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Reservoir Heterogeneities, in Fractured Fluvial Reservoirs of the Buchan Oilfield (Central North Sea)

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Résumé — Hétérogénéités du réservoir fluvial et fracturé du champ pétrolifère de Buchan (partie centrale de la mer du Nord) — Le réservoir pétrolier de Buchan, dans la mer du Nord, présente dans sa partie centrale une complexité du point de vue structural au niveau du Dévonien-Carbonifère. Ce réservoir se caractérise par une succession de séquences décroissantes, à dominance gréseuse de type chenaux en tresse.

L'analyse hiérarchique de la qualité du réservoir, à l'échelle microscopique (lames minces), à l'échelle moyenne ou méso (lithofaciès et séquences de faciès) et à grande échelle ou méga (plus d'une séquence), montre que le réservoir peut être divisé en six grandes unités. Cette subdivision a été réalisée en se basant sur les propriétés sédimentologiques, sur les valeurs de la perméabilité et de la porosité, ainsi que sur les réponses des logs électriques.

Les propriétés de ces unités aux échelles microscopique et moyenne, particulièrement la présence de fractures et les variations du coefficient de corrélation entre la porosité et le logarithme de la perméabilité, apportent une bonne contribution pour définir les zones efficaces et non efficaces du réservoir se trouvant dans ces unités.

La zone la plus efficace, située entre 2738 et 2788 m, est caractérisée par une prédominance de roches de type subarkose à quartzarénite fracturées. Cette zone diffère des autres zones gréseuses du réservoir par une préservation de la porosité intergranulaire primaire ainsi que par une porosité secondaire issue du système de fracturation présent. Les valeurs de la porosité et de la perméabilité peuvent atteindre jusqu'à 30,2 % pour la porosité et 1475 mD pour la perméabilité.

Une zone identique a été découverte, s'étendant presque tout le long du champ pétrolifère, et elle définit avec précision la partie la plus productive d'un point de vue qualité du réservoir.
Mots-clés : champ pétrolifère de Buchan, hétérogénéités du réservoir, évaluation de la zone productive.

Abstract — Reservoir Heterogeneities, in Fractured Fluvial Reservoirs of the Buchan Oilfield (Central North Sea) — *The Buchan Oilfield in the central North Sea is a structurally complex, pervasively fractured Upper Devonian-Carboniferous reservoir comprising vertically stacked, sandstone-dominated, fining-upward sequences deposited predominantly by braided streams.*

Hierarchical analysis of reservoir quality at the microscale (thin sections), mesoscale (lithofacies and facies sequences) and megascale (zones composed of more than one mesoscale sequence) levels shows that the reservoir can be divided into six megascale units based on their sedimentological properties, poroperm values and electric log response.

The microscale and mesoscale properties of these units, particularly the presence of fractures and variations in the correlation coefficient between the logarithm of permeability and porosity, provide a means of defining effective and non-effective reservoir zones, which correspond with, or occur within the units.

The most effective zone, between 2738 and 2788 m, consists predominantly of extensively fractured subarkoses which differ from other sandstones in the reservoir in that they contain more preserved primary intergranular porosity and secondary fracture porosity, with porosity values up to 30.2%, and permeabilities up to 1475 mD. This zone extends across most of the field where it defines, more precisely than has previously been possible, the best quality and most productive part of the reservoir section.

Keywords: Buchan Oilfield, reservoir heterogeneities, evaluating productive zone.

1 RESERVOIR HETEROGENEITIES

The Buchan Oilfield is located in the UK central North Sea some 150 km northeast of Aberdeen on the southwestern side of the Witch Ground graben in 115 m of water *(Fig. 1)*. It covers an area of about 24 km^2 and it lies within block 21/1a, extending westwards into *Texaco* block 20/5a.

The Buchan Field is an east-west-oriented titled horst block, draped and sealed by Lower Cretaceous mudstones of the Cromer Knoll Group Valhall Formation. The structure was initiated during late Jurassic extension and rifting, and when traced eastwards it passes into a major transcurrent fault zone, attributed to Palaeozoic fault reactivation. The horst structure was uplifted by at least 1000 m mainly during the Lower Cretaceous, although the precise age of uplift is uncertain. As a result the internal lithological subdivisions of the reservoir proposed by Andrews *et al.* (1990) and Edwards (1991) are poorly constrained, and in some cases the uppermost subdivisions have been differentially eroded off the crest of interfield block structures. In addition, pressure data from DST (Drill Stem Tests) reveals the presemnce of a normal pressure regime within the upper part of the section above the reservoir, passing through a thin transitional regime, into the highly overpressured regime of the reservoir itself (Hill and Smith, 1979).

Stratigraphically the Buchan Field consists of an Upper Devonian to Lower Carboniferous reservoir (Hill and Smith, 1979; Richards, 1985) up to 675 m thick, unconformably and erosively overlain by Cretaceous, locally developed Jurassic, Tertiary and Quaternary sediments *(Fig. 2)*.

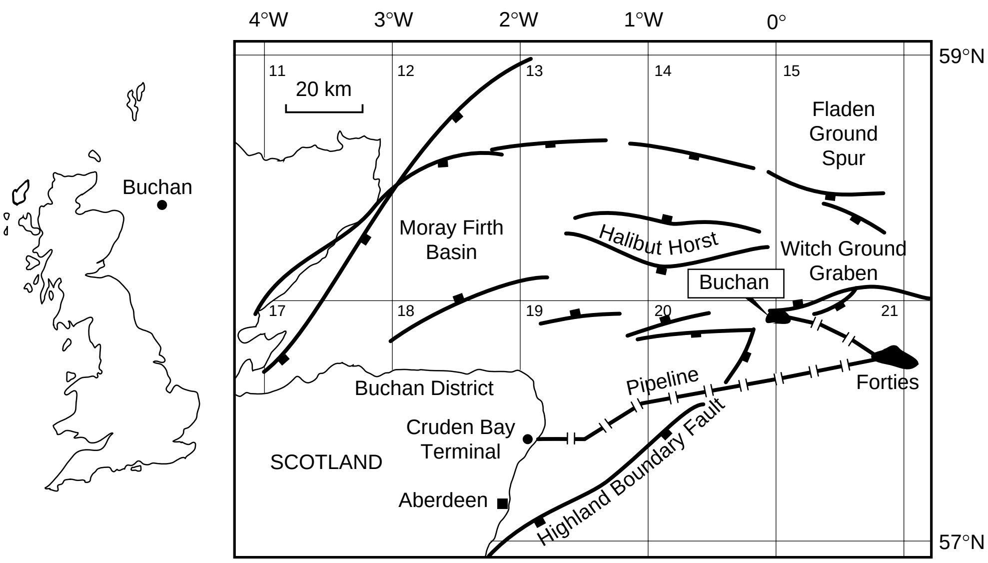


Figure 1

Location and structural setting of the Buchan Oilfield.

