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The application of detailed reservoir geological studies in the D18 Field, Balingian Province, offshore Sarawak

J. ALMOND, P. VINCENT AND L.R. WILLIAMS

Sarawak Shell Berhad

Abstract: The D18 Field is located 56 miles north-west of Bintulu in sub-block 4Q-15 of the Balingian geological province, offshore Sarawak. The productive reservoirs comprise Early Miocene (Cycle II) lower coastal plain and delta plain deposits. The field is a tectonically complex structure, bounded to the south by a series of *en echelon* reverse faults and is fault and dip closed to the north, west and east. The internal geometry is complicated by the presence of numerous cross cutting WSW/ENE and N/S trending faults.

The field was discovered in 1981 and following encouraging appraisal of the eastern part, an eight-slot production platform was installed. Five development wells were drilled and the field came on stream in 1986. The field produced at an initial rate of 5300 BOPD, although a rapid production decline was observed in some of the wells. The poorer than expected results combined with the presence of several different fluid contacts and variable sand distribution raised questions about the lateral extent and degree of interconnectedness of the reservoir sands.

A detailed reservoir geological study (including ten wells and approximately 1,400 ft of core) was therefore undertaken to develop a geological model for the Cycle II sediments which could be used to determine the characteristics (sand quality/heterogeneity) and architecture (geometry/lateral extent/ connectedness) of the reservoir sands. This was integrated with the results of a 3D seismic study which was undertaken to determine the extent of reservoir level faulting.

The Cycle II deposits have been sub-divided into an Upper, Middle and Lower interval. The main productive reservoirs occur in the Middle Cycle II. Four genetic sandbody types are identified, namely fluvial and distributary channel, crevasse, mouthbar and shallow marine sands. A geological model was proposed which envisages the north-west to north-easterly progradation and abandonment of small delta lobes in a river-dominated lower delta plain setting.

Detailed log correlation in the Middle Cycle II interval indicated the considerable lateral extent of both the shallow marine sands which occur field wide (> 22,000 ft), and the crevasse and mouthbar sands which can be correlated over distances of 3,000 to 10,000 ft. These sands are thin (10 to 30 ft) and exhibit a wide range in reservoir quality depending upon their location relative to either the proximal or distal parts of the abandoned delta lobe margin (shallow marine sands) or the active distributary channel (crevasse and mouthbar sands). The thicker (30 to 50 ft) and better reservoir quality fluvial and distributary channel sands are of more restricted lateral extent (typically 800 - 2,500 ft) and can only occasionally be correlated between wells on the current well spacing.

The geological model has provided an improved understanding of the distribution of the reservoir sands and recoverable reserves in the D18 Field. The study has indicated that different fluid contacts observed in laterally extensive sands are probably the result of offset by sealing faults. These faults compartmentalise the D18 Field into several fault bounded blocks each containing isolated reservoir sands capable of supporting their own

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fluid columns. Detailed mapping of the reservoir sands within the fault bounded blocks has enabled more accurate determinations of hydrocarbon volumes, predictions of ultimate well recoveries and the production potential of the D18 Field.

INTRODUCTION

The D18 Field is located 56 miles NW of Bintulu in production sub-block 4Q-15, offshore Sarawak, in a water depth of 115 ft (Figure 1). It is situated within the tectonically complex Balingian geological province (James, 1984) and the prospective reservoirs comprise Early Miocene (Cycle 11) sediments (Ho Kiam Fui, 1978; Figure 2) that were deposited in a lower coastal and delta plain environment.

The field was discovered in 1981 by the D18-1 exploration well and secured under the terms of a 1976 Production Sharing Contract between Sarawak Shell Berhad (operator) and Petronas (the State Oil company). Three appraisal wells (D18-2, D18-3 and D18-5) were subsequently drilled in the eastern part of the field based on a 2D seismic structural interpretation. Fluid contacts and RFT pressures in each of these appraisal wells indicated the presence of a significant oil column (max. 450 ft), Figure 3a. Based on this initial interpretation, a plan to develop the field from an eight-slot production platform (D18 MPA) was formulated. Prior to the start of development drilling a 3D seismic survey was acquired and interpreted and the revised structure maps were used to site five development wells (D18-102, 103, 104, 106 and 107).

The field came on stream in 1986 and produced at an initial rate of 5300 BOPD. The development wells indicated a more complex hydrocarbon distribution than was originally anticipated however, with several different fluid contacts being logged (Figure 3b). This, combined with rapid production declines in some wells and the occurrence of low and highly variable net to gross ratios highlighted the need for an extensive review of the geology of the field.

A detailed reservoir geological study was therefore undertaken to develop a depositional model for the Cycle II sediments. The study was supplemented by the drilling results from two further appraisal wells (D18-6 and D18-7) in the western part of the field. The prime objectives of the study were to determine the characteristics (sand quality/heterogeneity) and architecture (geometry, lateral extent and interconnectedness) of the reservoir sands. These geological studies were integrated with the results of a 3D seismic study, which used the latest techniques in horizon processing to identify subtle faulting at reservoir level. This paper discusses the results of the geological and seismic studies and their impact on determining estimates of hydrocarbon volumes, connected STOIIP, and ultimate well recoveries in the D18 Field.

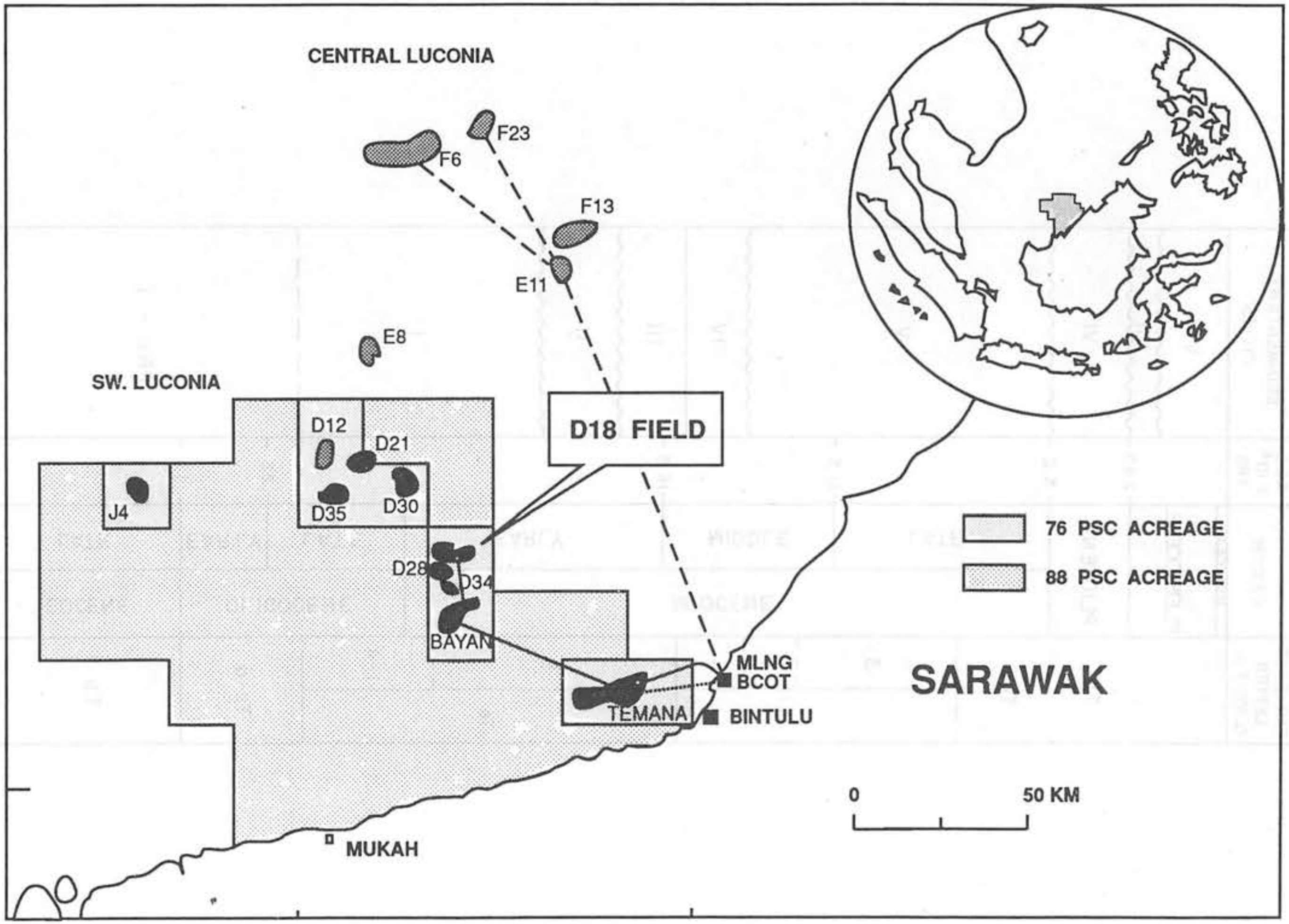

Figure 1: Location map offshore Sarawak.

