latter interpretation being supported by a number of derivative curve negative half slopes, indicative of partial penetration effects.
The fact that natural fracture welltest responses are not proved in most of the wells doesn't necessarily mean that these wells do not intersect fractures. Unlike a classical carbonate reservoir, the matrix permeability in many wells is significant (20-50 md), and it is thought that the fractures act to augment the matrix permeability rather than being the sole conduit for fluid flow. The permeabilities calculated from welltest analysis would be combined matrix and fracture properties in this case.

GEOMECHANICAL ANALYSIS

A detailed geomechanical analysis was undertaken to determine in-situ stress orientation and rock strength, as these parameters define likely fracture directions and can confirm the origin of fractures seen in the cores.

In-situ stress field. The Carapita field is situated in a regionally compressive thrust regime with the major faults running in a north-easterly direction, implying that the regional maximum horizontal stress should have a NW-SE orientation**.**

A study of wellbore breakout in the Carapita sands has been made with the available dipmeter and image log data to determine the current minimum in-situ stress orientations. Two trends are evident (figure 13), one running east-west in a direction consistent with the regional stress, and the other rotated some 60-70 degrees towards the NNW.
Analysis of mini-frac data from the field has also been made, to determine the magnitude of the minimum horizontal stresses. This data shows a marked increase in stress magnitude towards the south-east of the field. Figure 11 shows a composite of the geomechanical information, together with the location of a large structural anomaly which is seen in the Orocual Somero formations above Carapita. It may be seen that the abnormal horizontal stresses and orientations shown by WELL-13 and WELL-10 coincide with this anomaly, and it is thought that this feature may be responsible for changing the local stress regime in the south-eastern corner of Carapita.
Analysis of fractures and image log data in WELL-6 and WELL-14 confirms a north-south orientation for fracture strike, consistent with the regional tectonics, and it has been concluded that this is most likely to be the general fracture orientation in Carapita. Additional confirmation of this needs to be obtained from new wells, as the currently available information is very sparse. The change in the local stress regime in the south-eastern corner may be responsible for closing the fracture network, depending upon the timing of the formation of the fractures, and could explain the poor productivity of the wells in this area. Additionally, there appears to be enhancement of the fractures to the north of this zone, as shown by the DST data.

Fracture origin. The analysis of rock strength and stability during drilling requires knowledge of the direction and magnitude of the in-situ stress field and the geomechanical properties of the rock, which were determined from uniaxial and triaxial core tests (table 2).
The stress field in figure 13 exhibits two geomechanical tendencies. Wells in the south-eastern corner have abnormally high fracture gradients and minimum horizontal stresses, whilst other wells show a more normal stress regime. The rock properties of WELL-11 and WELL-14 are considered to be representative of the upper and lower limits of these two tendencies, and have been analysed to show the range of rock stability in Carapita. An analytical wellbore stability simulator was used to perform this analysis, using

Mohr-Coulomb linear-elastic theory[4].

The results are listed in table 3, and show that mud weights of 23.7 and 17.5 lb/gal form the upper and lower limits for the minimum fracturing pressure in Carapita. As the maximum mud weight used during drilling was 16.2 lb/gal, and most wells were drilled with around 14 lb/gal, it can be concluded that the lost circulation problems in Carapita, and the fractures seen in the cores and logs were caused by naturally occurring fracture systems, and not by fractures induced during the drilling process.

FRACTURE SYSTEM CHARACTERISATION

Currently there is insufficient data available in Carapita to warrant consideration of a dual porosity simulation model. The information obtained by integrating all of the analysed data has been used to derive effective properties which can be included in a conventional simulation model to represent the behaviour of this system.

Fracture regions. The production and geomechanical analyses provide strong evidence for a zone of enhanced fracturing in the northern Orocual region, with ineffective or closed fractures due to the change in stress direction in the south of this area. In the Chaguaramal area the fracture system is expected to be more effective along the crestal axis, although fractures are also seen in cored wells in the south.

Fracture orientation. The geomechanical, core and image log analyses have shown the fractures to be predominantly vertical, with a general tendency of approximately N-S within the reservoir, which is consistent with the regional tectonics.

Permeability and anisotropy. With little dual porosity welltest interpretation data available, representative areal calculation of fracture permeability was not possible. A geostatistical method was employed to create a distribution of effective permeabilities from DST data. Validated DST permeability-thickness values were available for fourteen well intervals. These values represent the effective matrix plus fracture flow performance of the sand units, and after determination of this effective permeability to oil in each sand, the horizontal permeability estimation throughout the model was made using 2D kriging by unit.