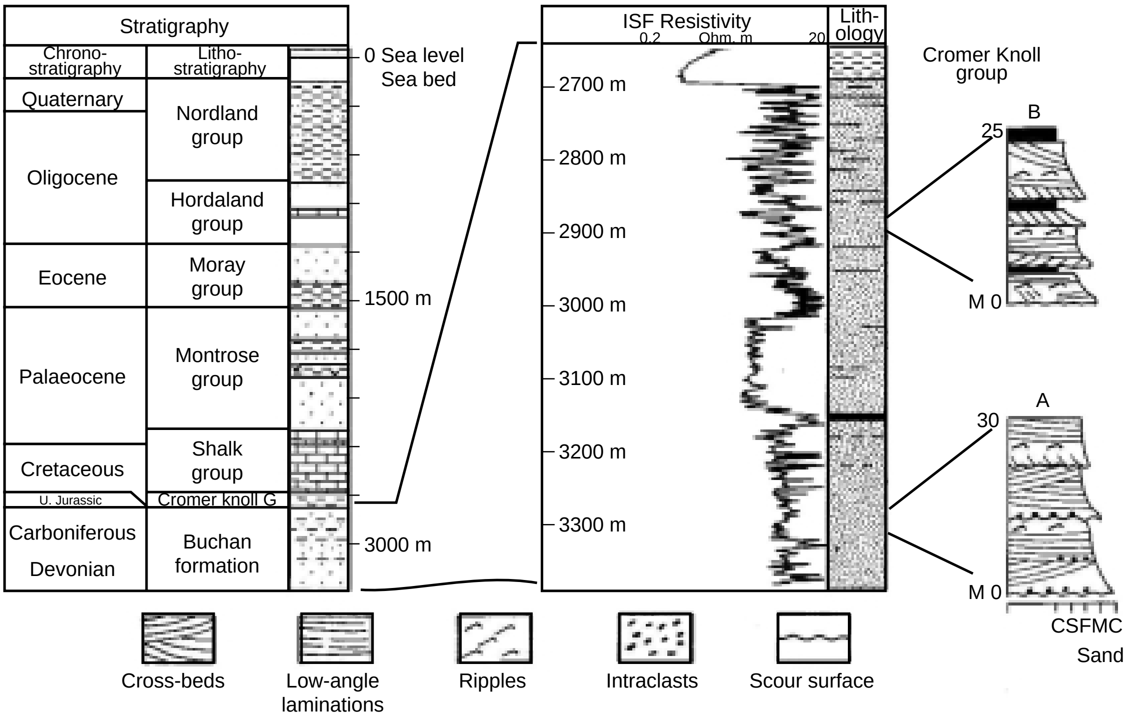


Figure 2

Stratigraphy of the Buchan Oilfield.

The reservoir section is composed of alluvial red beds similar to those encountered in the old red sandstone (ORS) of mainland Scotland. It is dominated by thin, muddy sandstones with lesser amounts of siltstone and mudstone arranged in vertically stacked, pedogenically influenced fining-upward sequences averaging from 3 to 5 m with a maximum thickness of about 10 m *(Fig. 2)*.

The sequences were deposited mainly by braided, low-sinuosity, ephemeral stream channels, draining part of an extensive desert area, located around latitude 15°S (Tarling, 1985). The sequences become progressively thinner towards the top of the reservoir interval concomitant with an overall fining-upward trend *(Fig. 2)* and increase in shale and pedogenic calcrete (Andrews *et al.*, 1990). These changes have been attributed to reduced source area relief and the development of more stable floodbasins, possibly drained by meandering streams (Richards, 1985), as the depositional system readjusted to the gradually decreasing gradients and energy levels. Because of the structural complexity of the reservoir, its internal heterogeneity and variable levels of production from different wells, a computer-based, hierarchical analysis of the reservoir was undertaken at the microscale (thin section petrography and diagenesis), mesoscale (lithofacies and facies sequences) and megascale (units composed of more than one mesoscale sequence) levels in order to assess their relative contributions to reservoir quality *(Fig. 3)*.

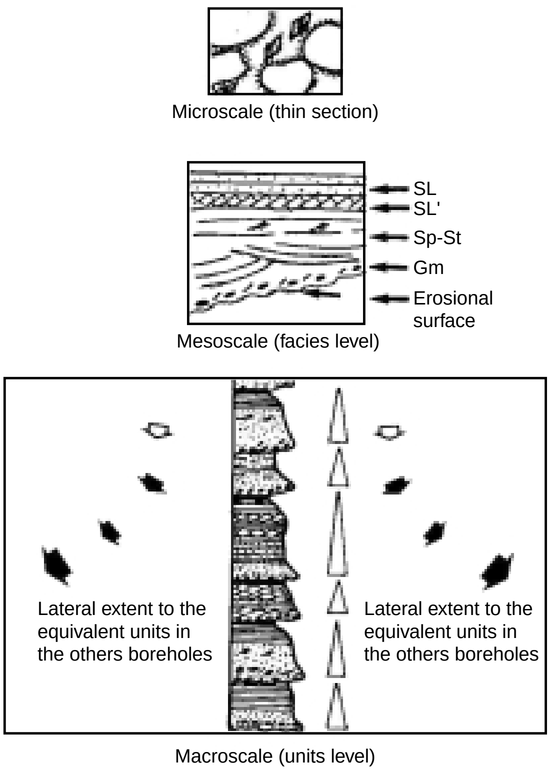


Figure 3

Hierarchical analysis of the reservoir section.

2 HIERARCHICAL ANALYSIS

The computer-generated flow chart *(Fig. 4)* shows the parameters and methodology on which this analysis of the Buchan Field is based. In order to assess the accuracy of this flow chart program, an artificial data has been used to test the ability of the program and to fulfil its objectives prior to its application. The test proved the program to be of potential value for assessing reservoir megascopic properties, which can be incorporated into a predictive reservoir model, and consequently for decision making at all levels of reservoir development. However, it should be stressed that the model can only be applied to sedimentary successions where facies and facies sequences are repeated throughout the succession, as in the Buchan Field. The more facies the sequence contains, the more difficult it is to apply the method, and as such it compares with the Markov-Chain analysis of facies sequences described by Walker (1990).

