

Structural and stratigraphic configuration of the late Miocene Stage IVC reservoirs in the St. Joseph field, offshore Sabah, NW Borneo

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Abstract : The St. Joseph field is a large, structurally and stratigraphically complex oil field situated offshore West Sabah. The paper describes the main geological characteristics of the field, highlighting the benefit of 3D seismic and core/well log data in developing a comprehensive three-dimensional geological model, which is being used to guide field development.

Structurally the field is situated along a major Lower Pliocene wrench fault zone (Bunbury-St. Joseph ridge) and comprises three distinctive areas :

- (1) NW Flank is a structurally simple area, dipping uniformly (at ca. 20°) to the NW, which contains the majority of recoverable oil reserves (ca. 95%).
- (2) Crestal Area is a structurally complex zone characterised by intense faulting, steeply dipping beds and incomplete stratigraphic sequences. Minor oil reserves are present which were discovered by the first exploration well (SJ-1) in 1975.
- (3) SE Flank is an area of moderate structural complexity with negligible oil reserves.

3D seismic data has significantly increased the quality of the structural definition of the field as a result of : (1) ability to map individual intra-Stage IVC reservoir intervals, (2) better fault definition, particularly in the structurally complex areas, and (3) identification of stratigraphic features, such as slump scars. Practical benefits include improved definition of the boundary between the NW Flank and Crestal Area, better delineation of the NE extent of the field (by faulting/slump scars) and improved location of development wells and drilling jackets.

Stratigraphically the main NW Flank reservoir (Upper Sand Unit) comprises a complex sequence of shallow marine sandstones and shales (late Miocene, Stage IVC), which display marked lateral variations in sand development, reservoir quality and shale layer thickness/continuity. Sedimentological studies of ca. 1600 ft of core (including 800 ft of continuous core from well SJ-7) and palaeontological data indicate deposition in a storm/wave-influenced shallow marine (neritic) environment. The main reservoir units comprise several stacked coarsening/fining upward sequences reflecting repeated progradation and transgression of coastal/delta front sand bodies. This subdivides the Upper Sand Unit into thirteen distinctive sub-units, which can be correlated field-wide.

Log calibration of the four main facies types and correlation of the genetic sequences have enabled construction of a three-dimensional reservoir geological model of the Upper Sand Unit. This thick (700 - 900 ft / 27 - 43 m), heterogeneous sequence is effectively a single, connected reservoir but with predictable lateral variations in sand and shale distribution:

- (1) reservoir sands are best developed in updip areas and in the southern part of the NW Flank.
- (2) reservoir quality deteriorates downdip (to NW) and alongstrike (to NE) in response to an increasingly more distal depositional setting.
- (3) shale layer frequency and continuity is also higher in these distal areas compared to the more proximal areas (to SE and SW).
- (4) shale layers are mainly discontinuous (except the field-wide E1.1 shale); RFT pressures indicate that in the NE they form pressure baffles whereas in the SW the reservoirs are fully connected.

The structural and stratigraphic interpretations presented herein provide a comprehensive three dimensional model of the St. Joseph field. The results have been incorporated into a full-field simulation model to optimize the field's ongoing development planning and reservoir management.

INTRODUCTION

The St. Joseph field is the second largest oil field offshore Sabah (after Samarang, Scherer, 1980). The field is located 35 km offshore in some 90 - 140 ft (27 - 43 m) of water, mainly in Sub-block 7U-13, but extending into Sub-block 7U-14 (Fig. 1). The field was discovered in 1975, by the exploration well SJ-1, and since then a total of eight appraisal wells (and two sidetracks) have been drilled on, and around, the field. This has led to the field's current active development with twenty-one production wells (and four sidetracks) having been drilled from four jackets (SJJT-A, -F, -H and -G). Two additional jackets (-B and -C) are planned for the near future, which will further optimize development of the field, possibly including pressure maintenance to enhance oil recovery.

The aim of this paper is to outline the geological characteristics of what is both structurally and stratigraphically a complex field. To resolve these geological uncertainties the field's structural configuration has been interpreted using 3D seismic data (acquired in 1985) and a comprehensive reservoir geological model was developed initially from some 1600 ft (488 m) of core (including 800 ft / 244 m of continuous core in appraisal well SJ-7), which could be calibrated with the other non-cored appraisal/development wells. Together, the 3D seismic and reservoir geological studies have resulted in a comprehensive structural/stratigraphic model of the field which provides the basis for more accurately predicting oil reserves and for selecting the most optimum development strategy. The reservoir geological model was also incorporated into reservoir simulation studies, which evaluated three different recovery processes : natural depletion, water injection and gas injection.

This paper describes how the geological model of the St. Joseph field has evolved, and illustrates how this greater insight of the field's geological characteristics is being used to enhance the field's development.

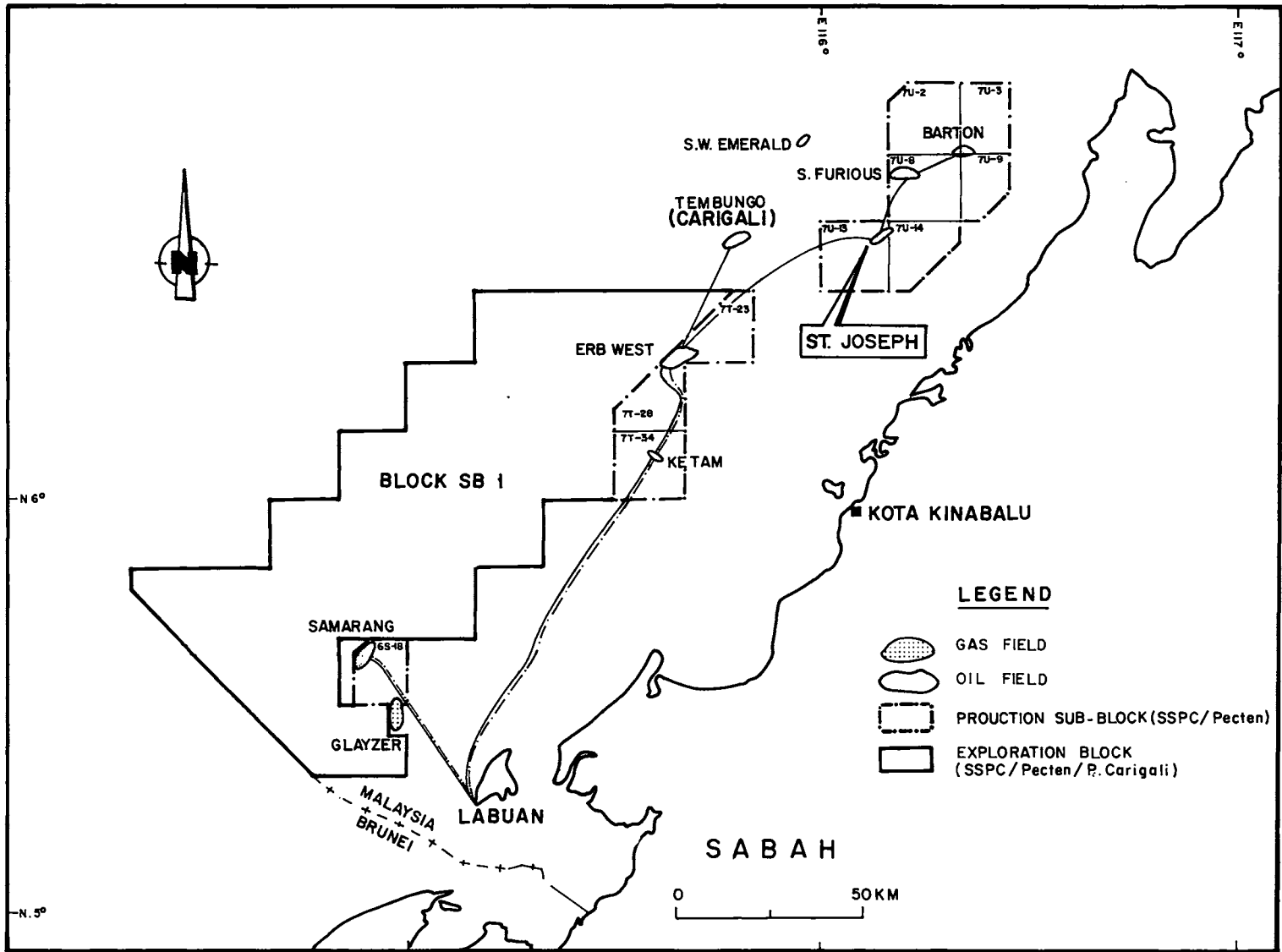


Figure 1 : Location map of St. Joseph.

GEOLOGICAL SETTING

Structural setting

The St. Joseph field is situated in the North Sabah geological province which comprises mainly Miocene/Pliocene sediments deposited in a tectonically - active basin and subsequently deformed, in places intensely (e.g. South Furious), by Lower Pliocene wrench-related compression (Bol and van Hoorn, 1980).

The St. Joseph structure itself forms part of a prominent structural trend offshore of Northwest Borneo which is orientated in a general southwest-northeast direction (Fig. 2). The field is situated along the Bunbury-St. Joseph-Bambazon Trend, which comprises a series of steep-sided anticlinal features thought to be related to deep-seated transcurrent basement faulting. These wrench faults have been interpreted as having a left-lateral movement with the anticlinal structures observed in the overburden formed in response to diapiric movement of underlying undercompacted shales resulting from the transpressive forces associated with the wrench movements (Bol and van Hoorn, 1980). As is typical of the structural style in N. Sabah, the steep-sided anticline (or 'ridge') is flanked by two broad synclines (Figs. 2 and 3): (1) the Bunbury syncline to the SE, and (2) the Pritchard syncline to the NW, which provided the source of the hydrocarbons in St. Joseph.

The structural interpretation of the field, as is currently understood, is drawn largely from the 1985 3D seismic survey, supported by well data, and is reviewed in more detail later. In general terms, however, the field is a broadly anticlinal feature, which comprises three structurally - contrasting areas (Figs. 4 and 5):

The Northwest Flank is a relatively undisturbed area dipping at around 20° towards the northwest. This flank contains the majority of recoverable hydrocarbons (ca. 95%) and is, therefore, the principal development area and the main subject of this paper.

The Crestal Area is a zone of considerable faulting some 1500 - 2000 ft (457 - 610 m) in width. This area is also hydrocarbon-bearing but is characterized by a complex series of normal and reverse faults, by steep structural dips and by incomplete stratigraphies.

The Southeast Flank is predominantly southeast-dipping at 10-30°. It contains numerous northeast-southwest striking normal and reverse faults, is more complex than the Northwest Flank and contains negligible hydrocarbons.

Stratigraphic setting

The St. Joseph reservoirs occur within a thick succession (up to 2.5 - 3 miles / 4 - 5 km) of mainly Middle to Late Miocene and Pliocene clastic sediments, which

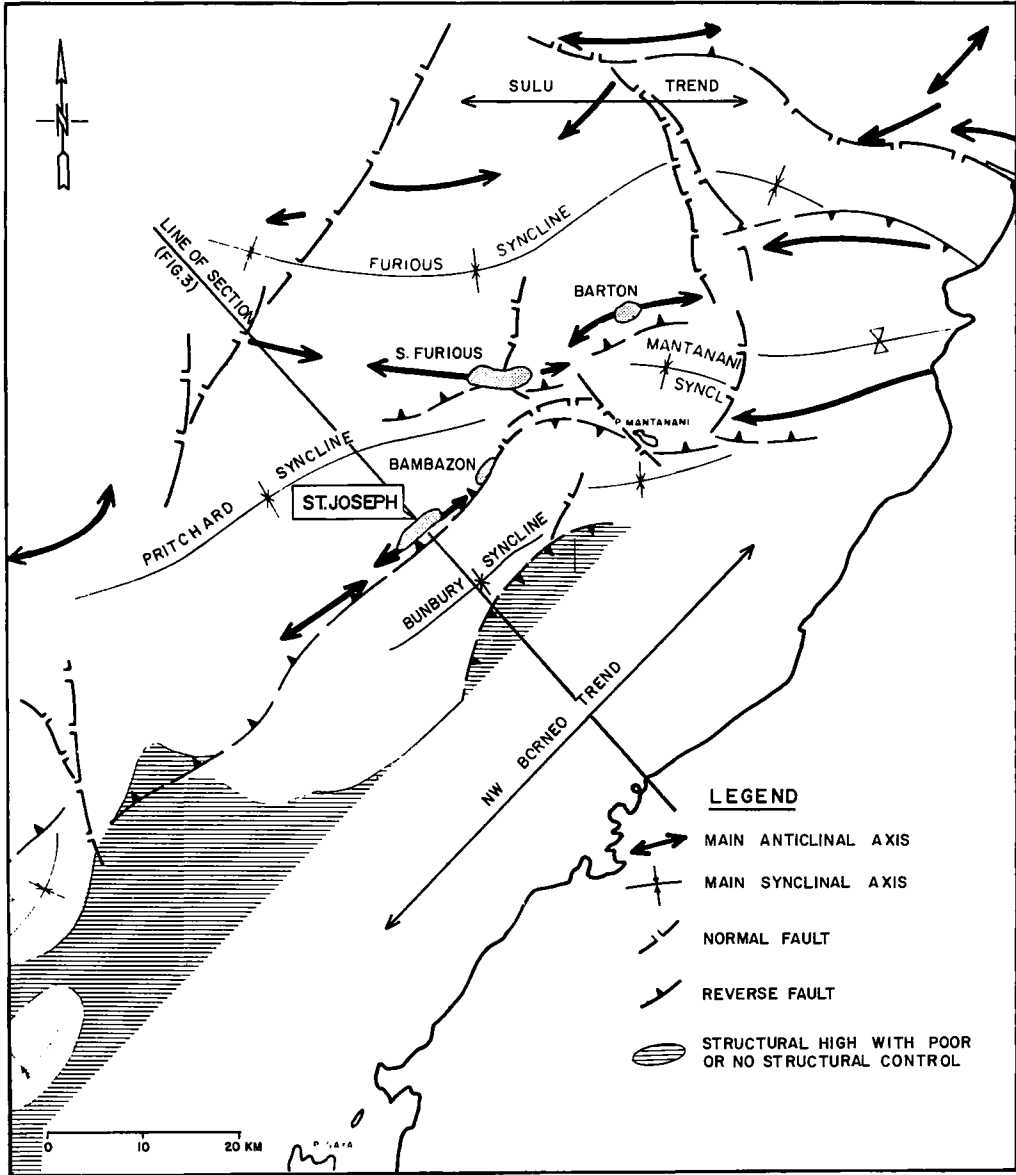
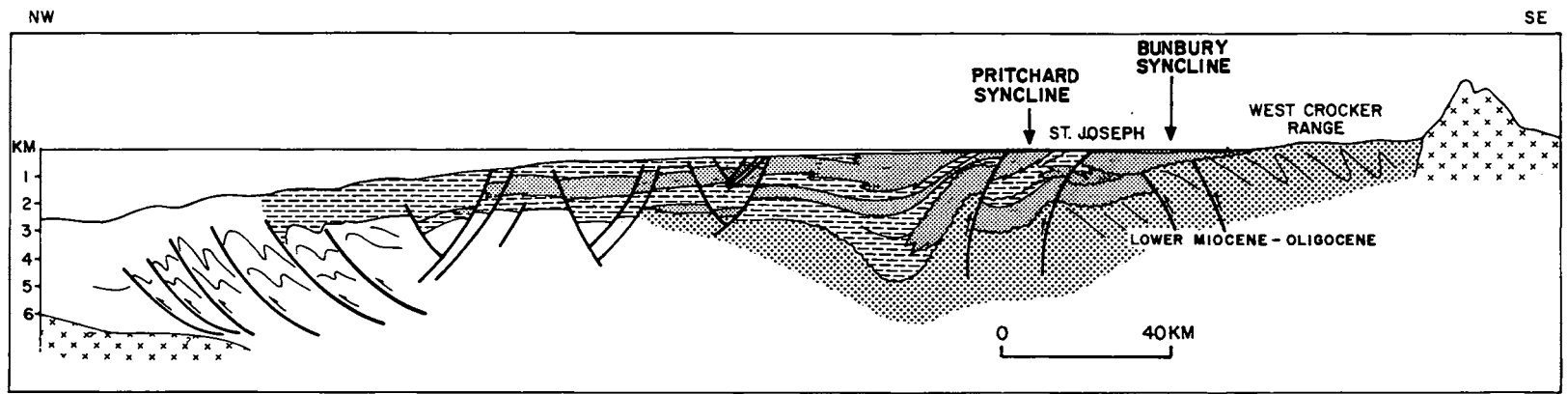


Figure 2: Regional tectonic setting of North Sabah







- | | |
|---|--|
| <p>  SANDY FORMATIONS (MIDDLE MIOCENE-PLIOCENE)
  SHALY FORMATIONS (MIDDLE MIOCENE-PLIOCENE) </p> | <p>  DEEP WATER SEDIMENTS (L. MIOCENE-OLIGOCENE)
  INTRUSIVE BODY </p> |
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Figure 3 : Regional cross-section through North Sabah.

