POST-DRILLING ANALYSIS OF THE NORTH FALKLAND BASIN—PART 2: PETROLEUM SYSTEM AND FUTURE PROSPECTS

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Six wells were drilled in the North Falkland Basin in 1998. Five of these wells recorded oil shows, and up to 32% gas was also recorded in mud returns to the rig floor. However, none of the wells encountered commercially viable petroleum accumulations.

The syn-rift and early post-rift intervals contain thick, lacustrine claystones with oil source potential as indicated by TOC values up to 7.5% and Rock-Eval S_2 values of up to 102 kg HC per tonne of rock. These source rocks were immature or only marginally mature in five of the wells but had attained maturity in one of them. Modelling suggests that the main source interval may well be within the peak oil generation window in deeper, undrilled parts of the basin. Calculations of the amount of oil expelled range up to 60 billion barrels.

Most of the wells tested a closely-related set of plays in large structures associated with a sandstone interval near the top of the late syn-rift to early post-rift source-rock succession. Post-drilling geological modelling of the basin suggests that oil is unlikely to have migrated into this sandstone play at the localities tested, and that the wells consequently failed largely due to a lack of charge. However, the play maintains exploration potential elsewhere. Other plays, particularly those stratigraphically associated with the base rather than the top of the source rock, may have a higher chance of exploration success.

INTRODUCTION

Several attempts were made before drilling to predict the nature of the North Falkland Basin's fill and its petroleum potential (Richards *et al*., 1996 a and b; Richards and Fannin, 1997; Thomson and Underhill, 1999; Bransden *et al*., 1999; Lawrence *et al*., 1999). Part 1 of this paper summarizes the new tectono-stratigraphic model which has been developed for the basin using all the existing well and seismic data from the region. In Part 2, we summarize the petroleum-related results of the six exploration wells which were drilled in the North Falkland Basin in the period April to November, 1998.

The oldest Mesozoic sedimentary rocks in the North Falkland Basin are Jurassic to Valanginian, early and late syn-rift successions of predominantly fluvio-lacustrine origin. The

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succeeding, post-rift, thermal sag deposits can be divided into five units (see Part 1 for details): a transitional unit characterized by lacustrine sedimentation; an early post-rift unit also characterized by lacustrine sedimentation, but with evidence of deltaic deposition from the northern, western and eastern margins of the basin; a middle post-rift phase characterized by the re-establishment of fluvial conditions; a late post-rift phase characterized by a transition from marginal-marine/fluvial more open-marine conditions; and a post-uplift sag phase unit recording open-marine conditions.

This study presents a summary of the results of the principal investigations into the nature of the petroleum system of the North Falkland Basin. A detailed breakdown of the proprietary analyses conducted for each well is beyond the scope of this paper, and accordingly only a summary of the salient features of the petroleum system is given.

MATERIALS AND METHODS

Geochemical analyses were conducted by each operating company (using a number of different laboratories), in order to determine the nature and maturity of the source rocks. Analyses included measurements of TOC and vitrinite reflectance. *Rock-Eval* pyrolysis was conducted on samples from each well, with the results comprising S_1 (amount of free-hydrocarbons), S_2 (hydrocarbon-generating potential), S_3 (volume of CO_2 evolved during pyrolysis), together with T_{max}, Hydrogen Index (HI), Oxygen Index (OI), and Production Index (PI). Oils recovered at surface while drilling, together with samples centrifugally spun from cores, were also analyzed in order to compare their isotope geochemistry with that of the source rocks studied. Burial history modelling was conducted independently by each company and by the authors, using a variety of heat-flow scenarios. Porosity and permeability measurements and petrological determinations from conventional and side-wall cores were integrated with petrophysical log readings in order to calculate water saturations (Sw) and log porosities.

SOURCE ROCKS IN THE NORTH FALKLAND BASIN

Extensive analyses have been conducted on claystones from all six wells. A complete review and listing of all the geochemical data available is beyond the scope of this paper, but a summary of TOC, *Rock-Eval* S_2 and vitrinite reflectance (VR) values recorded in the six wells is presented graphically in Figs. 1, 2 and 3. Key source rock data from the six wells are also presented in Table 1.

Although source rock data were collected and analyzed from all the wells in the basin, source-rock evaluation is probably best illustrated with reference to the claystone-rich intervals in Wells *14/5-1A* and *14/10-1*, which were drilled in a basinal setting within the Eastern Depocentre (see Figs. 1 and 2 in Part 1). The nature of the source rocks in the syn-rift to early post-rift intervals in these wells is discussed below.

Source rocks in the early syn-rift sequence (?mid Jurassic to ?Tithonian)

Average TOC values for this unit in Well *14/5-1A* were 0.76%, but ranged up to 1.6%. Although there are lacustrine components within this succession, it contains more fluviatile sediments than the overlying claystone-dominated units, and the depositional setting may have been relatively unfavourable for source-rock preservation. However, post-mature Type II source rocks are present below 4,150m in Well *14/5-1A*. Vitrinite reflectance studies suggest that the transition from wet gas/condensate to dry gas occurs at around 3,762m in Well *14/5-1A*, while significant levels of gas (up to 32%) are recorded from this unit below 4,000 m.