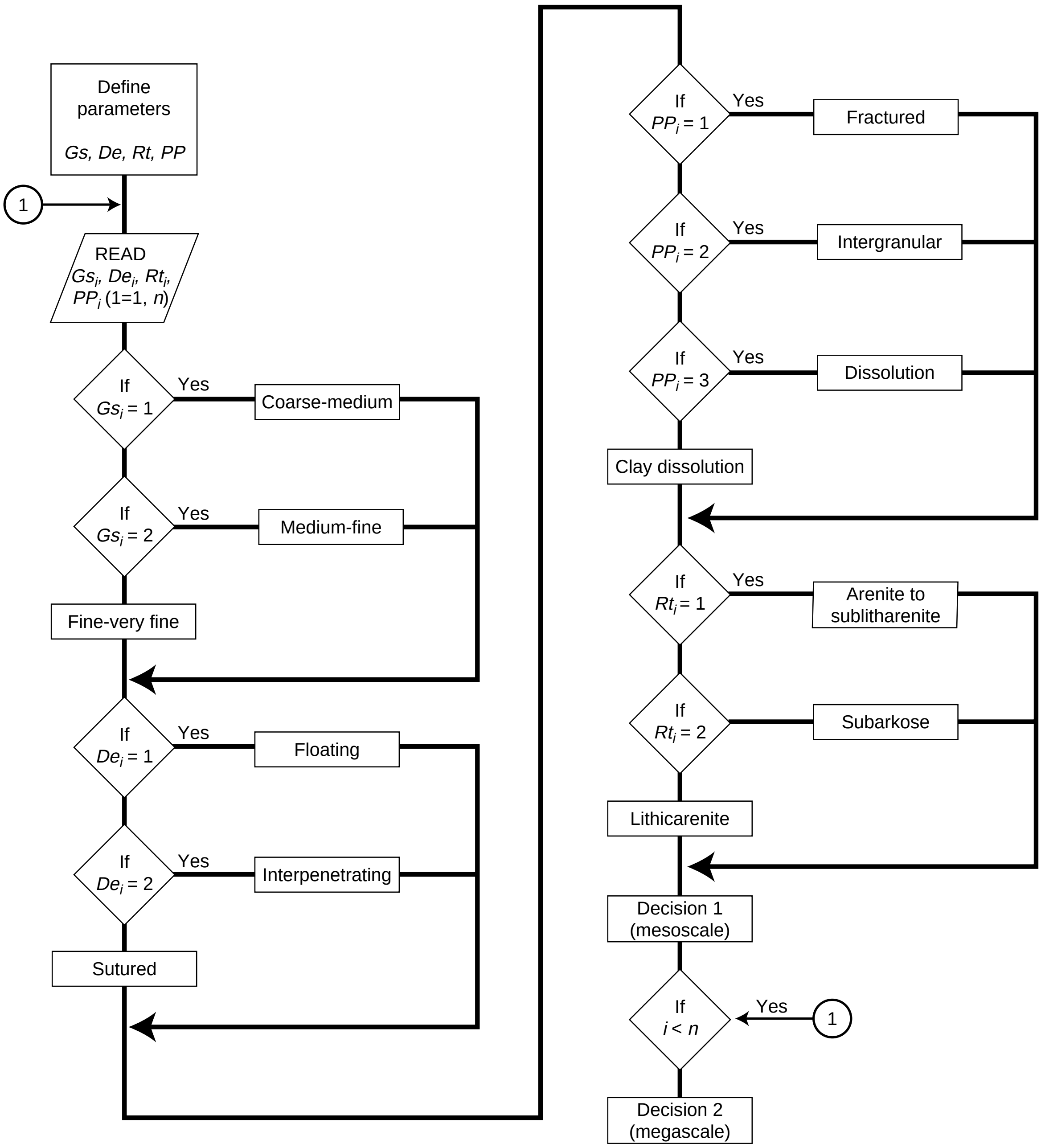


Figure 4

Flow chart program for hierarchical analysis of the Buchan Oilfield reservoir.

2.1 Microscale

Petrographic and diagenetic studies are based on thin sections cut from samples taken at 1 m intervals through some 440 m of core from well 21/1-6. The hydrocarbon bearing sandstones are poor to moderately sorted, immature to moderately mature sediments containing between 0.5% and 45% matrix, with an average of 8.5%. They are first-cycle sands which range in composition from subarkoses to lithic arenites and sublitharenites *(Fig. 5)* (Benzagouta, 1991; Edwards, 1991). The variable composition of the reservoir sandstones and their general northward thinning reflect derivation from mixed granitic, metamorphic and terrigenous provenance rocks located to the south. The variation in mineralogical composition also has an important control on reservoir heterogeneities at all hierarchical levels.

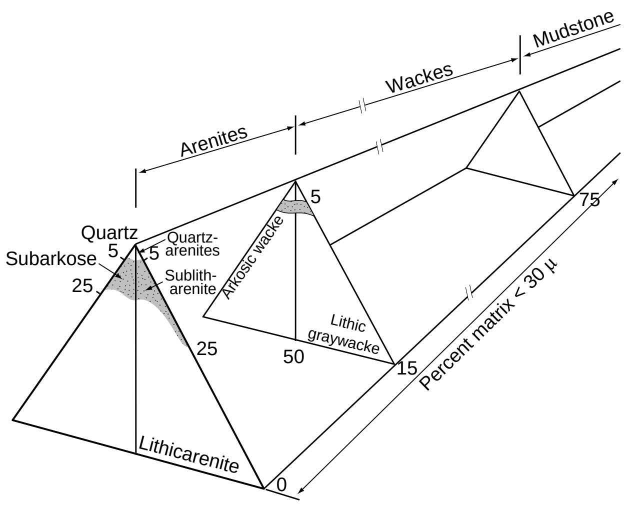


Figure 5

Sandstone composition in the Buchan Field.