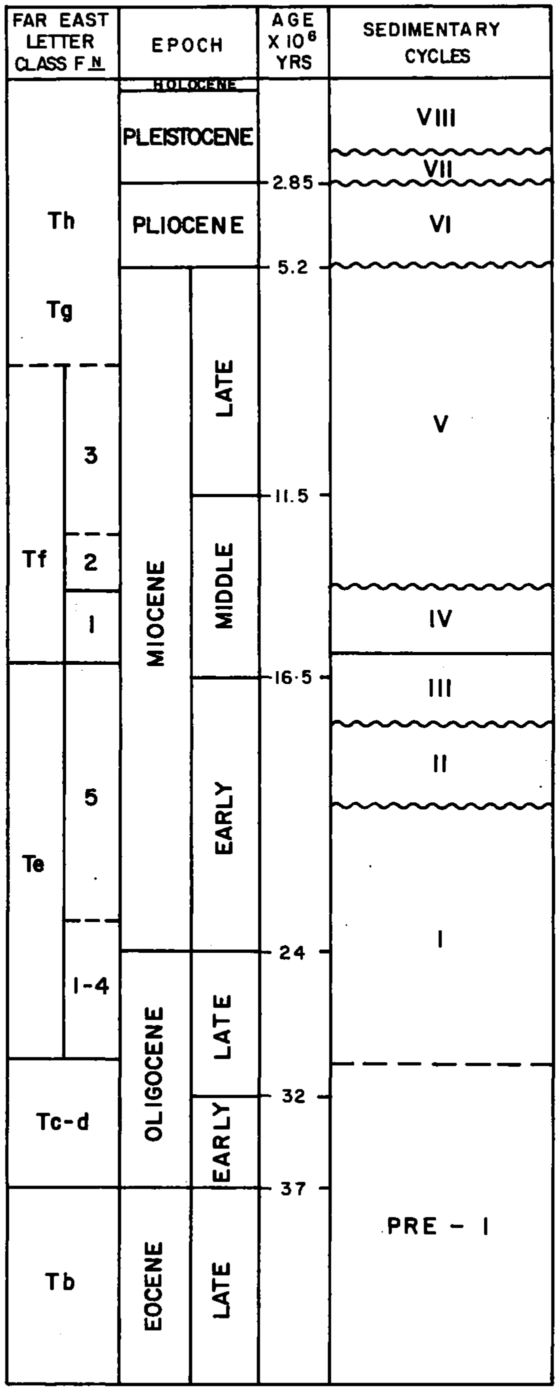

Figure 2: Stratigraphy of the Tertiary clastic deposits in the Balingian Province, offshore Sarawak

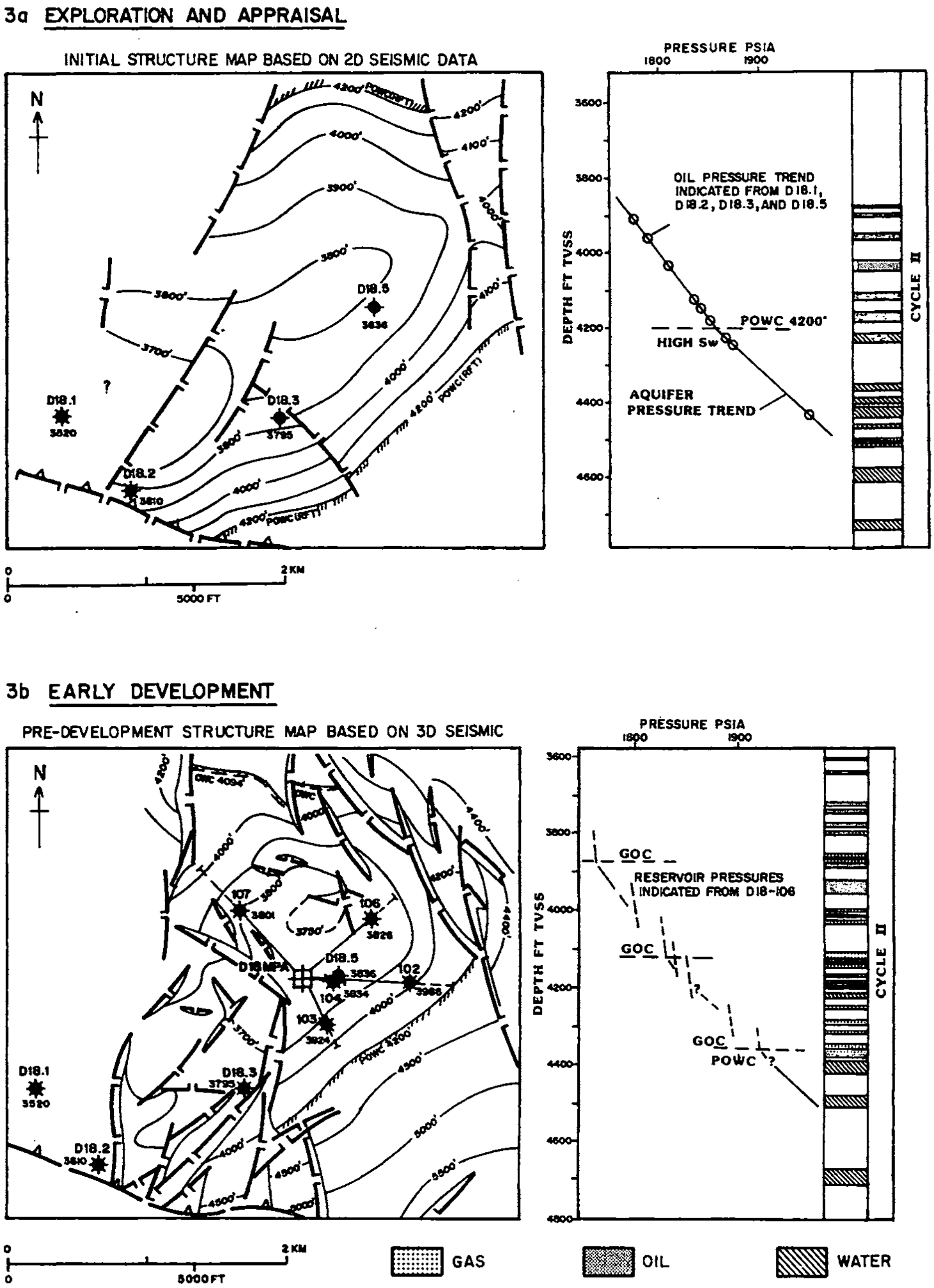

Figure 3: Early appraisal and development history of the D18 Field

GEOLOGICAL SETTING

The Balingian Province comprises a foreland basin which developed in response to Late Cretaceous to Early Tertiary, south to south-easterly directed subduction of oceanic crust under the continental NW Borneo plate (James, 1984). Following the cessation of subduction and uplift of the hinterland, a thick sequence of Tertiary clastic sediments were rapidly deposited (Figure 4).

The D18 field is located on the margins of the foreland basin situated on the north-easterly flanks of the Penian uplands, where the effects of tectonic rejuvenation in the hinterland resulted in the periodic uplift and erosion of earlier deposited sediments. Late Oligocene and Lower Miocene tectonic events define the Cycle II sediments in the D18 field (Base Cycle II and III unconformities) and are clearly evident on seismic (Figure 5). Local onlap against the Base Cycle II unconformity and variable deep erosion by the Base Cycle III unconformity accounts for the considerable thickness variations (700 to 1400 ft) which are observed in Cycle II across the field.

The field comprises an east-west trending asymmetric anticline that is fault closed to the south and dip and fault closed to the north, east and west. Structural development was initiated during the Lower Miocene, in response to a compressive stress regime which generated a series of north-west to south-east trending reverse faults. The complex southern boundary of the field is defined by an *en echelon* series of these faults. Later reactivation of WNW/ESE faults, superimposed by younger north-south faulting resulted in the structural complexity observed in the field (Figure 3b).

RESERVOIR STRATIGRAPHY

The Cycle II sediments in the D18 field comprise one upwards fining megasequence which reflects the break down of relief in the hinterland. It is sub-divided into a Lower, Middle and Upper interval based on gross lithological characteristics and the occurrence of a specific field wide marker (Figure 6).

Lower Cycle II

The Lower Cycle II unconformably overlies Early Miocene, Cycle I deposits. It is clearly distinguished on the well logs as an interval of thick, blocky sandstones (typically 50 to 100 ft in thickness) interbedded with mudstones containing a few thin coals. The net to gross ratio is highly variable ranging from 0.2 to 0.7 and porosities average 25%. There is a considerable variation in the thickness of the Lower Cycle II (100 to 450 ft) which is attributed to the infilling of the irregular Cycle I palaeo-topography. Local onlap against Cycle I highs is clearly evident on seismic. Sand development in this interval is good, but these reservoir sands are generally not hydrocarbon bearing.