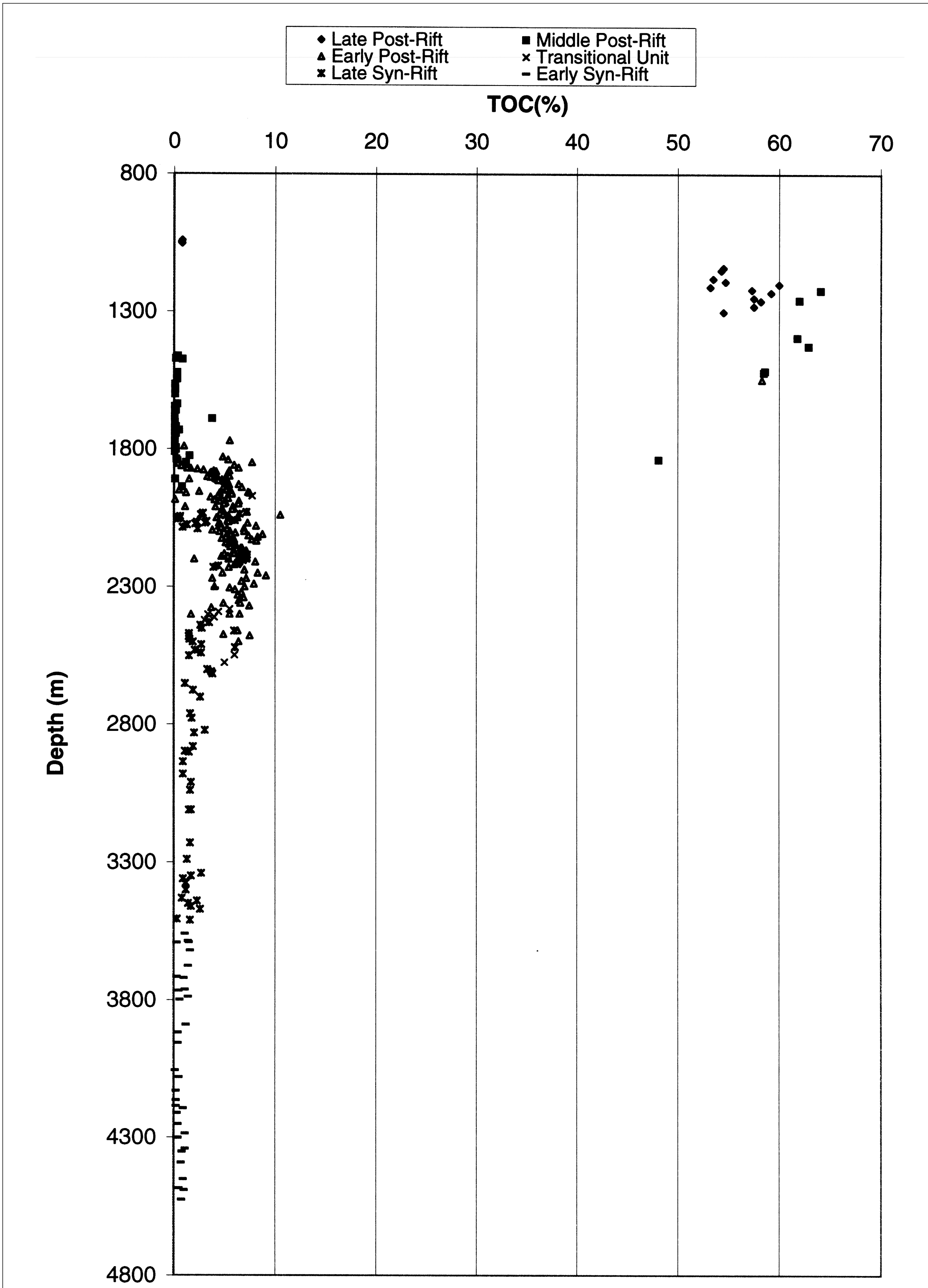

Fig. 1. Plot of TOC content (%) against depth (metres below KB) for the six wells in the North Falkland Basin.

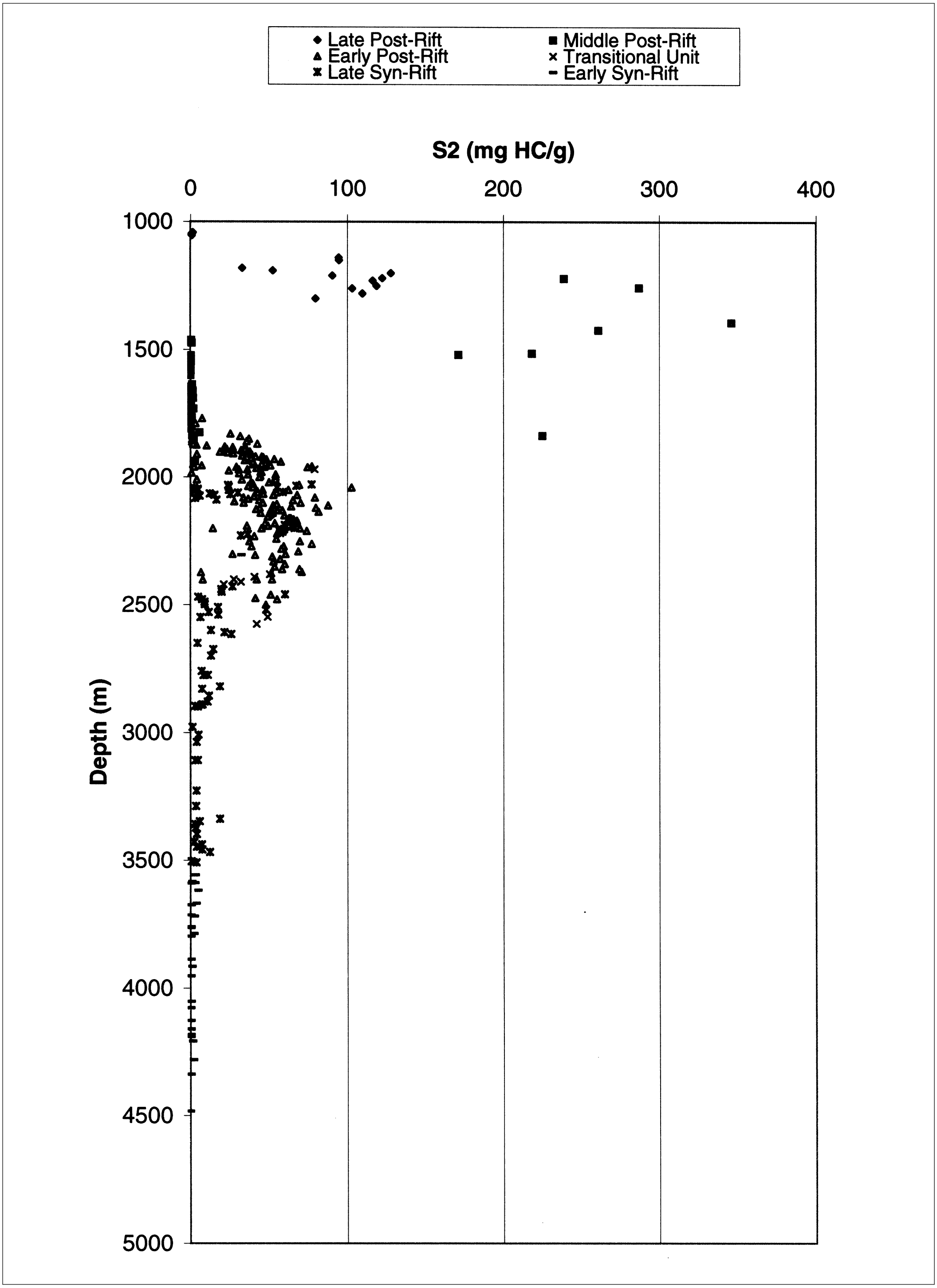

Fig. 2. Plot of S_2 values (oil yield in kg HC per tonne of rock) against depth (metres below KB) for the six wells in the North Falkland Basin.

