Unravelling complex filling histories by constraining the timing of events which modify oil fields after initial charge

M. LISK[1], P. J. EADINGTON[1] & G. W. O'BRIEN[2]

[1]*CSIRO Division of Petroleum Resources and Australian Petroleum Cooperative Research Centre, PO Box 1130, Technology Park, Bentley, WA6102, Australia*
[2]*Australian Geological Survey Organisation – Petroleum and Marine Division, GPO Box 378, Canberra, ACT 2601, Australia*

Abstract: Complex and multiphase charge histories are a feature of many hydrocarbon discoveries. Previous descriptions of charge history that have relied on the chemical properties of hydrocarbons do not define the geometry of hydrocarbon accumulations prior to the attainment of their present state. In this paper, examples of oil charge studies conducted on hydrocarbon discoveries from the Australian North West Shelf are presented to demonstrate the application of a new technique for the mapping of hydrocarbon charge called GOI® (Grains containing Oil-bearing fluid Inclusions). In Australian oil fields GOI values in oil leg samples are an order of magnitude higher than in underlying water zones and record the maximum oil saturation experienced through time. An empirical threshold for oil saturation consistent with accumulation (GOI > 5%) rather than migration (GOI < 1%) of oil has been established from a database of 20 Australian oil fields. Oil inclusions are retained if oil is lost from the pore spaces of the rock, which allows GOI to be used to identify relict oil columns and locate the original oil–water contact. GOI measurements allow the original size and disposition of palaeo-oil columns to be determined and the physical events controlling the composition and size of hydrocarbon accumulations to be deduced in space and time. These data allow issues which cause changes to the original fluid contacts, such as trap integrity, tilting and gas displacement, to be confidently identified and characterized. When combined with conventional approaches to prospect evaluation, these new data allow a more sophisticated description of the filling history of hydrocarbon discoveries. They also allow the oil charge risk associated with new plays to be appropriately constrained before new drilling is commissioned.

The accumulation of oil is a process that is seldom fully understood, with considerable uncertainty about the timing, source and phases of oil charge encountered in a hydrocarbon discovery. As a result of these uncertainties, risks associated with the migration and charge elements of a play concept are frequently simplified, often resulting in very poor control of these critical issues. In this paper, a series of case studies is presented that demonstrates the high level of resolution which can now be achieved in the mapping of oil charge. These studies draw on a new formation evaluation technique that describes the frequency and nature of oil-bearing fluid inclusions in sandstone reservoirs. When combined with other new techniques and conventional field appraisal methods, these data provide a more complete record of the filling history of hydrocarbon traps.

Oil inclusions

Fluid inclusions are small samples (< 50 μm, usually < 10 μm in diameter) of formation fluid that are encapsulated in framework minerals such as quartz, feldspar and carbonate as they crystallize. Inclusions that trap oil are easily identified in petrographic thin section by fluorescence emitted from the aromatic fraction of the oil under violet and ultra-violet fluorescence illumination (McLimans 1987). Previously, these fluorescence colours have been interpreted to reflect changing API as the maturity of the oil increases (Hagemann & Hollerbach 1985). Oil inclusions may be trapped in either of two ways. The formation of diagenetic minerals that have a framework lattice allows oil to be entrained during crystallization; this process requires that oil be present at the same time as the host mineral is crystallizing. A more continuous record of oil migration is recorded by oil inclusions that are trapped by the propagation and healing of fractures in detrital quartz and feldspar or pre-existing diagenetic minerals. This should not be considered a passive process, as fracturing creates a large pressure draw-down between the open fracture (at low pressure) and a pore space (at reservoir pressure). Draining of fluid from the pore space into the fracture plane is

LISK, M., EADINGTON, P. J. & O'BRIEN, G. W. 1998. Unravelling complex filling histories by constraining the timing of events which modify oil fields after initial charge. *In*: PARNELL, J. (ed.) 1998. *Dating and Duration of Fluid Flow and Fluid–Rock Interaction*. Geological Society, London, Special Publications, **144**, 189–203.

dynamically driven by this large pressure differential. Consequently, this process represents an efficient mechanism for the sampling of reservoir fluids by the formation of fluid inclusions. Trails of fluid inclusions through clastic and authigenic minerals, which are evidence for fluids being drawn into fractures from the surrounding pore space, demonstrate that the pressure differential exceeds the high capillary forces acting to inhibit ingress of fluid into such narrow fractures.