Figure 14 compares the areal permeability distributions from the DST values with those calculated from conventional petrophysical analysis. It may be seen that the north-eastern corner of the model has very high permeability values, which come from the DST interpretations of WELL-15 and WELL-14, and represent the most highly fractured region. The petrophysically derived permeabilities under-estimate the flow properties in this region and the simulation model cannot be history matched using these values. In general, permeabilities are higher in the northern part of the model, which is considered to have the most fracturing, and decline to the south, due to poorer fracturing and more severe asphaltene effects.

A simple Warren & Root[5] fracture model has been used with the available core and DST data to calculate a horizontal anisotropy ratio for the fracture system[6]. Assuming uni-directional, predominantly vertical fractures, the ratio between orthogonal horizontal permeabilities has been calculated as 1:2.68, which implies that a horizontal permeability ratio (K_x/K_y) of 0.37 can be used in the simulation model to account for the effects of the fracture system.

Rock compressibility. A major effect of the fracture network is enhancement of the effective rock compressibility to provide an additional reservoir drive mechanism, which is expected to ultimately increase the recovery factor by 10% of the oil in place. Material balance analysis showed that the effective compressibility had to be increased by an order of magnitude to match mapped volumetrics, and the history match of the reservoir simulation model was used to fine tune this parameter, in accordance with the regions defined above. The compressibilities are seen to reduce with declining reservoir pressure (table 4), as the fracture system closes. Calculations from the DST analyses imply that after approximately 4-5000 psi depletion, the fracture network provides little additional energy in most regions, and the system reverts to matrix compressibility.

NUMERICAL SIMULATION

A black oil numerical simulation model was constructed to validate the reservoir characterisation and define an exploitation plan for the reservoir. The model used a horizontal grid with 100m cells, and 6 vertical layers to represent sands A to C in each unit, giving a total of nearly 9900 active cells. The static petrophysical parameters and water saturation regions were included from the upscaled results of the geostatistical modelling. The reservoir model has a STOIIP of 118.3 mmstb, with 43.5 mmstb in Carapita Superior and 74.8 mmstb in Carapita Inferior.

History match. The concept of a high effective rock compressibility due to natural fracturing was used in the history match of the simulation model, where rock compressibility has been adjusted as one of the main matching parameters. This compressibility is considered to decline with depletion as the fractures close, and a value representing only matrix compressibility has been generally applied at a reservoir pressure of 4000 psi. It has been assumed that the compressibility decline is irreversible, which provides the most conservative case for prediction runs. The reservoir has only matrix compressibility in the SE corner, where the geomechanical stresses have been shown to rotate, and it is thought that most of the fractures are closed. The rock compressibility in other areas has been varied (table 4), according to the stress state, to provide the generally good regional history matches which are shown in figure 15. The overall field recovery factor to date is 15.9%.

Exploitation strategy. Pressure support from two gas injection wells has been designed to provide immiscible displacement and mitigate the current problems with asphaltene deposition. The optimum development plan requires 15 mmscfd of injection gas to be diverted from nearby facilities and one new well and three currently shut-in producers to be recompleted. Production is expected to increase by 120% over five years, and 140% by 2015 compared to the base case (figure 16), which although marginal provides the most efficient method for producing the remaining reserves. The final recovery factor increases from 23% to 34%, with ultimate recovery of 39.6 mmstb.

CONCLUSIONS

An integrated analysis of core, drilling, production and geomechanical data has been used to prove the existence of a natural fracture network in Carapita, and to define regions of enhanced and poorer fracturing which are related to local changes in the stress field.

Effective rock properties for permeability, anisotropy and compressibility have been calculated from considerations of dynamic reservoir data to allow a conventional numerical simulation to take into account the drive mechanism and flow properties associated with the fractures. A simulation model, based on a facies driven geostatistically derived static model, has been history matched and used to define a development plan which is expected to increase the recovery factor from 23% to 34% of STOIIP. The limitations of this method will become evident in the future when the gas injection process matures and gas breakthroughs occur, but the lack of data to properly define dual porosity parameters coupled with a significantly reduced study time, outweighed these considerations during this study of a marginal field.