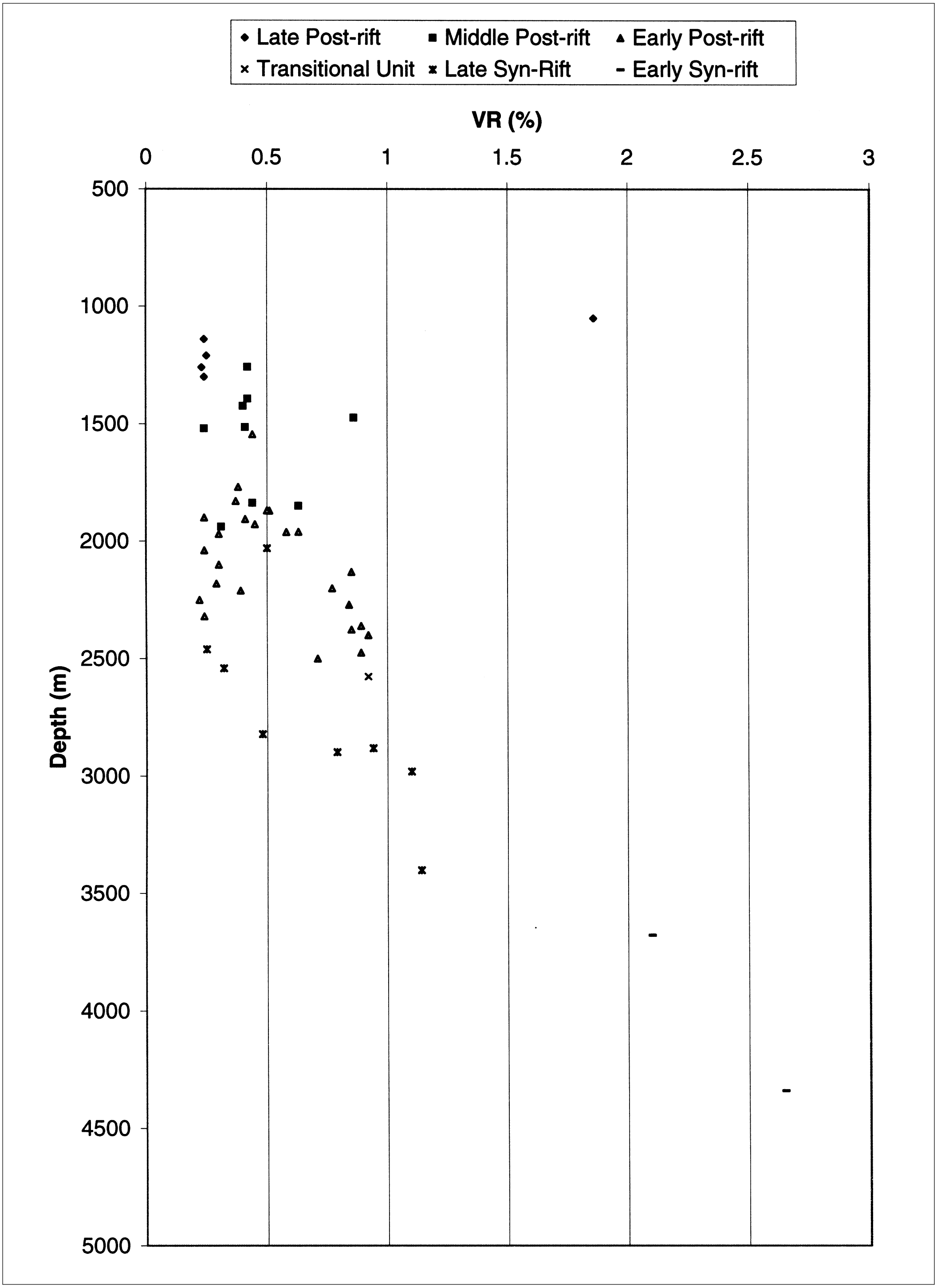

Fig. 3. Plot of VR values (%) against depth (metres below KB) for the six wells in the North Falkland Basin.

	Early Syn-Rift	Late Syn-Rift	Early Post-Rift and Trans. Unit
Kerogen type	II	II	I
TOC (%)	0.2-1.6	0.3 - 6	0.1 - 8.7
S_1 (kg HC/tonne rock)	0.06 - 6.1	0.6 - 8.3	0.8 - 11.1
S_2 (kg HC/tonne rock)	0.06 - 32	0.4 - 77	7.7 - 102.6
S_3 (kg HC/tonne rock)	0.3 - 4	0.1 - 3.2	0.08 - 4.8
HI (S_2x100/TOC)	12 - 390	235 - 719	650 - 1,095
OI (S_3x100/TOC)	25 - 680	9 - 286	11 - 160
PI (S_1/S_1+S_2)	0.04 - 0.62	0.01 - 0.65	0.04 - 0.49
T max (°C)	320 - 516	368 - 450	362 - 451
Thickness (m)	> 1,000	up to 930	up to 600

Table 1. Source rock data (kerogen type, TOC, and *Rock-Eval* pyrolysis results) for the six wells in the North Falkland Basin.

Outcropping Upper Permian source rocks in the Southern Junggar basin (NW China): average source values (data from Carroll et al., 1992)

Thickness:	800m
Average TOC:	4.1%
Average S_2:	26.2 kg HC/tonne of rock

North Falkland Basin average source rock values (late syn-rift to early post-rift units combined):

Thickness:	approx. 1,150m
Average TOC:	4.5%
Average S_2:	42 kg HC/tonne of rock

Table 2. Comparison of source-rock characteristics for the North Falkland Basin and for the Junggar Basin, NW China.

Source rocks in the late syn-rift sequence (Tithonian to Berriasian)

In Wells *14/5-1A* and *14/10-1*, the late syn-rift sequence is characterized by highly mature, predominantly Type II source rocks. The unit has average TOC values of 1.6% in the two wells, although values range up to 7.5% in one of the other wells. Average values of *Rock-Eval S_2* in well *14/5-1A* are 5.6 kg HC/tonne rock, with values as high as 77 kg HC/tonne recorded from one sample (Table 1). Vitrinite reflectance values of 0.9% were recorded for claystones at 3,000m below KB in Well *14/10-1*, placing the sequence at the very base of this well within the zone of peak oil generation.

Basin	Age of source rock	Kerogen type	Av. SPI value
Junggar	Late Permian	I	65
North Falkland	**Entire source interval**	**I/II**	**62.5**
North Falkland	**Early post-rift unit only**	**I**	**49.2**
Lower Congo	Early Cretaceous	I	46
Santa Barbara	Miocene	II	39
San Joaquin	Miocene	II	38
Central Sumatra	Eoc.-Oligocene	I	34
E.Venezuela	Mid-Late Cretaceous	II	27
North Falkland	**L. syn-rift & Trans. Unit only**	**I/II**	**21.5**
Middle Magdalena	Mid-Late Cretaceous	II	16
North Sea	Late Jurassic	II	15

Table 3. Average SPI values for source rocks worldwide (data from Demaison and Huizinga 1991), including source intervals from the North Falkland Basin.

Source rocks in the syn- to post-rift transition (Berriasian to Valanginian) and early post-rift sequence (Valanginian to early Aptian)

These claystone-dominated units are here treated together because they form the main lacustrine source-rock interval in the North Falkland Basin. The TOC content of the claystones generally increases downwards through this interval. TOC values reach 7.5% near the base of the units in Well *14/5-1A*. The downward increase in TOC values corresponds to a downward decrease in sonic log velocity values recorded in all the wells (see Fig. 2 in Part 1). The downward increase in TOC values is accompanied by a general downward increase in *Rock-Eval* S_2 values, from 3 kg HC/tonne at the top, to over 69 kg HC/tonne in places in Well *14/10-1*. However, S_2 values of over 100 kg HC/tonne were recorded from one sample in Well *14/24-1* (Table 1).

The organic matter in this claystone-dominated interval is mainly composed of Type I kerogens, principally alginite or lamalginite. Minor amounts of organic matter derived from terrestrial plants are also present. The algae are composed primarily of small unicellular types with some larger *Botryococcus*, and indicate deposition in a lacustrine environment. The bottom of the lake was probably well oxygenated during the later stages of the early-post rift interval, when a major, southwards-prograding axial delta (see Part 1) may have contributed to frequent overturning of the water column. However, the sudden downward increase in well-preserved algal matter below the foresets of the younger portion of delta (i.e. below about 2,050m in Well *14/5-1A*) indicates a change to more anaerobic bottom conditions. The transitional unit at the base of the claystone interval was probably deposited under slightly more oxygenated conditions than the overlying unit (see Part 1).

Comparisons with source rocks in other basins

The greyish-brown lacustrine source rocks occurring within the late syn-rift to early post-rift sections are lithologically similar to the Upper Permian lacustrine source rocks of the southern Junggar Basin of NW China. Carroll *et al*. (1992) described these rocks as ranking amongst the richest petroleum source rocks in the World, with TOC values up to 34% and *Rock-Eval* S_2 yields of up to 200 kg HC/ tonne of rock. While these maximum values are significantly higher than those recorded in the North Falkland Basin, the average values for both source rock intervals are much closer together (Table 2).

Source Potential Index (SPI) values (Demaison and Huizinga, 1991) can be calculated for any potential source rock using the formula:

$$SPI = h(S_1 + S_2)\rho/1000$$

where:

h	= source rock thickness (m);
S_1	= average *Rock-Eval* S_1 (kg HC/ tonne of rock);
S_2	= average *Rock-Eval* S_2 (kg HC/ tonne of rock); and
ρ	= density of the source rock (tonnes/m^3).

SPI values for the North Falkland Basin lacustrine sequences vary according to the units studied (Table 3). The average SPI for the entire source-rock interval, spanning the syn-rift through early post-rift successions, is 62.5. This calculation is based on an estimate of total source-rock thickness of 2,205 m, an average S_1 of 2.14, an average S_2 of 10.19, and a density of 2.3.