In sandstones the presence of oil inclusions within framework minerals indicates that the adjacent pore space once contained oil. The number of such grains containing these inclusions, therefore, reflects the filling of available pore space and so can be considered an approximate measure of oil saturation. The level of oil saturation is considered to be the principal control with factors which govern the opportunities for entrapment of fluid inclusions such as burial depth, degree of diagenesis and residence time playing secondary roles.

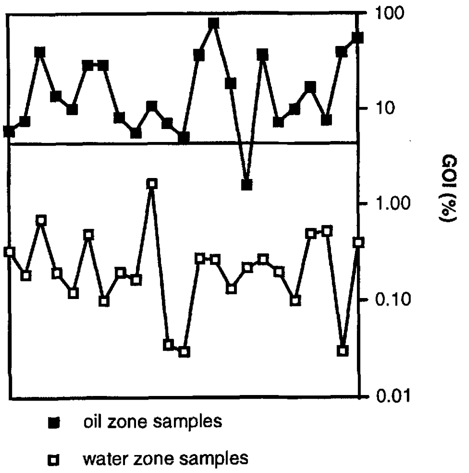

Fig. 1. Database of GOI values from Australian oil fields. Each data pair represents average GOI values recorded on samples from oil and water zones from a single oil field (23 fields shown).

The GOI technique

Previously, the presence of oil inclusions has largely been used to identify migration pathways for oil and to constrain the timing and phases of oil migration relative to the formation of authigenic minerals. Recognition that the abundance of oil-filled fluid inclusions can reflect the relative oil saturation obtained in sandstones is a relatively new observation (Lisk *et al.* 1993; Nedkvitne *et al.* 1993) and represents a significant advance in the application of fluid inclusion data to oil charge studies. In recent times at least two methods for quantifying oil inclusion abundance have been published (Lisk & Eadington 1994; Oxtoby *et al.* 1995). In this paper, the GOI method of Eadington *et al.* (1996) has been used to quantify oil inclusion frequency and to characterize palaeo-oil saturation. GOI is a petrographic technique that records the number of quartz and feldspar Grains containing Oil Inclusions, expressed as percentage of the total number of these grains in each thin section sample (Eadington *et al.* 1996; Lisk & Eadington 1994).

GOI data reported by Eadington *et al.* (1996) and Lisk & Eadington (1994) for more than twenty producing oil fields from Australian sedimentary basins reveal at least one order of magnitude difference between samples taken from within current oil zones when compared to samples with demonstrably low oil saturation from beneath the oil–water contact (OWC) (Fig. 1). Eadington *et al.* (1996) suggested a GOI value of 5% be taken as an empirical threshold for samples that have been exposed to high oil saturation, whereas values below 1% were likely to indicate zones of oil migration at much lower oil saturation. This observation is consistent with the results of analogue reservoir models, which suggest that oil migration occurs at low oil saturation and is restricted to isolated stringers which contact as little as 1% of the available rock volume (Carruthers & Ringrose 1998; Sylta *et al.* 1997; Hirsch & Thompson 1995).

The large variation in GOI values from current oil zones often correlates with changing oil saturation in response to variable reservoir quality, but factors which control opportunities for entrapment are also likely to contribute to the scatter of data. In addition, the GOI database is compiled from sandstones with a predominantly quartz arenite composition and is largely untested in sandstones with more lithic or arkose compositions. Work aimed at addressing these issues is currently being completed.

Charge history reconstruction

Oil inclusions are retained if oil is lost from the pore spaces of the rock, which allows GOI to be used to identify relict oil columns. GOI measurements in single wells allow the height of palaeo-oil columns to be deduced by recognizing original fluid contacts where GOI falls sharply from high to low values. The geometry of palaeo-oil columns can be further described where multiple wells allow fluid contacts to be traced across a structure allowing the physical events controlling the size of hydrocarbon accumulations to be deduced (Lisk *et al.* 1996*a*).