The sandstones show some primary intergranular porosity and rare intragranular porosity in thin section, with porosity values ranging from 3% to 30%. However, very little of the original primary porosity has been preserved due to early pore-filling carbonate cements (mostly partially oxidised, Mg-poor, ferroan calcite) and illitic clay, identified by SEM (Scanning Electron Microscope) and EDAX analysis. These tend to be better developed in the sublitharenites, although the carbonate cement shows a rather patchy distribution with an overall increase with depth. Although the pore-fills occlude pore space, they possess some dissolution microporosity (pores not connected) and also help to preserve detrital framework grains, and pore volume, from the effects of significant mechanical compaction, thereby reducing grain contacts and pressure solution effects. Theoretical modelling suggests that the presence of supporting (load-bearing) cement in a sandstone undergoing compaction is capable of preserving more pore volume than it occupies (Stephenson *et al.*, 1992). Furthermore, secondary quartz overgrowths, which makes up as much as 3% of the whole rock throughout the reservoir are poorly developed in the presence of early load-bearing carbonate cements and diagenetic clay rims on detrital grains, which formed before pore-filling clays. The clay rims are generally better developed in the sublitharenites, particularly in the coarser-grained parts, due to their better intergranular porosity and fluid flow characteristics. A similar relationship was documented experimentally by Houseknecht (1988).

The amount of original porosity destroyed by compaction and cementation can by calculated according to the method of Houseknecht (1983, 1987), using an estimated original porosity of 35.5% for the Buchan Field (Benzagouta, 1991). The results show that the original porosity destroyed by compaction ranges from 44% to 60% (mean 57%), whereas the original porosity destroyed by cementation varies from 26% to 32.5% (mean 28%). Thus, the dominant effect on porosity loss in the Buchan Field is mechanical rather than chemical, an interpretation that is supported by the increase of concavo-convex interpenetrating grain contacts (absence of cement in some samples) and decrease in porosity with increase in depth, together with increased mineralisation of fractures at all hierarchical levels. However, the Houseknecht (1983, 1987) method can only be applied to those intervals in the reservoir where original porosity is preserved, as defined below. Most porosity at this hierarchical level is secondary porosity derived from:

- dissolution of existing minerals;
- dissolution of cements (mainly carbonate);
- the presence of micropores (0.2-0.3 µm) and macropores (10-20 µm);

and macropores contribute very little towards secondary porosity and, apart from the development of local high-permeability streaks (Edwards, 1991), they are not important. Leaching and partial to complete dissolution of framework grains, particularly feldspar (mainly k-feldspar), make a more significant contribution. For example, total porosity has a mean value of 10.32% (Edwards, 1991), of which 12%-18% is secondary porosity related to feldspar dissolution. This is most commonly developed in the more feldspar-rich subarkoses. These values for secondary porosity would have been higher but for the replacement of some of the altered feldspar by authigenic carbonate and clay. Evidence of this relationship between feldspar dissolution and secondary porosity is seen in the presence of relict feldspars in secondary pores. Moreover, this secondary porosity is associated with kaolinite precipitation and illitization, illite being the most stable clay mineral phase under the diagenetic conditions prevailing in the Buchan Field (Benzagouta, 1991). However, secondary porosity due to dissolution of framework grains is insignificant compared to that derived from fractures, which are pervasive throughout the Buchan Field reservoir. In thin section numerous fractures can be seen cutting through individual grains *(Fig. 6)* or several grains *(Fig. 7)*, as well as the whole rock (mesoscale level) concomitant with an increase in fracture size. They may be open to partly open or completely occluded by authigenic minerals, particularly calcite and quartz. Some of the grain fractures are filled by clays, especially fractures in quartz grains. These fractures are orientated in different directions and vary in size according to the size of the detrital grains. Clay-filling fractures occur in close spatial relationship to pore-filling clays, and clearly postdate the pressures responsible for grain fracturing. Moreover, grain fractures are not confined to detrital grains but extend into adjacent cements (Narr, 1977), and owe their origin mainly to burial compaction and overpressuring of the reservoir which have kept them open to half open. Fractures are most common in the more brittle, quartz-rich sandstones due to their greater "index strength", that is, the degree of rock resistance under the effect of constraints, and the confining pressure (Price, 1966). A similar relationship between fractures and lithology was found by Harris and Rast (1960), Lucas and Drexeler (1976) and Futchbauer (1974).

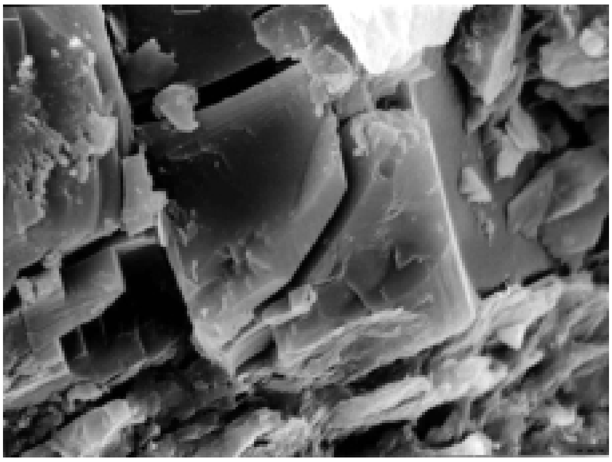
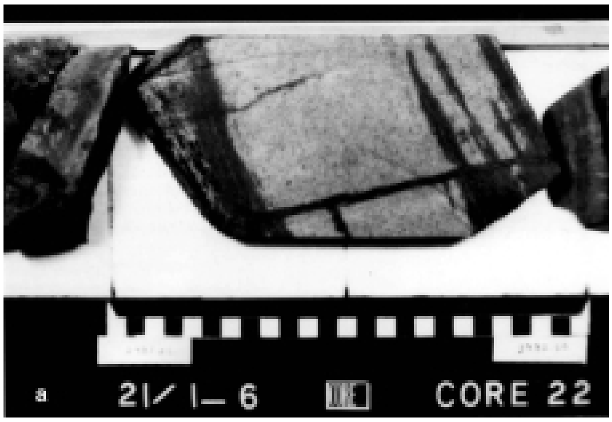


Figure 6

Scanning electron photomicrograph showing fracture cutting through a single quartz grain (× 2000).

The importance of fractures to reservoir quality at this hierarchical level is demonstrated by the relationship between grain size and porosity and permeability. Grain size analysis of the Buchan Field reservoir sandstones shows a grain size distribution characterised by a significant amount of fines and a reduced coarse tail *(Fig. 8)*. The mean grain size varies from 1.3 phi to 3.9 phi with an average of 2.52 phi, and sorting from 1.91 to 0.88 with a mean of 1.55. In the Buchan Field no clear relationship exists between porosity and permeability, and grain size, probably due to the predominantly small grain size of the sediments *(Fig. 8)*.



