

Geology of Kinabalu field and its water injection scheme

BONIFACE BAIT

Sabah Shell Petroleum Co. Ltd.
Locked Bag No. 1
98009 Miri, Sarawak

Abstract: This paper discusses the geology and development of the L reservoir unit in the Kinabalu field, Sabah and includes a description of the innovative water injection scheme being implemented for pressure maintenance to sustain oil production. Kinabalu field, situated 55 km west-north-west of Labuan Island was discovered in 1989 by KN-1 well with a total pay counts of 1,043 ft NOS, 113 ft NGS and 310 ft NHS. The field contains some 500 MMstb oil-in-place, developed in 1997 and to date some 50 million barrels had been produced. The gas and oil are transported by pipelines through Samarang facilities and then onwards to Labuan Crude Oil Terminal for storage and export. The major producing reservoirs in the Kinabalu field are K and L units trapping hydrocarbons against the Kinabalu Growth Fault.

The intercalated sands and shales of L reservoirs were deposited in a shallow marine environment during Late Miocene time (Stage IVD). Production performance and a very fast pressure drop in these reservoirs suggested very limited to no water-drive. Several options were investigated to provide pressure support to this major oil reservoir, including injecting seawater and dumping of shallower formation water. In the Kinabalu field, water is produced from the shallower sand bodies (B & C Sands) and injected into the L reservoir unit through two horizontal wells. To date a natural dumping rates up to 1,200 barrels per day are experienced in these wells and electric submersible pumps will be installed soon to increase the injection rate up to 20,000 barrels per day. Some 16 million barrels oil are expected to be extracted by this pressure maintenance scheme thus adding some two to four thousand barrels oil per day to the Kinabalu field production.

INTRODUCTION

The Kinabalu field was discovered in 1989 by exploration well KN-1 and is located 55 km west-north-west of Labuan Island, offshore Sabah in about 54 m water depth (Fig. 1). The field was subsequently appraised with the acquisition of 3D seismic survey in late 1989 and followed by three appraisal wells prior to embarking on a field development plan in 1991. The Kinabalu field consists of three separate accumulations, namely Kinabalu Main, Deep and East (Fig. 2). Oil is found in over thirty different sandstone reservoirs and the major part of the oil reserves is contained in the F, J, K, L, M and O reservoirs of the Kinabalu Main accumulation. The Kinabalu Main accumulation is separated by 1,700 feet of water-bearing sands-shales sequence from the Kinabalu Deep reservoirs which are filled with condensate rich gas and at least one (S1S2) oil rim. The Kinabalu East accumulation is mainly gas bearing but contains at least two oil rims.

The Kinabalu field contains 500 million barrels oil-in-place of which 24% are contained in the L reservoirs and 26% in the K reservoirs.

The revised 1995 Field Development Plan aimed to develop the Kinabalu Main reservoirs and assumed a moderate to strong aquifer drive to be

present in the field. It was expected that the aquifer would support the reservoir pressure to a large extent and therefore expected high recovery factor of up to 49% from the L2 reservoirs. As a result of the above assumptions, all the early development wells drilled to drained the K and L reservoirs were located near the crest of the structures with 3 horizontal wells in the K2 reservoirs and 5 horizontal wells in L2 reservoirs (Fig. 3).

The field first produced oil in December 1997. The crude oil and gas are evacuated through pipelines to Samarang complex, located 27 km to the northeast, where they are processed prior to transporting them to Labuan Crude Oil Terminal for storage and export. Oil production reached a peak of 48,000 barrels per day (bpd) during the first year of production however, gas breakthrough was observed in the producing wells and reservoir pressure was declining faster than expected especially in the L reservoirs (Fig. 4). This unusual production performance prompted remedial action plan to be implemented in 1999 and further development in 2000-1 (KN Round 2 development). A pressure maintenance scheme was also implemented during the second round of development drilling namely gas injection for the K2 reservoirs and water injection for the L2 reservoirs.

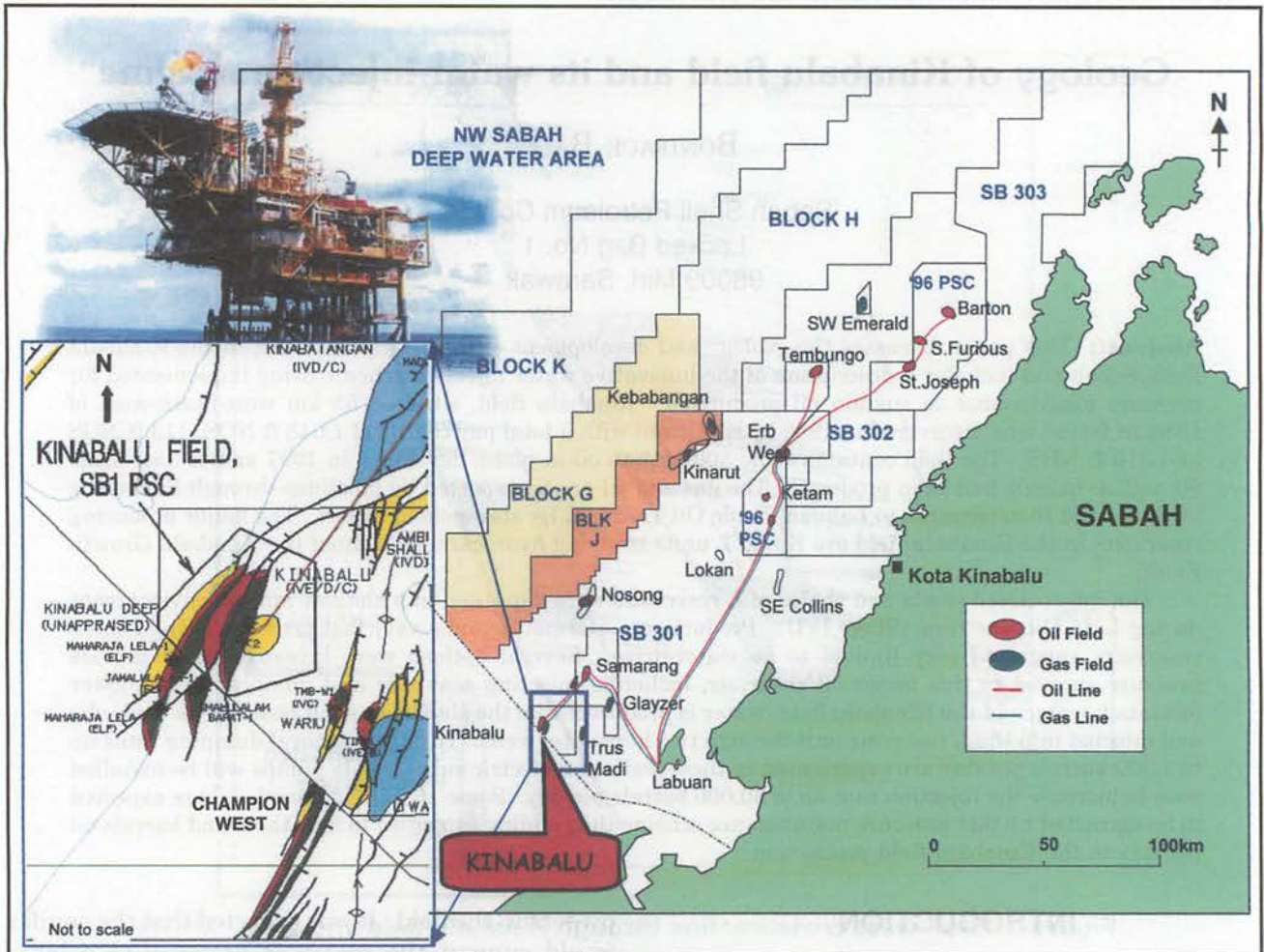


Figure 1. Kinabalu field location map.