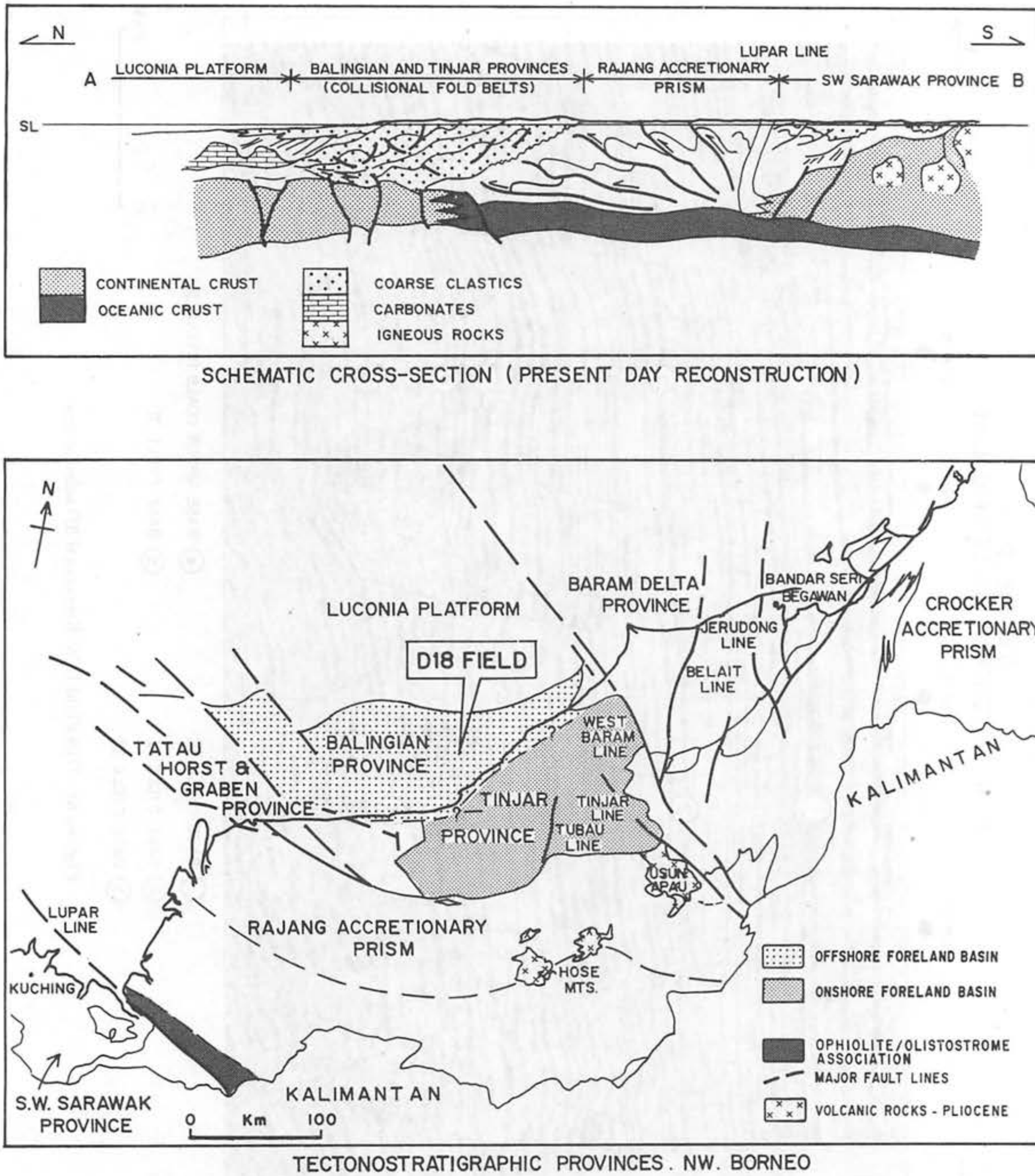

Figure 4: Evolution of the Balingian Province, offshore Sarawak (after James, 1984).

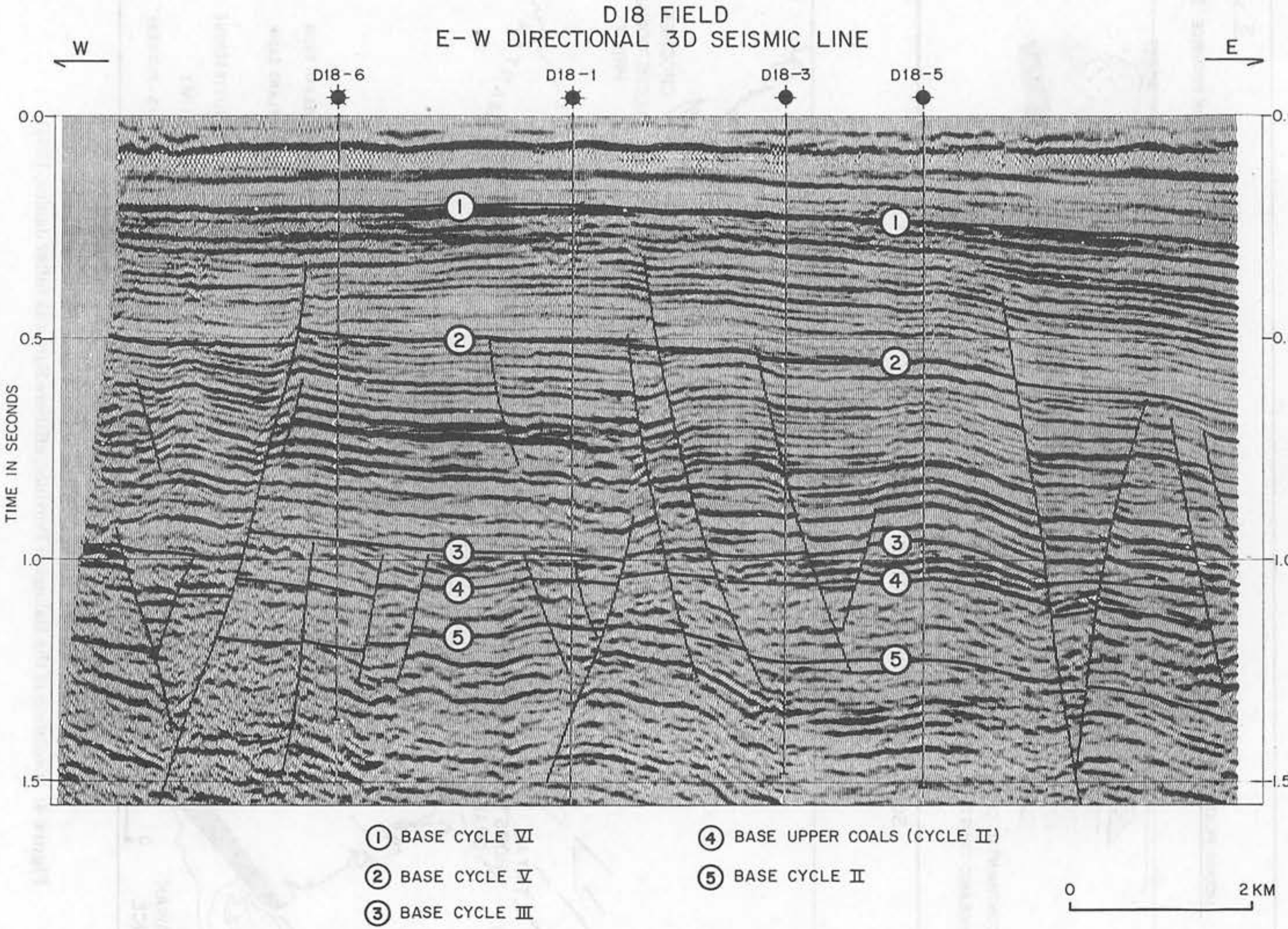

Figure 5: D18 Field E-W directional 3D seismic line.