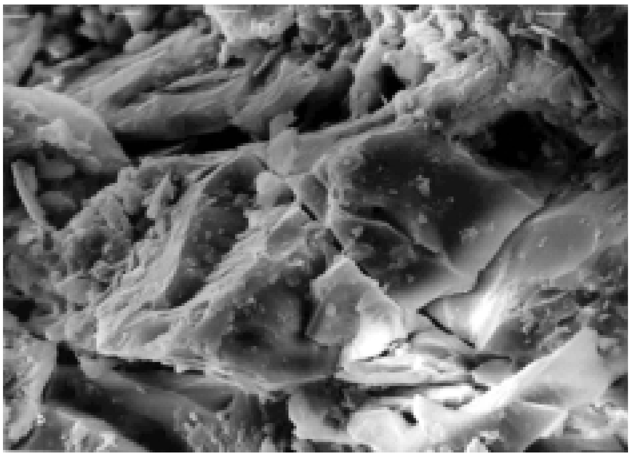


Figure 7

Scanning electron photomicrograph showing fracture cutting through several quartz grains (× 2000).

Since the fine-grained components of sediments tend to occupy available pore spaces, the overall porosity and permeability are reduced. Furthermore, sediments with a mixture of very fine to fine, medium and rarely coarse grains *(Fig. 8)* are unlikely to produce preserved primary porosities exceeding 25% and permeabilities in excess of 1 D (Pryor, 1973; Beard and Weyl, 1973; Selley, 1985; Pettijohn *et al.*, 1987) found in the Buchan Field. In view of this, such high values for porosity and permeability are most probably related to secondary porosity, and permeability fracturing, and not grain size. One of the major incentives for this study was to try and identify those parts of the succession that are most prone to fracturing, at both the microscale and mesoscale hierarchical levels, and assess their contribution to reservoir permeability and porosity.

2.2 Mesoscale

This hierarchical level is concerned primarily with reservoir characteristics seen in the core, within individual core samples, lithofacies and lithofacies sequence. Porosity and permeability measurements, based on more than 1000 core samples, show that permeability ranges from 1.5 D to 0.01 mD, with porosity fluctuating between 3% and 30% *(Fig. 9)*. The results of this study demonstrate the relationship between individual lithofacies and porosity and permeability, as well as the heterogeneous distribution of the poroperm values. The relationships between lithofacies types electric logs and poroperm values are plotted in Figure 9. Although certain lithofacies types appear to have a more significant influence on reservoir properties than others (Sp-St, SR, SL and SL') the overall permeability values are low, including the foreset laminae of Sp-St and SR lithofacies which normally have better than average permeabilities (Kortekas, 1983). Also, individual cross-bedded units (Sp-St) are commonly separated by thin juxtaposed, impermeable claystone interbeds which affect porosity by creating capillary pressure and mechanically trapping oil in *cul-de-sacs*, as evidenced by the occasional presence of oil in *cul-de-sacs* within intergranular pores (Selley, 1985). Moreover, capillary pressure is able to retain 35% to 40% of oil in place. Unfortunately the lack of an adequate number of samples precludes quantification of the capillary pressure in the Buchan Field, although this has been done for other fields (Waggoner *et al.*, 1986).

Allen (1978) has shown that channel sandstone interconnectedness is mainly controlled by the sand/shale ratio, and when this ratio exceeds a threshold value of 0.5 to 0.55 the degree of sandbody connectivity increases markedly. The architectural building block in the Buchan Field reservoir is a 3-5 m thick fining-upward sequence comprising a compound channel sandbody overlain by a lesser amount of overbank fines, giving a sand/shale ratio that exceeds Allen's (1978) threshold value. Accordingly, the degree of connectivity between individual sandstones is generally good, although some sandbodies appear to be locally isolated and poorly connected across low-permeability shale and siltstone barriers.

A characteristic feature of the channel sandbodies is the presence of abundant interconnected to isolated small shale lenses showing a preferred horizontal to subhorizontal fabric. Thin section examination of the interconnected shale lenses shows that they constitute the main microbarrier to fluid movement, and that they may isolate otherwise effective areas within the reservoir. Owing to their horizontal orientation the shale lenses reduce total permeability and produce a distinction between Kv and Kh, although their patchy distribution does not seriously affect the connectivity of the reservoir sandbodies. The isolated shale lenses only affect petrophysical characteristics to the extent that they occupy rock volume and create zones of locally ineffective microporosity.

Analysis of fractures at this hierarchical level shows a preferred vertical to subvertical orientation, with an average

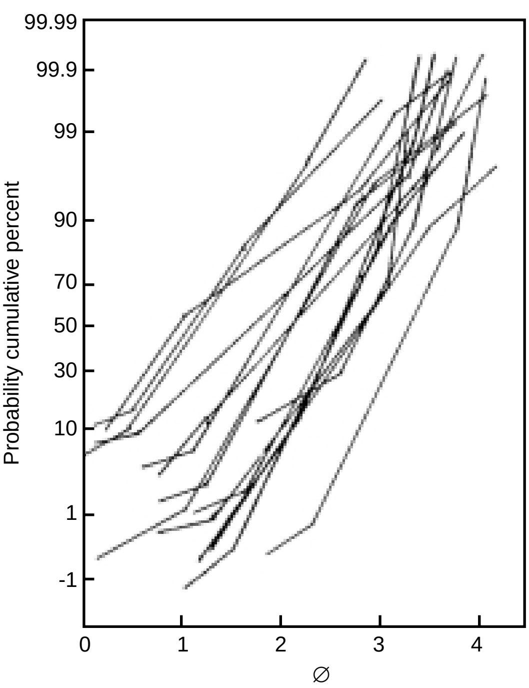


Figure 8

Log probability plot of Buchan Oilfield reservoir sandstone samples.