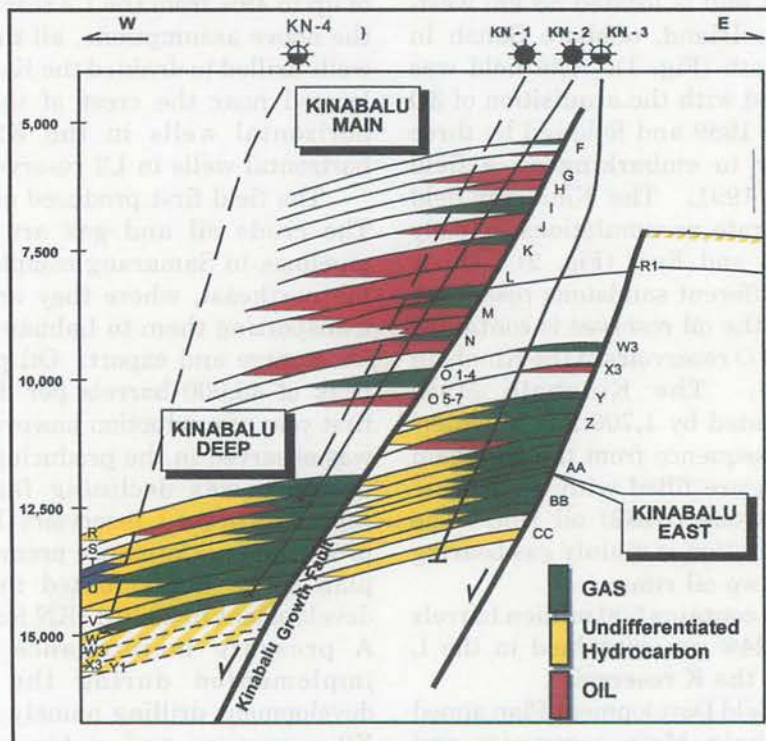


Figure 2. East-west cross-section through Kinabalu field showing the Kinabalu Main, East and Deep Accumulation.

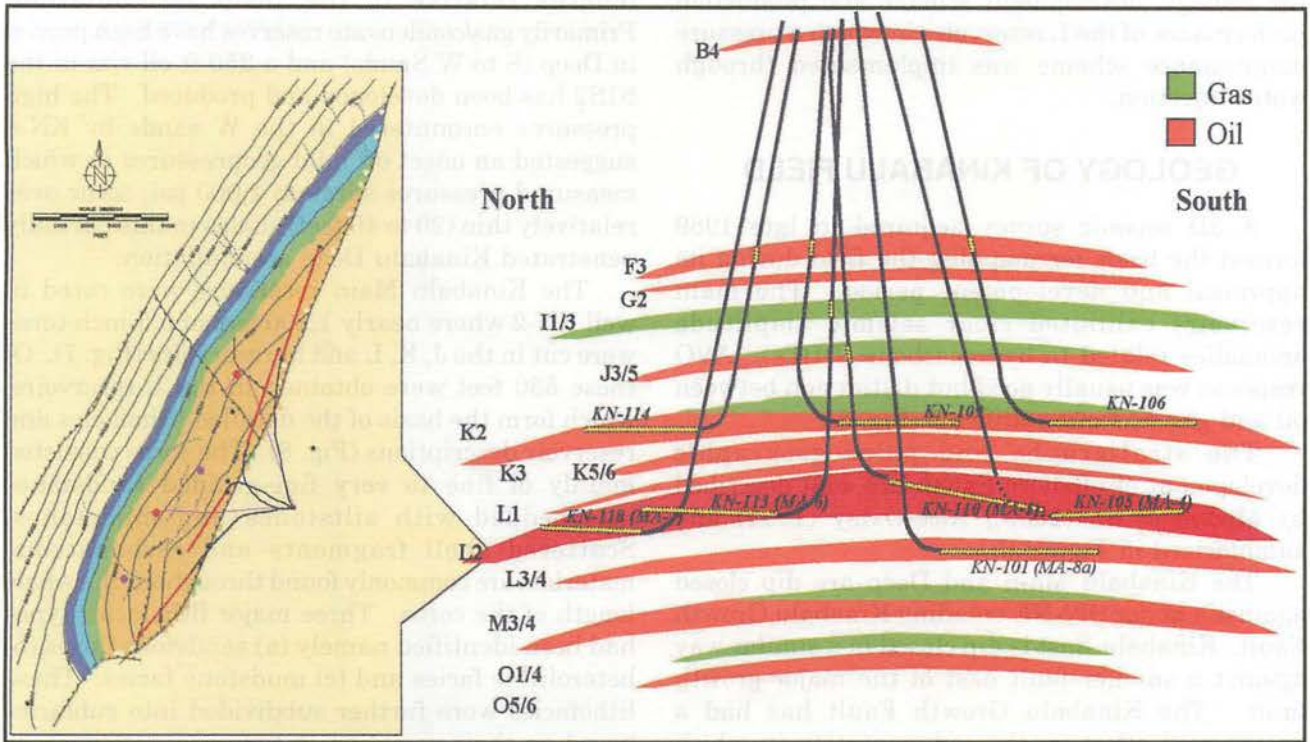


Figure 3. Schematic cross section of the Kinabalu Main with its first phase of development wells. Map of top L2 reservoir is shown on the left side.

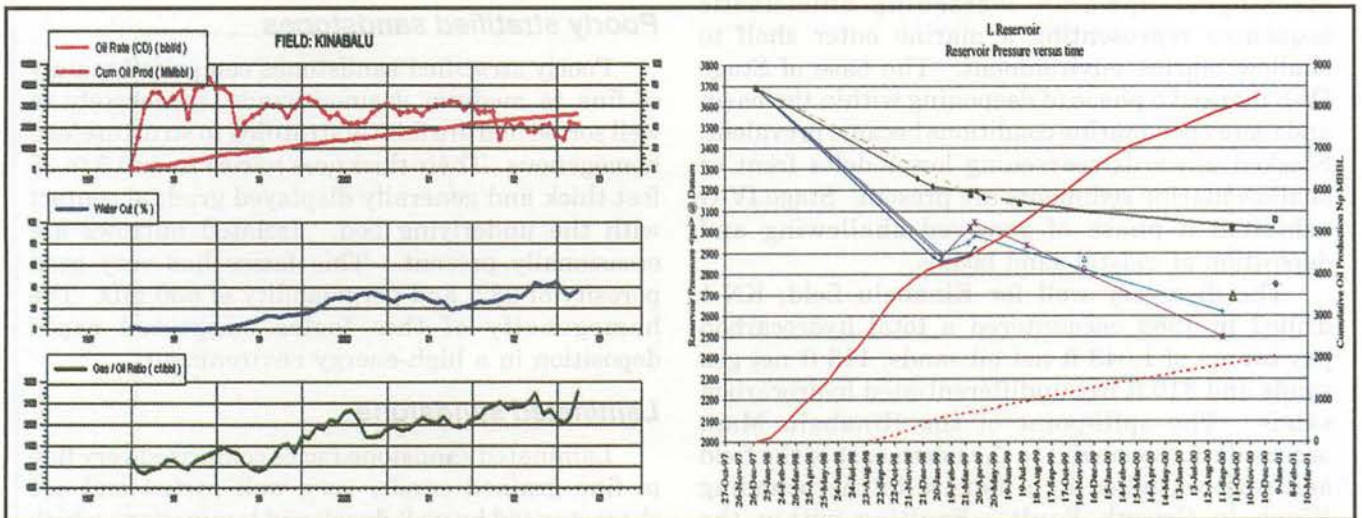


Figure 4. Plots on the left show production from Kinabalu field (oil in red, water in blue and gas-oil ratio in green). On the right shows pressure plots from L2 reservoir showing some 900 psi pressure drop after one year of production.

The following chapters describe in more detail the geology, development scheme and production performance of the L reservoirs in which a pressure maintenance scheme was implemented through water injection.

GEOLOGY OF KINABALU FIELD

A 3D seismic survey acquired in late 1989 formed the basis for mapping the field during its appraisal and development period. The main reservoirs exhibited clear seismic amplitude anomalies related to hydrocarbons (DHI's). AVO response was usually good but distinction between oil and gas was often difficult (Fig. 5).

The stratigraphy and palaeogeographic development of offshore Sabah are well described by Madon *et al.* (1999), Rice-Oxley (1991) and summarised in Figure 6.

The Kinabalu Main and Deep are dip closed against a major SW-NE trending Kinabalu Growth Fault. Kinabalu East is dip closed in a similar way against a smaller fault east of the major growth fault. The Kinabalu Growth Fault has had a pronounced effect on the sedimentation in which considerable expansion was seen over the Kinabalu Deep section which suggested the maximum movement along this fault was between 8.5 to 6.7 Ma before present. The main phase of growth occurred in the Upper Stage IV-D. The growth rate steadily declined during Stage IV-E and IV-F, and became negligible by upper Stage IV-F time. Overall, Stage IV-C, IV-D and IV-E in the Kinabalu area exhibited similar depositional sequences, characterised by the dominance and repeated stacking of upwards coarsening siliciclastic sequences representing a marine outer shelf to shallow marine environment. The base of Stage IV-F marked a phase of deepening within the basin and more open marine conditions became prevalent. Stacked upwards coarsening lower delta front or shallow marine sediments are present. Stage IV-G exhibited a phase of renewed shallowing and deposition of coastal sand bodies.

The discovery well for Kinabalu field, KN-1 drilled in 1989 encountered a total hydrocarbon pay counts of 1,043 ft net oil sands, 113 ft net gas sands and 310 ft net undifferentiated hydrocarbon sands. The spill-point of the Kinabalu Main accumulation occurred to the north east of the field and was controlled by a flexure in the bounding Kinabalu Growth Fault. Faulting within the Kinabalu Main block seemed limited to small, often sub-seismic, faults. The structural dip of the block was approximately 8 degrees towards the WNW, slightly less at the crest of the field.