In this paper, case studies are presented that demonstrate the application of GOI data and show how a more sophisticated description of the filling history of hydrocarbon discoveries can be achieved when these data are combined with conventional approaches to prospect evaluation.

Geological setting

The North West Shelf is Australia's most prolific hydrocarbon province. Comprising four major sedimentary basins, the North West Shelf extends *c.* 2400 km along the northwest margin of the Australian continent (Fig. 2). The development of these basins can be related to successive cycles of Palaeozoic and Mesozoic rifting, which culminated in the ultimate break-up of the Gondwana supercontinent and subsequent passive margin sedimentation through the Tertiary. Similarities in basin architecture, source and reservoir facies, oil chemistry and hydrology suggest that the margin experienced a similar geological history, and belongs to the one petroleum system (Fig. 3; Bradshaw *et al.* 1994). Excellent quality sandstone reservoirs are developed within the region, with permeabilities often in the multi-darcy range and porosities generally greater than 20%. Source facies comprise intercalated shales within the main reservoir sequence and thick mudstones which generally form an excellent top and lateral seal. Hydrocarbon traps mostly rely on faults for seal, although there are examples of four-way dip-closed and combination traps formed mainly in response to Tertiary wrenching (Kopsen & McGann 1985). Three fields have been selected to demonstrate the application of GOI data to the issues of seal integrity assessment, oil-leg prediction and structural tilting.

Seal integrity assessment

Loss of an oil column due to failure of the seal can occur where hydrocarbon buoyancy pressures are sufficient to overcome the capillary properties of the seal, or where breach of seal is tectonically induced. In the Vulcan Sub-basin (Fig. 2), where most traps rely on faults to achieve closure, seal integrity has been adversely affected by reactivation of these faults during Mio-Pliocene collision of the Australian and Eurasian plates (O'Brien & Woods 1995; O'Brien *et al.* 1996). The breaching of fault seal represents a significant risk in exploration, with residual oil zones commonly observed below present OWCs, and also in many wells that are now completely water saturated (Whibley & Jacobson 1990; O'Brien & Woods 1995; O'Brien *et al.* 1996; Smith *et al.* 1996).

As a consequence of this variable seal integrity, drilling results in this region have been disappointing, particularly given the apparently favourable combination of source, reservoir and seal facies that characterize the area. The concern surrounding trap integrity has lowered the perceived prospectivity of this area and has led to a reduction in exploration activity in recent times.

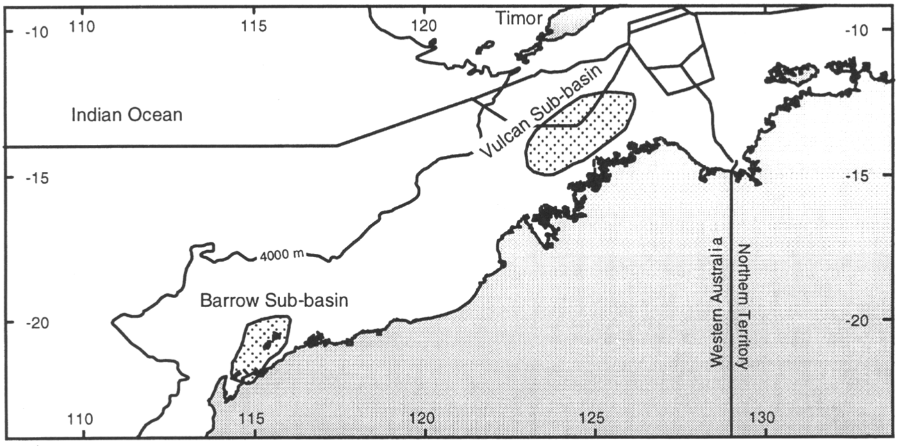

Fig. 2. The North West Shelf region.