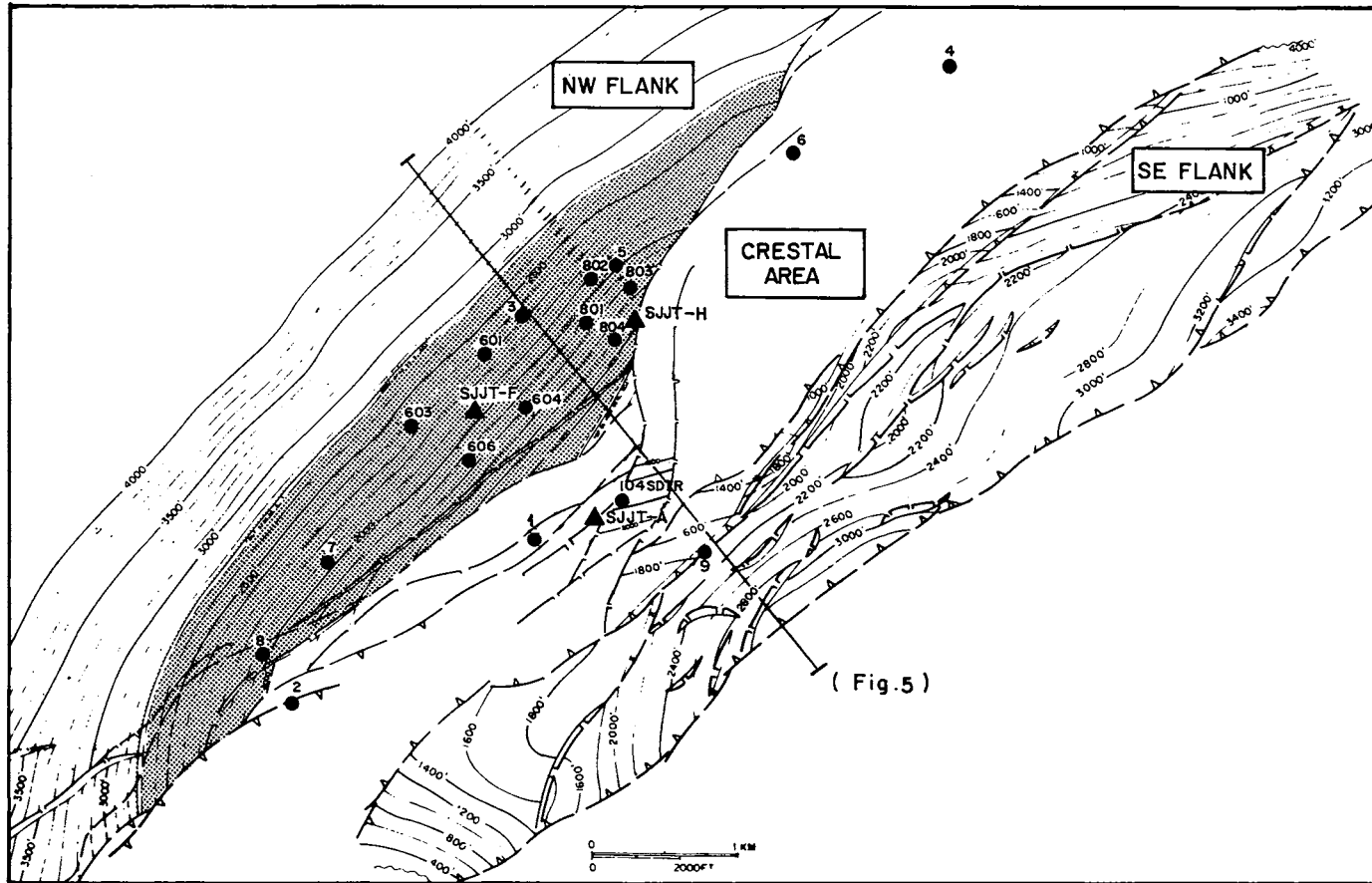


Figure 4 : Structural map of the top objective sequence (B1.0 Sands) and its lateral equivalents.

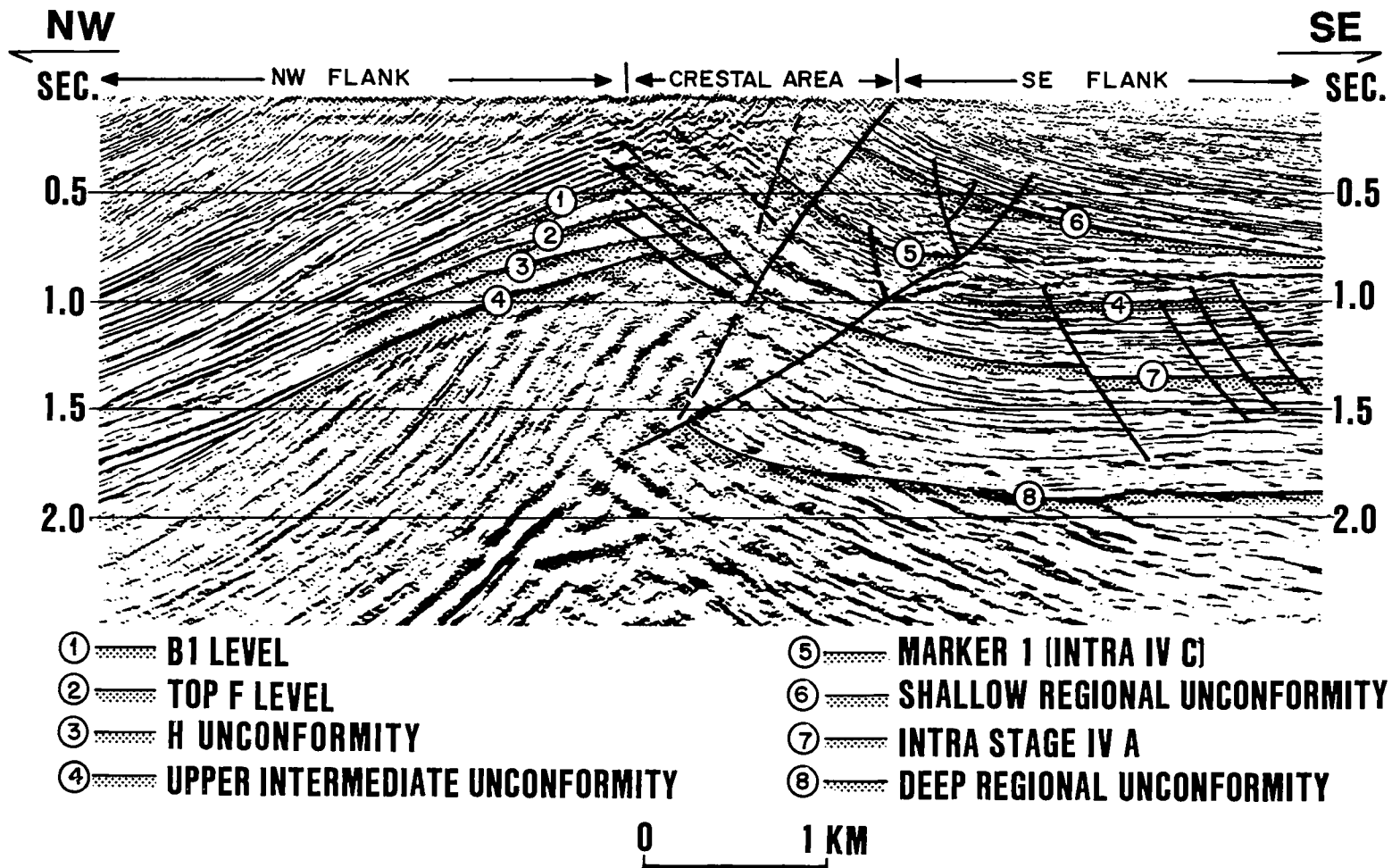


Figure 5 : 3D seismic section across St. Joseph.

are separated by several major regional unconformities (e.g. the Deep, Intermediate, Shallow Regional Unconformities, Levell, 1987). The clastic sediments between these unconformities, particularly those of Middle Miocene and younger age, can generally be assigned to regressive-transgressive 'Cycles' (referred to as 'Stages' in offshore Sabah) which are often bounded on structural highs by both the regional and local unconformities (Fig. 6). These Stages comprise a series of north-westward prograding shelf/slope sequences which were deposited contemporaneously with important basement wrench faulting (Fig. 3).

In St. Joseph, clastic sediments occur in two main intervals :

- (1) **Stage IVA** consists of lower coastal plain deposits with well-developed sands, but with only limited and marginal hydrocarbon potential, and
- (2) **Stage IVC** comprises a shallow marine sand-shale sequence (Late Miocene age), which is separated from the older Stage IVA by the Upper Intermediate Unconformity (latest Middle Miocene).

The Stage IVC is the main hydrocarbon-bearing interval and is subdivided into four informal units (Fig. 7) : (1) **Lower Unit** is an interbedded sand-shale sequence, ca. 500 - 700 ft (152 - 213 m) thick, with up to eight reservoir units (H3.0 to J2.0), (2) **Middle Unit** comprises the F1.0 to G1.0 shale unit, ca. 300 - 700 ft (91 - 213 m) thick, which overlies a local unconformity ('H' Unconformity), (3) **Upper Sand Unit** is the main hydrocarbon-bearing interval comprising ca. 700 - 900 ft (213 - 274 m) of interbedded sands and shales with up to seven main reservoirs (B1.0 to F1.0), and (4) **Upper Shale Unit** is the top reservoir seal, which is several 100's ft thick. The detailed reservoir geology of the Upper Sand Unit is described later in this paper.

Depositional setting

During late Miocene times the Bunbury-St. Joseph Ridge was a rotating, seaward-dipping, flank above a buried wrench fault zone (Fig. 8, Levell and Kasumajaya, 1985). Palaeographically, well data suggests that the coastline was probably on the landward (SE) side of the ridge and that a relatively narrow (ca. 3 - 6 miles / 5 - 10 km) shallow marine shelf extended across the ridge. Seismostratigraphically, the Stage IVC in St. Joseph comprises parallel-bedded topset deposits, which on the basis of their palaeontological and sedimentological characteristics (described later) are of shallow marine origin (Fig. 8).

The shelf edge was an area of extreme instability, possibly due to oversteepening on the seaward (NW) side of the ridge, which is now defined by a series of prominent and spectacular slump scars (Levell and Kasumajaya, 1985). The stratigraphic complexities within the St. Joseph field are believed to be partly due to slumping, particularly the sudden shaling-out of reservoirs to the NE and, possibly, even in parts of the Crestal Area. In addition, the Upper and Intermediate Regional Unconformities, and the less extensive 'H' Unconformity, are also believed to be the result of submarine erosion/shelf-edge slumping.

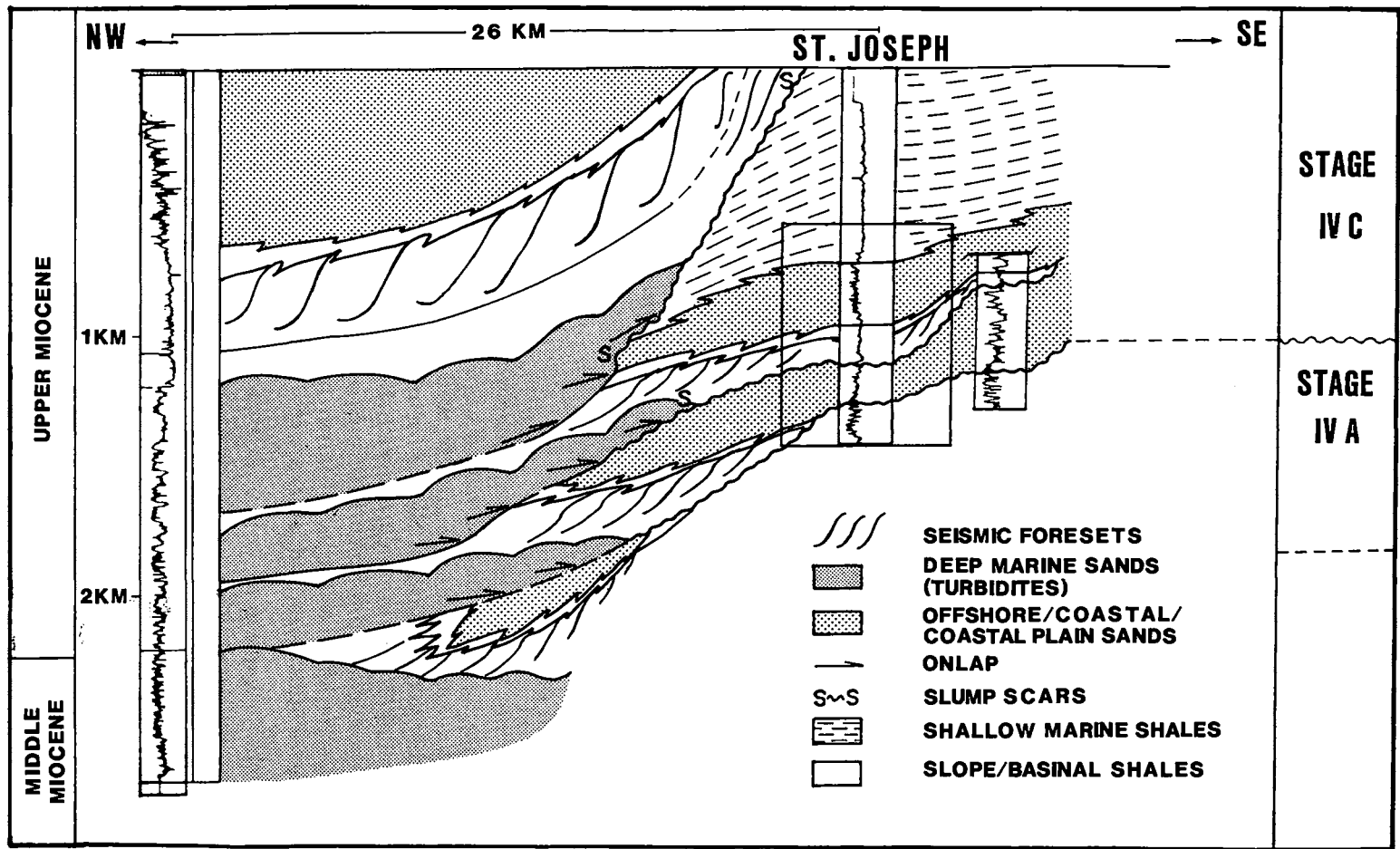


Figure 6 : Stratigraphic framework of the Middle-Upper Miocene deposits (Stages IV A/C) in the St. Joseph area.