The Kinabalu Main reservoirs are "normally"

pressured and have shorter hydrocarbon column lengths relative to the Deep accumulation. Primarily gas/condensate reserves have been proven in Deep (S to W Sands) and a 250 ft oil rim in the S1S2 has been developed and produced. The high pressures encountered in the W sands by KN-4 suggested an onset of mild geopressures in which measured pressures surge to 1,000 psi, occur over relatively thin (20 to 40 feet) shales in this partially penetrated Kinabalu Deep accumulation.

The Kinabalu Main reservoirs were cored in well KN-2 where nearly 1,200 feet of 5.5-inch cores were cut in the J, K, L and M reservoirs (Fig. 7). Of these 530 feet were obtained in the L reservoirs, which form the basis of the detailed lithofacies and reservoir descriptions (Fig. 8). The cores consisted mainly of fine to very fine-grained sandstones interbedded with siltstones and mudstones. Scattered shell fragments and carbonaceous materials are commonly found throughout the whole length of the cores. Three major lithofacies types had been identified namely (a) sandstone facies (b) heterolithic facies and (c) mudstone facies. These lithofacies were further subdivided into subfacies based on their variation in textures, sedimentary structures, degree of bioturbation and porosity/permeability properties. The main characteristics of these lithofacies are described below.

(a) Sandstone facies

The three sandstone subfacies were recognised namely:

- Poorly stratified sandstones
- Laminated sandstone
- Bioturbated sandstone

Poorly stratified sandstones

Poorly stratified sandstones comprised mainly of fine to medium grained sands, moderately to well sorted and are faintly stratified to structureless/homogenous. Their thickness varies from 0.5 to 35 feet thick and generally displayed gradual contact with the underlying bed. Isolated burrows are occasionally present. This facies has very good porosity of 23% and permeability of 630 mD. The homogeneity of this facies suggested rapid deposition in a high-energy environment.

Laminated sandstone

Laminated sandstone facies comprised very fine to fine grained sands, very well sorted and are characterised by well developed laminations which are both parallel to very low angle laminations. Their thickness varies from 0.5 to 26 feet thick and often display a fining upward trend usually with a distinct erosive base overlain by ripped-off mud clasts and the top of the bed are generally rippled

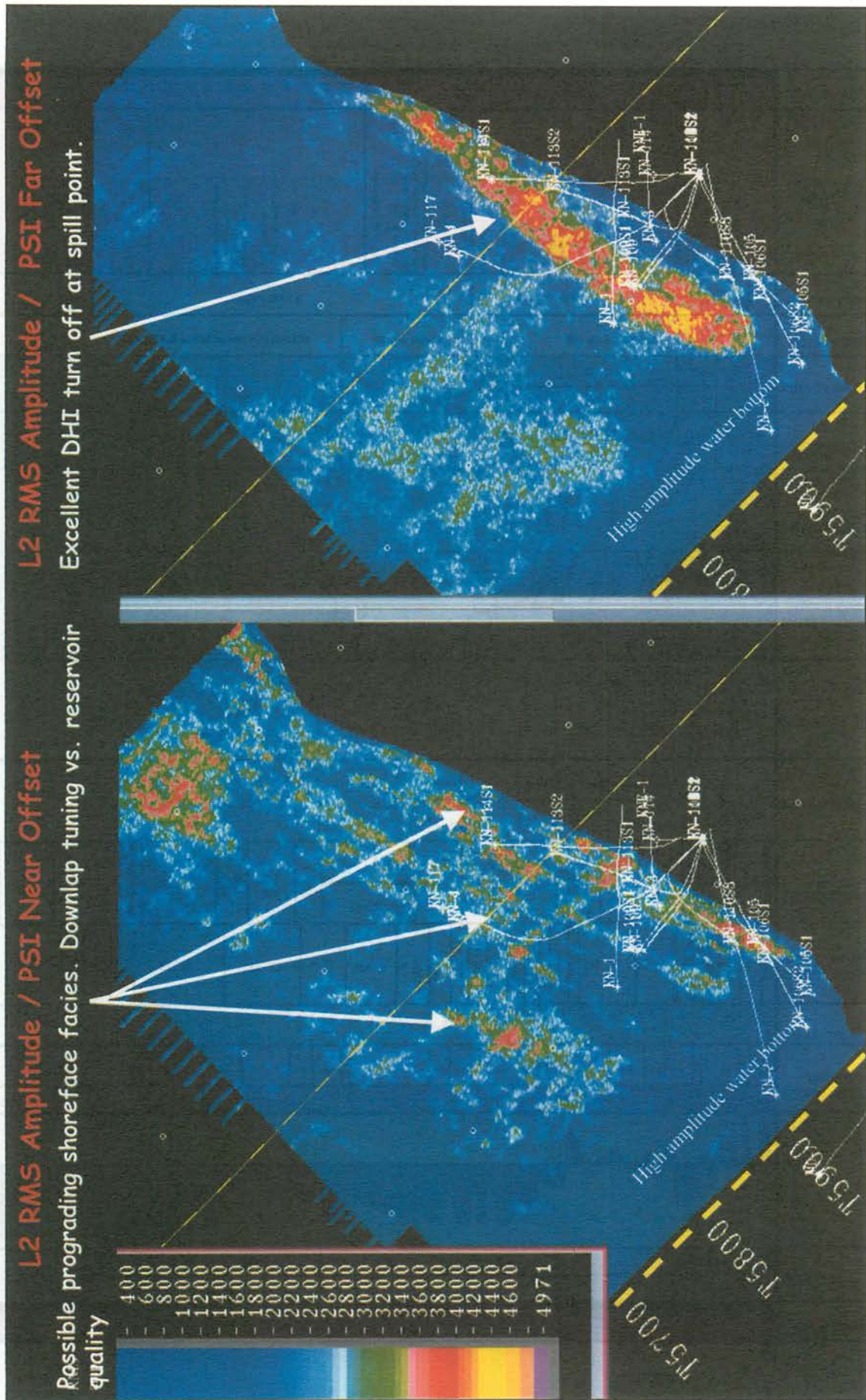


Figure 5. Kinabalu seismic showing lithology vs fluid effects on AVO processed 3D seismic.