The SPI value for the Valanginian to early Aptian, early post-rift unit only (the interval with the highest TOC values) is calculated to be 49.2, based on an estimated h = 485 m, average S_1 = 3.7, average S_2 = 40.4 and ρ = 2.3. The SPI for the late syn-rift (Tithonian to Berriasian) and the rift to post-rift Transitional Unit (Berriasian to Valanginian) is 21.5 (h = 820 m, average S_1 = 4.56, average S_2 = 6.83, and ρ = 2.3): this interval does not contain as much organic carbon as the younger sequences. The stratigraphically lower units are probably within the main oil generation window, and they are therefore probably the units that are best suited to comparison with source rocks from oil-producing basins elsewhere (Table 3). Based on SPI values, the late syn-rift and transitional units in the North Falkland Basin may constitute the seventh-best source rock known (excluding overlying, less mature units in the same basin) on the basis of the available data.

The early post-rift and Transitional Unit claystones that form the primary source rock interval in the North Falkland Basin are located in a tectono-stratigraphic setting similar to that of the Aptian ?marine early sag succession in the Colorado Basin, offshore Buenos Aires Province, Argentina. Bushnell *et al*. (1997) described this undrilled unit as potentially the most promising source-rock succession in the basin. In common with the early post-rift source rock of the North Falkland Basin, it is characterized on seismic sections by a package of high amplitude reflectors (see Part 1). However, the unit in the Colorado Basin is currently buried to depths of more than 5,000 m below sea level, and is therefore below the oil-generation window (Bushnell *et al*., 1997).

The main source rock in the nearby Malvinas Basin is the Barremian to Aptian, Lower Inoceramus Formation, described by Galeazzi (1998) as a regressive wedge deposited in an anoxic marine setting. This source rock contains Types II and III kerogens, and is more closely comparable to Cretaceous anoxic-marine claystones described by Jacquin and Graciansky (1988) from DSDP drill sites on the Maurice Ewing Bank, to the East of the Falkland Islands, than to the lacustrine claystones of the North Falkland Basin.

Timing of oil generation

Modelling the timing of oil generation is imprecise because it is difficult to define precisely the time of peak heat-flow in the basin: it may have been either from about 150 to 125 Ma (during Jurassic to Valanginian rifting), or around 90 Ma (during the post-rift phase, perhaps associated with the opening of the South Atlantic). A regional unconformity has been recognized in the Turonian at about 90 Ma (see Part 1). This presumably represents a phase of regional uplift and crustal thinning, and could therefore be associated with increased heat flows at that time.

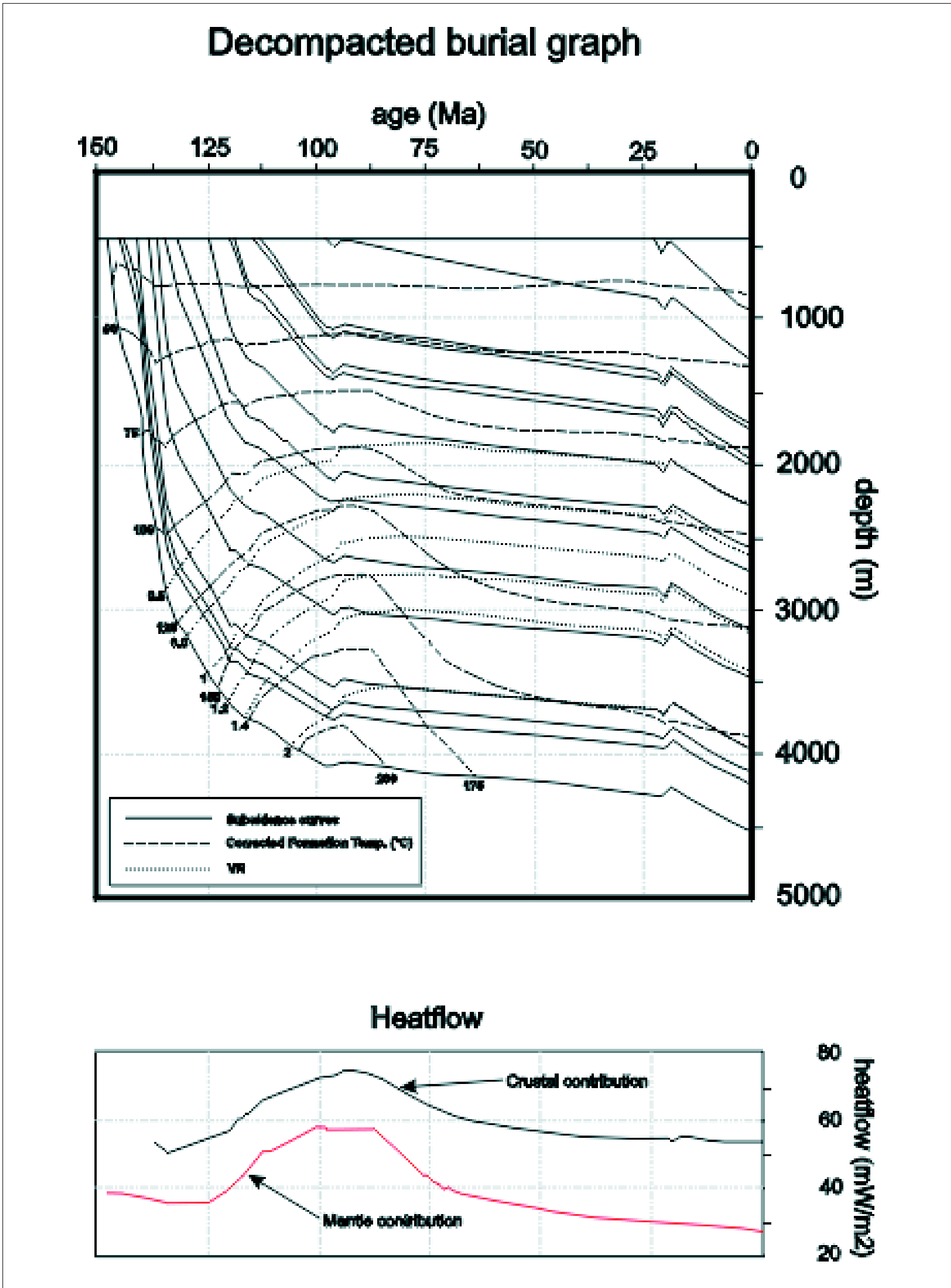

Fig. 4. The subsidence curves and heat-flow scenario that best fits the vitrinite reflectance, calculated and observed formation temperatures, used to model the maturation of source rocks in the North Falkland Basin.

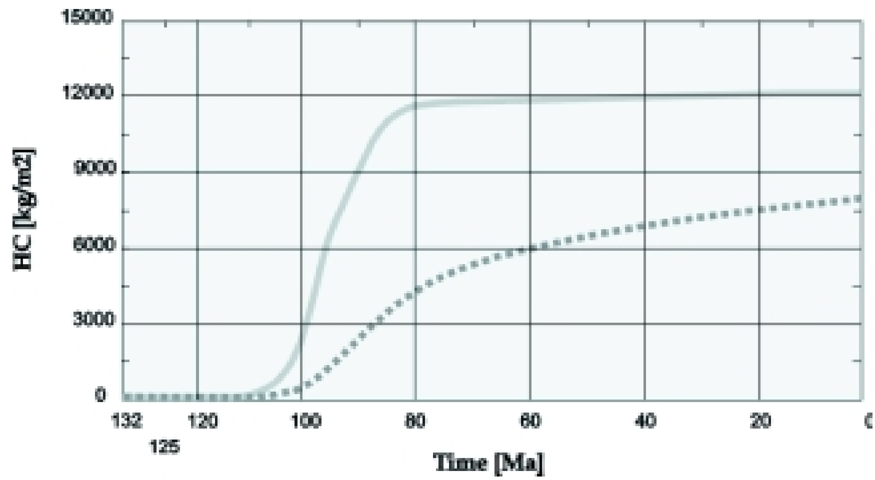

Fig. 5. Modelled generation (solid line) and expulsion (dashed line) of oil from the base of the main source rock interval (the early post-rift lacustrine claystone). The oil generation/expulsion scale on the y-axis assumes a thickness of 400 m of mature source rocks.