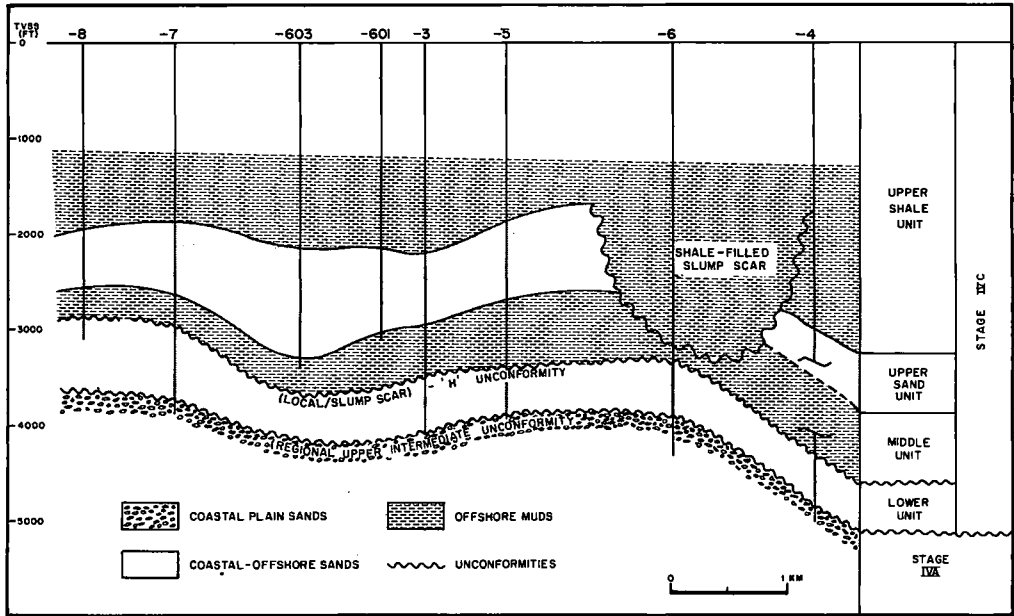


Figure 7: Lithostratigraphic framework of the Stage IVC in the St. Joseph field.

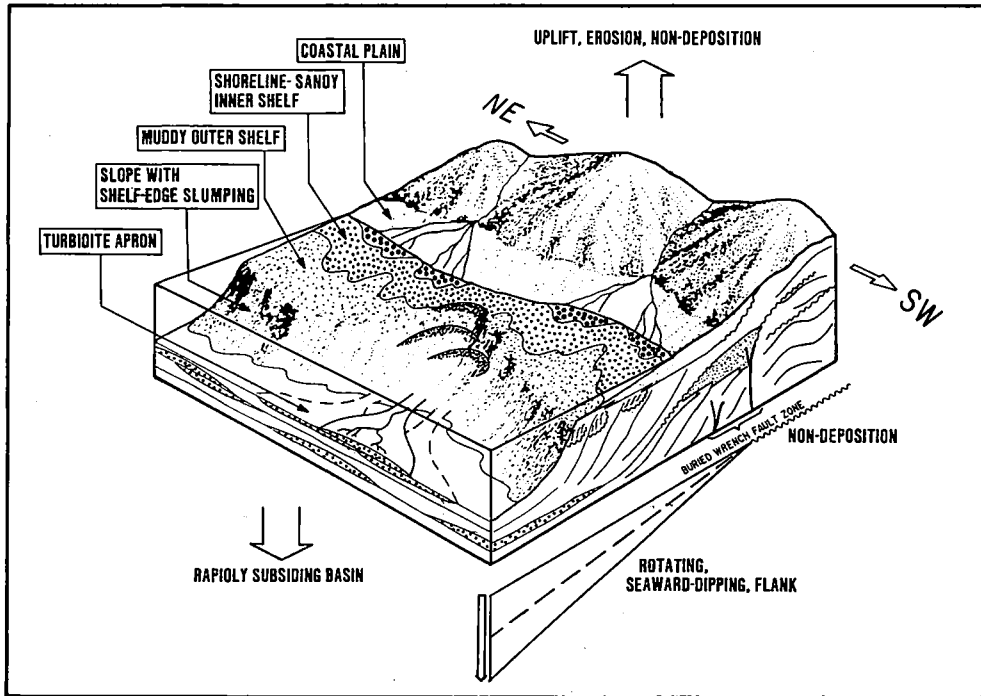


Figure 8: Depositional model of the Lower Stage IVC in North Sabah.

Downflank and basinwards (NW) of the slump scar belt is situated a thick (up to 1.1 miles / 1.8 km thick) succession of deep water sediments containing sand-rich turbidites (Levell and Kasumajaya, 1985). The latter were presumably derived from the shallow shelf area along the Bunbury-St. Joseph Ridge via the slump scars.

The St. Joseph Stage IVC reservoirs, therefore, form part of a late Miocene, shelf/slope system which prograded rapidly across a tectonically-active basin margin defined by syndepositional fault zones (Fig. 8). This provides the framework within which the reservoir geological characteristics of the Stage IVC deposits on the NW Flank are described.

STRUCTURAL GEOLOGICAL CONFIGURATION

Early exploration stage

Structural interpretations of the St. Joseph field, and other similar North Sabah 'ridges', have been hampered by difficulties in obtaining good quality seismic data over the heavily faulted and steeply-dipping crestal areas. Various structural interpretations have therefore resulted (Fig. 9).

The St. Joseph structure was first recognized on 2D seismic data acquired in 1969 (Fig. 10). Although data quality was very poor, it was sufficient to delineate a possible anticlinal trap along the Bunbury-St. Joseph Ridge and additional seismic was acquired in 1973 and 1974 to firm-up a viable structural test (Fig. 10). Of particular importance was the interpretation of the Sabah ridges as wrench-related features, rather than diapiric structures which would tend to be shale-prone. The 1973/74 high resolution seismic data was sufficient to identify a dip-closed structure at the Deep Regional Unconformity level, which was tested by well SJ-1 (1975) in a crestal position. This proved to be the first successful test of a Sabah ridge with some 181 ft of net oil sand being found in late Miocene (Stage IVC) sandstones (a secondary objective of the well). Although this confirmed the 'ridge' interpretation, detailed structural mapping of the crestal area was impossible due to the poor seismic data quality resulting from a combination of steep dips and intense faulting (Fig. 11).

Additional high resolution seismic data was acquired and interpreted in 1976. Although this gave better fault definition it still could not resolve the extent of the SJ-1 closure. Hence the first exploratory appraisal well, SJ-2, was drilled 2.1 km to the SW and along strike from SJ-1, some 650 ft downdip (Fig. 9b). The well also encountered hydrocarbons, partly at equivalent levels to those in SJ-1 (in the Stage IVC above the Upper Intermediate Unconformity - UIU) but also in the deeper Stage IVA, below the UIU. Well results indicated rapid deterioration in reservoir quality with depth (10-15% porosity below ca. 5000 ft / 1524 m), due to pressure solution/quartz cementation, and production tests pointed to limited drainage areas; barriers clearly existed between the two crestal wells, probably due to faulting, but nothing could be mapped in detail (Fig. 9b).

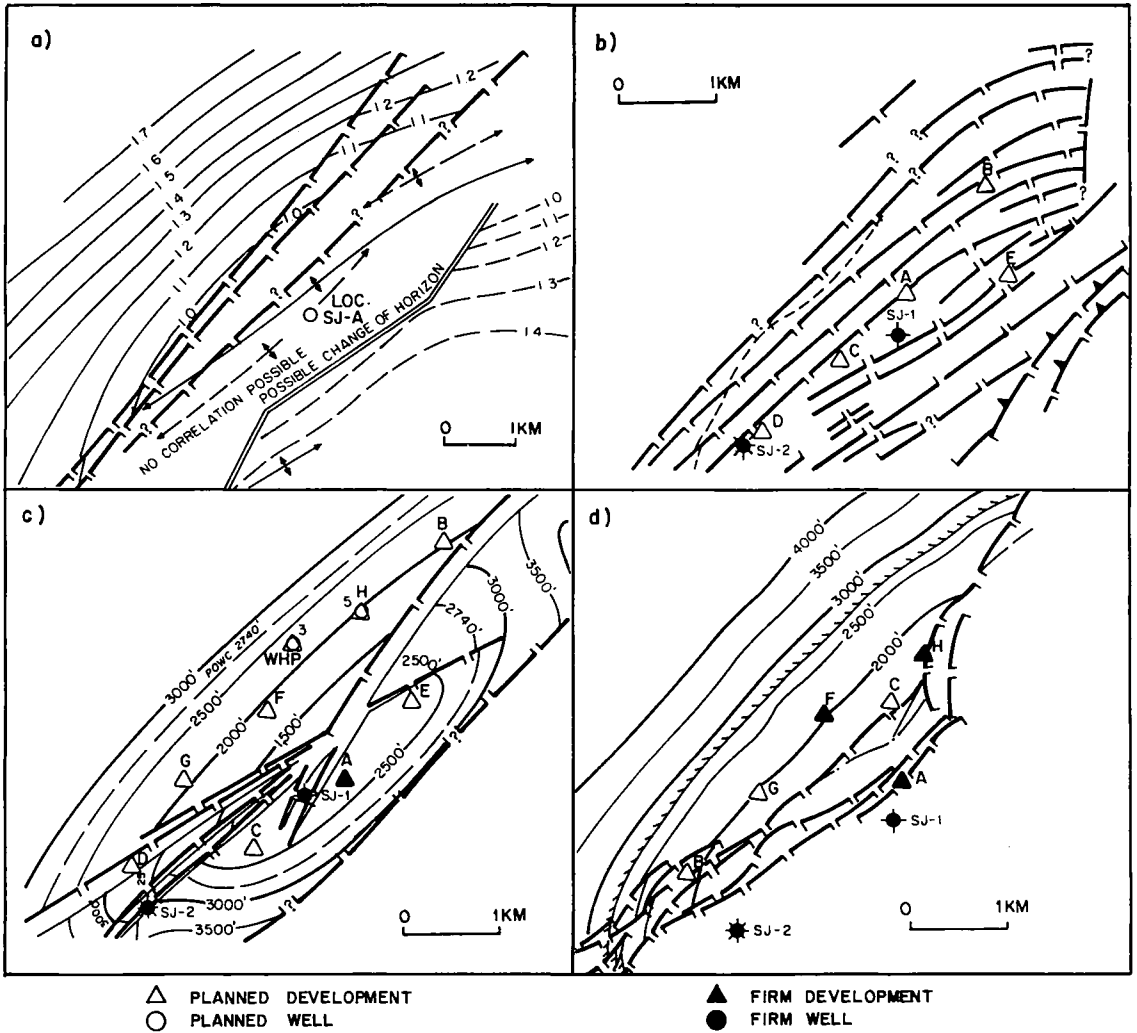


Figure 9: Structural interpretation of the main objective interval(s) in St. Joseph: (a) 1975, (b) 1978, (c) 1981, and (d) 1988 (3D seismic).

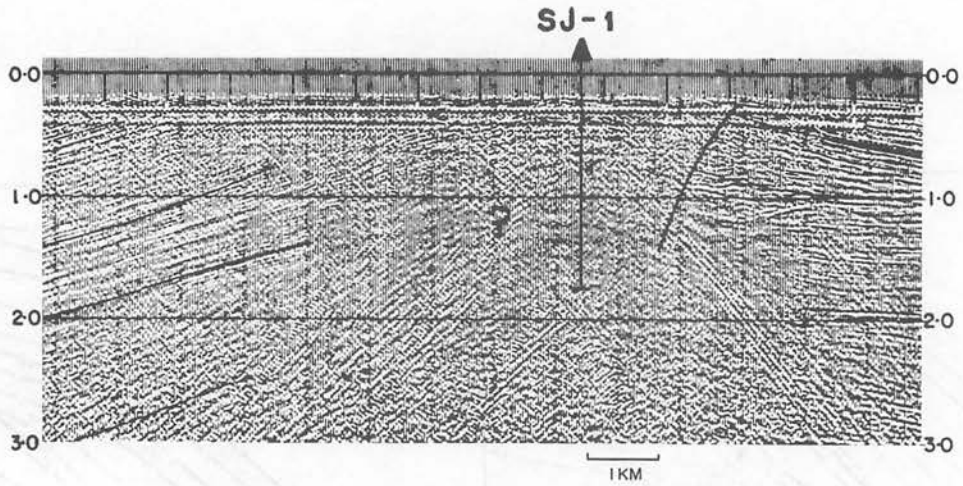


Figure 10: 1969 seismic section across St. Joseph.

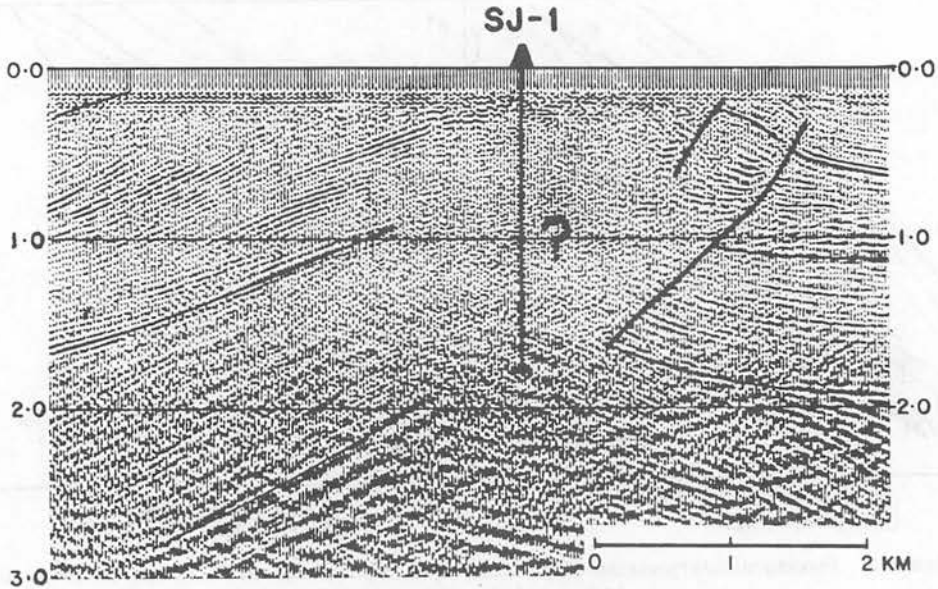


Figure 11: 1973 seismic section across St. Joseph.

These results suggested, therefore, an accumulation of limited size and development of the proven crestal area was proposed in 1978, which led to installation of SJJT-A in 1981.