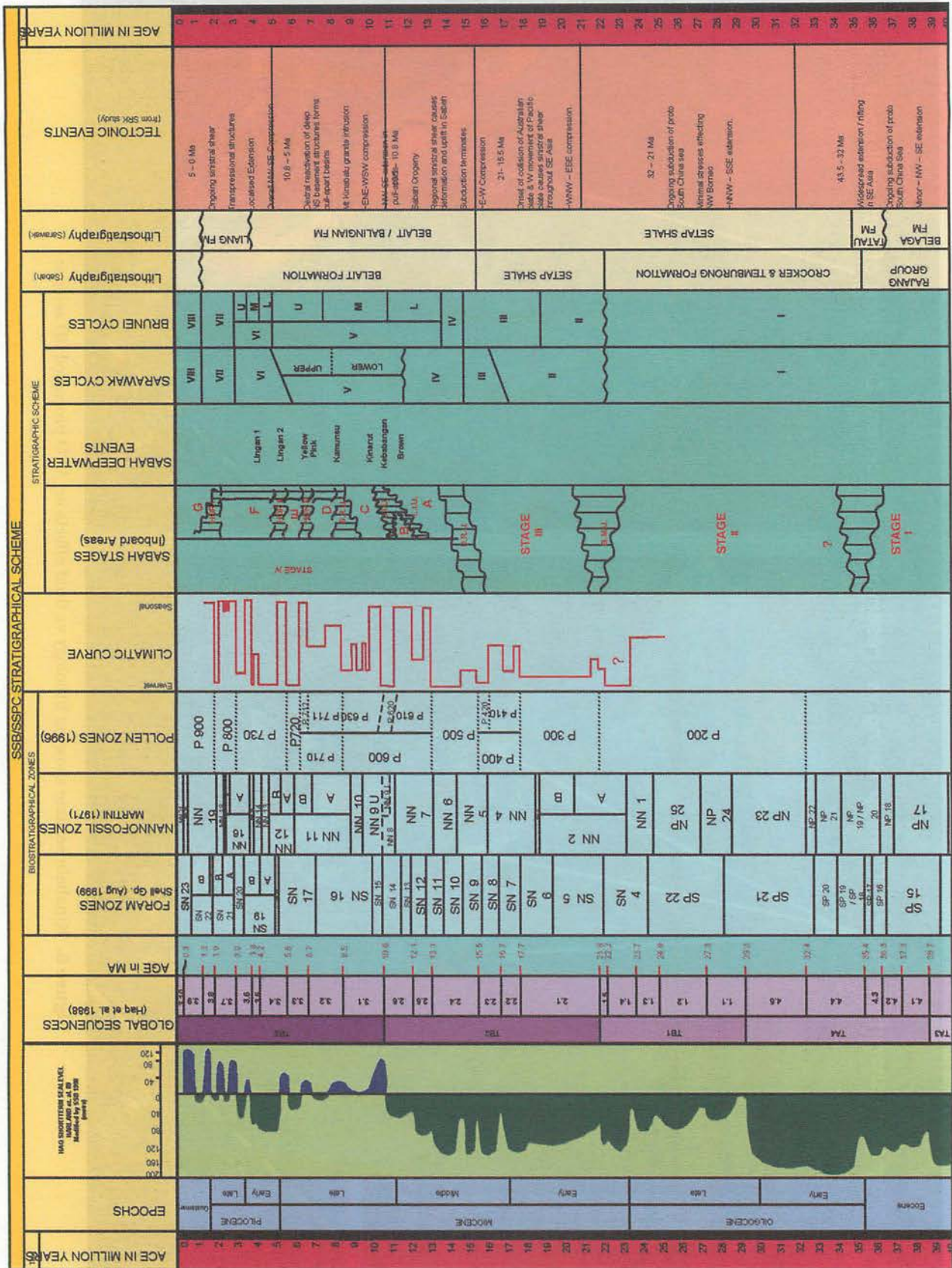


Figure 6. SSB/SSPC stratigraphical schemes (after Madon et al., 1999 and Rice-Oxley 1991).

and burrowed. This facies has good porosity of 21% and permeability of 126 mD. Erosive base of this facies reflected initial high energy conditions followed by a gradual waning of energy, which generally occur during storm events (Reineck and Singh, 1986).

Bioturbated sandstone

Bioturbated sandstone facies comprises fine to very fine grained sands, moderate to poor sorted and are highly burrowed. Their thickness varies from 0.5 to 50 ft and contains high amount of fines/clays. Thus this facies has poor porosity of 16% and permeability of 11 mD. This facies may have been deposited in a low energy environment in which the rate of burrowings exceeds rate of deposition.

(b) Heterolithic facies

Heterolithic facies comprises an alternation of sandstones and mudstones and can be further subdivided into:

- Sand-dominated heterolithics
- Mud-dominated heterolithics

Sand-dominated heterolithics

Sand-dominated heterolithics comprised interbedded very fine grained sandstones some 4 inches thick alternating with thin mudstones (< 1 inch thick). They are generally highly burrowed. The thin sands have poor porosity of 20% and permeability of 100 mD however, the high clay content in the burrowed sands reduced porosity to 12% and permeability to 2 mD. Thinly alternating beds and high degree of bioturbation, points to low depositional energy alternating with moderately high energy to transport the sands.

Mud-dominated heterolithics

Mud-dominated heterolithics comprised laminated mudstones interbedded with thin sandstones. They are generally highly burrowed thus have poor porosity of 10% and permeability of 1 mD. This facies was deposited in a low energy environment.

(c) Mudstone facies

Mudstone facies comprise laminated to massive mudstones, which are generally burrowed. They form baffles or seal barriers and were deposited in a very low energy environment.

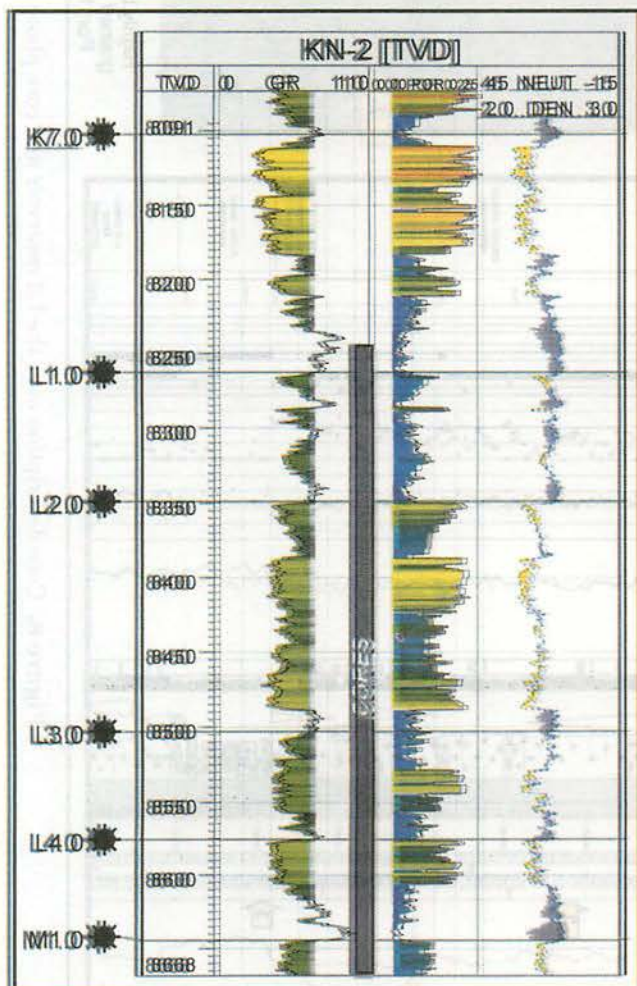


Figure 7. Type log of the L reservoirs showing the cored intervals.

DEPOSITIONAL SETTING

Based on facies analysis, stacking patterns and faunal content/palaeontology, four main genetic sequences can be identified namely (1) shoal complexes, (2) intershoal sands, (3) distal/low energy shelf sediments and (4) shelf/transgressive muds, all deposited in a shallow marine environment (Fig. 9). The overall high net to gross of the L reservoirs point to a high sand supply probably sourced from a deltaic system nearby. The occurrences of sand shoals probably indicated that most of these deltaic sediments were reworked and redeposited by storm processes and longshore currents into elongated sand bars (Johnson and Baldwin, 1986). The orientation and areal distribution of the shoal complexes can be inferred from the near offset amplitude maps as shown in Figure 5. This depositional model fits well with the palaeogeographic reconstruction of the Lower Miocene to Pliocene sediments of offshore west Sabah (Rice-Oxley, 1991).

Shoal complexes

Shoal complexes are normally stacked and attain up to 55 ft thick and individual bodies are generally 10 ft to 30 ft thick. They can be laterally extensive as seen from wells correlation (Fig. 10). The shoals are characterized by coarsening upward