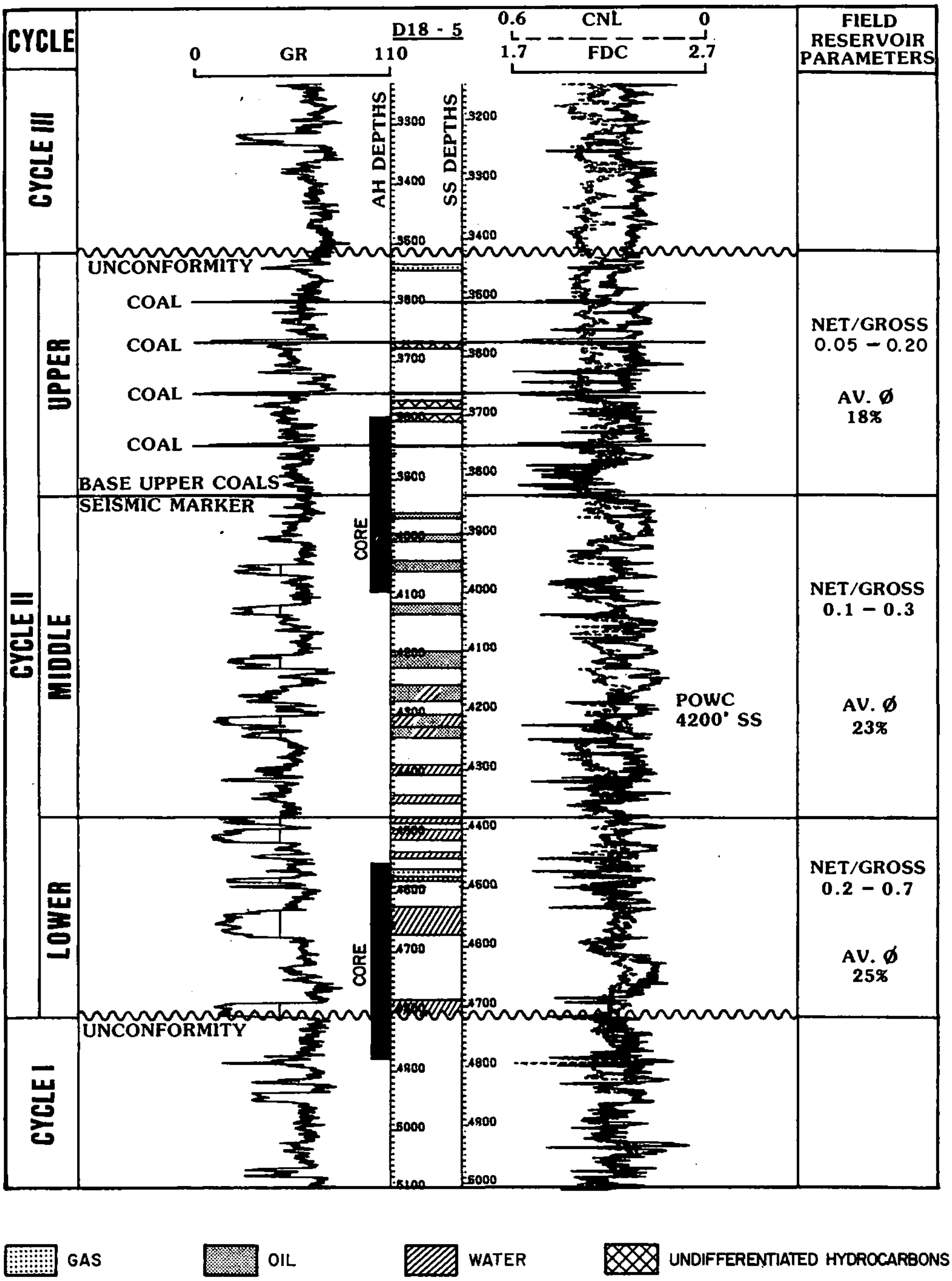

Figure 6: D18 Field Cycle II reservoir sub-division

Middle Cycle II

The Middle Cycle II is the main productive reservoir interval in the field. It ranges from 420 to 660 ft in thickness and consists of a heterolithic sequence of interbedded thin sandstones (range 10 - 50 ft) and coal bearing mudstones. The net to gross is low, ranging from 0.1 to 0.3 and porosities average 23%.

Upper Cycle II

The upper Cycle II is a mudstone dominated interval characterised by very low net to gross ratios ranging from 0.05 to 0.15 and porosities in the order of 18%. The base to the interval comprises a well developed coal bearing sequence that is clearly evident on seismic and can be mapped across the field (Base Upper Coals Seismic Marker), Figures 5 and 6. The Upper Cycle II ranges from 120 to 445 ft in thickness reflecting local deep erosion by the Base Cycle III unconformity. Only minor hydrocarbon accumulations occur within this reservoir interval.

RESERVOIR DESCRIPTION

Characteristics of the Reservoir Sands

Core coverage in the D18 field is extensive, comprising approximately 1400 ft of core from five wells, mainly taken within the Middle Cycle II interval. Detailed core description and lithofacies interpretation resulted in the identification of four main genetic sandbody types: fluvial and distributary channel, distributary mouthbar, crevasse (minor channels and mouthbars) and shallow marine sands.

The genetic sandbodies are characteristic of deposition within a river-dominated lower delta plain, probably similar to the modern day Mississippi river delta (Coleman and Prior 1981). Three depositional sequences were identified from the cores. These represent the progradation over delta front mudstones and mouthbar sands of distributary channel and floodplain sediments, the infilling of shallow brackish water interdistributary bays by crevasse and mouthbar sands and the marine reworking of fluvial sediments following delta lobe abandonment and subsidence. The identification of shallow marine sands in the cores proved significant in view of their implications of considerable lateral extent. The genetic sandbody types are summarised in Figures 7 and 8 and are discussed in detail below.

Fluvial and Distributary Channel Sands: The lithologies of the channel deposits comprise very coarse to very fine grained moderately well sorted sandstones. The sands overlie scoured, lower erosion surfaces and typically exhibit a vertical transition from cross-bedded to parallel laminated and ripple

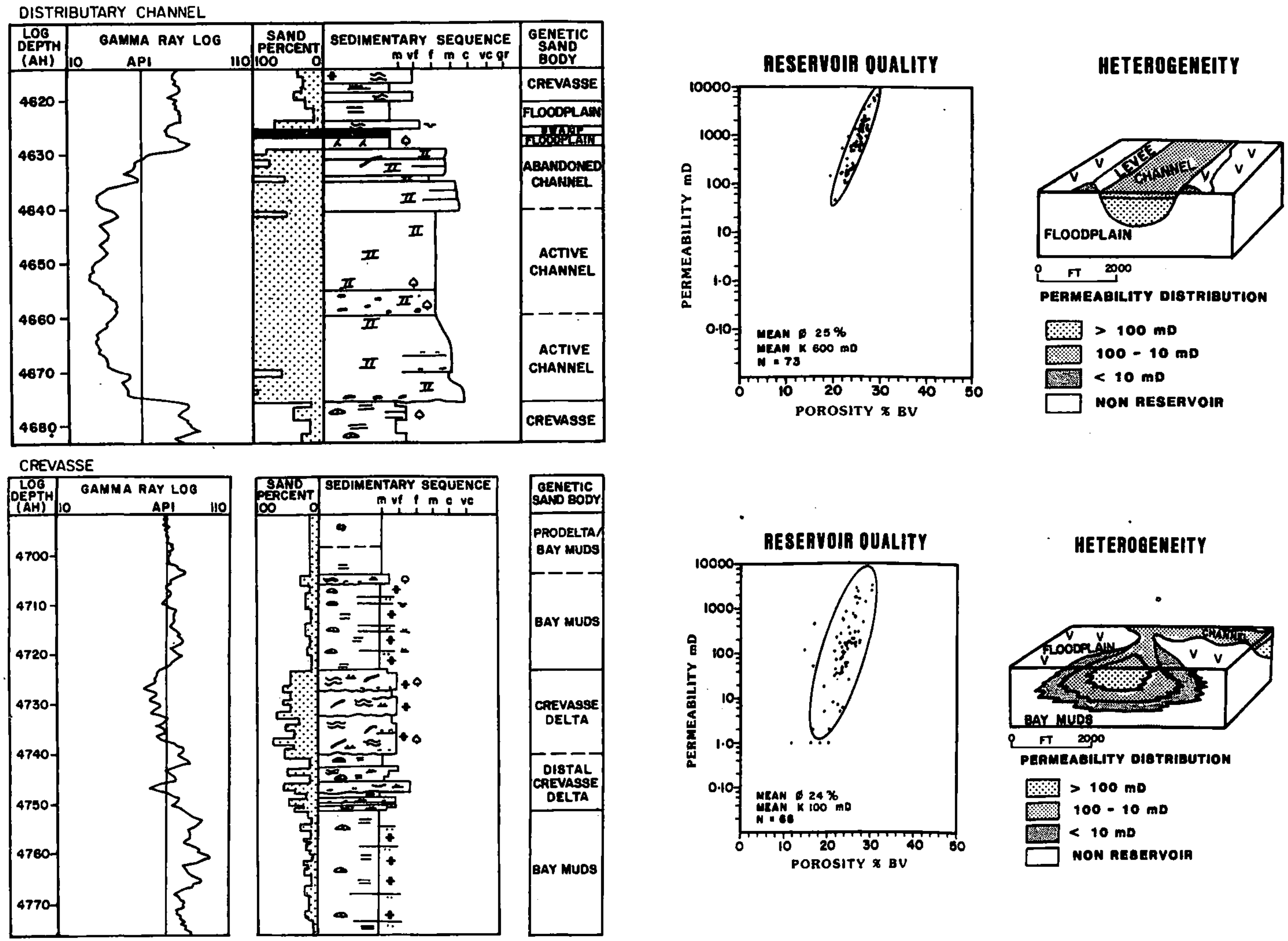

Figure 7: Reservoir characteristics of distributary channel and crevasse sands.