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NOMENCLATURE

STOIIP = Stock tank oil initially in place (stb)

SI METRIC CONVERSION FACTORS

cp	x 1.0	E-03	= Pa.s
ft	x 3.048	E-01	= m
md	x 9.869 233	E-04	= ? m^2
lb/gal	x 1.198 466	E+02	= kg/m^3
psi	x 6.894 757	E+00	= kPa
stb	x 1.589 874	E-01	= m^3

Table 1 Reservoir fluid properties

Parameter	Carapita Superior	Carapita Inferior
Initial reservoir pressure at 12000' datum (psia)	9391	9177
API gravity	35-36	33-34
GOR (scf/stb)	1802	1189
Bubble point (psia)	5253	4332
Bo at $P_{initial}$ (rb/stb)	1.82	1.56

Table 2 Average in-situ rock properties

Parameter	Value
Rock compressibility	$2e^{-6}$ psi^{-1}
Young's Modulus	$4.4e^{6}$ psi
Poisson's ratio	0.2
Uniaxial confined strain	11,100 psi
Tensile stress	890 psi
Friction angle	50 deg.

Table 3 Geomechanical rock stability analysis

Parameter	WELL-11	WELL-14
Min. fracturing pressure	14,000 psi	12,100 psi
Mud weight needed to induce fractures	23.7 lb/gal	17.5 lb/gal
Mud weight during drilling	14.5 lb/gal	14.1 lb/gal
Observed fractures	Natural	Natural

Table 4 Effective rock compressibilities

Reservoir pressure (psia)	Fractured region (psi^{-1})	Highly fractured region (psi^{-1})	Non fractured region (psi^{-1})
9500	$40e^{-6}$	$120e^{-6}$	$2e^{-6}$
8000	$25e^{-6}$	$100e^{-6}$	$2e^{-6}$
6000	$15e^{-6}$	$50e^{-6}$	$2e^{-6}$
4000	$2e^{-6}$	$10e^{-6}$	$2e^{-6}$