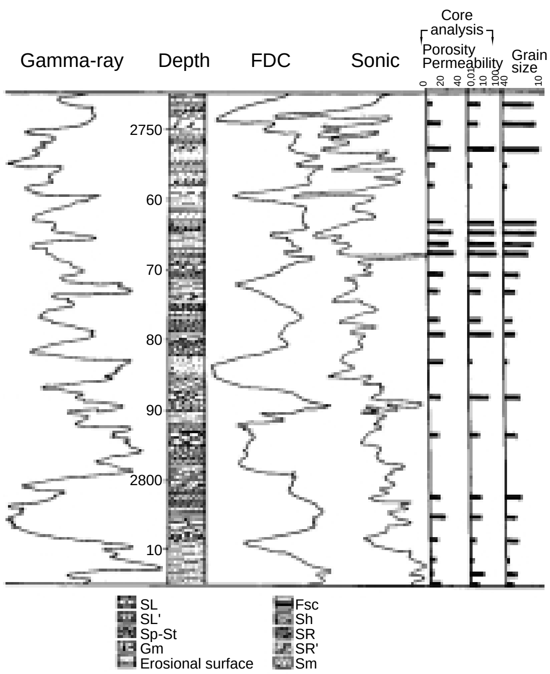


Figure 9

Electric log poroperm and grain size analysis of lithofacies and lithofacies sequences in a selected interval (well 21/1-6).

density of 5-40 fractures per metre of core. The fractures can be divided into two interrelated types primary fractures and secondary fractures. Primary fractures range from 12 to 18 cm long and 0.3 to 0.4 cm wide, and they are partially to completely filled, mainly by carbonate (late diagenetic calcite and dolomite) or quartz as in the grain (microscale) fractures. Other fracture-filling minerals include baryte, galena, sphalerite and pyrite (Edwards, 1991). Late diagenetic calcite and dolomite also alter and replace some of the detrital minerals, including quartz and feldspar. Details of the diagenesis of the Buchan Field reservoir are given in Benzagouta (1991).

Secondary fractures are smaller ramifying offshoots of the main primary fractures, but they show no preferred orientation. The fractures, which range from 2 to 6 cm long, are generally less than 0.4 cm wide, and are open to half open or filled, mainly by quartz or carbonate cements. The carbonate cements commonly fill fractures as single crystals, and exhibit surface textures which reflect different degrees of alteration. Primary fractures at the mesoscale level have a similar orientation to that of adjacent faults, suggesting that both faulting and fracturing owe their origin to the same tectonic stresses. Price (1966) found that extensional failure, as in the Buchan Field, leads to the development of a single main orientation for both faulting and associated fractures, whereas compressive failure produces a twofold fracture orientation (conjugate shear failure). Faulting of the field ceased by the beginning of chalk deposition, although minor adjustments across major faults persisted until the Maastrichtian (Edwards, 1991).

Analysis of the relationship between poroperm values and fractures is revealing. Some porous core samples, for example, have little or no permeability, yet oil is found seeping from the edges of core fractures. Other non-porous core samples have a high permeability, and fractures soaked with oil. Thus, both non-porous and non-permeable rocks acquire reservoir properties because of the presence of fractures. In contrast to this, parts of the Buchan Field have very little porosity and permeability despite the presence of fractures. This suggests that the relationship between fractures and the poroperm values depends not just on the presence of fractures and fracture density, but also on the type of fractures *(Fig. 10)*. For example, fractures in the lower part of the reservoir section have a high density, but are mostly filled by minerals and sedimentary material, whereas in the upper part of the reservoir section, where fracture density is also high, they are mostly unfilled. Moreover, the fracture fill may have been subjected to dissolution effects creating a second cycle of fracture porosity.

2.3 Megascale

At the megascale level, the reservoir has been divided up into six units *(Fig. 11)*, each unit being composed of more than one mesoscale sequence. Because most of the lower unit 6 occurs below the oil-water contact (OWC), and does not produce oil, it has not been considered in the analysis. A simpler fourfold subdivision of the reservoir was recognised by Andrews *et al.* (1990) and Edwards (1991), with the

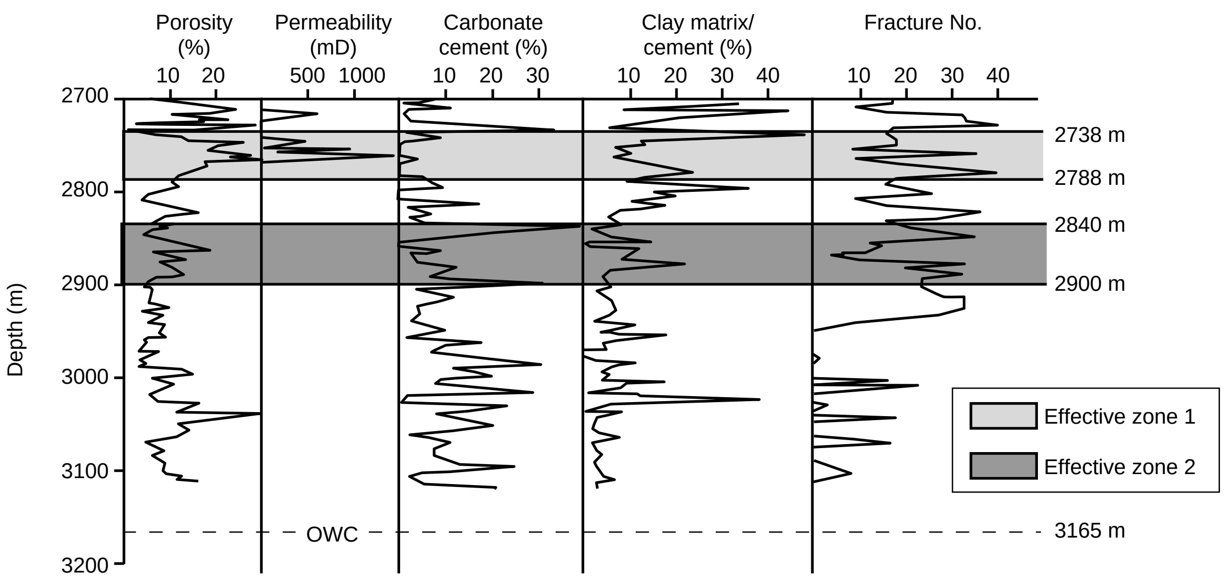


Figure 10

Relation between porosity, permeability, carbonate cement, clay matrix and fractures in a selected interval (well 21/1-6).

lowermost unit located mainly below the OWC. The volume of shale in these units *(Vsh)*, calculated on the basis of gamma-ray readings (Schlumberger, 1972), varies from 40% to 70%. Such high values for the volume of shale reflect the presence of pure clay zones and the dominance of fine-grained, muddy and micaceous sediments of overbank floodplain origin belonging to the Fsc lithofacies (Benzagouta, 1991). Low shale values reflect the dominance within the reservoir interval of coarser-grained channel sand deposits, especially the microconglomerate (Gm) and cross-bedded (Sp-St) lithofacies from the lower part of channel sandbodies. Even effective reservoir units, with high sandstone/shale ratio, may contain muddy, micaceous sandstones and relatively large volume of shale (up to 58%). Nevertheless, they still contain a number of well-defined but relatively thin, clean sandstone where the gamma-ray deflection is at its lowest level (20-25°API). Major controls on reservoir properties at this hierarchical level are the lateral continuity and vertical connectivity between major units. The horizontal and vertical extent of these units has been plotted on two selected cross-sections from N-S and E-W across the field *(Fig. 11)*. These provide a means of quantifying reservoir properties by looking at the microscale and mesoscale properties of the units, in terms of the computerised flow chart *(Fig. 4)*. This in turn enables the reservoir to be divided up into effective and non-effective zones, as a function of reservoir quality *(Fig. 11)*.