Follow-up exploration/appraisal stage

The remaining unresolved questions were attempted to be answered by an ultra high resolution seismic survey in 1977 (dip oriented lines at 328 ft / 100 m spacing). This resulted in improved seismic data quality (Fig. 12a) and recognition, for the first time, of structural closure on the NW Flank (Fig. 9c). This was tested by well SJ-3, which discovered 123 ft (37 m) of net oil extending down to similar depths as SJ-1 and with a similar pressure regime.

SJ-3, therefore, discovered the main NW Flank accumulation and was able to confirm that hydrocarbons had been generated from Stage IVA source rocks situated in the nearby Pritchard syncline (to the NW).

Subsequent appraisal of the NW Flank continued (SJ-4, -5 and -6) but with variable success; major stratigraphic complexities emerged with the main reservoirs shaled-out in both SJ-4 and -6. Nevertheless, wells SJ-3 and -5 had confirmed sufficient reserves on the NW Flank to justify its initial development from SJJT-F in 1982. The existing structural model proved largely correct but, despite additional super high resolution 2D seismic (e.g. in 1980), it was still not possible to accurately define detailed aspects of structural interpretation, particularly faulting in and around the Crestal Area, nor to resolve the growing stratigraphic complexities.

Later appraisal/development stage

A 3D seismic survey was shot in 1985 (after drilling six exploration/appraisal wells and seven development wells) mainly aimed at (1) resolving the complex nature of the Crestal Area, (2) determining the updip limit of the NW Flank and its boundary with the Crestal Area, (3) defining the NE limit of the field (between SJ-5 and the shaled-out SJ-6), and (4) helping to identify lateral facies variations from amplitude studies (already apparent from early development well results).

The 3D survey covered ca. 48 sq. miles (125 sq. km), consisting of 768 lines of 6.8 miles (10.9 km) length and at a spacing of 49 ft (15 km). The resulting 3D seismic data was of much superior quality to that of previous vintages of 2D data (Figs. 12 a and b). The main regional markers and the Intra-Stage IVC reservoir intervals could be mapped with a high degree confidence, particularly over the prospective NW Flank (Fig. 13). The NE extent of the field could also be mapped with more confidence (Fig. 14), as could the boundary between the NW Flank and the complex Crestal Area (Fig. 15). The latter remains very difficult to resolve, even on the 3D seismic. Nevertheless, development wells (e.g. from SJJT-H) in this critical area were successfully re-targetted and avoided the shale-dominated and heavily faulted Crestal Area.

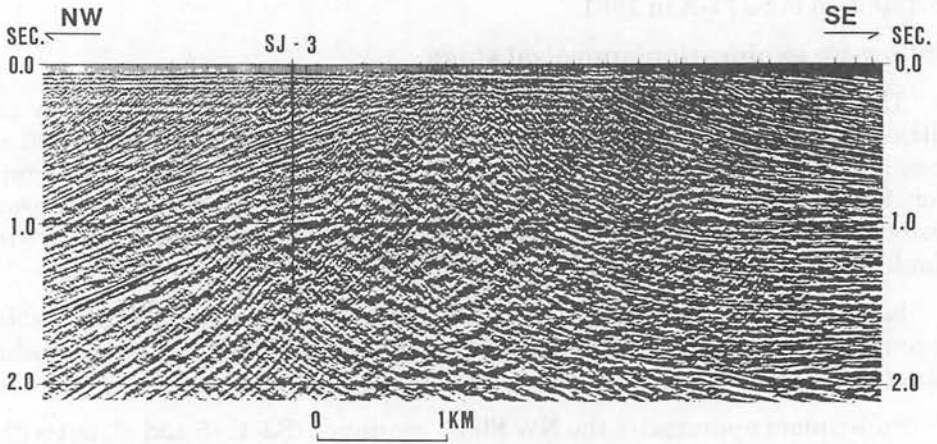


Figure 12a: Comparison of recent seismic data over St. Joseph: 2D (1980).

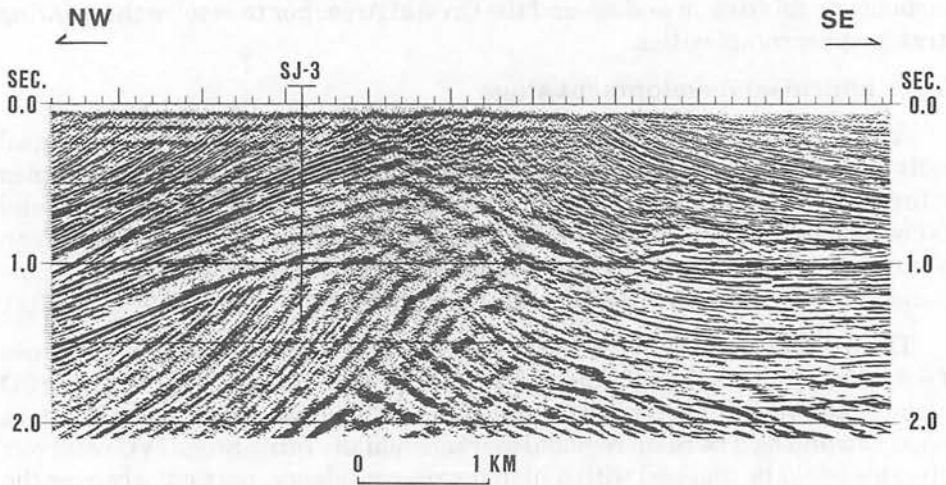


Figure 12b: Comparison of recent seismic data over St. Joseph: 3D (1985).

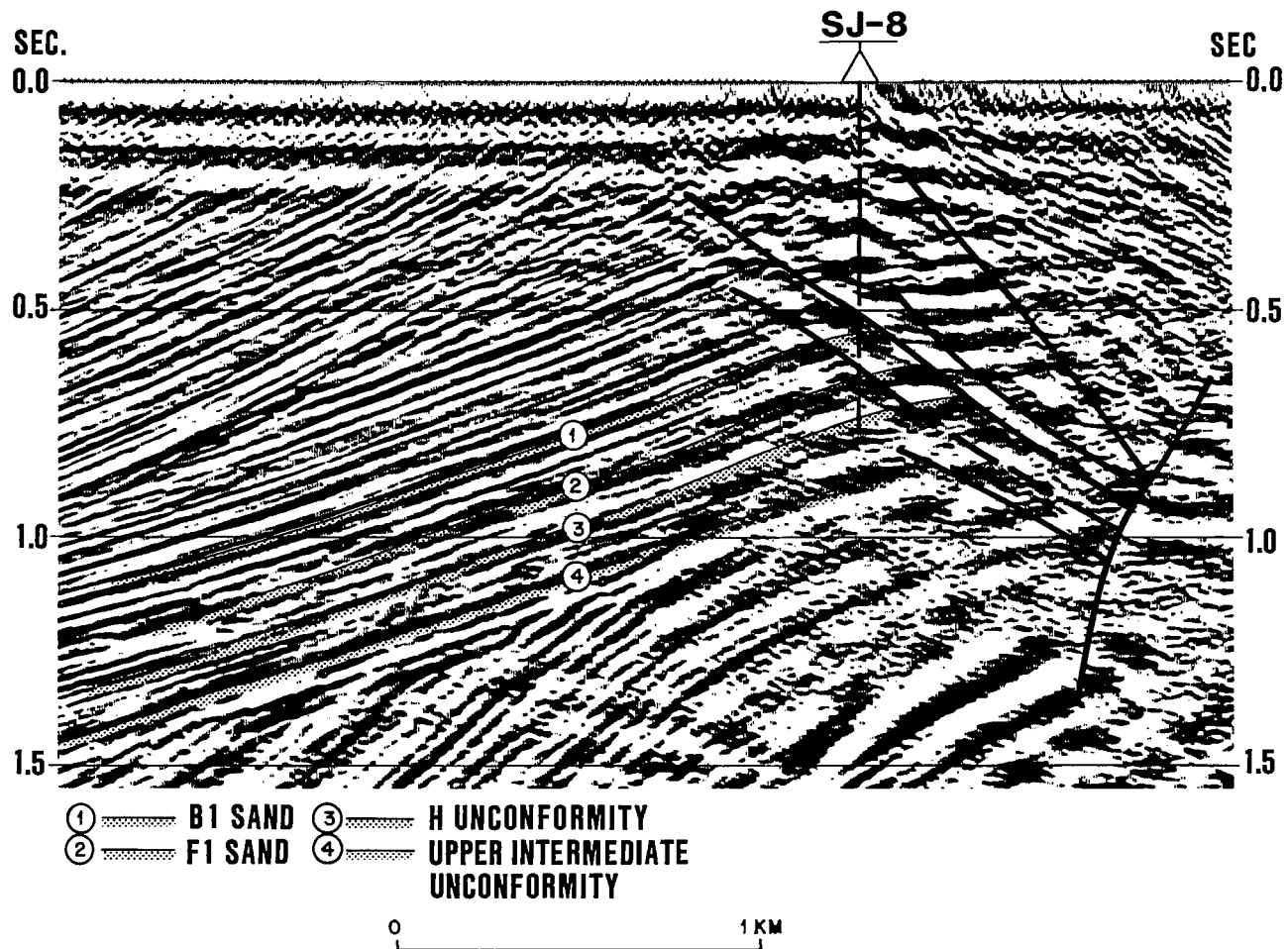


Figure 13 : Details of a 3D seismic interpreted section of the NW Flank.

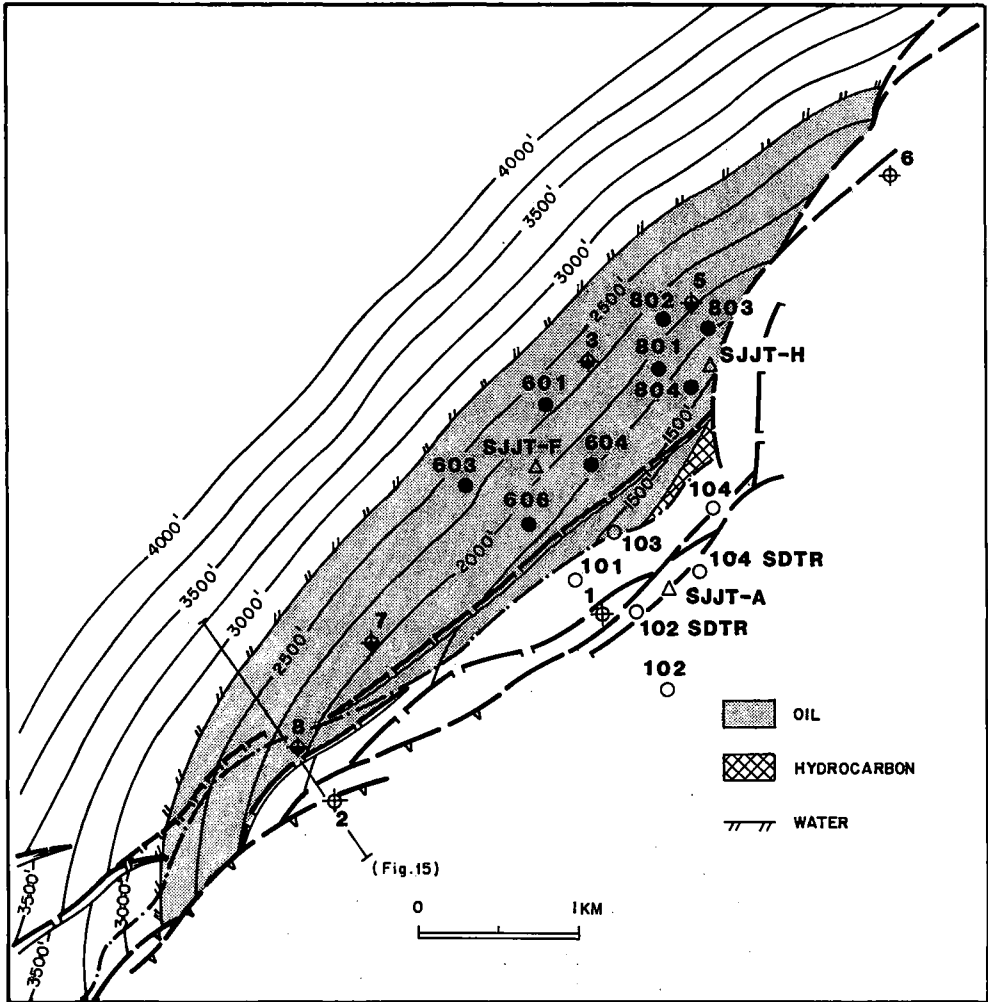


Figure 14: Structural map of the main prospective interval on the NW Flank

The high confidence level of the structural configuration of the NW Flank is enabling successful development drilling to proceed in this area. However, significant stratigraphic variability, largely beyond the resolution of 3D seismic data, also needed to be resolved.

SEDIMENTOLOGY OF THE STAGE IVC RESERVOIRS

The early NW Flank appraisal and development wells confirmed the stratigraphically - complex nature of the Stage IVC reservoirs. Although the main reservoir units could be defined and correlated using logs (Fig. 16), significant lateral variations in facies types, reservoir thickness/quality and shale thickness/extent were initially unpredictable. Detailed reservoir subdivision and correlation of the Upper Sand Unit was problematic and therefore hampering development of the NV Flank.

To address these issues a sedimentological study of some 1,600 ft (488 m) of core from five wells on the NV Flank was undertaken. This included the analysis of a continuous 800 ft (244 m) cored interval in appraisal well SJ-7 (1986), which was specifically planned to provide a comprehensive data set of all the main sub-units of the Upper Sand Unit and to provide a control point for other uncored appraisal/development wells. This would provide a genetic depositional framework to enable the development of a reservoir geological model (Fig. 17). The results of these studies are presented in the following sections.

Facies characteristics

The Upper Sand Unit is 700 - 900 ft (213 - 274 m) and comprises a complex alteration of sands and shales (Fig. 18). Core studies of SJ-7 identified seven facies on the basis of lithology (grain size, sorting, sand/shale content, etc.), primary sedimentary structures, bioturbation and porosity/permeability (Fig. 19). Six of these facies form a continuum in depositional processes ranging from high-energy sandstones (poorly stratified sands - Sps, laminated sandstones Sl), through moderate-energy interbedded sandstone and mudstone (sand-dominated heterolithic facies - SM) and into low-energy mainly mudstone facies (mud-dominated heterolithic - MS, laminated mudstone - Ml, and massive mudstone - Mm). The seventh facies comprises relatively low-energy, strongly bioturbated, argillaceous sandstone (Sb).

The three mudstone-dominated facies (Ml, Mm and MS) display the following features: (1) mainly laminated (weakly to non-bioturbated) but occasionally massive (strongly bioturbated), (2) thin layers/lenses of very fine sandstone and siltstone, (3) calcareous nodules, (4) disseminated carbonaceous material, and (5) mainly fluviomarine and, less abundantly, holomarine inner neritic microfauna.