A number of burial history models with varying heat-flows have been calculated for the basin. A model with a peak heat-flow of around 80 mW/m^2 at 90 Ma (Fig. 4) was found to most closely match the observed VR, temperature and geochemical data, and indicates that oil generation took place from the early post-rift source rock during the Late Cretaceous, between 70 and 100 Ma (Fig. 5). This model suggests that at a depth of around 3,000m below sea level, over 50% of the organic material will have been converted to oil. Modelling based on an earlier heat-flow peak (around 125Ma) results in peak oil generation around the present day, but suggests that there would be only about 2% conversion of organic matter and this is not consistent with the maturation analyses carried out on the source rocks themselves. A third model, with a heat-flow peak at around 112 Ma and with an estimated source rock interval at 3,400m below sea level (feasible for deeper, undrilled parts of the basin), predicts about 35% organic matter conversion to oil but with maximum expulsion occurring in the Aptian.

Burial history modelling of the (relatively lean) deeper potential source rocks of mid- Jurassic to Berriasian age within the early and late syn-rift successions suggests that they are currently post-mature, but have possibly been a (marginal) source, mostly for gas. They probably reached peak generation in the Early Cretaceous, with most of the hydrocarbons expelled by about 90 Ma (Cenomanian to Turonian).

SHOWS AND HYDROCARBON TYPES

Oil or oil and gas shows were encountered in five of the six wells, but the only hydrocarbons that flowed to surface were waxy oils (27° API) from Well *14/10-1*. The shows were recorded from reservoir rocks at various levels, and also while drilling through the late syn-rift to early post-rift interval, apparently seeping directly from the source. The characteristics of these oil samples are summarized in Table 4.

Oils within the middle post-rift sandstones in Well *14/9-1*, and those recovered from the late syn-rift succession in Well *14/10-1*, were derived from the lowermost part of the early post-rift lacustrine, Type I source rock. By contrast, shows in the middle post-rift sandstones in Well *14/5-1A* are from a different, Type II source rock, characteristic of the late syn-rift succession. The oil recovered from near the base of Well *14/10-1* was probably expelled

Well Number	Sample depth	Oil sample characteristics	Tectono-strat unit
14/5-1A	1,728 m	Biodegraded, but of mature character. Corresponding Type II source rock contained predominantly structureless organic matter; similar to that in a side-wall core sample analysed from 2,677m below rig floor (within the uppermost parts of the late syn-rift sequence).	Middle post-rift
14/5-1A	1,948 m	Biomarkers exhibit a high degree of maturity, and show the oil is derived from the early post-rift, Type I source rock	Early post-rift
14/5-1A	1,950 m	The sample is immature as indicated by presence of the thermally unstable compound C27-22,29,30-trisnor-17b(H)-hopane, the concentration of which reaches zero at the earliest oil window. The differences between this and the sample from 1,948 m may be due to the fact that part of the organic matter in this interval represents indigenous, immature material, whereas another part is derived from migration of low mature material.	Early post-rift
14/10-1	?3,000 m	Oil (API 27.1) was collected at surface during terminal logging. The complete sterane isomerisation observed indicates that this oil has been expelled from a mature source rock. This source rock contained structureless organic matter with a significant algal component, and is equivalent to the Type I lacustrine claystones found in the the early post-rift source rock interval in Well 14/5-1A. However, the source rock interval from which this recovered oil was derived was apparently more mature than the early post-rift source rocks analysed from well 14/5-1A.	Late syn-rift
14/9-1	1,830 m	Oil was centrifugally spun from a core sample. This oil has an early mature, highly paraffinic composition, and has been derived from a Type I lacustrine source rock. The oil is Carbon isotope depleted, and is similar in nature to the Valanginian to Barremian source rocks comprising the lowermost part of the early post-rift succession recorded in Well 14/5-1A. The oil is also isotopically similar to the oil recovered at surface in Well 14/10-1.	Middle post-rift
14/24-1	1,790 m	Post-well geochemical analyses indicate that a sandstone from near the base of the middle post-rift sequence contained traces of hydrocarbons that were not detected during drilling, presumably due to their very low concentration (although dull gold to yellow fluorescence was noted while drilling through the underlying source rocks). These hydrocarbons are characterised by normal alkanes with a mature configuration, and do not resemble the indigenous hydrocarbons detected in the immediately underlying claystones. They probably represent migrated hydrocarbons originating from a deeper, mature zone of the underlying Type I claystones.	Middle post-rift

Table 4. Summary of oil sample characteristics from Wells *14/5-1A, 14/10-1, 14/9-1* and 14/24-1.

downwards from the early post-rift succession, whereas the oil spun from the middle post-rift core in well *14/9-1* appears to have migrated vertically and laterally for at least six kilometres from a deeper kitchen area, as have the oil shows recorded from the middle post-rift sandstones in Well *14/5-1A*. The vertical migration pathway appears to have been less efficient than the downward migration pathway, because live oils were recovered from horizons below the main source interval but only shows were reported from above (see below for further discussion of migration pathways).

Gas shows

Gas shows observed during drilling ranged from less than 1% to in excess of 32% in the early syn-rift sequence in Well *14/5-1A* (from thin sandstones in a unit comprising about 120 m of net sandstone — see Part 1). Gases were dominated by C_1 types with minor amounts of C_2 and C_3, although high levels of C_2 to C_5 were also recorded locally. Gas shows in the stratigraphically-higher sandstones are generally less voluminous with, for example, up to 2,900 ppm C_1 and only traces of C_2 recorded from the middle post-rift sandstones in Well *14/9-2*. Gas shows directly from syn-rift and early post-rift lacustrine claystones are up to 12.1% (in Well *14/10-1*), with a complete range of C_1 through C_5 gases recorded.

POTENTIAL RESERVOIR ROCKS IN THE NORTH FALKLAND BASIN

All six exploration wells encountered potential reservoir rocks, ranging in age from Late Jurassic to Late Cretaceous. Lower Cretaceous potential reservoirs were most commonly encountered, particularly within the early and middle post-rift units. The lithologies of these intervals were described in Part 1.

Early and late syn-rift potential reservoir rocks (mid-Jurassic to Berriasian)

Several siliciclastic reservoir intervals were encountered within these units in Well *14/5-1A*. One sand-dominated, early syn-rift interval has a net reservoir thickness of nearly 40m, with porosities of 4.4 to 7.5%; a second early syn-rift interval has a net thickness of over 10 m but porosities of only up to 4.6%; a third reservoir interval, which spans the boundary between the early and late syn-rift sequences in Well *14/5-1A*, has net a thickness of 74m and porosities of up to 9.0%. The thickest late syn-rift reservoir interval in Well *14/5-1A* has a net thickness of 125m, with porosities ranging from 27.8 to 30.4% and Sw values as low as 51%. Although these net sand values are relatively high, the sandstones themselves are thinly bedded.

Well *14/10-1* also encountered two thin, late syn-rift reservoir intervals. The lower of these had a net thickness of 1.2 m; the upper had a net thickness of 2.4 m. Both of these sandstones had log-derived Sw values as low as 36%. Well *14/9-1* also encountered potential reservoir within the late syn-rift sequence, with porosities of up to 30% and water saturations as low as 70%, but sampling using a wireline formation tester was unsuccessful, suggesting that the sandstones were tight.