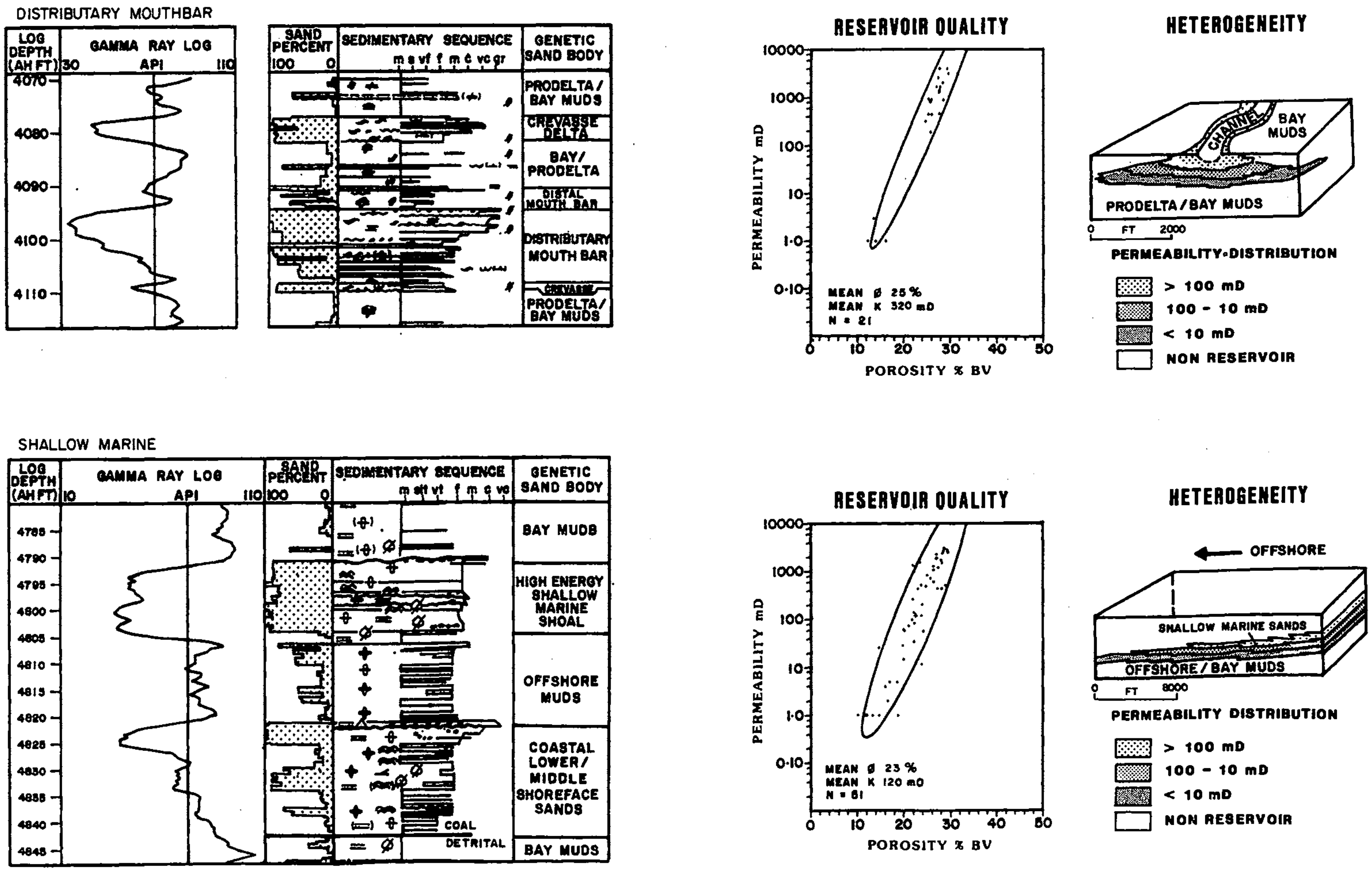

Figure 8: Reservoir characteristics of distributary mouthbar and shallow marine sands.

cross-laminated sandstones. They are occasionally overlain by rootletted mudstones and rarely, coals. Individual sands are typically in the order of 20 to 50 ft in thickness and exhibit blocky to bell shaped Gamma Ray profiles. The channel sands consistently exhibit the better reservoir properties, with porosities of 12 to 29% (mean 25%) and permeabilities of 60 to 7,000 mD's (mean 600 mD).

Crevasse Sands: The lithologies range from coarse to very fine grained sandstones. Two distinct crevasse sequences are recognised. Thin, (5 to 10 ft), cross-bedded and ripple cross-laminated sandstones interbedded with floodplain mudstones and coals are interpreted as crevasse splay sands. Upwards coarsening sequences exhibiting a vertical transition from heterolithic facies to ripple cross-laminated and cross-bedded sandstones comprise crevasse delta sands (minor mouthbar/crevasse channel couplets) and represent the infilling of shallow interdistributary bays (Elliot, 1974). A wide range in reservoir quality is observed in these sands, depending on their location proximal or distal to the fluvial or distributary channel and extent of bioturbation (increased incorporation of clays). Porosities range from 11 to 31% (mean 24%) and permeabilities from 1 mD to 4,000 mD (mean 100 mD).

Distributary Mouthbar Sands: The lithologies of the mouthbar sands range from very fine to coarse (locally pebbly) grained sandstones that typically exhibit an upwards coarsening trend. Typical vertical lithofacies profiles exhibit a transition from heterolithic facies (alternating sandstones and mudstones) to ripple cross-laminated and cross-bedded sandstones. The mouthbars occur interbedded with prodelta or interdistributary bay mudstones and may be erosively overlain by the distributary channel. As with the crevasse sands a wide range in reservoir quality is observed within these sandbodies, reflecting their location (proximal or distal) to the distributary channel and the extent of bioturbation. Porosities range from 12 to 29% (mean 25%) and permeabilities from 1 to 4,000 mD (mean 320 mD). Intercalated mudstones within the lower and distal parts of the mouthbars reduce the vertical permeability.

Shallow Marine Sands: The lithologies range from coarse to very fine grained sandstones. The sands generally exhibit an upwards coarsening trend characterised by a vertical transition from heterolithic lithofacies to rippled cross-laminated and cross-bedded sandstones. Bioturbation (*Ophiomorpha*) is often intense resulting in the total destratification of beds. These sands represent the marine reworking of the fluvially emplaced sands into coastal shoreface and offshore bar/shoal sands (Penland, *el al.,* 1986) and occur interbedded with interdistributary bay/prodelta or offshore muds. A wide range in the reservoir quality of these sands is observed depending upon the extent of bioturbation, calcite cementation and their depositional setting proximal or distal to the abandoned delta lobe margin. Porosities range from 14 to 28% (mean 23%) and permeabilities from 2 - 1,950 mD (mean 120 mD).

Reservoir Architecture

Detailed loq correlation of the Cycle II sediments was undertaken in order to determine the lateral extent and degree of interconnectedness of the reservoir sands encountered in the D18 MPA development wells.

This involved detailed core facies and log calibration studies to assist in sandbody identification in non-cored reservoir intervals, supported by dipmeter interpretation to define the main depositional trends. The geometries of the genetic sandbody types were determined from correlation and comparisons with an inhouse database of sandbody width to thickness relationships.

Differentiation of the crevasse, mouthbar and shallow marine sands proved difficult however because they all exhibit similar cylinderical to funnel shaped Gamma Ray profiles. This highlighted the value of the extensive coring programme which enabled two shallow marine sands identified in cores taken in both the eastern (D18-103) and western (D18-6, D18-7) parts of the field to be correlated over extensive distances (10,000 ft to 22,000 ft). These sands provided a framework for detailed correlation of the reservoir sands in the productive Middle Cycle II interval, Figure 9.

The shallow marine sands comprise extensive sandsheets which are thickest in the south and south-eastern parts of the field and thin with increasing shale intercalations towards the north and north-west (more offshore).The crevasse and mouthbar sands comprise radial to lobate shaped sandbodies which occur either adjacent to (crevasse sands) or perpendicular to (mouthbar sands) the main distributary channel sands. These sands could be correlated between wells over distances of 3,000 to 10,000 ft in the D18 field.

The fluvial and distributary channel sands comprise, elongate sandbodies of restricted lateral extent that can only occasionally be correlated between wells on the existing well spacing. Most are interpreted as low sinuosity channels, which on the basis of correlation and comparisons with width to thickness ratios for low sinuosity fluvial and distributary channels are typically in the order of 800 - 2,500 ft in width. Dipmeter data suggests that the channels flowed towards the north-west and north-east.

The results of this study highlighted the extensive nature of the thinner (10 to 30 ft) crevasse, mouthbar and shallow marine sands. The net to gross ratio within the productive Middle Cycle II interval is low however, suggesting that these sands occur as isolated bodies, encased within floodplain and interdistributary bay mudstones. Vertical communication between these reservoirs is therefore expected to be poor.