Attempts to correlate different sedimentological parameters and petrophysical properties at the microscale and mesoscale levels have proved disappointing. However, at the megascale level a useful correlation has been established between the logarithm of permeability and porosity *(Fig. 12)*. Moreover, variations in the correlation coefficient occur between different zones, with the highest values signifying the most effective zones within the reservoir, where reservoir quality is better developed. Accordingly, the two most effective zones in the reservoir, with the highest correlation coefficients of 0.79 and 0.75 respectively, are located in the interval 2738-2788 m (equivalent to unit 2) and 2840-2900 m well 21/1-6 (bottom of unit 3) *(Fig. 11)*.

However, the overall porosity and permeability are considerably less, and the grain size smaller, in the interval 2840-2900 m (Benzagouta, 1991).

At the microscale level the most effective of the two zones, between 2738 and 2788 m, is composed predominantly of medium-grained, moderately sorted, relatively quartz-rich (53%-70%) subarkosic sandstones with minor sublitharenites (Benzagouta, 1991). The main differences are that they contain comparatively little clay matrix (6%-24.5% with an average of 11%), and carbonate cement is absent or present in minor amounts (< 9%) *(Fig. 9)*. The presence of a limited amount of early carbonate cement, supporting the detrital grain framework, favours the preservation of primary intergranular porosity (Bjorlykke, 1988). In addition, secondary pore-filling quartz overgrowths and sutured, interpenetrating grain contacts are poorly developed. This is attributed to the inhibiting effect of numerous early-formed diagenetic clay rims and pore linings, and the effect of overpressure reducing compaction and grain to grain stress. These diagenetic factors have helped to preserve more primarily porosity in this zone than in any other parts of the core. In contrast, secondary porosity due to feldspar dissolution is relatively minor. This reflects the low feldspar content of these sandstones (<10%) and the replacement of some of the altered feldspar by carbonate and clay. An additional factor here may be the reduction in water flow and potential for secondary porosity in strongly overpressured areas of the reservoir.

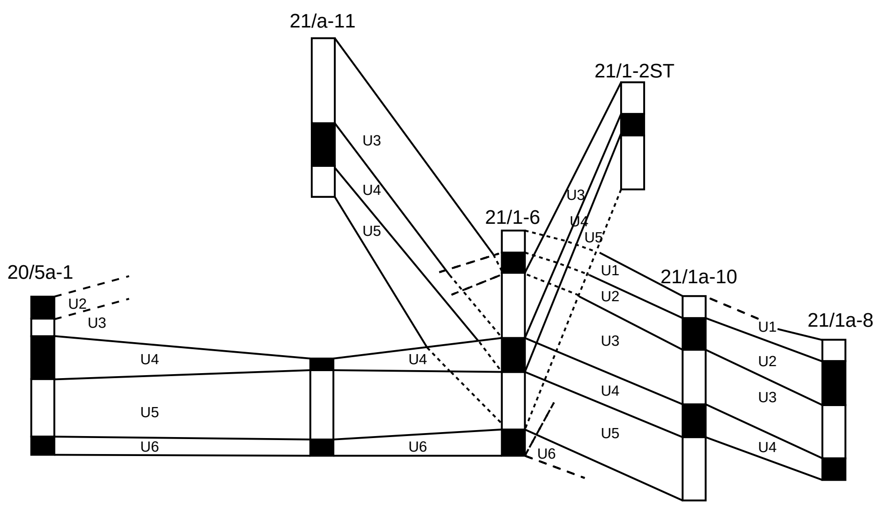


Figure 11

Cross-section showing subdivision of the reservoir into units. (The correlation coefficient for the entire reservoir sequence is 0.66.)

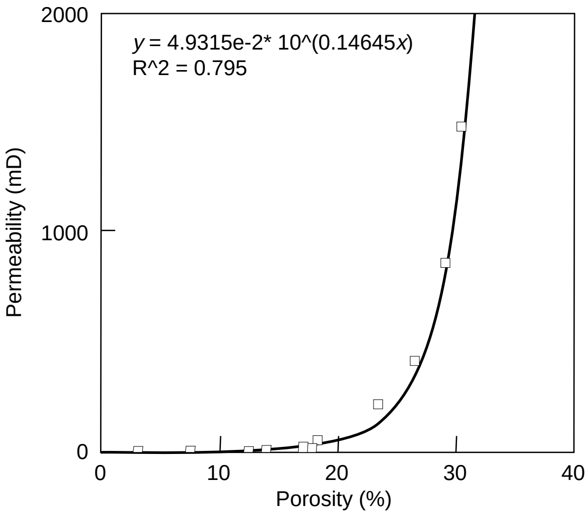


Figure 12

Relation permeability *versus* porosity in the reservoir interval 2738-2788 m.

Within the zone 2738-2788 m, porosity values range from 13% to 30.2% *(Fig. 11)* with an average porosity of 9.2% with a range from 6.3% to 10.4% for this lithofacies zone 2, which includes the interval 2738-2788 m. Permeability values range from 0.48 to 1475 mD *(Fig. 9)* with an average of 304 mD. However, the best poroperm values within this zone, of 30.2% and 1475 mD respectively, occur between 2753 and 2779 m where fracture density is only 8 fractures per metre of core *(Fig. 9)*. In contrast that part of the core with a maximum fracture density of 40 fractures per metre has much lower poroperm values of 16.7% and 15 mD respectively. Thus, even though fracture density is high throughout most of this zone, compared to the rest of the core, the most significant factor influencing poroperm values is not the number of fractures but the proportion of fractures which are open and unfilled by minerals.

At the mesoscale level, the zone 2738-2788 m is characterised by a dominance of channel sand deposits (Fig. 17 in Andrews *et al.*, 1990), a high sand/shale ratio and the presence of Sp-St (cross-bedded) lithofacies which is more abundant in this zone than in any other part of the reservoir *(Table 1)*. At the same time the proportion of overbank fines (Fsc lithofacies) is relatively high compared to other parts of the reservoir succession, which shows an increasing sand content with depth *(Table 1)*.