Typical characteristics of the main sandstone facies (Sps, Sl and SM) include the following: (1) very fine to fine grained (Sps occasionally medium grained), (2)

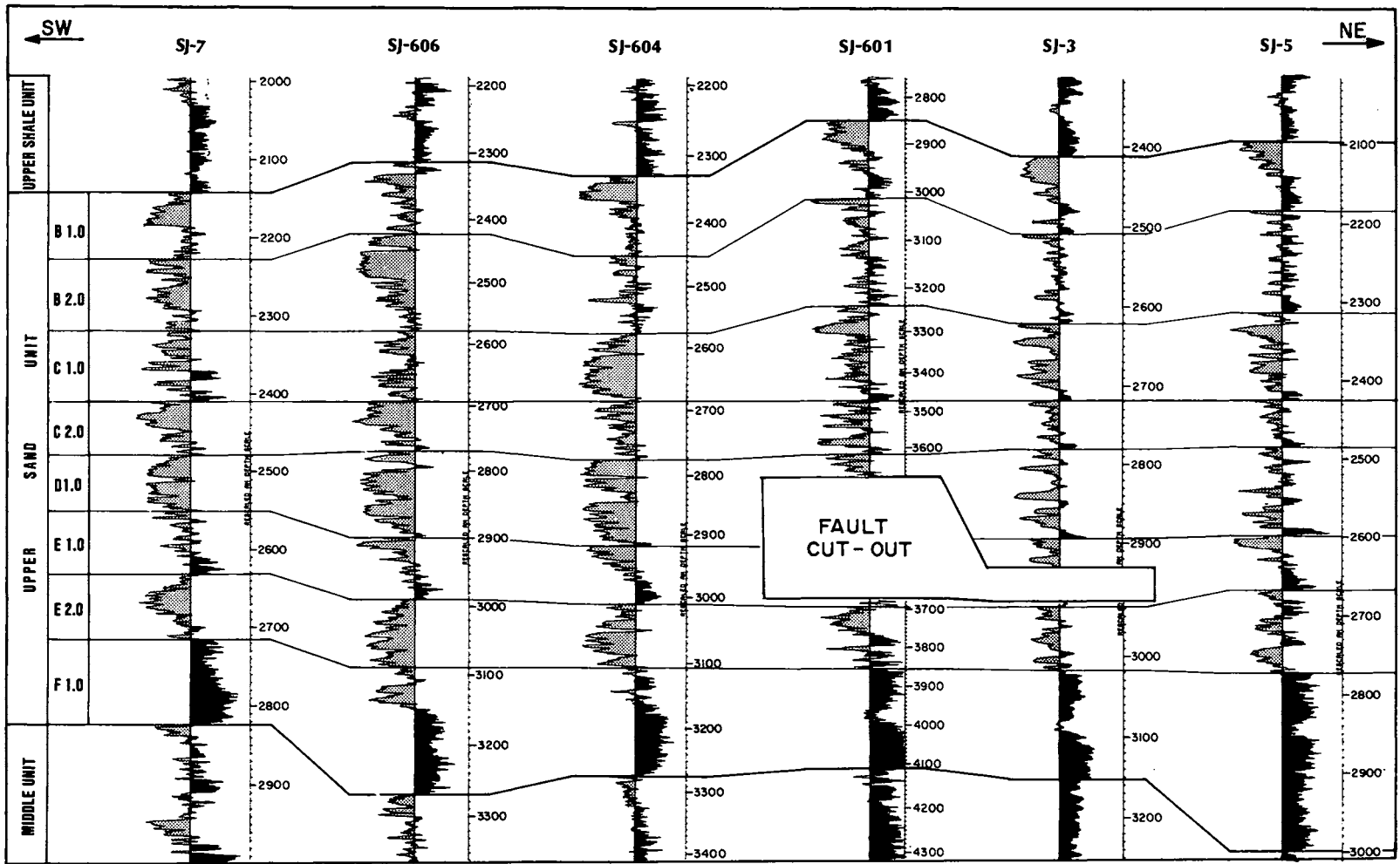


Figure 16 : Well log correlation panel from the NW Flank showing variable sand development of the Upper Sand Unit.

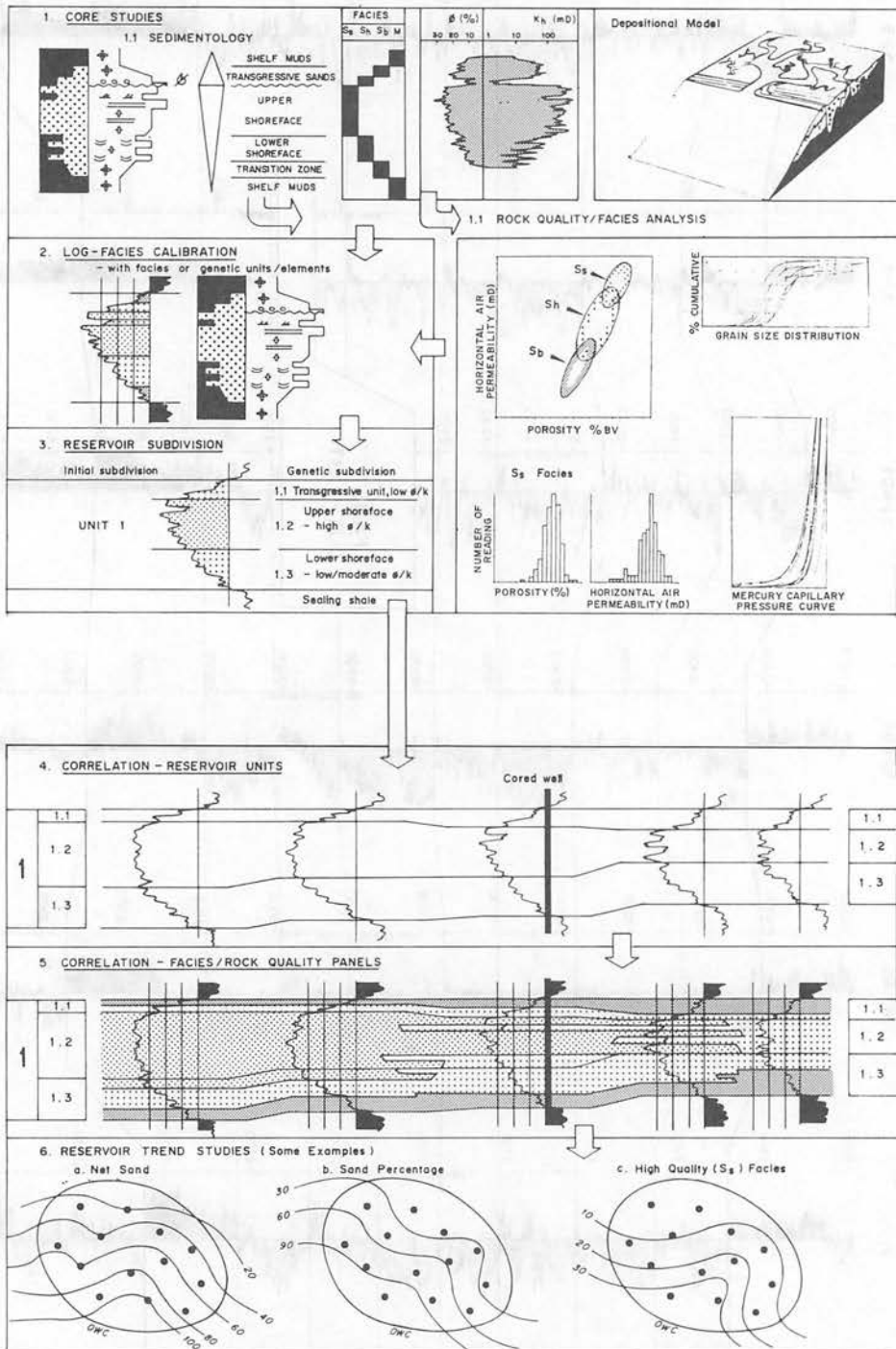


Figure 17: Graphic representation of a reservoir geological modelling approach.

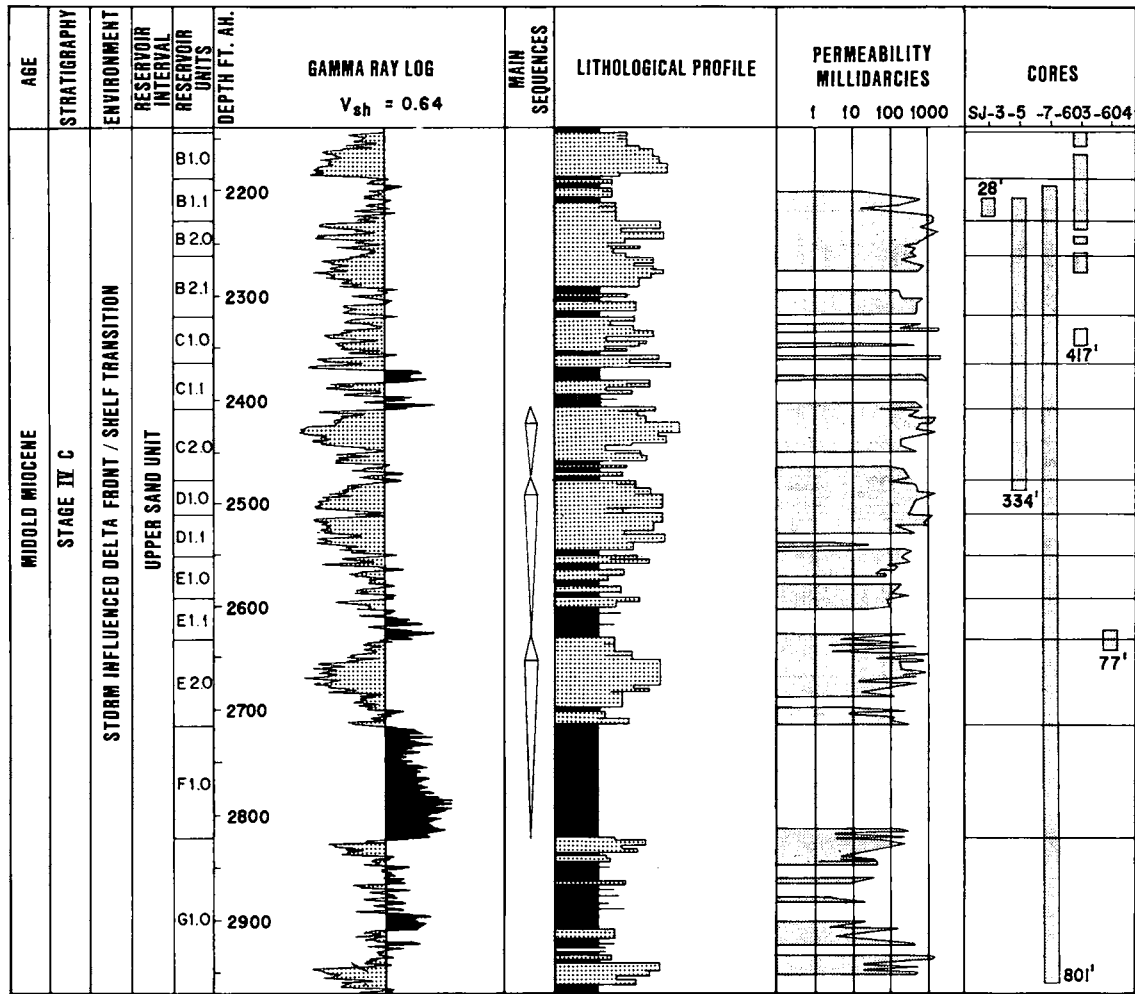


Figure 18 : Well log profile through the Upper Sands in SJ-7, highlighting the main lithology and permeability characteristics. Core coverage in St. Joseph shown on the right.

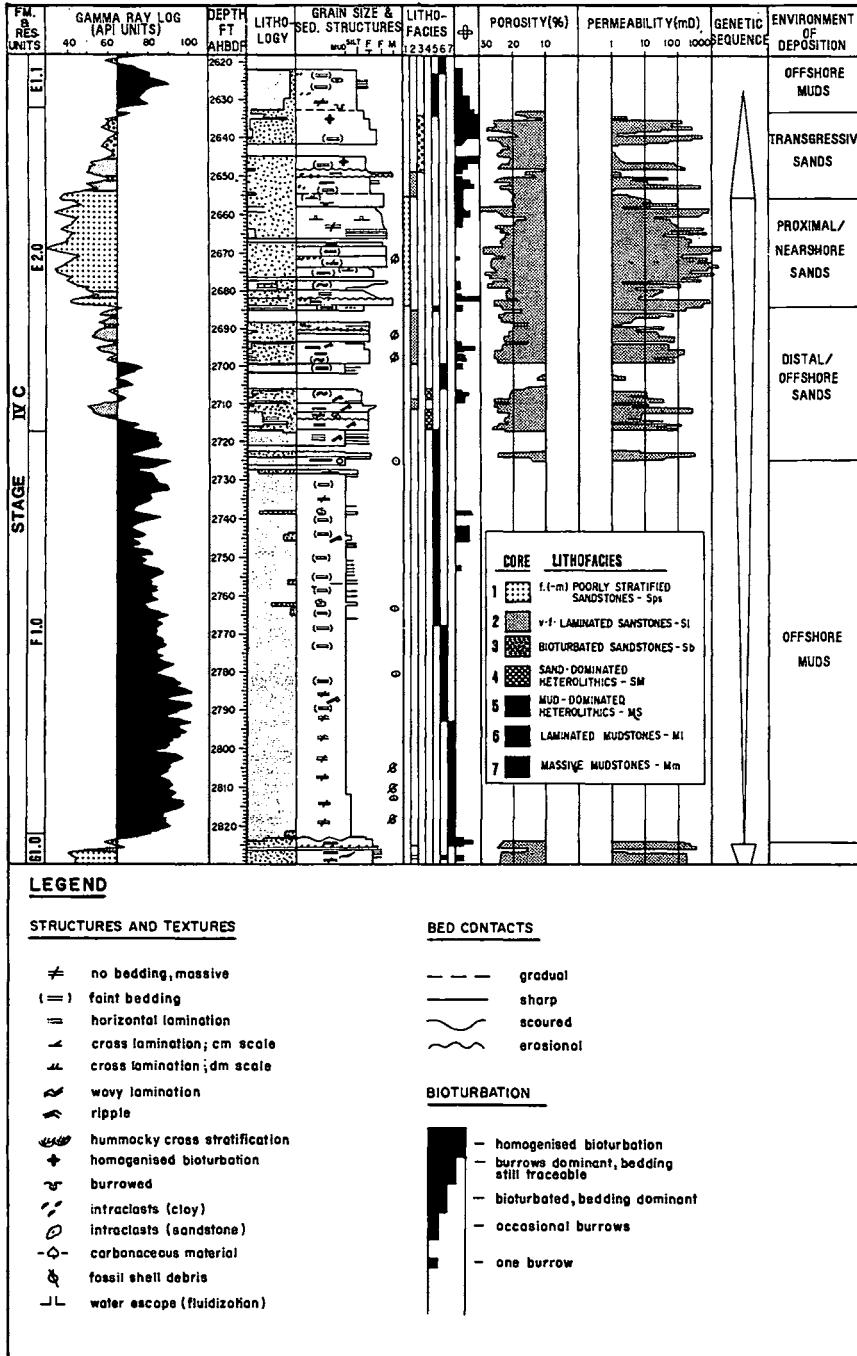


Figure 19: Typical genetic sequence in the Upper Sands trend (F1.0/E2.0/E1.1 interval) based on core and log data from well SJ-7.

well to very well sorted, (3) sharp/erosional-based sandstone beds with gradational tops ranging in thickness from 0.8 - 4 ins (2 - 10 cm) (SM facies), through 2 - 6 ins (5 - 15 cm) (SI facies) to 6 - 20 ins (15 - 50 cm) (Sps facies), (4) predominance of parallel to wavy lamination, occasional hummocky cross-stratification, wave ripple cross-lamination and rare cross-bedding (Sps facies only), (5) scattered clay clasts and carbonaceous material, particularly above the erosional bases of sandstone beds, and (6) rare bioturbation mainly in the form of isolated, clay lined *Ophimorpha* burrows.