Figure 1 Location and structural setting of the Orocual field

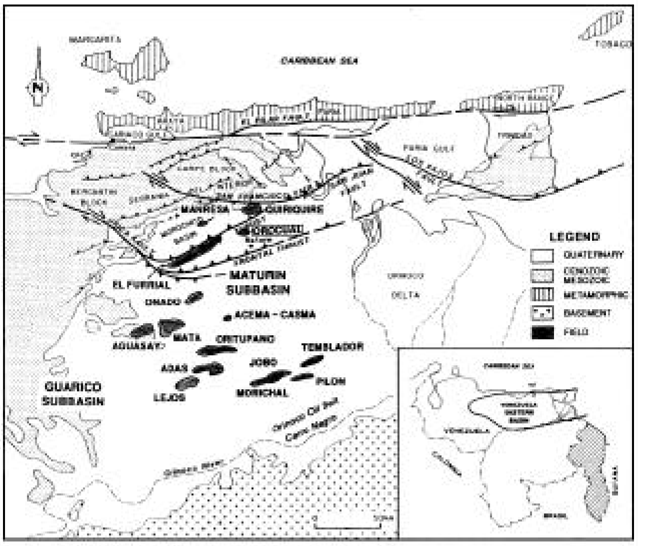

Figure 2 Stratigraphic column and Carapita type log

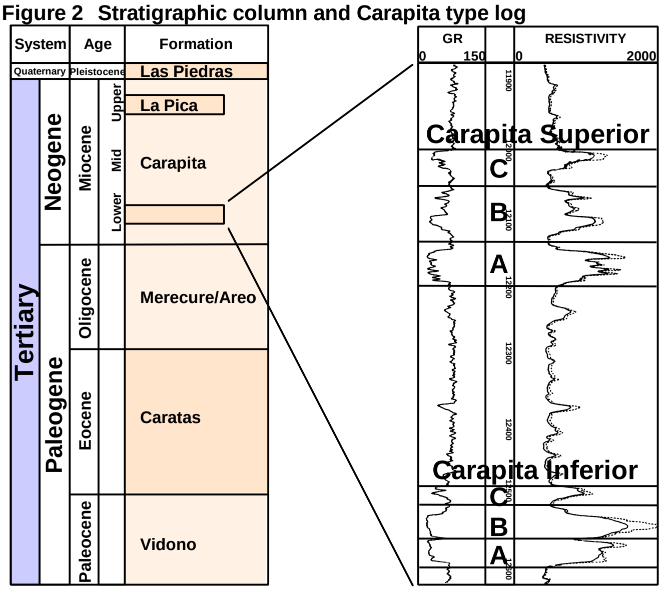

Figure 3 Carapita field oil production rate

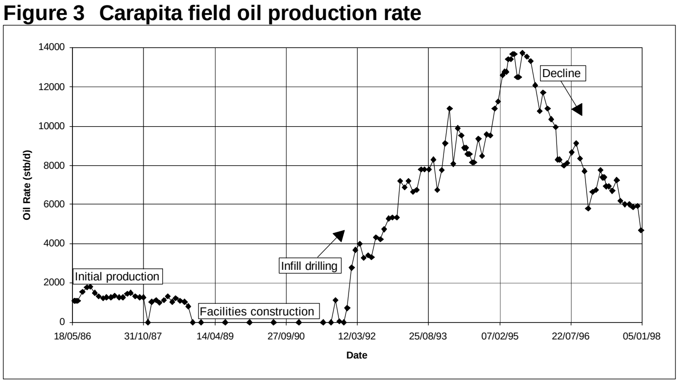

Figure 4 Carapita structural map

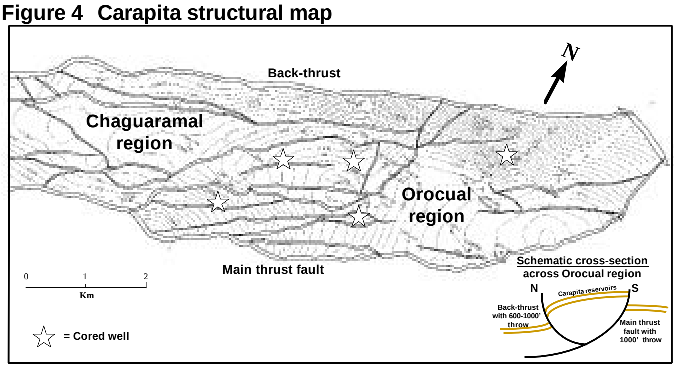

Figure 5 Vertical proportion curves for Inferior AB units

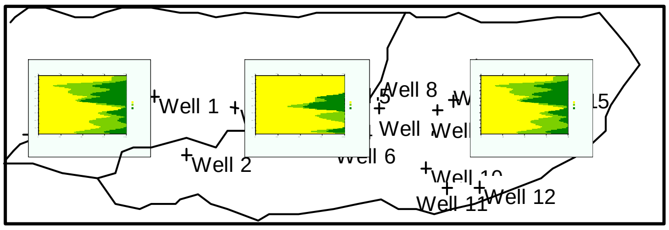