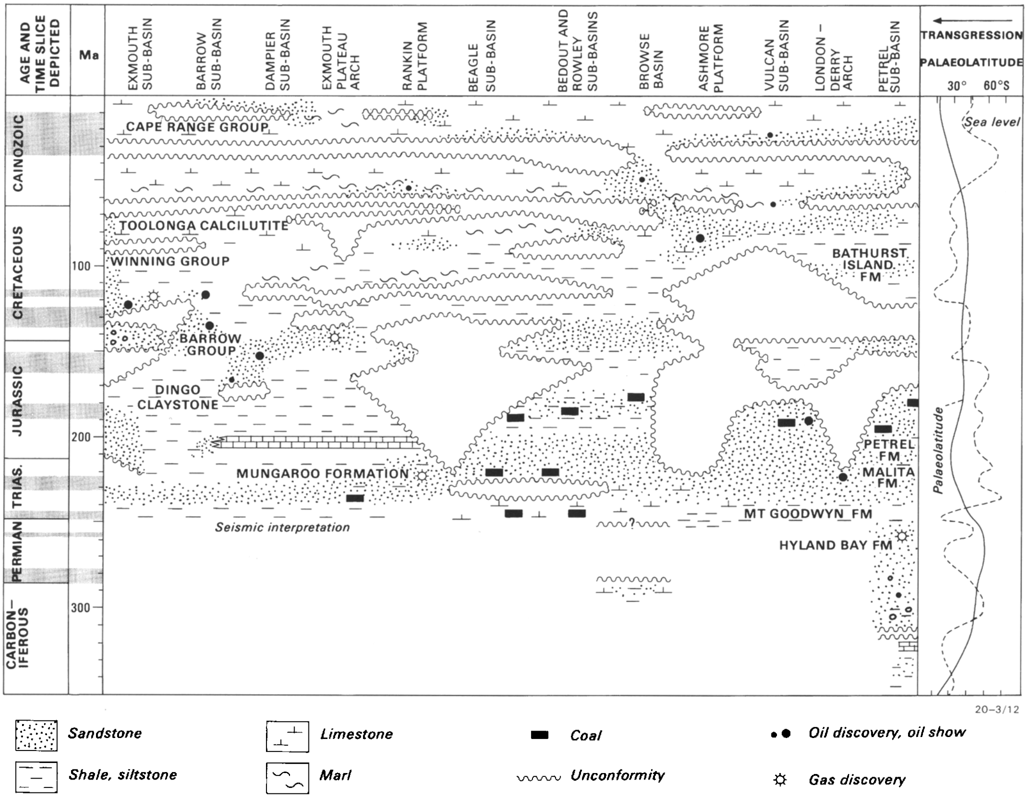

Fig. 3. Stratigraphic elements of the Westralian Petroleum System, North West Shelf (from Bradshaw *et al.* 1988).

Jabiru-1A, Vulcan sub-basin

The Jabiru oil field, located in the Vulcan Sub-basin (Fig. 2), was discovered in 1983 with Jabiru-1A encountering a 57 m oil column in Jurassic sandstones (Fig. 3; MacDaniel 1988). The Jabiru trap presently contains approximately 169 million barrels (MMBBL) of 42.5° API oil, of which 88 MMBBL have been produced (O'Brien *et al.* 1996).

Samples from within the current oil zone have high GOI values, consistent with the present oil column (Fig. 4). However, GOI values above the 5% threshold continue in samples from beneath the present OWC, suggesting the oil column was significantly thicker in the past. The generally high GOI values recorded in the present oil zone are thought to be in response to the excellent reservoir quality (average $\phi = 22\%$, $K = 30$ to $> 10\,000$ mD; MacDaniel 1988), with GOI values below the 5% threshold seen only in isolated zones of much poorer reservoir quality (Fig. 4). A fall to GOI values expected for a water-saturated rock occurs in the 1715 m sample (GOI $< 1\%$), some 65 m below the present OWC, and is almost 50 times lower than recorded in the sample at 1700 m. Collectively, these data define an original oil column of between 107 and 122 m at Jabiru-1A (O'Brien *et al.* 1996).