Facies sequences

The Upper Sand Unit comprises several stacked coarsening/fining upward sequences which range in thickness from 80 - 200 ft (24 - 60 m) (Fig. 20). The most complete sequence is represented by the F1.0 to E2.0 interval in which massive, fossiliferous mudstones with holomarine inner neritic microfauna give way initially to laminated mudstone with fluviomarine inner neritic microfauna, followed by mud-dominated heterolithic facies (Fig. 19). Sandstone bed thickness and frequency, and overall sand content continue to increase to form the main E2.0 reservoir. The fining upward part of the sequence is marked by increased bioturbation and clay content before being gradually succeeded by the E1.1 shale interval.

This pattern is repeated throughout the remainder of the interval, particularly up to the top of the C2.0 unit. Thereafter, the same facies occur in similar but generally less well-developed and more incomplete sequences.

Depositional model

Palaeontological and sedimentological data point to deposition in a shallow marine environment, with some fluviomarine influence. Sandstone characteristics are indicative of rapid deposition probably in a storm/wave-influenced environment (Johnson and Baldwin, 1986; Craft and Bridge, 1987). The facies sequences comprises several repetitive and relatively small-scale regressive/transgressive units. They are interpreted as representing the progradation and retreat of coastal/nearshore sand bodies, possibly connected landward (SE) with either delta distributaries and/or coastal barriers (Fig. 8). Within St. Joseph the sequence was deposited in an entirely shallow marine environment, there being no evidence of either emergence or complete coastal progradation. Only one, but possibly correlatable, horizon rich in organic material and containing lower coastal plain microfauna has been recognized (C1.0 Unit, Fig. 20).

The rapid vertical and lateral variations in facies/sequence types reflects fluctuations in sedimentation rates and/or relative rates of sea level rises. Such variability is consistent with the regional depositional/tectonic setting during Stage IVC times.

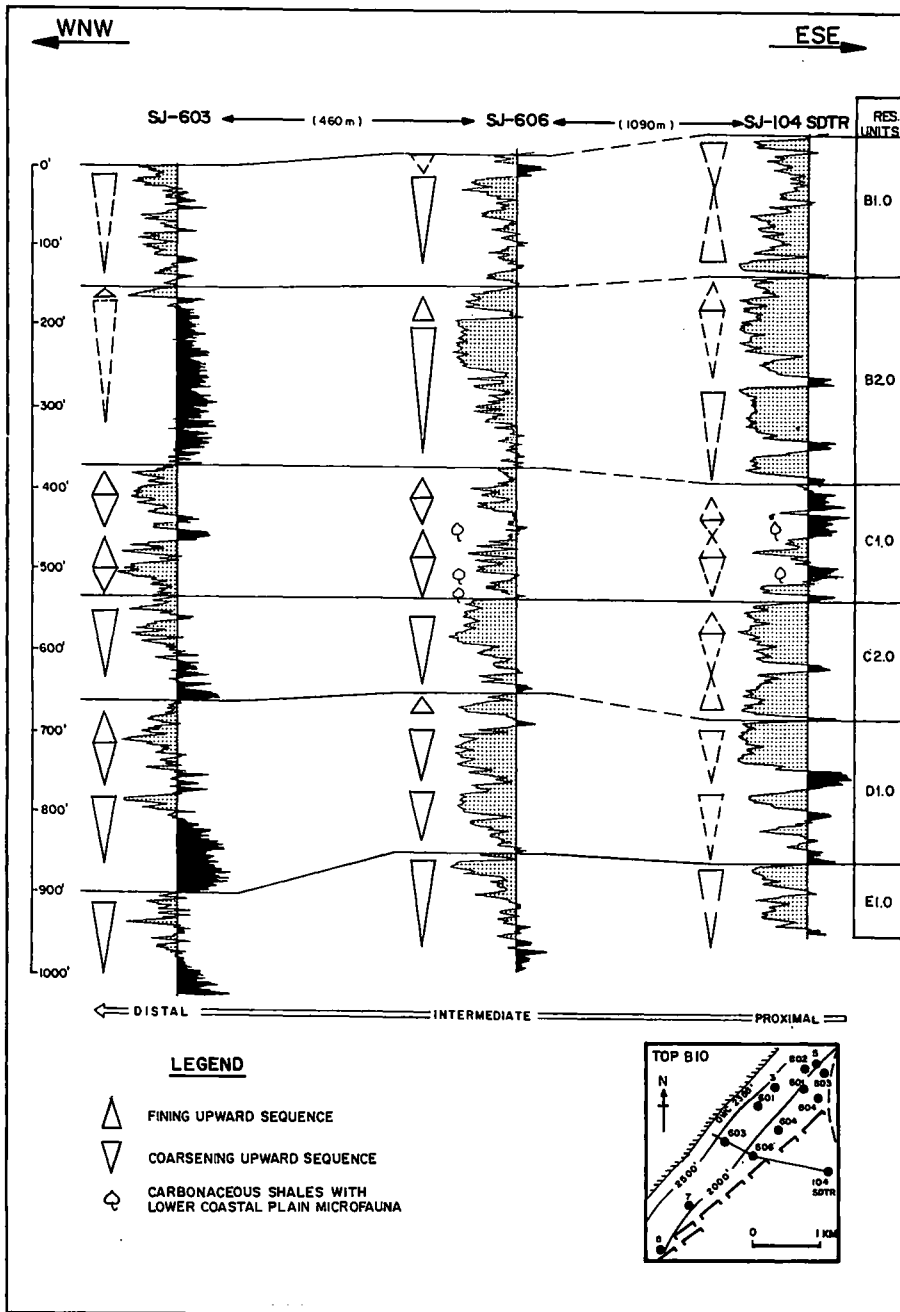


Figure 20 : Well log profile along a proximal to distal trend (SE to NW) illustrating the rapid lateral change in sand development. Note the predominance of coarsening/sandier upward sequences with subordinate fining/shalier upward sequences.

RESERVOIR GEOLOGY OF THE STAGE IVC RESERVOIRS

Reservoir properties

The seven facies described from sedimentological studies could not be directly applied to log calibration due to overlap in rock properties and log response (e.g. SM and Sb facies). Instead four simplified log facies were defined, each with distinctive reservoir properties (Figs. 21 and 22) :

- **Mud-dominated units** comprise both the mudstone facies (M1 and Ms) and mudstone-dominated heterolithic facies (MS). Thin sandstone beds within the MS facies display marginal reservoir quality (porosity ca. 10 - 18%, permeability 1-60 mD) but their contribution is considered negligible.

These non-reservoir units form barriers to vertical fluid flow; sealing potential is mainly related to their lateral extent (discussed later).

- **Heterolithic units** comprise intervals of interbedded sandstone and mudstone (SM facies) and bioturbated sandstone (Sb facies). Reservoir quality is relatively poor (porosity ca. 10 - 25%, permeability ca. 10 - 30 mD). These properties are effectively further reduced by the numerous, thin and discontinuous shale layers (SM facies) and/or by the high, dispersed clay content (Sb facies).
- **Laminated sandstone units** are represented by the S1 facies, in which reservoir quality is variable, but mainly moderate (porosity ca. 15 - 28%, permeability 50 - 600 mD).
- **Poorly stratified sandstone units** comprise the Sps facies which displays relatively good reservoir quality (porosity ca. 23 - 28%, permeability 100 - 1000 mD).

Log calibration

Facies discrimination was based on four well logs (gamma ray, density, neutron and sonic) but the gamma ray most useful since both the facies and their genetic sequences are mainly sand content-related. Despite some degree of overlap between facies, the scheme provides a practical method for applying a consistent facies/genetic sequence model to all NW Flank wells (Figs. 21 and 22).

Net sand definition

There is a high frequency of thin bedded sandstones in the St. Joseph field with gradational facies sequences being the norm. The SJ-7 cores enabled the shalier intervals to be quantified in terms of their sand content, their likely reservoir properties and their significance in terms of fluid flow (baffle or barrier). This demonstrated that an earlier Vshale cut-off value (0.5) has been over pessimistic and that many shale-dominated intervals comprised hetero-

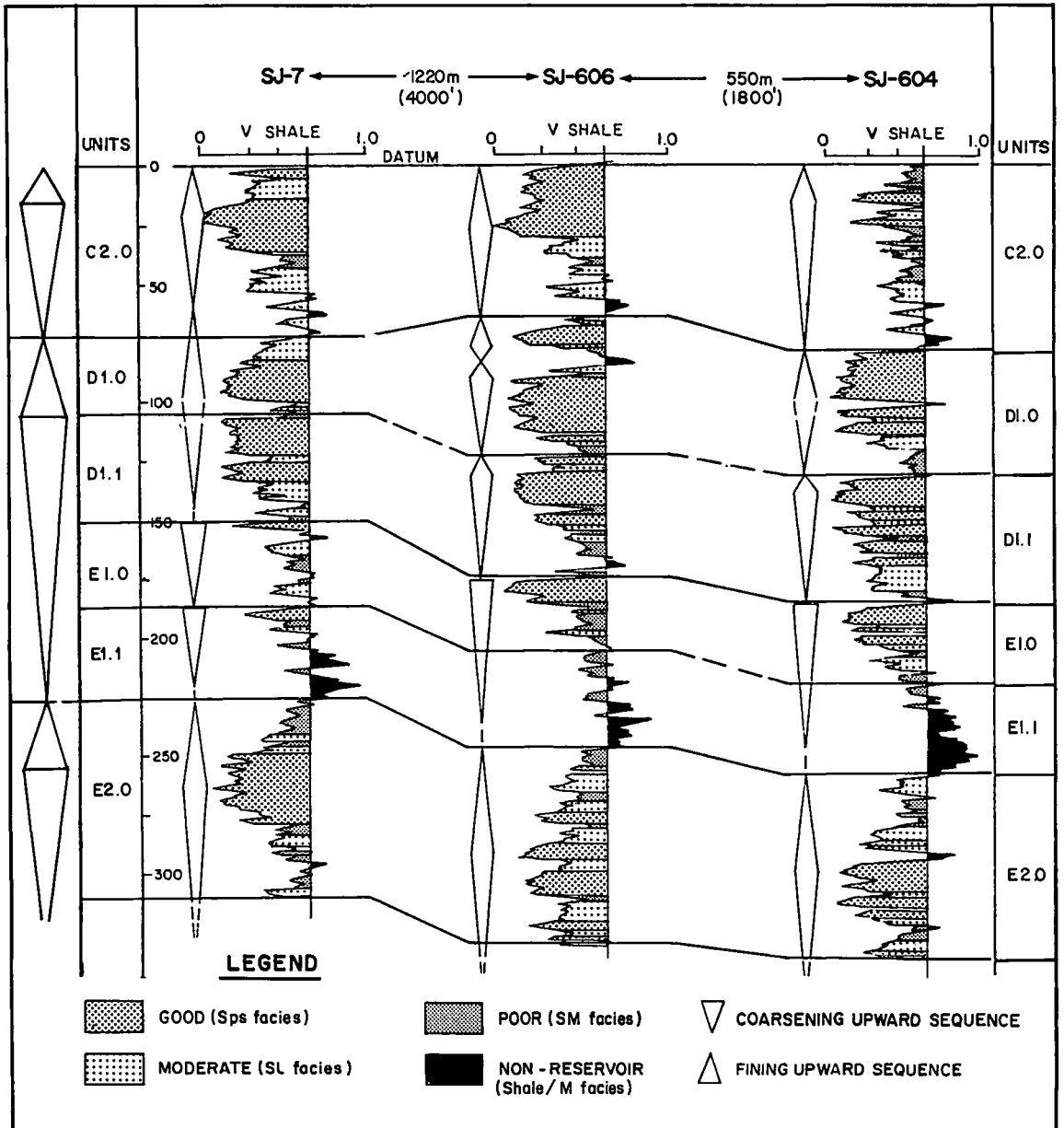


Figure 21: Log facies and sequence characteristics in the C2.0 to E2.0 interval, illustrating the repetitive coarsening/fining upward sequences.

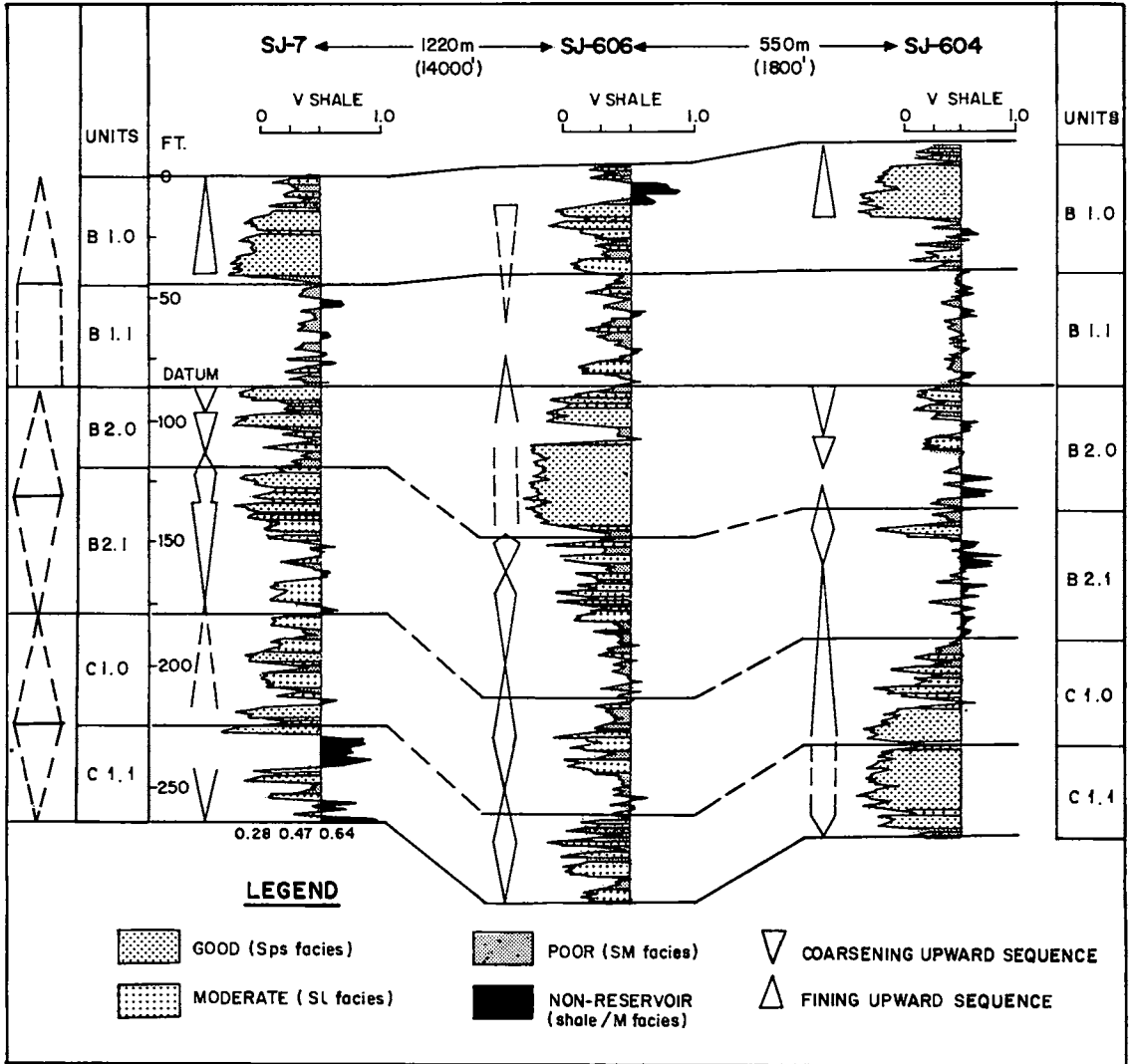


Figure 22: Log facies and sequence characteristics in the B1.0 to C1.1 interval, illustrating the more elastic/incomplete nature of the facies sequences.

lithic (SM) facies (Fig. 23). The revised Vshale cut-off value (0.64) allows a more accurate net sand count and a better definition of genuine non-reservoir impermeable intervals (Fig. 23). This proved particularly important in determining a realistic reservoir model for simulating different recovery processes (e.g. defining reservoir connectivity).