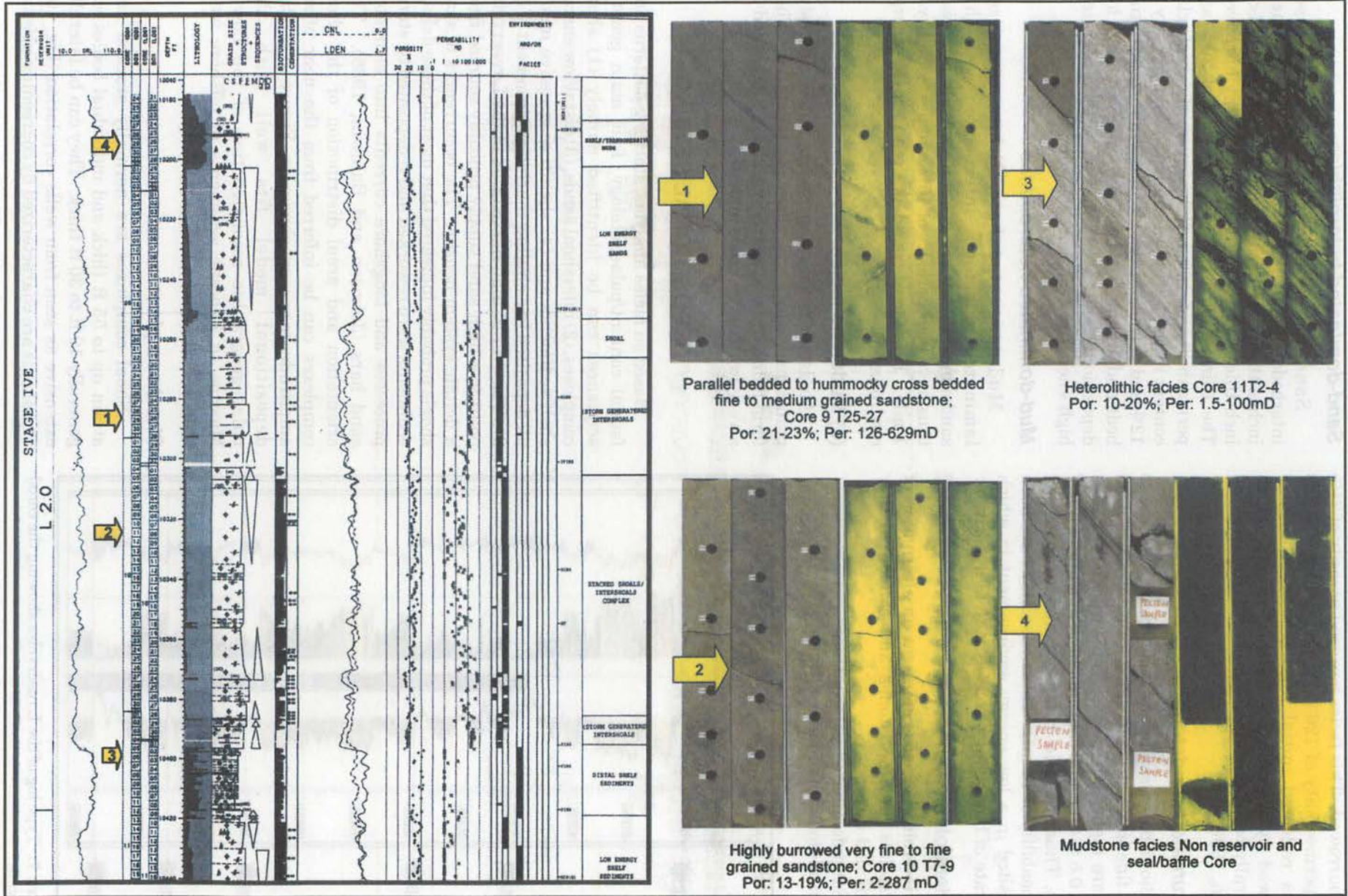


Figure 8. Core description over the L2 reservoir and core photo (colour and UV) of the different facies.

pattern and together with the gradual decrease in fines content towards the top of the complexes, a marked improvement of the reservoir quality is observed (average porosity 20%, permeability 300 mD).

Intershoal sands

Intershoal sands comprise minor fining upwards sequences of up to 5 ft thick and are interbedded with thin shales and burrowed heterolithics. They were interpreted to be deposited during storms and or tidal processes (Johnson and Baldwin, 1986) and have average porosity of 22% and permeability of 480 mD.

Distal shelf/low energy shelf sediments

Distal shelf/low energy shelf sediments comprise predominantly of heterolithic facies and bioturbated fining upward sands generally a foot thick. The total thickness varies from 10 ft to 50 ft and displays poor reservoir quality (average porosity 10%, permeability 13 mD).

The Shelf/Transgressive muds

The Shelf/Transgressive muds form distinct

intervals of 10 ft to 50 ft thick and comprise mainly massive bioturbated mudstones. They form the main sealing shales that separate the major reservoir packages. The shales represent periods of widespread mud deposition either due to increasing water depth or switching of source for sand supply. In the Kinabalu field they may be related to the sudden increase in relative subsidence rates along the Kinabalu Growth Fault.

Static geological models were made based on the above premise, including other well data and were later simulated for production forecasting in order to get the optimal development option for the field.

FIELD DEVELOPMENT AND PRODUCTION PERFORMANCE

The updated Kinabalu field development plan (FDP) of 1995 comprises an integrated 20 slot drilling and production facility (KNDP-A) which was installed in 1997 and has the capability of being remotely operated and started up from Labuan Crude Oil Terminal (LCOT). A 12-inch oil pipeline and a 14-inch gas pipeline are linked from

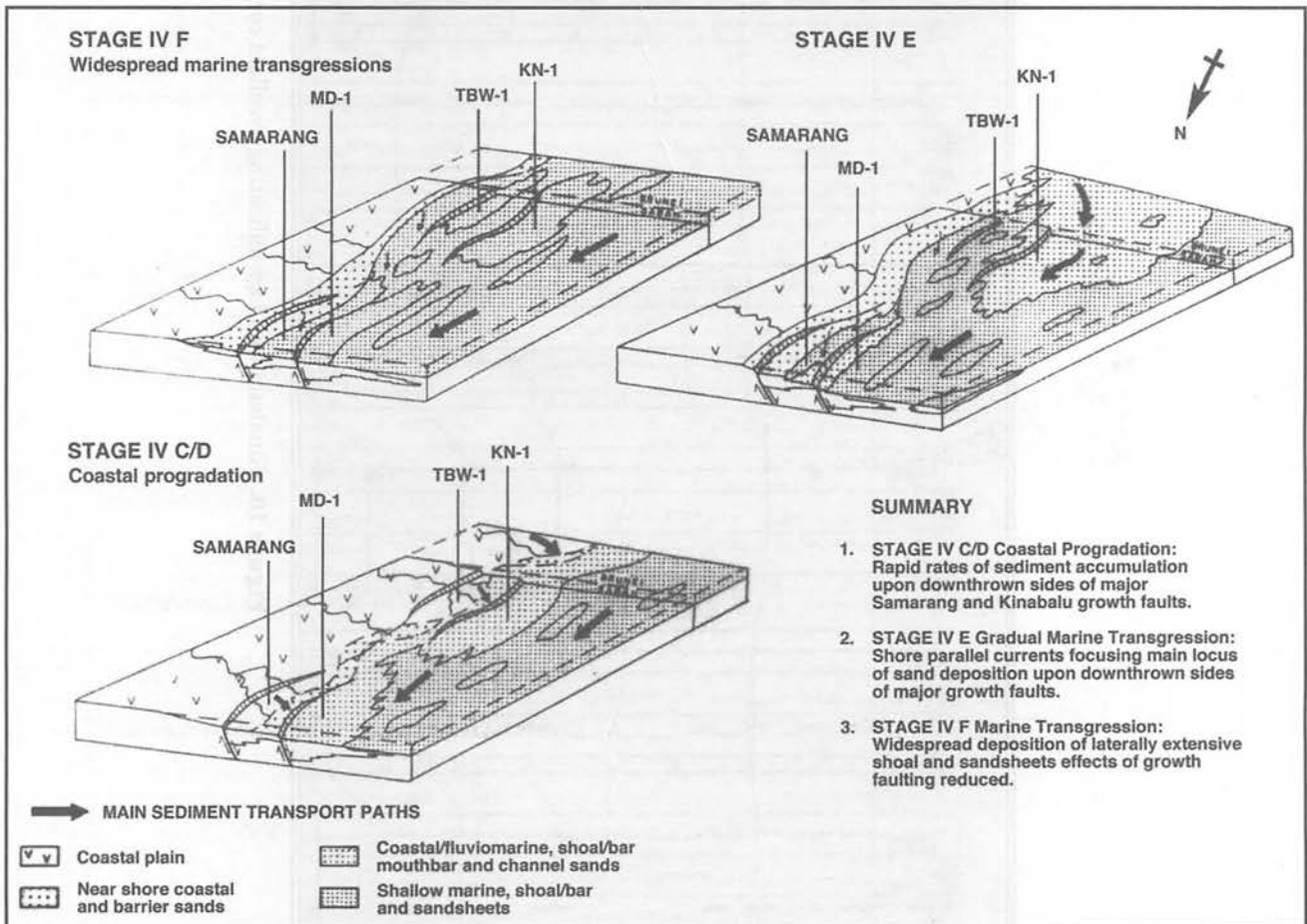


Figure 9. Depositional model of the Kinabalu field based on core and well log data.