Further characterization of the original oil column is provided by published geochemical analyses of palaeo-oil within fluid inclusions, which confirms that the palaeo and presently reservoired oil are genetically related, having been derived from a similar source facies (George *et al.* 1997). However, maturity levels are slightly lower in the palaeo-oil, suggesting that the oil trapped by fluid inclusions represents early charge to the Jabiru structure with the drill stem test composition diluted through ongoing charge by oil with progressively higher maturity (George *et al.* 1997). This conclusion is consistent with petrographic data which show that oil inclusions are abundant within quartz overgrowths, and fluid inclusion palaeotemperature data

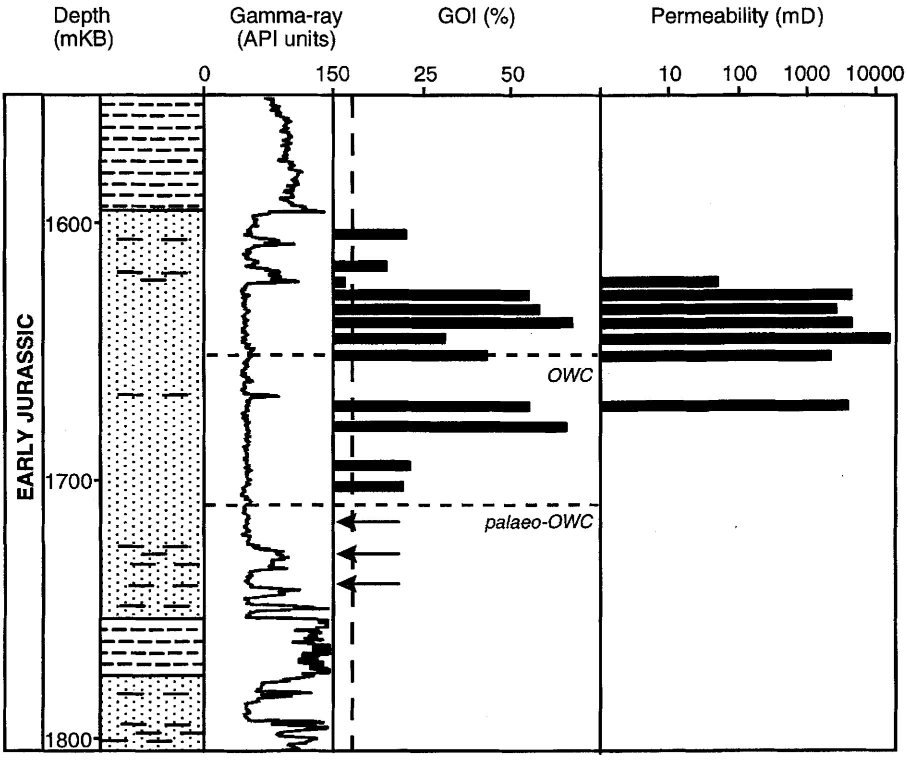

Fig. 4. GOI values recorded on samples from Jabiru-1A showing present and interpreted palaeo-OWCs. Arrows indicate samples with GOI values < 1%. The vertical dashed line represents an empirical threshold for oil accumulation as derived from data shown in Fig. 1.

which suggest that quartz overgrowths began trapping oil inclusions from about 6 Ma (Lisk & Eadington 1994) when source rocks would have been less mature.

The original size of the Jabiru oil field can be appreciated when the height of the original oil column, as derived from GOI data, is combined with the relevant information on rock volumes and reservoir parameters to obtain a volumetric calculation of the original oil in place. Using these inputs, O'Brien *et al.* (1996) estimated the original oil in place to be approximately 560 MMBBL which, when combined with estimates of oil currently in place (170 MMBBL), suggests that a substantial volume of oil (> 390 MMBBL) may have been lost from the trap.

Reactivation of faults bounding the Jabiru structure is generally thought responsible for the loss of hydrocarbons (O'Brien & Woods 1995; O'Brien *et al.* 1996). Palaeoformation water salinities derived from analysis of aqueous fluid inclusions within quartz overgrowths from Jabiru-1A support a breach of fault seal. These data record the migration of hot, highly saline waters through the residual and water zones of the Jabiru structure and overlying aquifers (Fig. 5; O'Brien *et al.* 1996), with these fluids having previously been ascribed to cross-formational flow from Palaeozoic evaporites (Eadington *et al.* 1990). Significantly, the absence of such waters from the current oil zone indicates that the migration of these fluids occurred after oil charge, and the migration event is seen as a direct by-product of the reactivation process which leaked much of the reservoired oil (O'Brien *et al.* 1996).