Correlation and facies/sequence trends

The genetic facies sequence provide the basis for subdividing the Upper Sand Unit into eight major units and thirteen subunits. Particularly in the lower part (F1.0 to C2.0), the unit and subunit horizons correspond to the boundaries of the coarsening/fining upward sequences. Although the precise nature of each sequence varies laterally, correlation (based on twenty-three wells) demonstrates that these genetic units extend throughout the field, and hence provide a framework for mapping reservoir trends. Two representative examples are provided by the E2.0 and C2.0 reservoir units (Figs. 24 and 25).

The E2.0 reservoir unit is of field-wide extent and occurs between two distinctive and laterally extensive shale units (F1.0 and E1.1). In SJ-7 core data defined this reservoir as a large-scale coarsening/fining upward sequence, although in detail there is an indication that it may be composite in nature (Fig. 19). The gross coarsening/fining nature of the unit is apparent in all wells but its composite character becomes more apparent to the NE (Fig. 24). In the same direction there is a gradual increase in gross thickness, a decrease in the proportion of high quality sands (Sps) and an increase in the thickness and proportion of shale layers.

The C2.0 reservoir unit shows a similar trend (Fig. 25). In this case a single coarsening/fining upward sequence is present in all wells, but there is a similar reduction in reservoir quality/increase in shale content to the NE.

Similar correlation and facies mapping was undertaken for each subunit in order to define the precise facies trends and from this to construct reservoir quality maps for volumetric and simulation purposes (e.g. isopach, net/gross, net sand, shale layer extent, etc.).

Reservoir geological model

From the foregoing a reservoir geological model of the Upper Sand Unit has been developed (Figs. 26 and 27). The reservoir distribution pattern (based on twenty-three wells, excluding the six recent SJJT-G wells) is thought to reflect the intermittent NW to NE progradation of coastal/delta front sands which were being supplied from a source in the SW part of the field. The result in terms of reservoir distribution on the NW Flank is summarized as follows:

- The reservoir sands are generally better developed in the updip wells and poorer in the downdip wells (cf. Figs. 26 and 27).

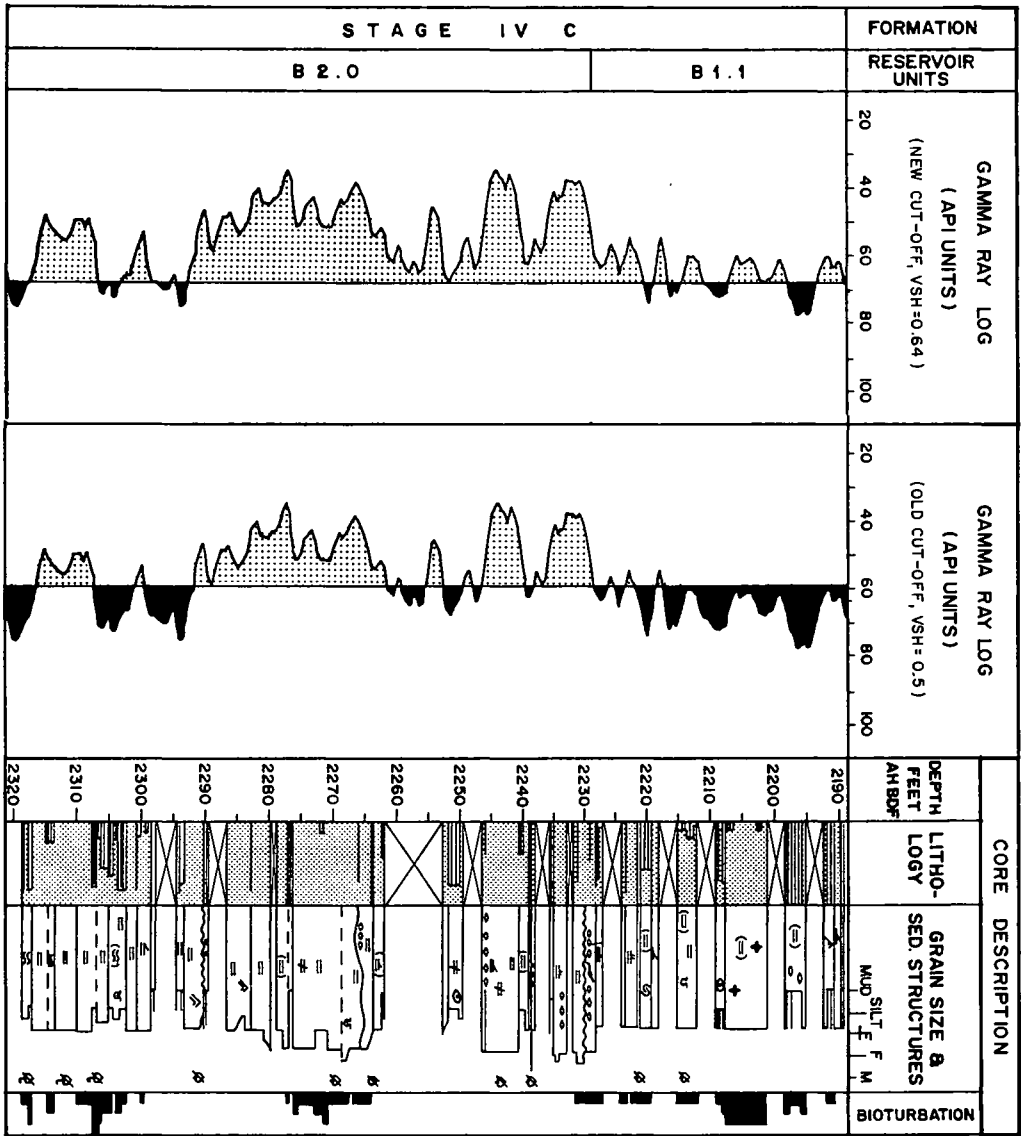


Figure 23: Net sand definition in St. Joseph, illustrating the old and new Vshale cut-off values in comparison with equivalent core data (well SJ-7).

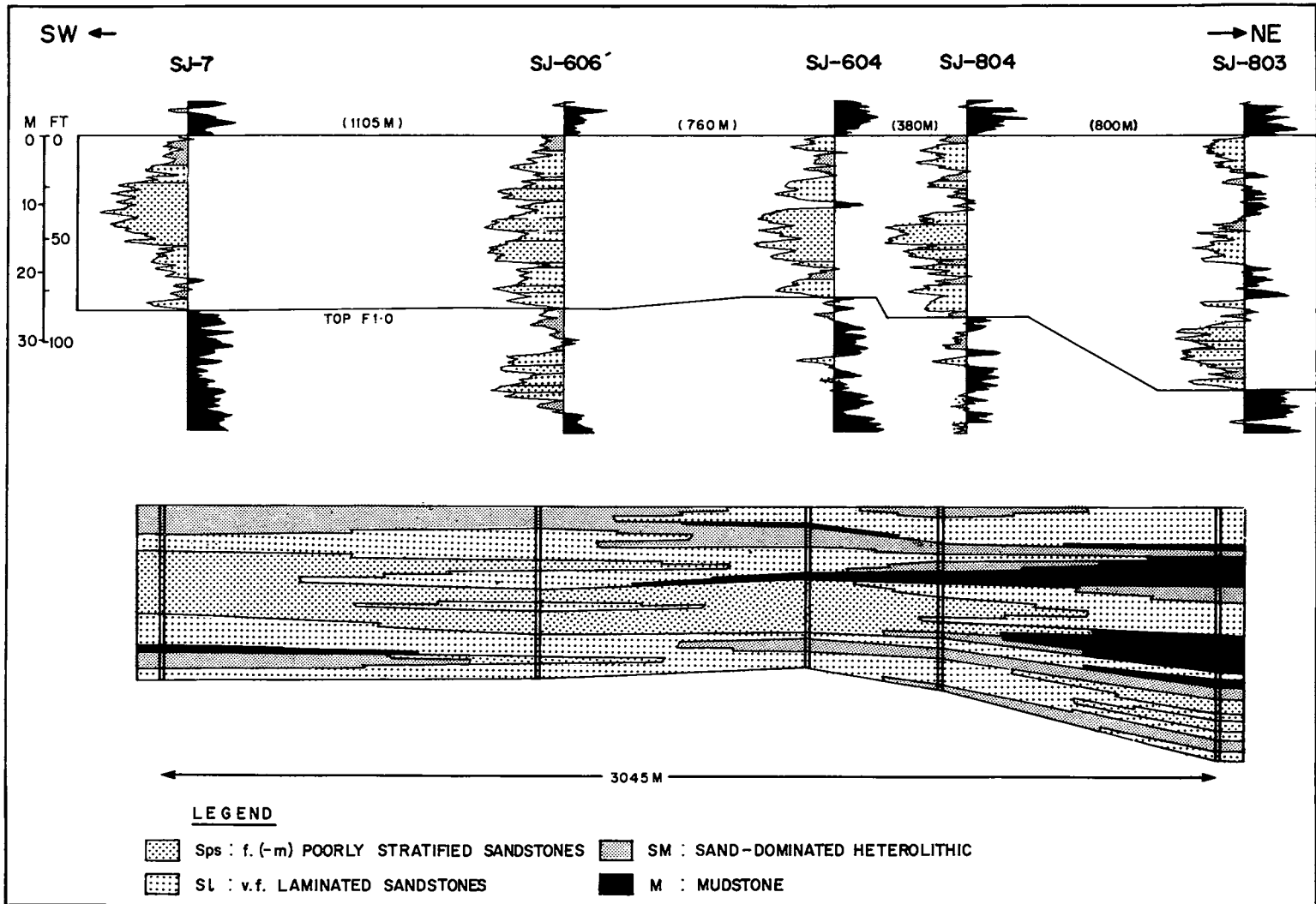


Figure 24 : Log facies correlation panel and interpreted facies distribution, E2.0 reservoir unit.

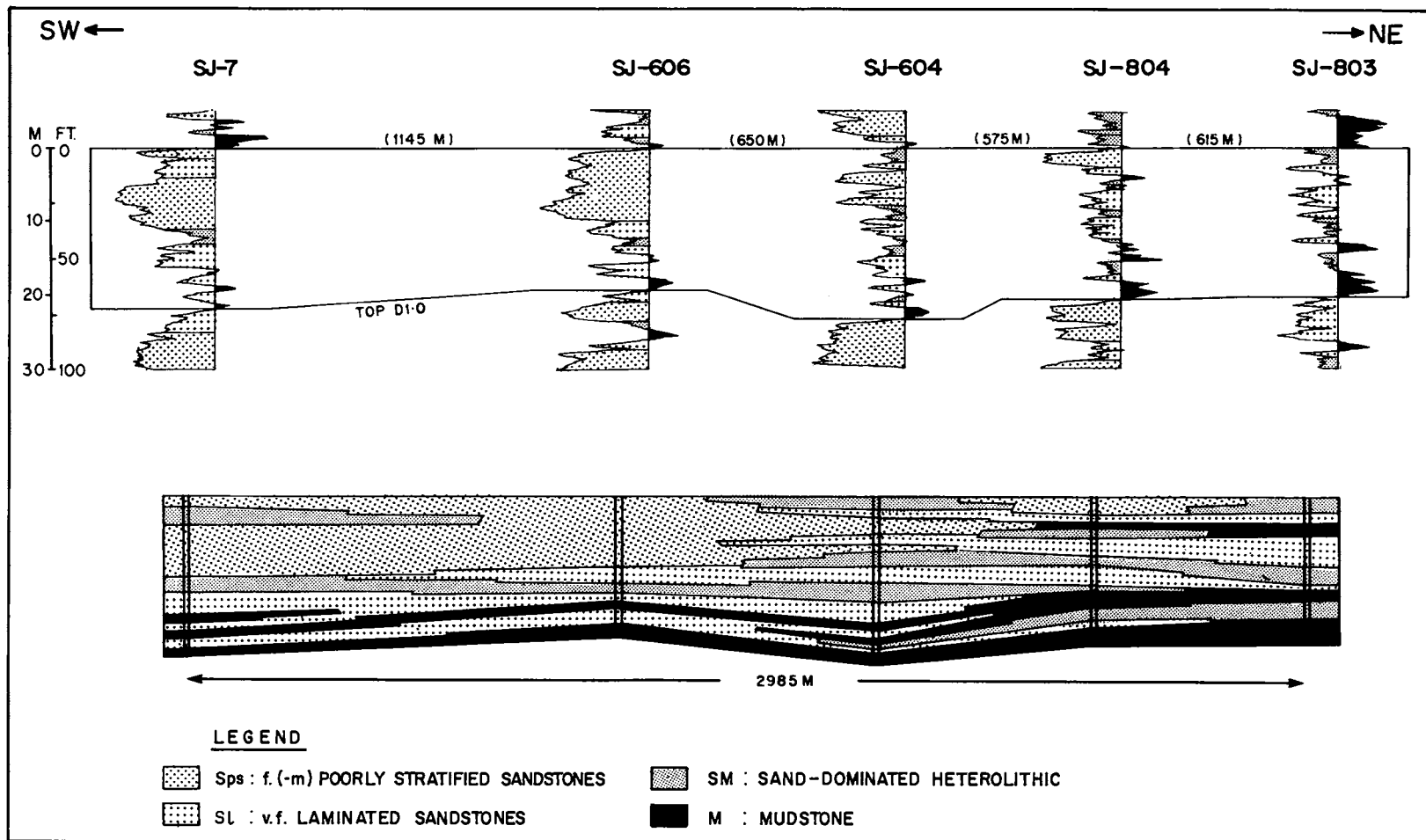


Figure 25 : Log facies correlation panel and interpreted facies distribution, C2.0 reservoir unit.