Early post-rift reservoir rocks (Valanginian to early Aptian)

Early post-rift sandstones were only encountered in Well *14/5-1A*, where they form part of the southerly-prograding axial delta deposits in the Eastern Depocentre. A sandstone-dominated interval identified within the delta foresets contained 38m of net sandstone reservoir, with up to 28% porosity and 974 mD permeability, but 89% water saturation.

Middle post-rift reservoir rocks (Aptian to Albian)

Middle post-rift reservoir sandstones were deposited in a transgressive, fluvio-lacustrine setting following the end of lacustrine deposition. Therefore, these reservoir rocks lie immediately above the main source interval. They are present in all of the wells. In Well *14/5-1A*, the sandstones have a net thickness of nearly 23m, with a net-to-gross ratio of 0.56 and a porosity range of 19.6 to 25.4%. Furthermore, 79 m of net sandstone in this interval were encountered in Well *14/10-1*, while over 133 m of net sandstone were found in Well *14/24-1*.

These sandstones constituted a prime exploration target in four of the wells, and an important secondary target in the other two. However, the relatively low permeabilities and high water saturations, together with the common occurrence of pore-throat-blocking kaolinite cements, has reduced their reservoir quality. Furthermore, their effectiveness as a trap for hydrocarbons migrating from the underlying source rock interval may be limited by the sealing nature of the uppermost parts of the claystone interval, which may have acted as a barrier to vertical fluid migration (see discussions below of migration routes and seals).

In summary, some significant sandstone reservoir intervals have been encountered. Well *14/5-1A* encountered a total of 390 m of net reservoir (deltaic and fluvial sandstones) with an average porosity of 13%; while Well *14/10-1* had a total of 84 m of net sandstones, with porosities averaging 27.5%.

TRAPS, SEALS AND MIGRATION ROUTES

Traps

A number of different trap styles were tested by the six wells drilled in the North Falkland Basin. Four of the wells tested four-way dip closures with reservoirs in the middle post-rift succession. Well *14/9-1* was designed to test early and late syn-rift sandstones within a tilted fault block forming part of the Intra-Graben High, in addition to the four-way drape at the top of the early post-rift level. Well *14/9-2* was designed to test a syn-rift closed high on the eastern flank of the Intra-Graben High. Well *14/13-1* was designed to test a similar structure within the Western Depocentre (the so-called Minke High). Wells *14/5-1A* and *14/10-1* tested four-way dip closures within the early post-rift sequence, in addition to the middle post-rift drapes.

Seals and Migration routes

An understanding of migration pathways and seals may provide the key to predicting the presence of hydrocarbon accumulations in the North Falkland Basin. The most effective top seal is probably provided by the early post-rift source rock itself, just as the Kimmeridge Clay Formation acts as both source and regional seal in the central and northern North Sea. The uppermost 600 m or so of the early post-rift claystone interval is above the oil generation window in the central parts of the Eastern Depocentre. Headspace gas analyses suggest that there has been no vertical migration of gas through this claystone, pointing to its viability as an effective seal.

The main source rock interval (the Valanginian to early Aptian, early post-rift sequence) is represented on seismic sections by a Low Velocity Zone (LVZ), and before drilling this was thought to represent an overpressured zone. However, no overpressures were recorded in the basin during drilling, and the LVZ represents an extremely organic rich interval with a low density: the low density values, and a downwards decrease in density with depth is accompanied by a downwards increase in TOC values in each well (Fig. 1), and also by a downwards increase in *Rock-Eval* S_2 values (Fig. 2) which represent a downwards increase in hydrocarbon expulsion.

Since the claystones are not overpressured, the fluid-flow system beneath the claystones is not confined and hydrocarbons are therefore more likely to have migrated laterally down-section, along migration channels provided by sandstones within or just below the claystones. This type of migration would tend to favour the accumulation of oil either near the basin margin in marginally-attached fans, in tilted fault blocks stratigraphically beneath the claystone blanket, or in syn-rift reservoirs along features such as the Intra-Graben High. Thus, it is possible that the syn-rift succession penetrated in Well *14/9-1*, which was found to have poor reservoir qualities at this location, may be a viable target at other sites along the Intra-Graben High. Some younger, middle post-rift targets may also be viable if they are near to faults which breach the early post-rift claystone seal.

Analyses of the oils recovered at the surface and observed as shows tend to confirm the model of preferential downwards migration. Only oil shows were observed in apparently under-charged sandstones above the main early post-rift source interval, whereas live oil was recovered from beneath the early post-rift source rock in Well *14/10-1*.

An unconfined migration system could mean that relatively long-distance, lateral migration into syn-rift sandstones within the Western Depocentre is a possibility. Therefore, structures such as the Minke High (drilled by Well *14/13-1*) could contain oil where they comprise syn-rift sedimentary rocks rather than basement. Because Well *14/13-1* did not penetrate beneath the base of the claystone, it is not known whether syn-rift sandstones are present within that structure or down-flank to the east of the well location.

In summary, it seems probable that the main source rock interval provides an efficient vertical barrier to migration, and this possibly explains why only small amounts of oil were able to migrate from the mature, basal parts of the source rock interval up into the middle post-rift transgressive and fluvial sandstones penetrated in all six wells. However, vertical migration into the middle post-rift sandstones may be possible where traps lie close to penetrative faults which provide a migration pathway down into the main kitchen area in the Eastern Depocentre, particularly adjacent to the basin margins. Lateral migration beneath the claystones and then into sub-source rock tilted fault blocks, fans attached to the eastern margin, or syn-rift sandstones in places along the Intra-Graben High, is possibly the most efficient migration pathway in the basin.

Large volumes of oil may have been generated in the basin, but there are only relatively minor shows in post-rift traps, while syn-rift traps have not been adequately tested.

FUTURE PLAYS AND PROSPECTS

A variety of play types were planned to be targeted by the 1998 drilling campaign, but post-well analyses indicate that only three play types were actually partially tested. These tested plays were the early post-rift deltas, the middle post-rift transgressive and fluvial sandstones, and the syn-rift succession in the core of the Intra-Graben High. More untested than partially-tested plays remain in the basin and a selection of both types are reviewed below.

Partially-tested plays

Syn-rift sandstones on the crests of tilted fault blocks

Only Well *14/9-1* tested this play within closure on the crest of the Intra-Graben High. The mid-Jurassic to Berriasian sandstones encountered on the Intra-Graben High had reasonable reservoir properties, particularly those within the Tithonian to Berriasian, late syn-rift unit: log-derived porosities up to 30% and Sw values as low as 70% were recorded. Although permeabilities appear to be poor at the *14/9-1* location, the prospectivity of the syn-rift succession cannot be ruled out elsewhere.

Two thin sandstone beds (3- and 5-m thick) were also penetrated in the late syn-rift sequence by Well *14/10-1*, in a palaeo-lake centre setting. It is thought that these two sandstones were not within closure at the level they were encountered, and therefore were not fully oil charged. However, both the sandstones had oil shows, with porosities of about 19% and Sw values of about 36%. These characteristics indicate that the syn-rift succession may have considerable reservoir potential. The play has been only partially tested and may merit further drilling at other locations, particularly on the eastern flank of the Intra-Graben High. The syn-rift succession should not be taken to represent economic basement in the region without considerable further drilling data being acquired.

Middle post-rift transgressive and fluvial sandstones

All six wells encountered reservoir quality sandstones within the Aptian to Albian middle post-rift unit that directly overlies the main source-rock succession, and five of them had oil shows. The play has been only partially tested and may merit further exploration, particularly if viable migration pathways can be mapped. For example, there are several relatively shallow closures along the crest of the Intra-Graben High. These closures may also be located immediately adjacent to a fault which breaches the early post-rift seal, and which provides a direct migration pathway from the kitchen area in the middle of the Eastern Depocentre.