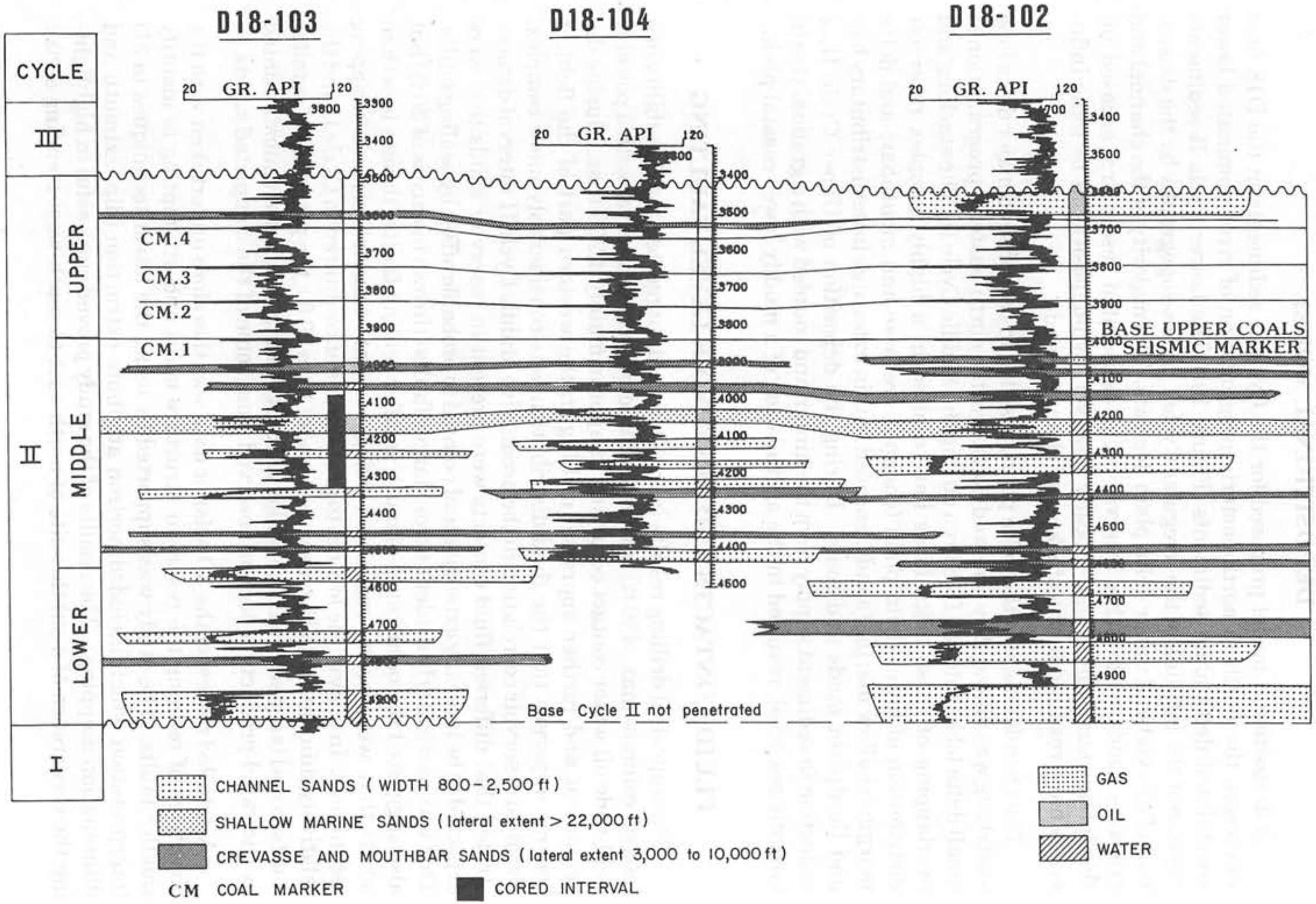

Figure 9: Reservoir correlation of the Cycle II sands in the D18–103, 104 and 102 development wells.

DEPOSITIONAL MODEL

A depositional model proposed for the Cycle II sediments in the D18 field envisages the north to north-easterly progradation of river dominated lower coastal and delta plain sediments (Figure 10). The Lower Cycle II sediments represent the infilling of the irregular Cycle I palaeo-topography by the deposition of alluvial and upper delta plain deposits. The majority of the channel and crevasse sands within this interval occur as isolated reservoirs, encased in floodplain muds and coals. Locally however, syn-depositional tectonic influences have resulted in the stacking of channel sands.

The abandonment of the delta plain, possibly in response to major delta lobe switching was followed by renewed north-west to north-easterly progradation of small delta lobes into the D18 area during the Middle Cycle II. The stacking and overlapping of these delta lobes has resulted in a highly complex reservoir distribution of lower delta plain (channel, crevasse and mouthbar) and delta margin (shallow marine) sands, encased within extensive interdistributary bay and floodplain muds and coals. During the deposition of Upper Cycle II, a reduction in sediment supply from the hinterland coupled with a gradual rise in eustatic sea level, resulted in the aggradation of a muddy lower coastal plain.

FLUID CONTACTS AND RESERVOIR LEVEL FAULTING

The appraisal drilling results in the D18 field, suggested the possibility of a long oil column (max. 450 ft) within the Middle Cycle II interval with a possible field-wide oil water contact occurring at approximately 4,200 ft ss. During development and further appraisal drilling in the western part of the field, it became apparent that the fluid distribution was considerably more complex. Detailed reservoir correlation in the productive Middle Cycle II interval demonstrated that different fluid contacts were present in reservoir sands that were expected to be laterally extensive and pointed to probable offset by sealing faults. This was particularly evident across larger faults (throws in excess of 30 ft) but also suggested the occurrence of much smaller sealing faults (throws less than 30 ft) that were below resolution using current standard seismic mapping techniques. In view of the low net to gross ratios encountered in Cycle II and the relatively thin nature of the reservoir sands (10 to 30 ft), the potential of smaller faults to seal is considered highly likely. Fault sealing was further substantiated by the rapid production decline observed from some of the completed sands.

A detailed review of the 3D seismic data was therefore undertaken with the objectives of refining the reservoir structure maps and attempting to identify smaller faults. The study was supported by using the latest techniques in 3D interpretation which included horizon attribute extraction (dip, azimuth and illumination mapping). The results of the study proved successful in highlighting the occurrence of a subtle suite of north-east to south-west trending strike

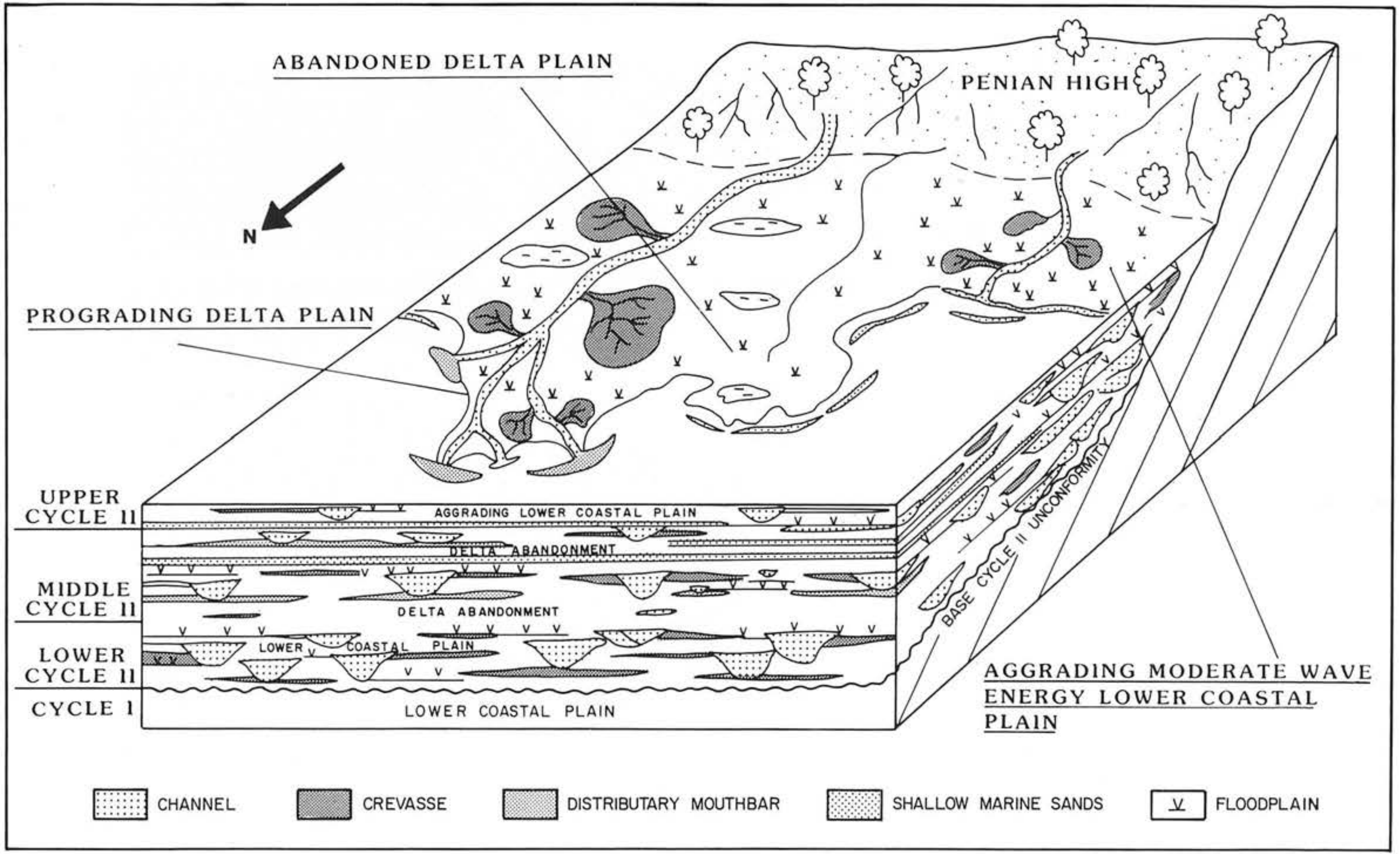

Figure 10: Depositional setting of the Cycle II sediments in the D18 Field.

slip faults which were previously not detected (Figure 11). The revised field structure map (Figure 12) shows the compartmentalisation of the D18 field, into several additional fault-bounded blocks.