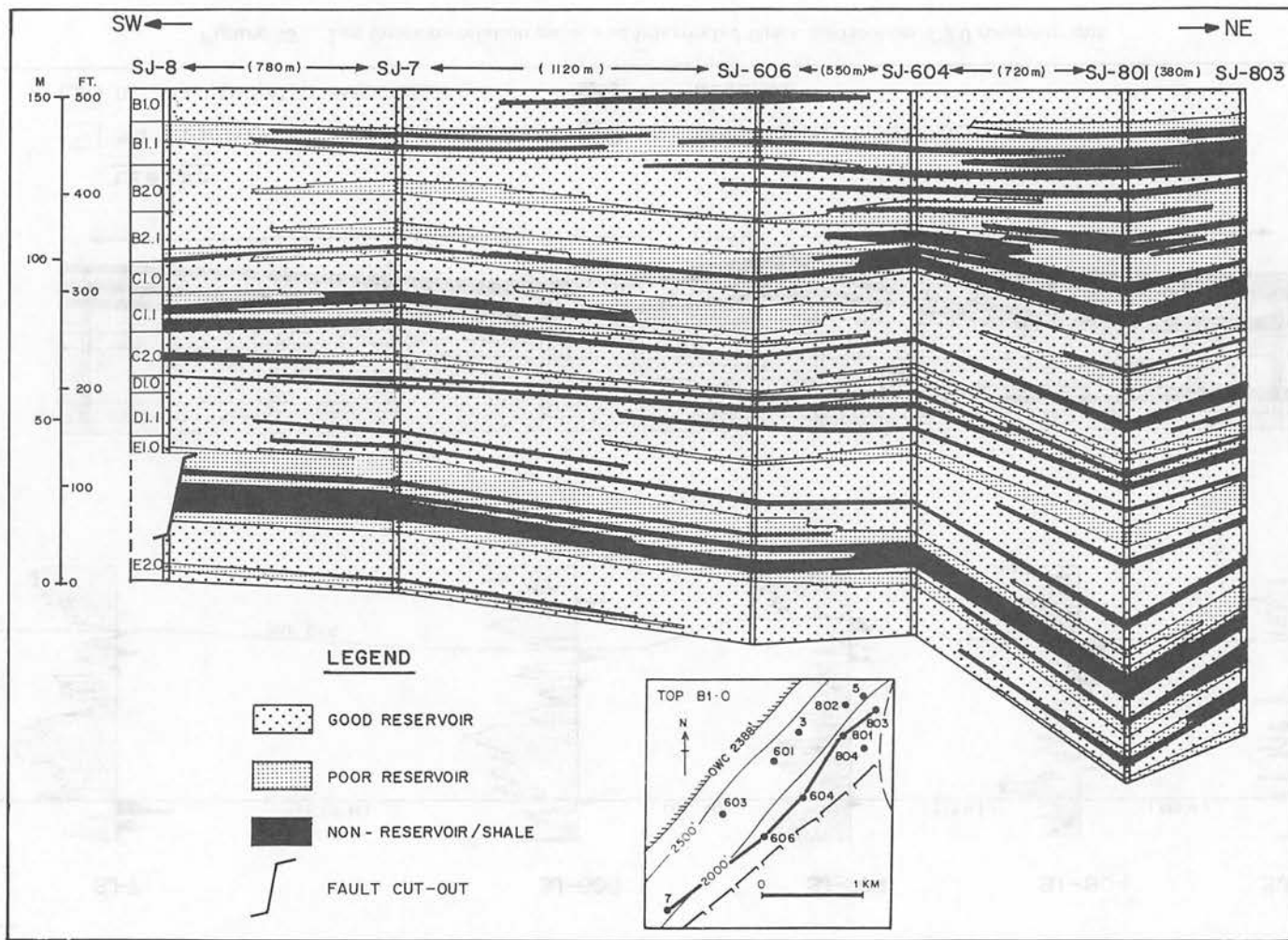


Figure 26 : Reservoir geological model of the updip area of the NW Flank.

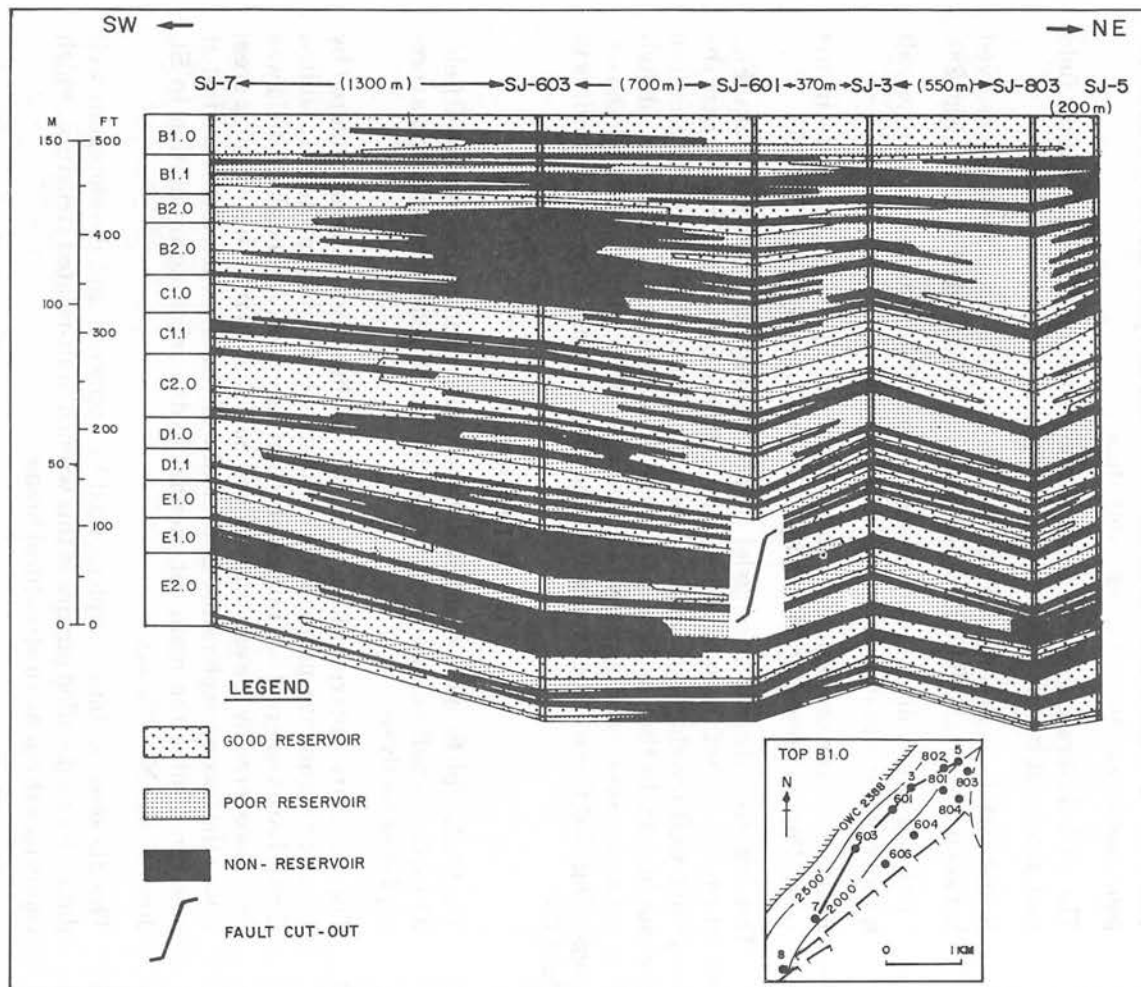


Figure 27 : Reservoir geological model of the downdip area of the NW Flank.

- The reservoir sequence thickens but becomes more distal towards the northeast with an increase in both the number and thickness of intercalated shales, and also a general decrease in sand quality (Fig. 26).
- The reservoirs thicken towards the northeast and pass laterally into either poor quality sands or non-reservoir shales.
- The shale layers are mainly concentrated in the northern part of the field and pinch-out in a southwestward direction.
- Rapid variations in sand quality can occur over short distances as observed between SJ-606 and SJ-603, which are only 1575 ft / 480 m apart (Fig. 28).
- The gross reservoir interval becomes thinner, but also improves in overall quality (eg. increasing N/G), towards the south.
- Reservoir interconnectedness is variable; it is good to moderate in the crestal/updip area (Fig. 26) and poor in the downdip area (Fig. 27).

This reservoir distribution model is supported by RFT pressure data (Fig. 29), which shows that the sand units in the southern part of the field (where the sands are well developed and have less intercalated shales) are in pressure communication. In the northern part of the field differential pressure subdivision exists between sand units, which coincides with the intercalated shales, suggesting that these shale layers are behaving as localised vertical barriers to fluid flow.

CONCLUSIONS

1. The St. Joseph field is a structurally and stratigraphically complex oil field, which has benefited significantly from both a 3D seismic survey and a core-log facies analysis.
2. The structural interpretation of St. Joseph has always been hindered by seismic data quality, particularly in the steeply dipping and heavily faulted Crestal Area where it has invariably been very poor. Although the field was first discovered by the exploration well SJ-1 drilled into this complex area, it was the second exploratory appraisal well (SJ-3) which discovered what now constitutes the main commercial hydrocarbon accumulation in St. Joseph (the NW Flank).
3. The 3D seismic data, supplemented by appraisal and development well data, gives a detailed picture of this wrench fault-related structure, which comprises three main structural areas:
 - The NW Flank is a relatively simple, virtually unfaulted area dipping uniformly (at ca. 20°) to the NW and containing some 95% of the recoverable reserves in St. Joseph.

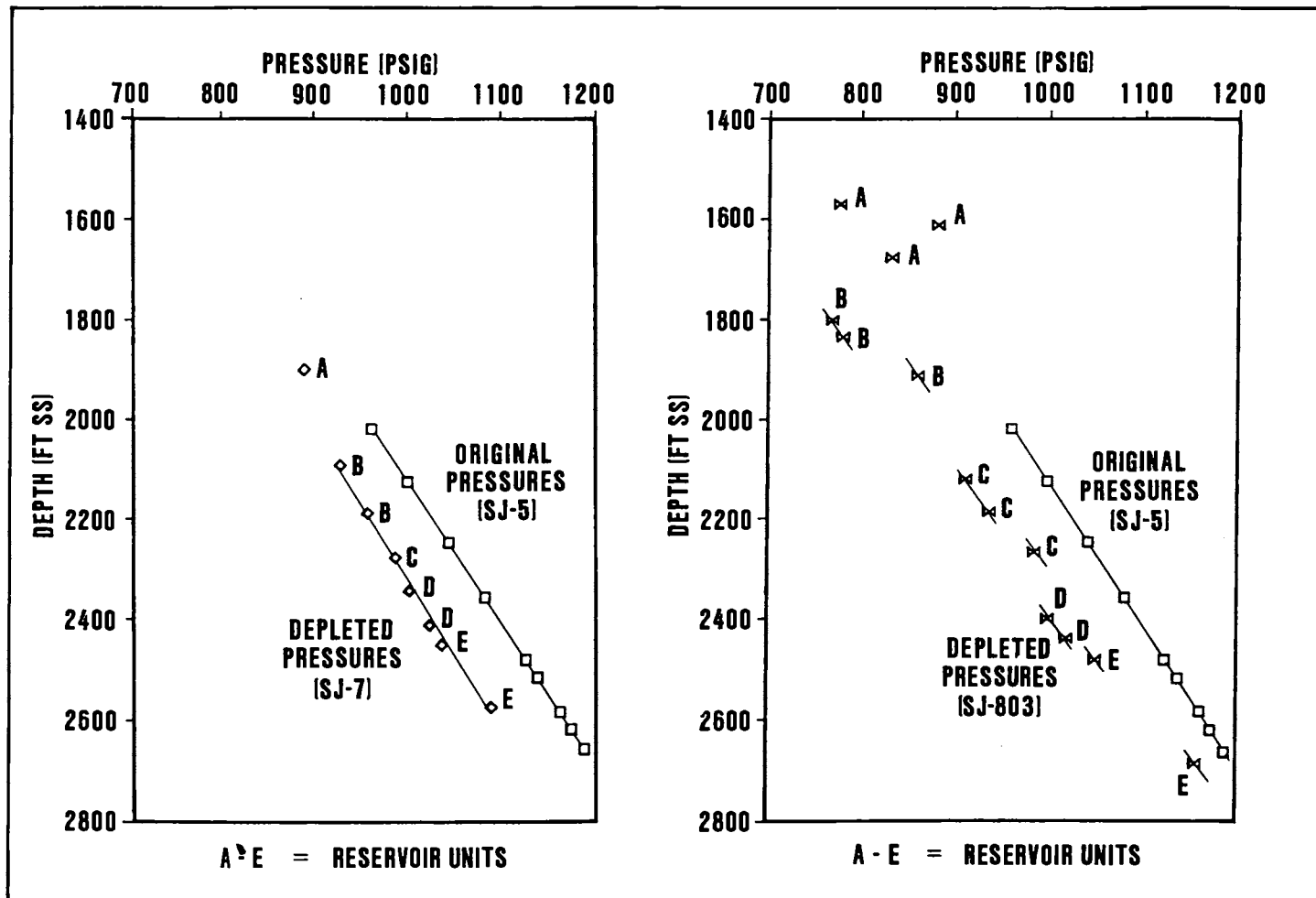


Figure 29 : RFT pressure measurements from the Upper Sands of the NW Flank.

- The Crestal Area is an intensely faulted zone with major through-going faults, steeply dipping beds and incomplete stratigraphies. It contains only minor oil reserves.
 - The SE Flank comprises a SE-dipping (10 - 30°) and moderately to strongly faulted area with negligible hydrocarbons.
4. The main benefits of the 3D seismic survey have been the following:
 - Improved delineation of the three main structural areas, particularly the important boundary between the NW Flank and the Crestal Area.
 - Enhanced quality and confidence of the structural definition of the NW Flank, including mapping of additional Intra-Stage IVC reservoir intervals.
 - Improved definition of the NE limit of the field.
 - Better location of both development wells, particularly in the updip part of the NW Flank, and drilling jackets.
 5. Accurate definition of the Crestal Area remains problematic even with 3D seismic, although it is better than previous vintages of 2D seismic.
 6. The main hydrocarbon reservoir on the NW Flank comprises the heterogeneous Upper Sand Unit (ca. 700 - 900 ft / 213 - 244m thick), which displays significant lateral variations in sand thickness, reservoir quality and shale layer distribution.
 7. Sedimentological studies of ca. 1600 ft (488 m) core demonstrate that the Upper Sand Unit comprises a composite interval of shallow marine (inner neritic to coastal), storm/wave-influenced sandstones and shales arranged in a number of coarsening/fining upwards sequences. They are interpreted as the product of repeated progradation (to the NW and NE) and transgression of coastal/nearshore sand bodies, possibly connected landward (SE) with either delta distributaries and/or coastal barriers.
 8. Continuous coring (800 ft / 244 m) of this unit in appraisal well SJ-7 provided a basis for a detailed core-log facies analysis to better define reservoir variability on the NW Flank. It enabled the interpretation of all uncored wells in terms of genetically-distinctive facies types.
 9. A reservoir geological model has been developed which provides a framework for mapping reservoir development/quality variations. In general better developed and/or higher quality sands occur in the Crestal Area and SE (updip area) and SW parts of the NW Flank. These pass downdip (NW) and along strike (NE) into lower quality, shalier deposits. Most shale layers are well-developed in the NE but becomes discontinuous to the SW.

10. The reservoir geological model was used to guide input into a full field, three dimensional reservoir simulation model. The latter has enables alternative recovery processes to be evaluated, leading to optimum oil recovery and improved reservoir management.
11. The combination of 3D seismic data and a core-derived facies analysis/reservoir geological model provides an ideal combination for unravelling the geological characteristics of this complex field.

ACKNOWLEDGEMENTS

This paper has benefitted from the work undertaken by several generations of Shell geologists and geophysicists who collectively have contributed to unravelling the geological characteristics of the St. Joseph field. Although too numerous to mention individually, the following are thanked for their respective contributions, from which we have drawn freely: B. van Hoorn and B.K. Levell (Exploration), J. Blokzijl and A. Guidou (Production Geology) and P. Cassidy (Production Seismology/3D Seismic Interpretation).

Permission to publish this paper was kindly granted by Shell Internationale Petroleum Maatschappij B.V., The Hague, Pecten Malaysia Co., Houston and PETRONAS, Kuala Lumpur.

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