Early post-rift axial delta play and associated basin floor sandstones

Only Well *14/5-1A* addressed the Valanginian to early Aptian, early post-rift axial delta play. Thick sandstones are likely to occur at delta-top and delta-front levels to the north of the *14/5-1A* well location, but there is very little seismic data in that area at present. Possible channel features which have been imaged appear to cut into the front of the delta in the Eastern Depocentre, and may also have significant potential especially as they are encased in source rocks which may provide a straightforward migration pathway and therefore relatively easy charge. They may also have carried sand further out into the lacustrine basin, into as yet undrilled acreage, which is only sparsely covered by seismic data.

Untested plays

Fan sandstones along the eastern margin of the Eastern Depocentre

Jurassic to earliest Cretaceous fan sandstones, deposited during the syn-rift phase, may be developed along the margins of the basin in situations analogous to the Brae complex in the South Viking Graben. Such sandstones would be stratigraphically subjacent to the mature, basal part of the source rock, and may therefore be likely to be charged with hydrocarbons. Fan-like bodies have been mapped in places along the basin margin, but are difficult to identify on existing seismic data.

Laterally-derived delta sandstones along both basin margins

Early Cretaceous deltaic bodies that prograded into the basin from marginal areas during the early post-rift phase may be sand-rich and may also be closer to migration pathways, particularly those associated with the basin-margin faults. They may therefore be more to likely to have been charged with hydrocarbons than sandstones within the axial delta. It is difficult to identify their distribution with any certainty using existing seismic data, but they may be significantly more extensive than is currently thought.

Basin margin sandstones developed during overstepping of the eastern rift shoulder

Shoreline and/or transgressive sandstones of Aptian to Albian age may have been deposited along the margins of the basin during the initial overstepping of the flanks in the middle post-rift phase. Although such sandstones would be stratigraphically above the main mature part of the source rock succession, they might have been charged by fluid flow up basin-margin faults.

Closed high plays to the south of the drilled areas

Mapping of the 2D seismic data acquired by Desire Petroleum during 1998 in the southern part of the North Falkland Basin is not yet complete, but early results point to the presence of numerous closed highs in a number of discrete, deep sub-basins that extend to at least four seconds of two-way-travel time. No definitive correlations have yet been established with the drilled areas to the north, although it seems likely that the deeper parts of the section equate with the early syn-rift sediments penetrated in Well *14/5-1A*. These sediments were the source of gas in that well, although they are capable of generating oil where less deeply buried.

DISCUSSION

Good quality source rocks, reservoirs, seals and traps have been identified in the North Falkland Basin. Although oil was recovered at surface in small quantities, the structures and primary reservoir targets drilled by the six wells did not contain commercially viable accumulations of hydrocarbons. However, all of the elements of a working petroleum system are present in the basin, suggesting that further drilling, planned using information such as that derived from this post-well analysis, could lead to better commercial results.

The present-day geothermal gradient for the basin has been established as approximately 44^{o}C/km. With this geothermal gradient, oil-prone claystones would begin to generate oil at about 2,700m below sea level, with peak generation occurring at depths greater than 3,000m.

The main oil-prone source-rock intervals are provided by early post-rift lacustrine claystones of Valanginian to early Aptian age, although there is also some source potential in underlying units. Valanginian to early Aptian claystones have not yet been penetrated at depths greater than 3,000m, although both they and the older source rocks are more deeply buried in undrilled parts of the basin. Fig. 6 is a depth map on the top of the late syn-rift unit, and indicates the area in which the lower portion of the potential source-rock succession is buried to depths greater than 2,700m, the probable depth at which oil generation begins.

There is probably a sufficient thickness of source rock in the basin, buried to depths in excess of 3,000m, to generate significant volumes of oil. One (perhaps optimistic) calculation suggests that up to 60 billion barrels of oil may have been expelled. This figure is based on the source-rock pyrolysis data obtained from the wells (Fig. 2), and assumes a mature interval some 400-m thick at the base of the source-rock succession (as shown by Well *14/10-1*), extending over an area of 40 km by 40 km. Even when calculations are based on more conservative figures for the thickness and extent of the mature source and the richness and generative potential of the kerogen, significant volumes are predicted. For example, a 200-m thick mature interval over an area of 35km by 12km may have expelled over 11.5 billion barrels of oil, even at oil yields of 8 kg HC/tonne, which are rather low compared to the results of *Rock-Eval* pyrolysis. When the area of potentially mature source rocks is reduced to 180 km^2 (30km by 6km), and a very low potential oil-yield of only 2 kg HC/tonne of rock is used, over 1.2 billion barrels of oil are predicted to have been expelled.

Kinetic modelling of the early post-rift claystones were conducted for Shell (by a commercial laboratory) on samples from Well *14/5-1A*, in order to assess the timing of organic matter conversion into hydrocarbons. Details of the modelling are beyond the scope of this paper, but in summary the results indicate that a sample from 2,100m (within the uppermost parts of the early post-rift sequence) reached the onset of oil generation at a VR value of 0.74% with peak generation at a VR of 0.86%; while a sample from 2,478m (within the lowermost part of the