Figure 6 Vertical proporion curve matrix in Carapita Inferior AB

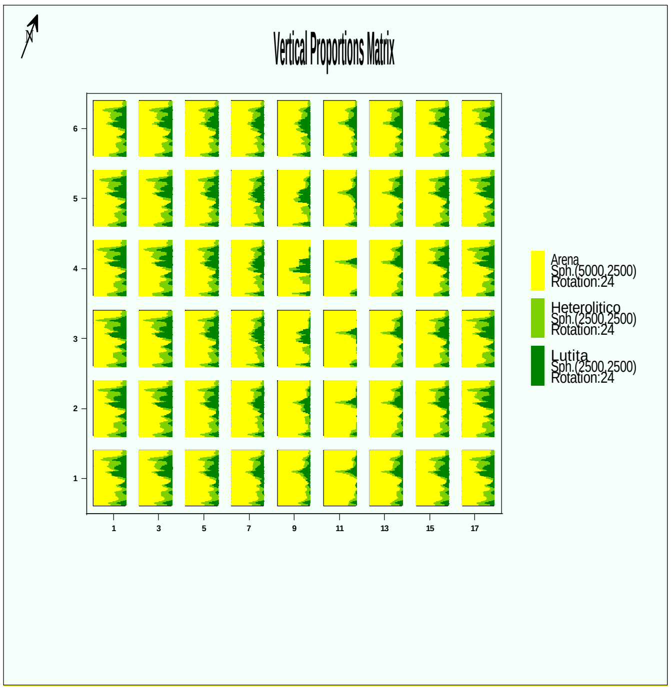

Figure 7 Est-West section in Carapita Inferior AB

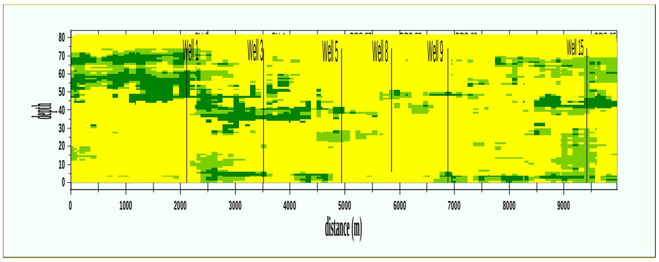

Figure 8 Bi-modal distribution of water saturation

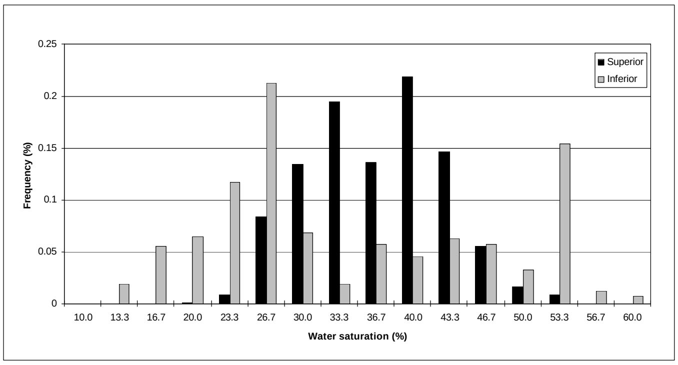

Figure 9 Material balance plot for Orocual Superior region

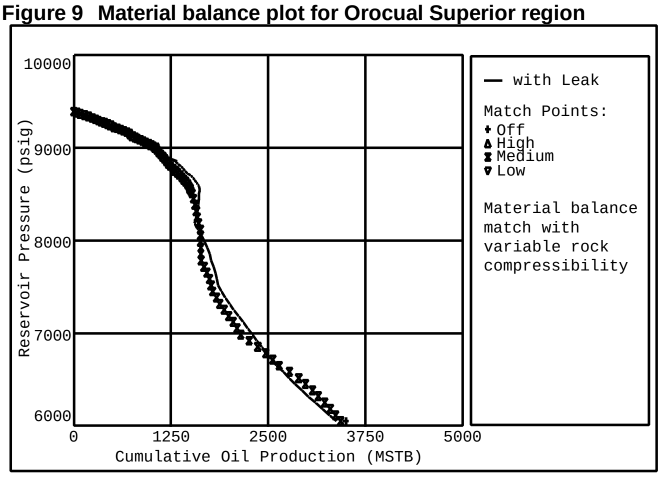

Figure 10 Fracture inclination from core

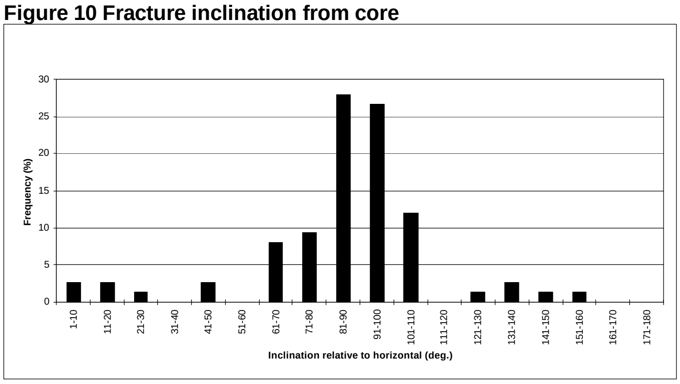