The frequency distribution of facies indicates that the finer grained SL (upper flow regime with parallel laminated sandstone) and SL' (upper flow regime with subhorizontal to inclined laminated sandstone) lithofacies increase markedly in abundance at depth below 2788 m, concomitant with a similar decrease in the Sp-St (cross-bedded sandstone) and Gm (structureless microconglomerate) lithofacies *(Table 1)*. This relationship is attributed to the shallower and more ephemeral nature of the stream channels during deposition of this lower part of the reservoir, in response to climatic and tectonic factors. Furthermore, the SL and SL' lithofacies generally contain more filled fractures than other facies, and as a result the reservoir quality is poor and non-productive. At the megascale level the zone 2738-2788 m consists predominantly of multistorey and multilateral, interconnected channel sandbodies as depicted by Andrews *et al.* (1990).

SUMMARY AND CONCLUSIONS

Reservoir heterogeneities are one of the most important factors in evaluating reservoir quality. Thus, any improvement in our understanding of reservoir heterogeneities, and their quantification, leads to the development of better geological models and more efficient reservoir modelling. In the Buchan Field, a computer-based hierarchical analysis of the heterogeneous, alluvial sandbody reservoir has established the presence of a number of effective and non-effective zones. These zones correspond with, or occur within the reservoir units defined on the basis of their sedimentological properties, electric logs and statistical analysis of poroperm relationships. These units serve as the fundamental building block within the reservoir, not only for

TABLE 1

Facies distribution *versus* depth

	Fsc	Sh	SR	SR'	SL	SL'	Sp-St	Sm	Gm	Total
2700-2738	20.9	25.3	5.9	3	12	0	10.5	1.5	20.9	67
2738-2788	13.1	15.8	10.5	5.1	15.8	2.7	15.8	2.7	18.5	38
2788-2840	5.3	8	14.6	8	28	21.3	4	1.5	9.3	75
2840-2900	8.6	10.3	5.2	7.8	28.4	23.3	6.9	5.2	4.4	116
2900-2940	3.6	1.2	12.1	14.1	33.8	23	2.5	7.2	2.5	83
2940-3010	10.7	1.5	9	4.6	36.4	28.8	3	0	6	66
3010-3040	6.9	2.1	7	5	37	28.7	5.1	1.2	7	51.5
3040-3116	11.9	5.6	3	8.9	21.2	19.5	10	0.8	19.5	73

testing the sensitivity of the reservoir model, but also as a basis for further work on the Buchan Field or similar reservoirs elsewhere.

The distribution of these units, when plotted on a fence diagram *(Fig. 11)*, shows that all units are present in reference to well 21/1-6, where they range from 35 to 118 m thickness. When traced across, the units vary in their lateral extent and thickness, even though the distance between individual wells is generally less than 1 km. In wells 21/1-2ST, 21/1a-11 and 21/1-7ST, only three of the six units recognised in well 21/1-6 are present. This interval scale lateral discontinuity of strata has an important effect on reservoir quality and is typical of many sandbody reservoirs. It is also a major problem in subsurface wireline log correlations in some North Sea gasfields, especially in the coal measure in the southern North Sea. In the Buchan Field these discontinuities can be attributed to two main factors:

– erosion of strata during and after deposition;
– rapid facies changes and their irregular distribution of fluvial channel sandbodies due to variable channel discharge regime (dry, semi-arid climate), patterns of channel shifting and their tectonic setting.

Edwards (1991) divided the Buchan Field reservoir into four lithofacies zones on the basis of electric log and sedimentological characteristics. These lithofacies, which could be identified over most of the field, correspond to changes in the depositional environment of the reservoir sequence. Edwards (1991) showed that the most effective part of the reservoir occurred towards the top, between 2700 and 2900 m, within his lithofacies 2. This is equivalent to the greater part of unit D of Andrews *et al.* (1990), who also divided the reservoir interval into four parts. This part of the reservoir is characterised by increasing proportions of shale and pedogenic calcrete nodules within overbank fines, as the succession passes from a braided to a meandering channel depositional system (fining-upward trend) that straddles the Devonian-Carboniferous boundary (Edwards, 1991). Although reservoir quality is reduced by the increased levels of shale, calcrete and shaley sandstone in this part of the reservoir, the density of open fractures is very high. However, hierarchical analysis provides a means of more closely identifying which specific parts of this 200 m thick productive reservoir intervals (lithofacies 2 of Edwards, 1991) possess the best reservoir quality. This shows that the most effective zone in well 21/1-6 occurs between 2738 and 2788 m, in the upper part of Andrews *et al.* (1990) unit D (our unit 2) where it coincides with a less shaley, sandstone-dominated part of the reservoir succession. This zone has also been recognised in wells 21/1a-10, 21/1a-8 and 21/5a-1, and may be present in 21/1-7ST. The data of Edwards (1991) suggests that this zone may also be present in wells 21/1a-9 and 21/1a-14, which were not included in this study. It has not been found in wells 21/1a-11 and 21/1-2ST, although the second most effective zone identified in reference to well 21/1-6, between 2840 and 2900 m, does occur *(Fig. 9)*.

Current production is exclusively from lithofacies zones 1 and 2 in the upper part of the reservoir, and PLT logs indicate that production was mainly from thin, discrete intervals within these lithofacies zones. Hierarchical analysis suggests that the most productive zone is a 50 m thick, channel sand-dominated interval within parts of Edwards (1991) unit D. Production figures for the field show that well 21/1-6 is currently the best producer with rates varying from 5319 to 3325 stb/d. This is followed in turn by wells 21/1-6-7ST (3667-2831 stb/d), 20/5a-1 (2435-1574 stb/d), 921/1a-11 (2840-860 stb/d), 21/2-ST (2226-1267 stb/d) and 21/1a-8 (808-624 stb/d) (*BP*, written communication). Well 21/1a-8 has the poorest production figures despite intersecting the most effective interval in the reservoir (2738-2788 m) on the south side of the field. A possible reason for this anomaly is that it occupies an intrafield fault block on the southern, deeper flank of the Buchan structure where poroperm values tend to fall off and mineralisation and filling of fractures increase, compared to the central area (Edwards, 1991). Wells 21/1a-11 and 21/1-2ST only intersect the second most effective zone in the reservoir between 2840 and 2900 m. This is consistent with their more moderate production figures.

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