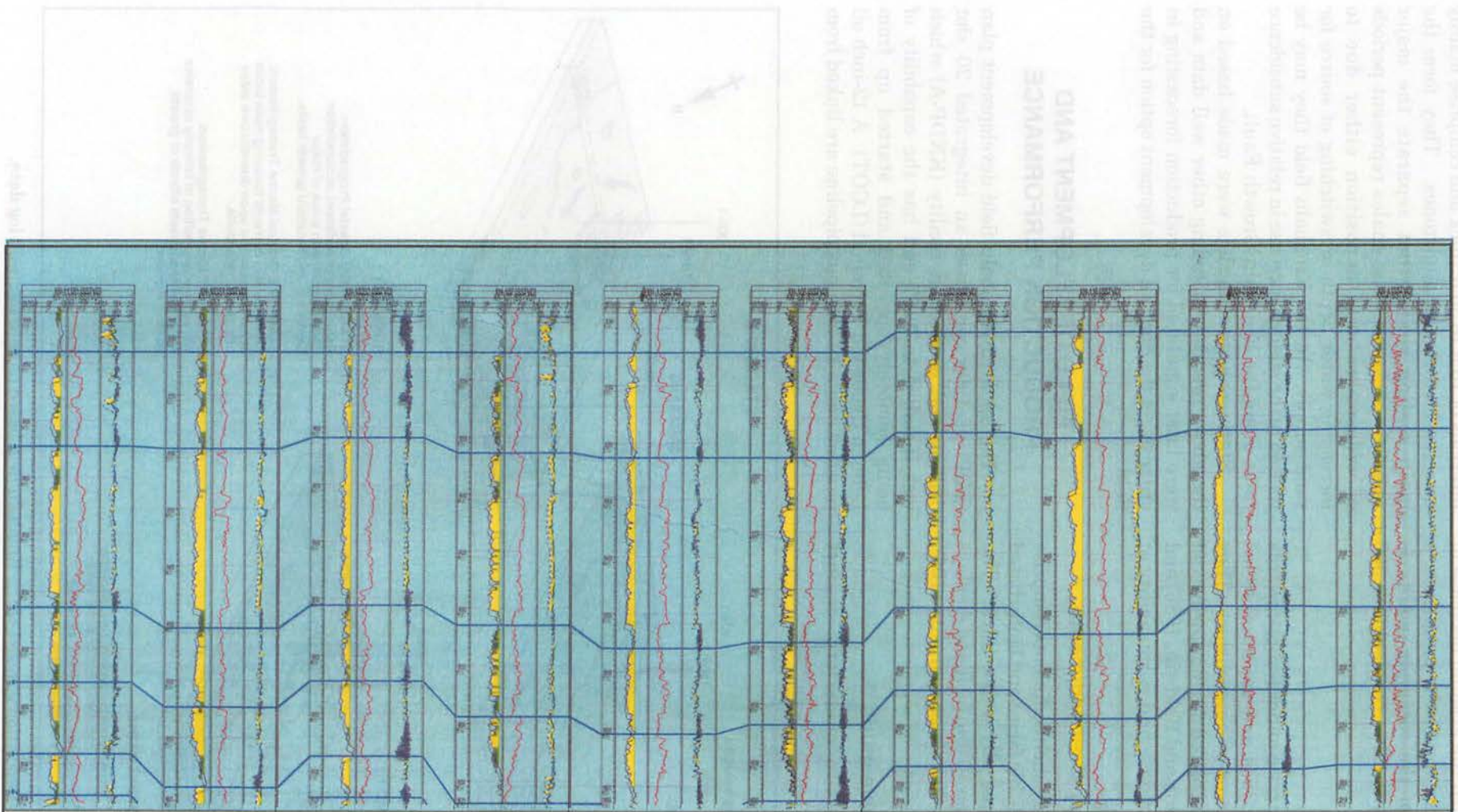


Figure 10. Kinabalu well logs indicating excellent correlation between wells drilled in the field.

KNDP-A to the Samarang facilities where the hydrocarbons are further processed and stabilised prior to transporting to LCOT for storage and export (see Fig. 1).

The initial oil development of the Kinabalu Main accumulation was by drilling three horizontal wells in the K reservoirs and 5 horizontal wells in the L reservoirs, which together contained up to 50% of the field's oil in place. Secondary development objectives in these eight wells were in the F and J sands. The first oil from this development came on stream in December 1997.

The first production from the L reservoir was in January 1998 and production was gradually increased as more wells were brought online. All wells in the L reservoir were on stream by July 1998 and production was increased from 15,000 bpd to a peak monthly average rate of 21,500 bpd in November 1998. During the first seven months of production, the gas-oil ratio (GOR) had risen from 650 to 1,000 scf/stb and continued to rise to 1,250 scf/stb in November 1998. This GOR trend was not consistent with that forecasted in the 1995 FDP and indicated that the L reservoir had a weak to no aquifer drive. Pressure surveys carried out in early 1999 and material balance work confirmed the absence of strong pressures in these reservoirs.

A remedial campaign was executed at the Kinabalu field in the second half of 1999 where two highly deviated wells were successfully drilled aimed at penetrating as many major oil-bearing reservoirs as possible such that they can be completed and accessed at any time through zone changes for flexible reservoir management. Subsequently the second round of development comprising drilling six highly deviated wells were executed during 2000–2001, following the successful development concepts applied in the remedial wells so as to sustain oil production from the Kinabalu field.

SELECTION OF OPTIONS FOR PRESSURE MAINTENANCE

Recognising that any pressure maintenance scheme would have to be implemented quickly to be economically attractive it was clear that an innovative solution would be needed. Studies were initiated to determine if the shallow C and B aquifer Sands could deliver and sustain sufficient volumes of water for voidage replacement in the deeper L2 reservoirs. Other options included dumping of raw filtered seawater and de-oxygenated/treated seawater were also investigated for Kinabalu pressure maintenance schemes. Gas injection was carried out in the K2 reservoir because it has a big gas cap and availability of existing wells (KN-105S,

–113S) for gas injection into these reservoirs. The studies indicated that gas injection in the L reservoir was less favourable than water injection. This was principally due to the absence of gas cap and active aquifer in the L reservoir. Other reasons for not implementing gas injection in the L reservoirs are the sub optimal location of development wells which were placed near crestal positions, shallow dip of the reservoirs which are vertically stratified and potentially early gas breakthrough which would result in gas recycling and the requirement for an additional offshore structure to accommodate the large compressors for gas injection. Gas injection is not discussed in this paper.

The B and C aquifers are thick, shallow marine alternations of sandstones and shales, with high porosity and net-to-gross reservoirs (Fig. 11). Average gross thickness, based on available well data for the B and C Sands are 1,377 ft and 667 ft with corresponding net thickness of 1,196 ft and 429 ft respectively. Porosity ranges between 28% and 33% (average 30%) within the B Sands and between 26% and 32% (average 28 %) within the C sands. Estimates of the aquifer volume (water-in-place) of the C Sands were 69 billion barrels and that of B Sands were 213 billion barrels.

These sands have water salinity of some 17,000 ppm NaCl equivalent which is just slightly more concentrated than the L2 reservoir water (13,000 ppm NaCl equivalent) thus, makes it compatible for the water injection scheme.

The regional 2D and 3D seismic data were reviewed to determine the expected lateral extent, continuity and/or potential location of the B and C aquifer flow barriers, present in the greater Kinabalu/Samarang flank area. All intervals, apart from the B2-B3 interval, are characterized by very mildly varying AMPLEX values, suggesting that lateral variations in sand properties are overall very subtle in the Kinabalu-Samarang flank (see Fig. 11). The B2-B3 interval contains a feature, which appears to be a slump-like erosional surface or slump scars (Levell and Kasumajaya, 1985), broadening down-flank and with sharply defined canyon walls (Fig. 12).

A Jason Inversion study identified some very shallow events in the Samarang region that are highly reflective and cause considerable dimming within the B to C intervals. When suitable corrections are applied to balance the dimming by the shallow reflectors, the extracted RMS amplitudes over the various B and C intervals show even less lateral variation than prior to the correction, indicating that the aquifer reservoirs are even more continuous than indicated by the extracted RMS amplitudes as shown in Figure 11. No faulting could be identified on the Samarang