The latest structural interpretation is consistent with the geological model which indicates that faults are a significant factor in isolating the reservoir sands (Figure 13). This has contributed to the complex hydrocarbon distribution pattern within the field and accounts for the poor performance in some wells.

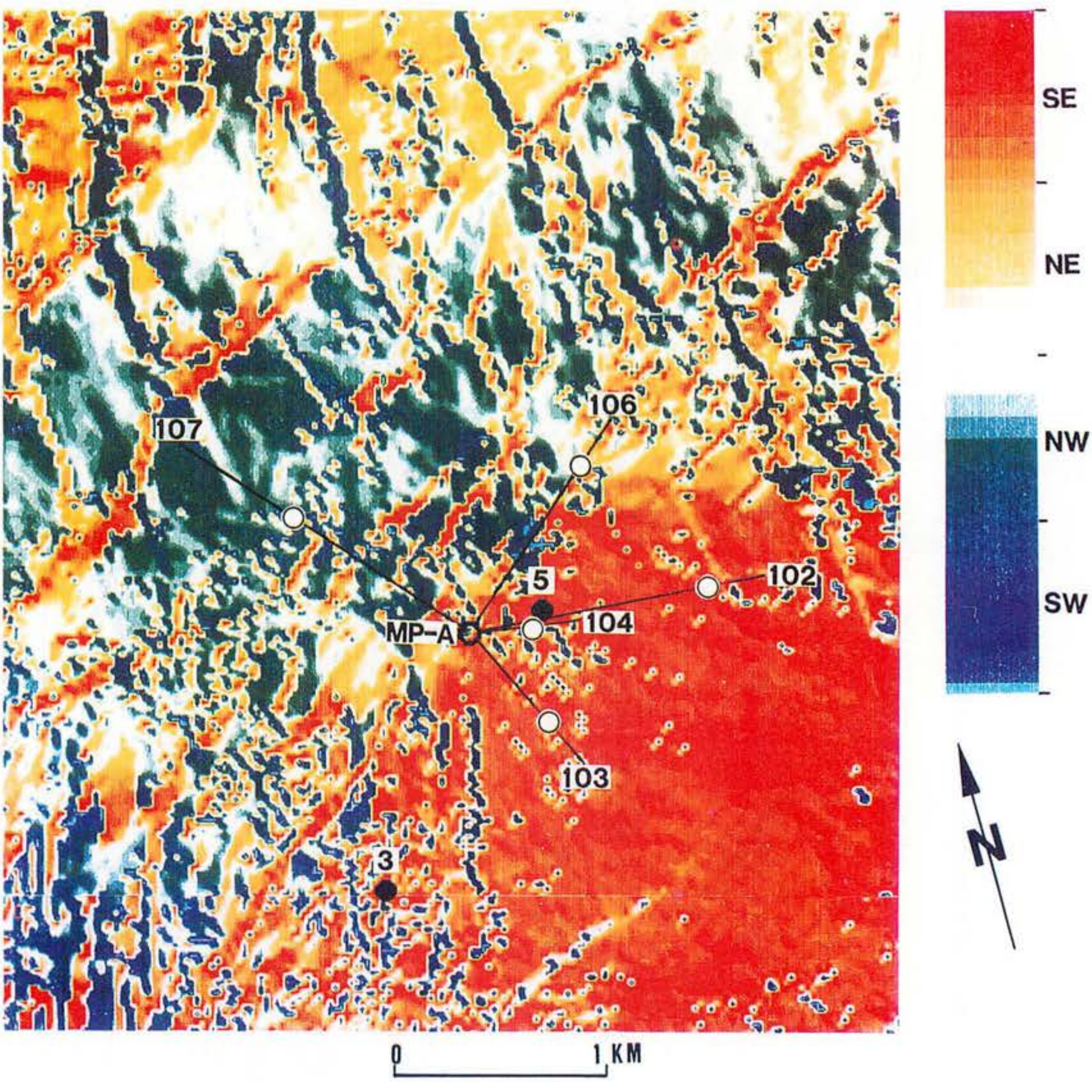

Figure 11: D18 East azimuth display: Base coals (Cycle II)

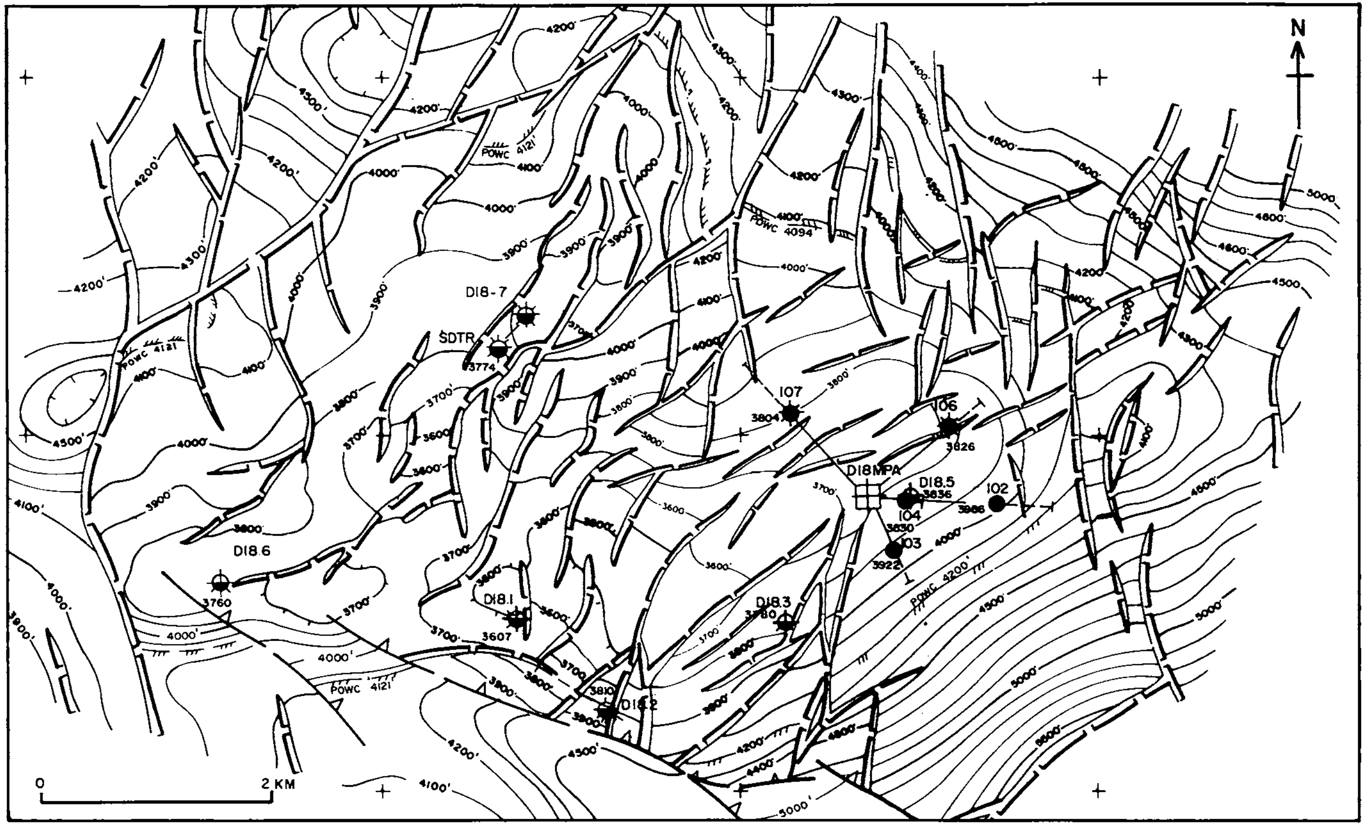

Figure 12: D18 Field depth map: Base upper coals, Cycle II final 3D interpretation.