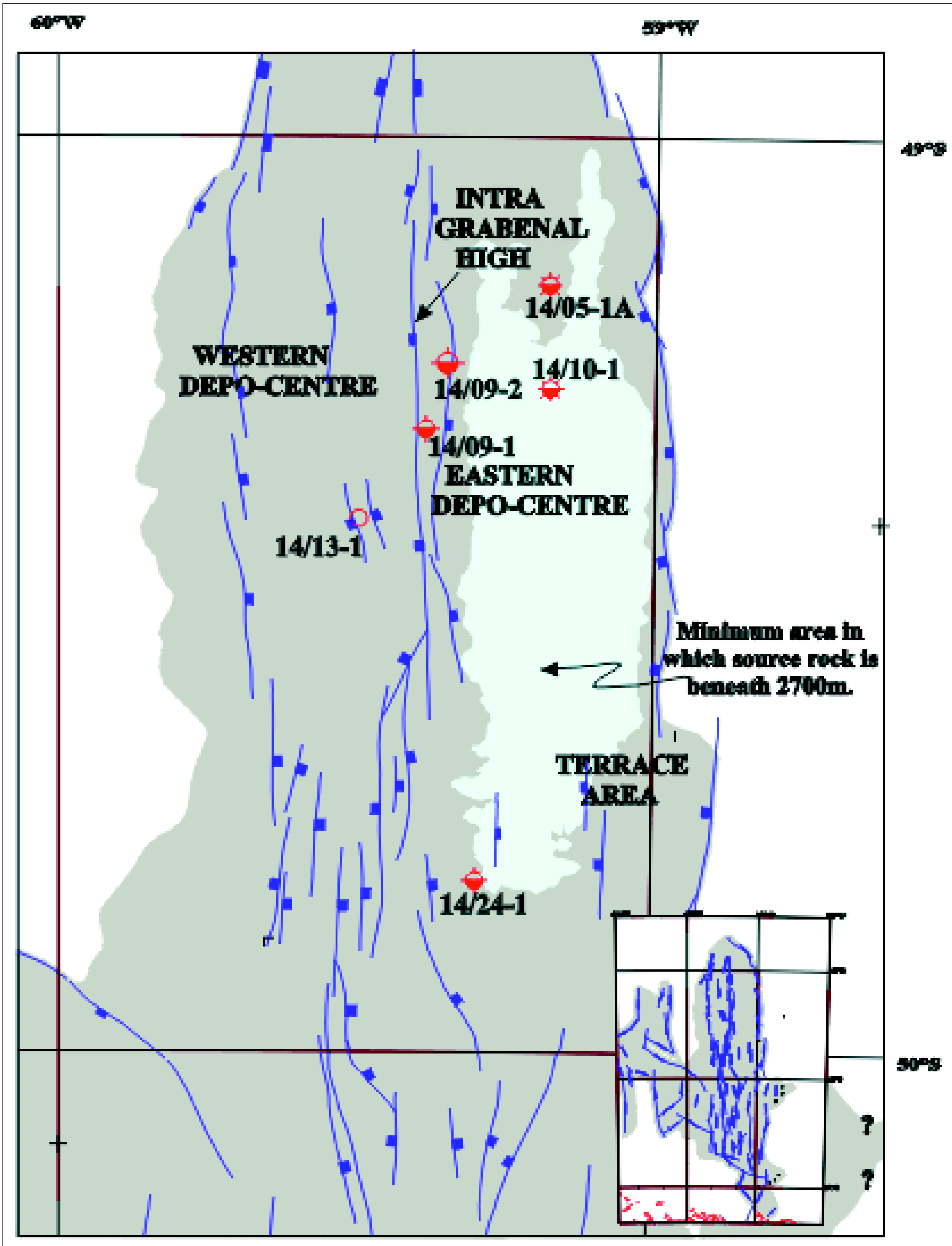

Fig. 6. Map of the base of the syn- to post-rift transitional unit, based on depth- converted interpretation of seismic data in the basin, showing the minimum area in which source rocks are buried to depths greater than the 2,700 m threshold required for oil generation.

early post-rift sequence) reached oil generation onset at VR = 0.76% and peak generation at VR = 0.9%. VR= 0.76% is higher than the value generally accepted for the onset of oil generation (0.7%), and may reflect the greater thermal maturity and greater depth of burial required to generate oil from Type I kerogens than from source rocks characterized by mixed kerogen assemblages.

The extrapolated VR measurements in Well *14/5-1A* suggest that the most prolific oil-prone interval (from 2,000m to 2,550m: the early post-rift unit) is still immature, while the less rich basal part of the interval (2,550m to 2,615m: the transitional unit) is just entering the oil window, and is currently generating minor quantities of waxy crude oil. However, results from Well *14/10-1* indicate that the syn to post-rift transitional succession of the claystone-dominated interval at this locality is within the zone of peak oil generation, with VR values of 0.9% recorded.

The six wells were drilled in quick succession, using a single rig, on pre-planned locations that had been site-surveyed several months previously. Although some scope for testing different play types had been built into the exploration programme by the drilling companies, each had picked the largest, most easily defined structure to test in their own acreage. These structures all relied on a primary reservoir being located in early or middle post-rift sandstones situated within or above the early post-rift sequence that was correctly predicted to be the main source interval in the basin. Because the wells were drilled back to back, with little time available to analyze data obtained from previous wells, there was very limited opportunity for the companies to refocus wells to target different play concepts. Consequently, all six wells focused primarily on targeting sandstones that are located on probably the least effective migration pathway in the basin, and all found under-charged reservoirs.

High quality reservoirs may yet be found in other parts of the basin, on more viable migration routes. Particularly favourable locations may lie along the eastern basin flank and elsewhere beneath the main-source rock succession, as well as in various deltaic settings (perhaps to the north of Well *14/5-1A*), and in delta-front channels and associated fans further south.

Possible analogues in the East African Rift Valley

Studies of modern lakes in the East African Rift Valley may assist exploration in the North Falkland Basin. For example, a number of sandstone depositional environments have been described from Lake Malawi (Johnson and Ng'ang'a, 1990: the following discussion is based on this reference). The sedimentary architecture of the lake is complex and includes the deposition of coarse-grained clastic material in river deltas and along border faults. Coarse-grained aprons or fans of sediment attached to the northern border faults extend for several kilometres lakewards. A number of river-fed deltas extend into the lake – the Ruhuhu delta fan, for example, covers an area of about 400 sq. km. Fluvial discharge is greatest in rivers draining the higher rainfall areas to the north. The deltas have well-developed, incised channel systems that funnel turbidity currents into the deep offshore basin. Acoustic maps show that nearshore sands extend to depths of about 100m in many parts of the Lake Malawi, indicating the great depths to which surface waves can influence sedimentation in large lakes. The nearshore sands were thought to be texturally and mineralogically immature, reflecting the short transport distance from source areas on the rift margins. However, the beach sands are likely to be the best sorted of the various sandy facies, because winnowing by waves is a very effective sorting mechanism in very shallow waters.

The North Rukuru and Ruhuhu deltas in the north of Lake Malawi are together about half of the size of the delta interpreted in the early post-rift sequence in the North Falkland Basin (see Part 1). The upper section of the North Rukuru fan extends about 25 km into the basin, and shows evidence of several incised turbidite channels, similar to those observed on 3D seismic cutting the front of the axial North Falkland Basin delta. The surface of the Ruhuhu delta is transected by deep distributary channels, floored by gravel, which radiate from the river mouth. Gravity cores from both deltas were found to contain turbidite sands and debris flow deposits by Johnson and Ng'ang'a (1990). They noted that multi-channel seismic data (Scholz and Rosendahl, 1988) suggest that some sand units, such as those off the Ruhuhu delta, may be up to 1,000-m thick.

Cohen (1990) reviewed the setting of depositional systems in Lake Tanganyika. Axial rift drainage is important here, and axial-margin rivers such as the Ruzizi supply thick, prograding deltas which may provide analogues for the axial delta in the North Falkland Basin. However, Cohen (1990) noted that platform-margin deltas (such as the Malagarasi River delta, possibly analogous to the easterly and westerly-derived deltas in the North Falkland Basin) may have more advantageous source-reservoir-seal geometries.

CONCLUSIONS

A very rich source rock has been encountered in the North Falkland Basin and is capable of generating up to 102 kg HC/tonne of rock. Although much of the vertical thickness of the source rock is immature, it is capable of generating hydrocarbons below about 2,700m and reaches peak oil generation at a depth of about 3,000m. Estimates of the volume of source rock that lie within the oil-mature window range from 36 x 10^9 m^3 to 400 x 10^9 m^3, depending on the seismic horizon mapped. It has been estimated that up to 60 billion barrels of oil may have been expelled in the basin.

Some thick (approximately 100 m) sandstones have been encountered above the main source-rock interval, with porosities ranging up to about 30%. Well *14/5-1A* encountered a total of about 390 m of net sandstone throughout the syn- to post-rift interval, indicating that there are significant sandstone bodies within the basin. Very few thick sandstones with good reservoir properties have yet been encountered in the syn-rift succession beneath the main source rock interval, but few of the wells have penetrated this section.

The absence of overpressures within the basin suggests that any expelled oils may have migrated laterally, and they may therefore be trapped preferentially in syn-rift reservoirs developed beneath and lateral to the main source rock interval. Reservoirs of this age have been encountered within structural closure only in Well *14/9-1*, where they had good porosities but assumed poor permeabilities (based on failed wireline formation tests). Several structures that contain syn-rift sedimentary rocks have been mapped, and these may provide adequate exploration targets for future drilling. However, most play-concept mapping has so far concentrated on early to mid post-rift reservoirs and associated targets, and little information has been gathered about syn-rift plays.

The six wells drilled so far in the basin targeted a middle post-rift sandstone lying immediately above the main source-rock interval as the main play. This source rock is immature in its upper parts, and acts as an effective seal over much of the basin, being breached by faults only at the basin margins. Consequently, hydrocarbon charge into the middle post-rift sandstones was low where they were tested by the six wells.

The optimum plays that should be tested by future wells, given the probable sealing nature of the thick source rock interval, are sub-source sandstones in both stratigraphic traps and tilted fault blocks. These may be difficult to locate on the present seismic data, which was acquired and processed primarily with the intention of exploring the younger, shallower parts of the basin.

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