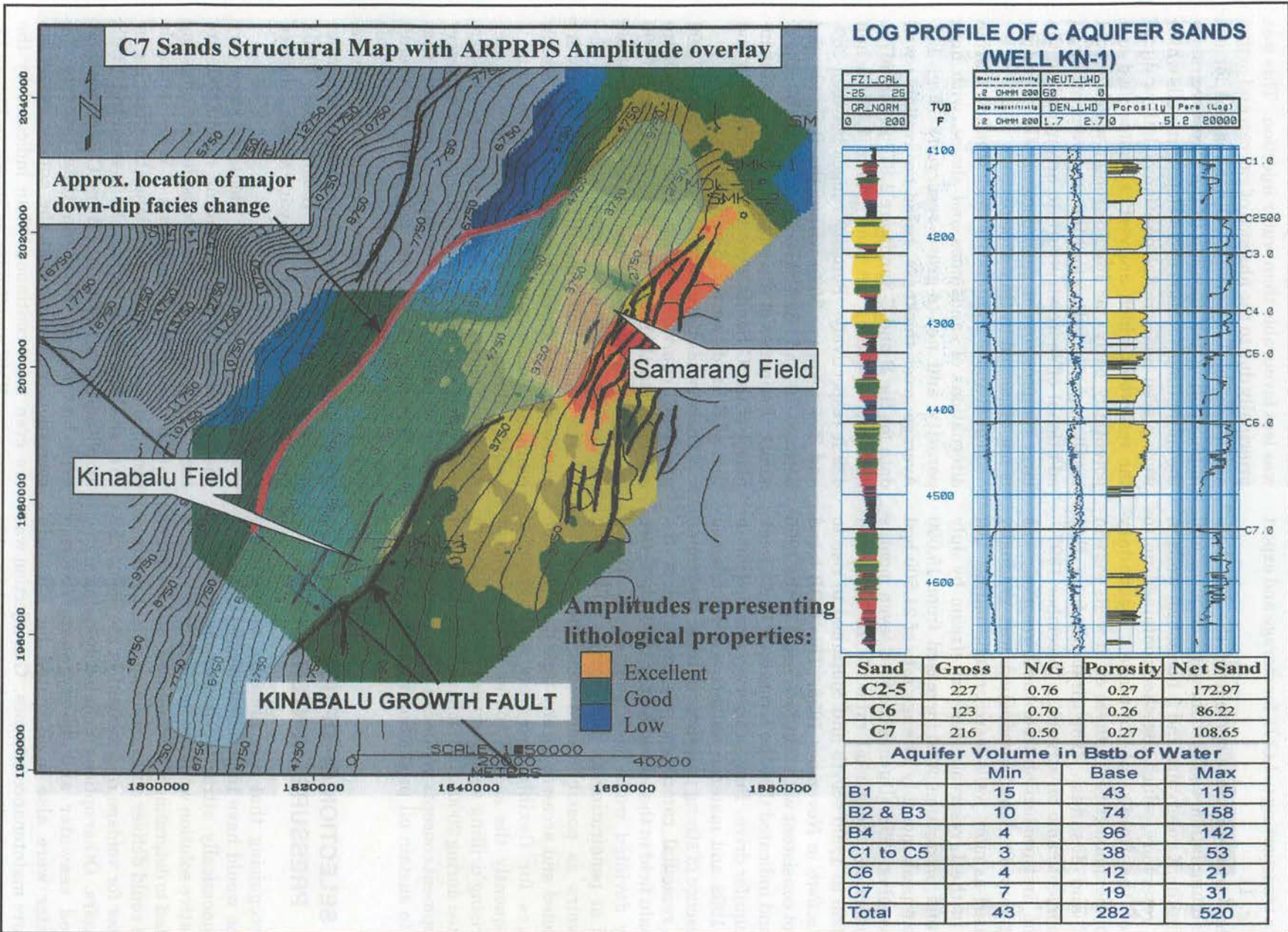


Figure 11. Excellent lateral continuity of C Sands and only terminated by seismostratigraphic changes downdip indicative of facies changes/slump scars. Productibility: 100 b/d/psi.

flank, beyond the heavily faulted structural crest. Several mainly antithetic faults are well expressed in the Kinabalu flank, parallel to the Kinabalu Growth Fault. In some locations, evidence of fault sealing is confirmed on seismic by amplitude brightening.

The deliverability of the C Sands aquifer were analysed and simulated in order to ascertain whether they can sustain water production for dump-flooding. Sufficient water production rates with expected PI's range between 160–377 bbl/d/psi can be achieved to ensure voidage replacement in the L2 reservoirs. This would require injection rates approximately 20,000 bbl/d into the L2 reservoirs.

The B Sands are significantly thicker than the C Sands and hence productivity and sustainability are expected to be better than the C Sands, as the B4 Sand contains hydrocarbons which will be developed at a later stage of the field development cycle. The B Sands (aquifer) will not be utilised until the oil is recovered. Reserving the B aquifer for future use ensures that a contingency supply is

maintained which could also be used for other future pressure maintenance schemes.

IMPLEMENTATION OF WATER INJECTION SCHEME AND RESULTS

A water injection scheme selected for Kinabalu field comprised injecting water sourced from the shallow C aquifers and using an inverted electric submersible pump (ESP) to assist injection at a rate of some 20,000 bpd for full voidage replacement (Fig. 13). The proposed scheme is to be executed in two phases. Phase I includes the drilling of a horizontal water injector/dump-flood well in 1999 in the southern part of the field supporting both the Round 1 wells and the recently drilled Round 2 wells. Phase II includes drilling a second horizontal water injector/dump-flood well in the northern part of the field in 2001. Installation of ESP and their ancillaries in the injection wells have been much delayed due to the various activities happening at the platform and currently plan to start in late 2003.

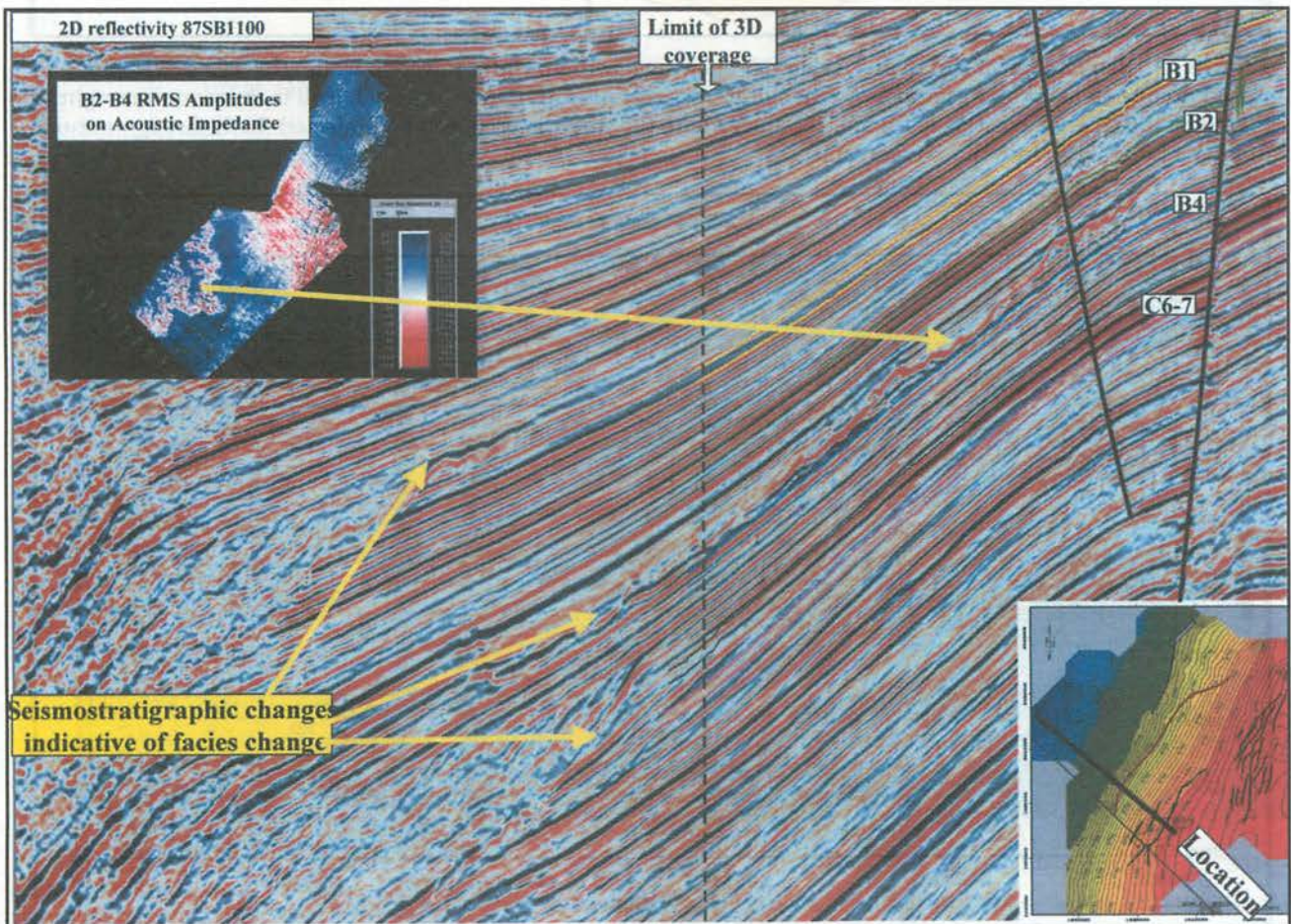


Figure 12. Seismic section over the shallow aquifer showing excellent lateral continuity of C Sands and only terminated by seismostratigraphic changes indicative of facies changes/slump scars.