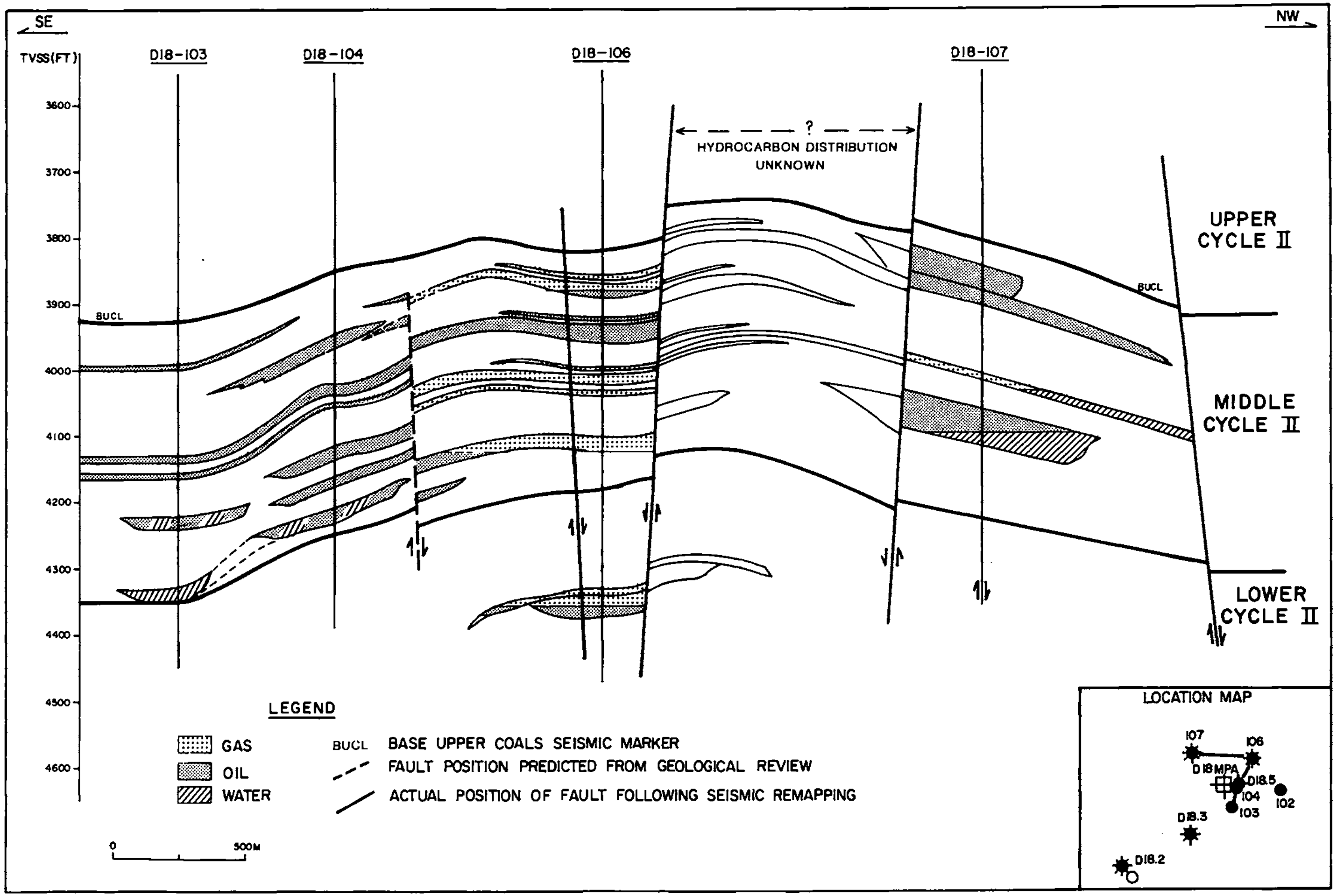

Figure 13: Schematic representation of reservoir and hydrocarbon distributions middle Cycle II, D18 Field.

ESTIMATES OF HYDROCARBON RESERVES

Net sand maps were constructed for the main reservoir sands encountered in the D18 MPA development wells using the results of the reservoir geological and seismic studies. These maps were used in conjunction with material balance estimates from production performance to better define in-place hydrocarbon volumes, ultimate well recoveries and recovery factors.

The geometry and degree of continuity of each individual sandbody was established from the detailed reservoir correlation and geological modelling. The compartmentalisation of these sandbodies as reflected by the production performance and fluid distribution was accounted for by superimposing the fault pattern onto the net sand maps (Figure 14). Hydrocarbon volumes were estimated for each fault compartment assuming that the faults generally act as barriers, at least during the production lifetime.

This approach has proved useful in better defining the developed hydrocarbon volumes. In addition, it has assisted in identifying sands and fault blocks within the field which are currently undrained.

CONCLUSIONS

The integration of detailed reservoir geological and seismic studies has resulted in an improved understanding of the reservoir characteristics and hydrocarbon distributions within a field where the prospective sequence has a low net to gross, the reservoir distribution and quality is highly variable and the structure is complex. This has enabled a more accurate estimate of hydrocarbon reserves and has led to the identification of potential infill well locations in the D18 MPA area. The results of this study have also provided support in the planning for the future development of the western part of the field which has similar reservoir and structural complexities. It also highlights the value of undertaking a comprehensive study of the geology and seismic at an early stage of field development.

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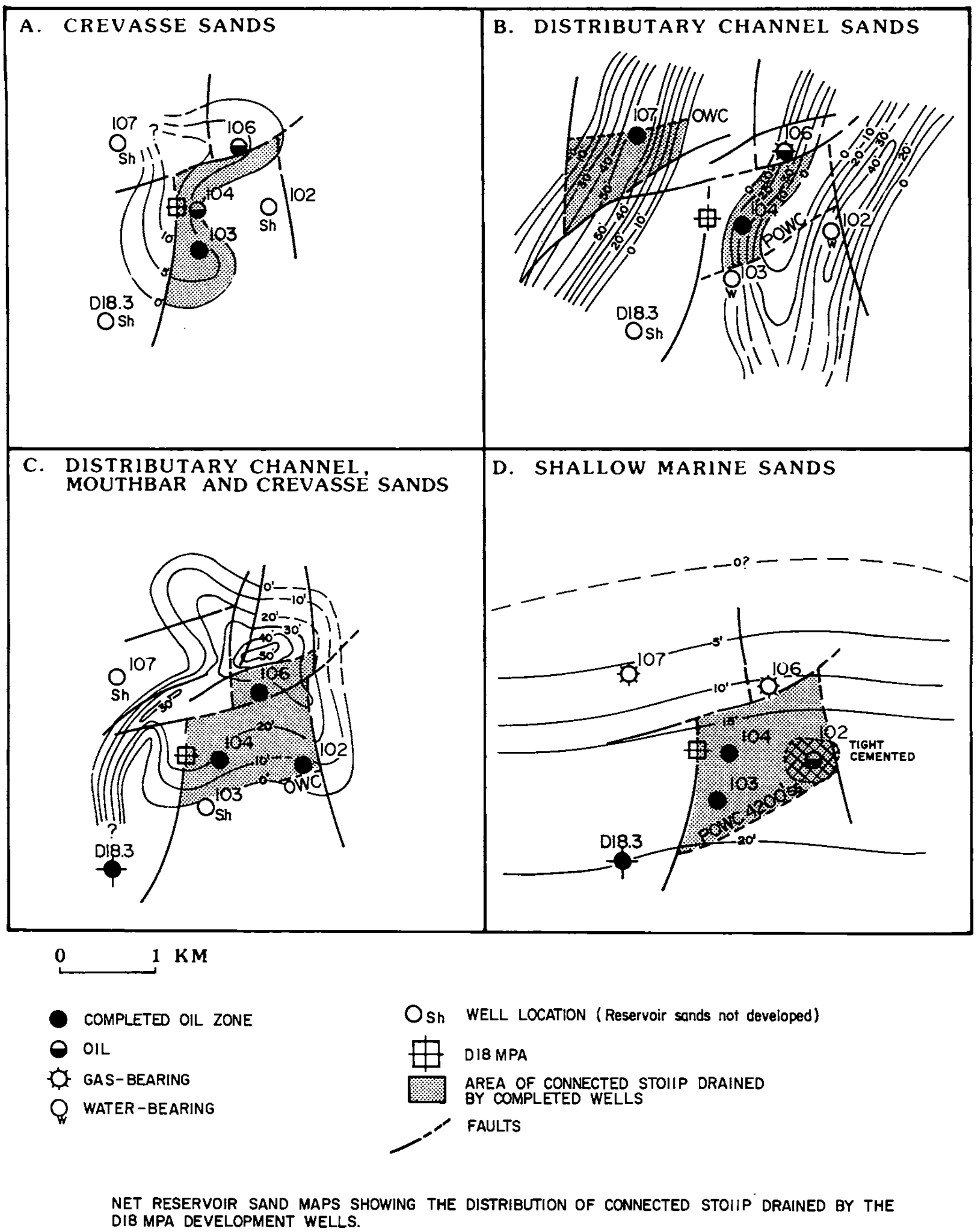

Figure 14: Reservoir sand mapping, D18 Field

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