Figure 11 Well production & wells with lost circulation problems

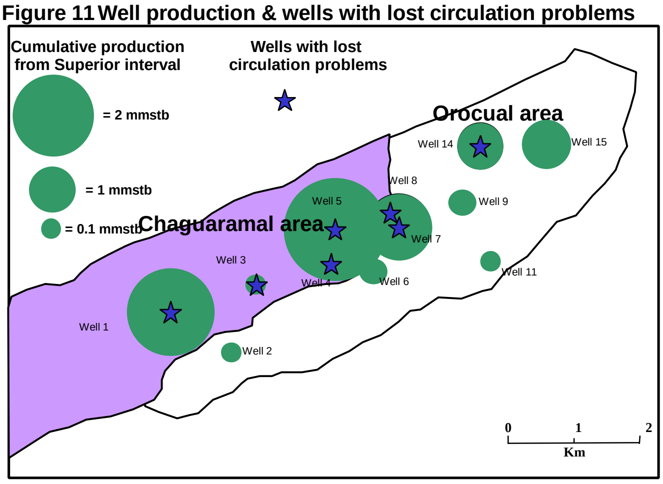

Figure 12 DST vs petrophysical permeability

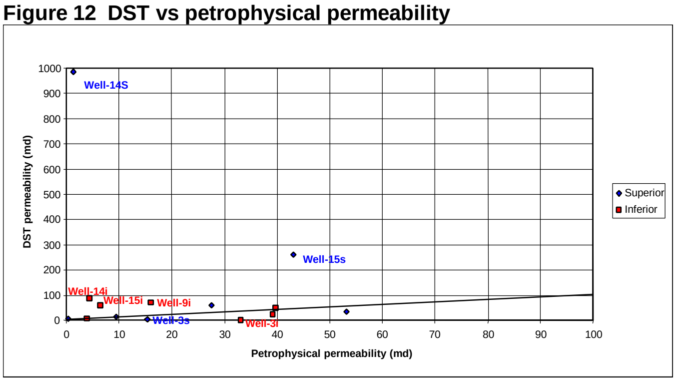

Figure 15 Simulation model history match

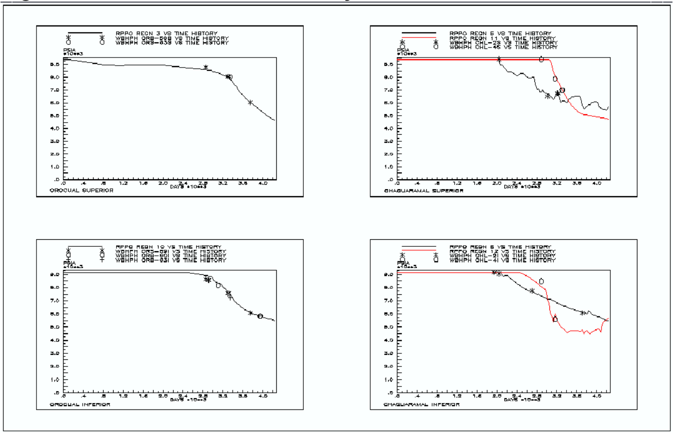

Figure 13 Carapita stress field

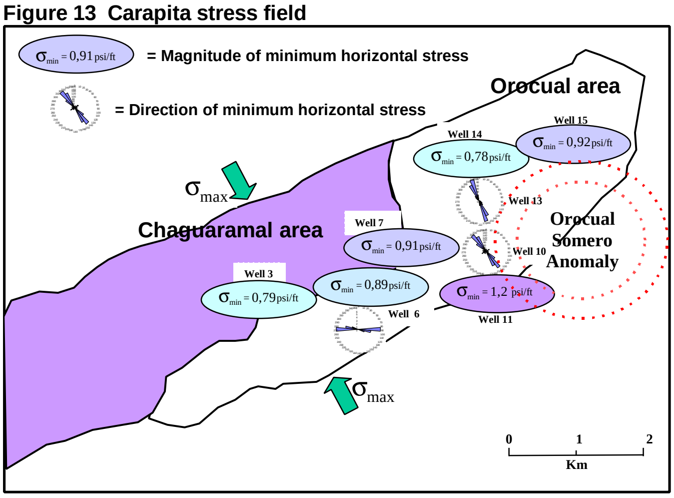

Figure 16 Simulated production increase from exploitation plan

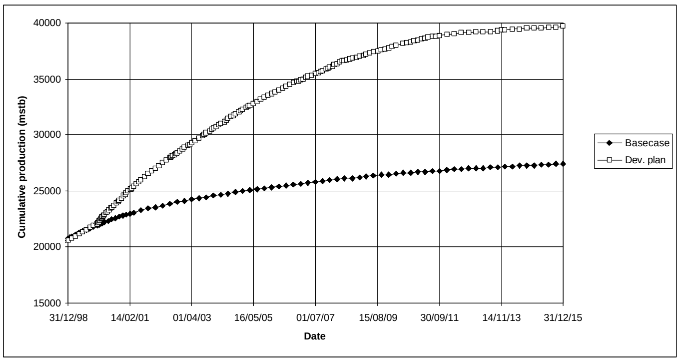

Figure 14 Permeability distribution maps