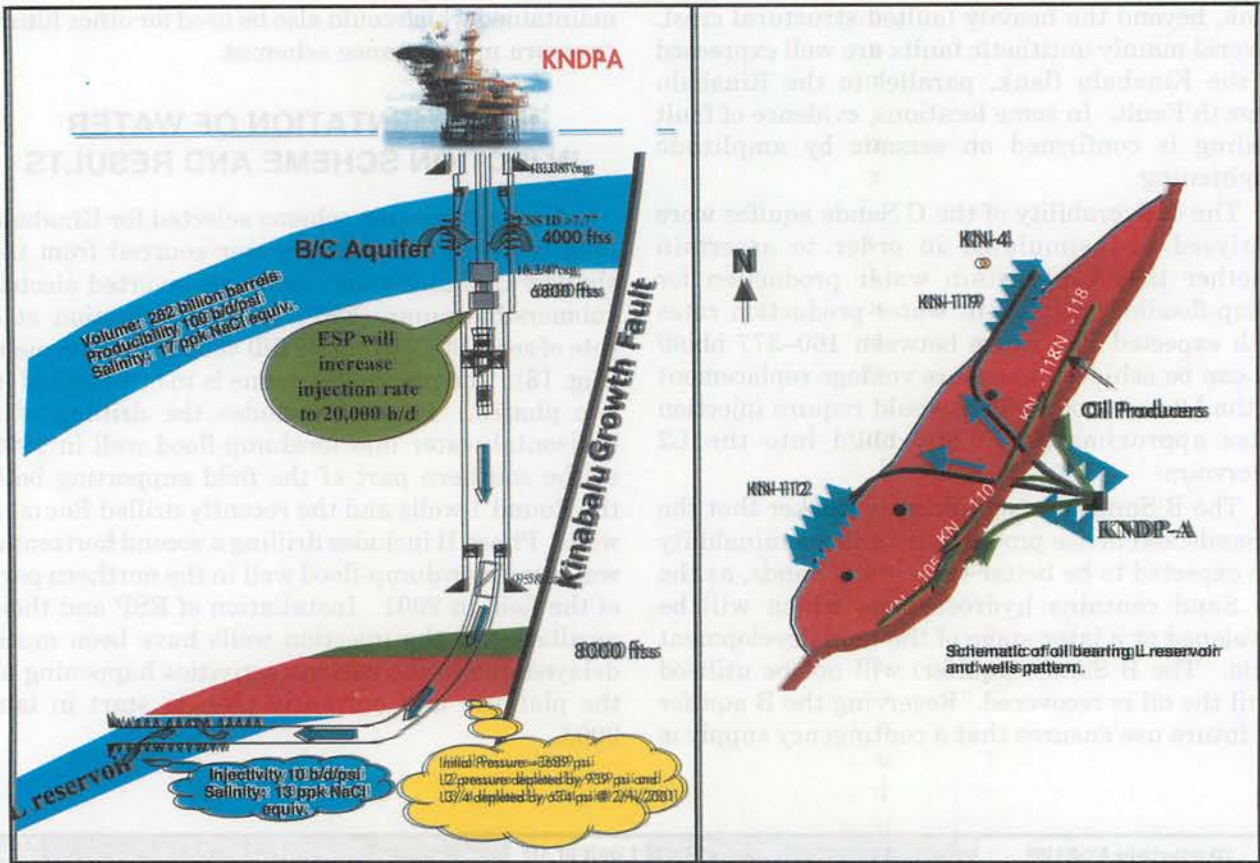


Figure 13. Sketch map of Kinabalu L reservoir showing down-dip water injection wells (KN-112 & KN-119) and the oil producers at crestal position. A schematic cross section of the water injection well is shown on the right to illustrate the relative positions of B and C Sands where the water is produced and injected (both through natural dumping by gravity) into the L reservoirs.

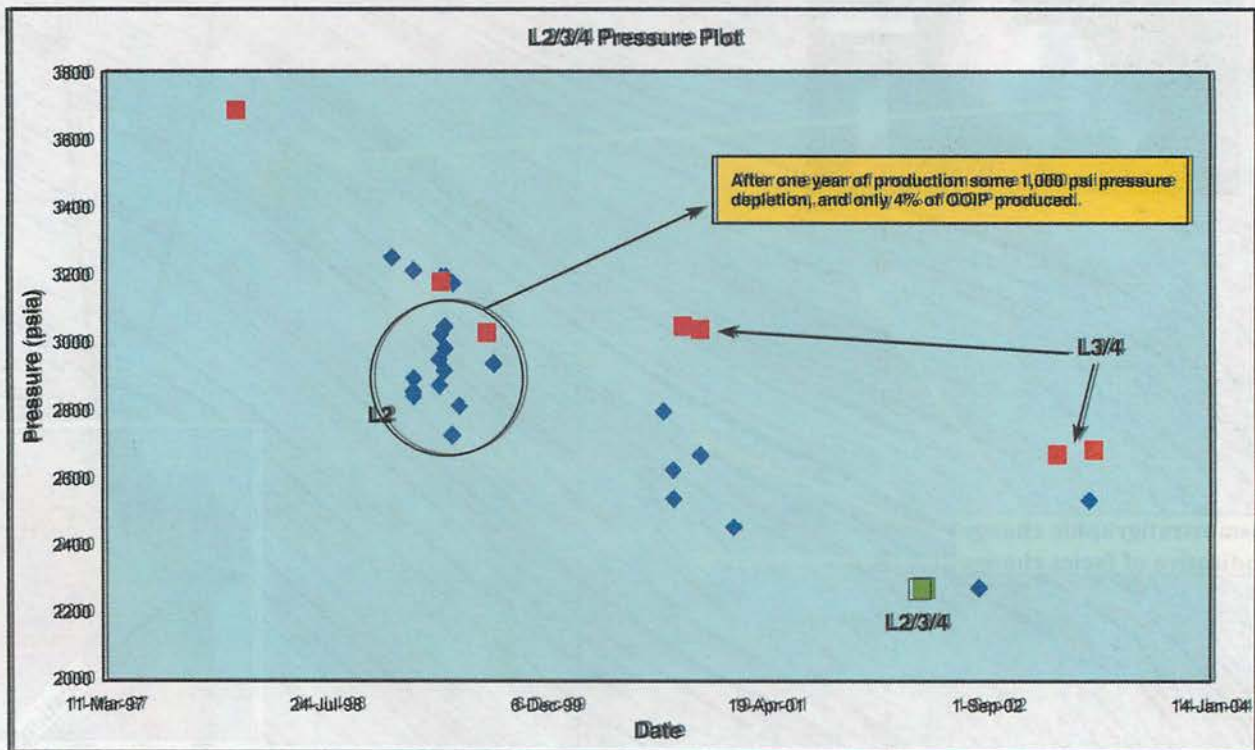


Figure 14. Pressure plots in the L reservoirs showing their early faster than expected depletion and some stabilisation of pressures in the later years after water injection/natural dumping.

The simulation study indicated that the required volumes of water could be injected with a horizontal well with higher injection pressures than that required in multilateral wells. These injection pressures were below the estimated fracture pressure of 6,118 psi. The oil reserves associated with Phase I range between 15–24 MMstb depending upon the injection rate achieved. Implementation of Phase II would further increase reserves by 4 million to 13 million barrels. It is expected that this water injection scheme at Kinabalu would improve oil recovery factor in the L reservoirs from 21% to 35%.

Production logging made in one of the injector wells (KN-112) during late 2001 indicated that natural dumping by gravitation from the C Sands into the L2 reservoirs occurred at a rate of some 1,200 barrels per day. Chemical tracers were added to the injected water in August 2002 and to date no trace of this chemical were detected in the produced water from nearby wells, thus suggesting a consistent waterfront from this dump flooding scheme. Pressure surveys taken in the later (2002) wells drilled in the field and the static surveys taken over the L reservoirs indicated some stabilization of reservoir pressures despite continuous production (Fig. 14). It could be concluded that natural water dumping by gravity in the two water-injection wells has been successful in arresting a fast pressure decline in the L2 reservoirs. The application of this pressure maintenance scheme would be reviewed further for other Kinabalu reservoirs especially in improving oil recovery factors from this field and also in sustaining longer-term oil production.

It should be noted that during appraisal drilling of Kinabalu Deep reservoirs by well KN-4 in 2002, the well penetrated the water-bearing L2 reservoirs. After acquiring all the required data and production testing of the Kinabalu Deep reservoirs, the well was subsequently abandoned at the lower parts and the upper parts however allowing connectivity between L2 and C Sands along the middle part of the well configuration. This would allow natural water dump-flooding from the C Sands into the L reservoirs near the northern part of Kinabalu field (see Fig. 10).

CONCLUSIONS

The development concept initially applied in the Kinabalu field was drilling eight horizontal wells in the major K and L reservoirs, which were placed near to the crest of the structures. This initial development concept was based on the

assumption that these reservoirs were laterally extensive over the Kinabalu area as seen from well correlation and seismic data and that there was moderate to strong aquifer support in these reservoirs. Subsequent poorer than expected production performance from these wells prompted remedial actions to be taken in order to sustain oil production. Various pressure maintenance schemes were investigated including gas injection and various water injection schemes. The availability of huge and shallow B and C Sands aquifer and the relatively small gas cap made water injection into L2 reservoir a very attractive option. Good water injectivity (1,200 barrels water per day) had been tested in the L2 reservoir especially by gravity drainage and additional injection rate of up to 2,000 barrels per day will be done with the used of an inverted electric submersible pump installed in the water injection wells. This pressure maintenance scheme will add some 16 million barrels oil to be developed, thus increasing the recovery factors of L reservoirs in the Kinabalu field from 17% to 43%.

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