Regional significance

Similar studies to those carried out on Jabiru-1A have been completed on many other wells from the Timor Sea, allowing regional patterns in seal integrity to be recognized through a better understanding of charge history and basin hydrology (O'Brien & Woods 1995; O'Brien *et al.* 1996; Lisk *et al.* 1997). For example, similar palaeosalinity data to those presented for Jabiru-1A have been collected from other hydrocarbon traps throughout the Timor Sea. The pre-

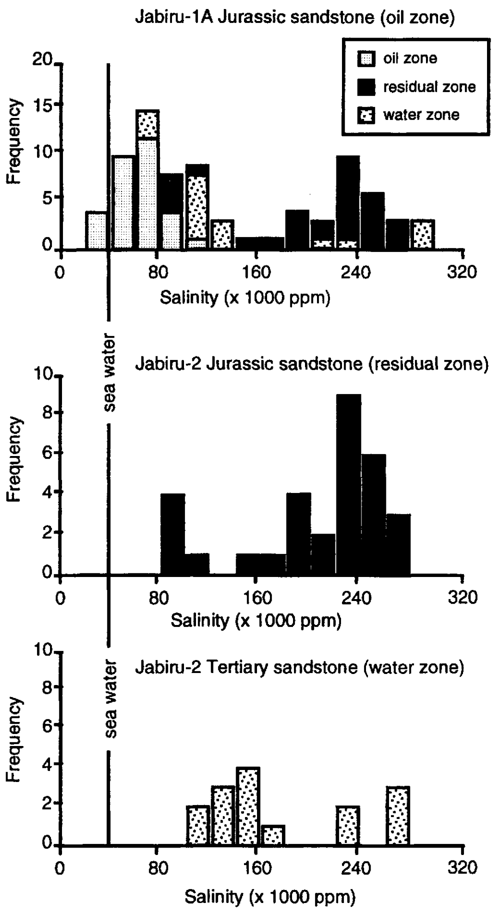

Fig. 5. Calculated salinity of palaeoformation water trapped in aqueous fluid inclusions within quartz overgrowths from Jurassic and Tertiary sandstones in Jabiru-1A.

sence of high salinity fluids in samples from residual zones and their absence from intact hydrocarbon zones have shown this trend to be a feature of hydrocarbon fields of this region (Fig. 6), suggesting that such fluid inclusion data may be a useful discriminator between loss of oil due to fault breach and loss relating to effects such as structural tilting or gas displacement (Lisk *et al.* 1997).

In addition, these data have been used in combination with a new method for appraising trap integrity through the recognition of diagenetic effects that accompany hydrocarbon leakage. O'Brien & Woods (1995) & O'Brien *et al.* (1996) first proposed a system for evaluating trap integrity in the Timor Sea on the basis of the distribution of locally pervasive and isotopically light carbonate cements present in Tertiary (Eocene) sandstones located above leaky Jurassic hydrocarbon reservoirs. Essentially, the size and acoustic velocity of these carbonate-cemented zones, which O'Brien & Woods (1995) called hydrocarbon-related diagenetic zones (HRDZs), are thought to reflect the total hydrocarbon fluid flux through near-surface aquifer sands. Bacterial oxidation of the migrating hydrocarbons has produced carbonate cementation; the greater the amount of leakage, the larger the diagenetic effect (Fig. 7).

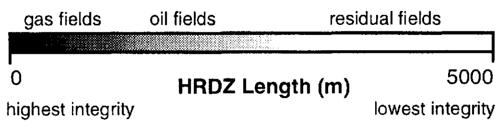

Fig. 7. Schematic cartoon showing relationship between size of hydrocarbon-related diagenesis zone (HRDZ) and trap integrity (modified from O'Brien *et al.* 1996).

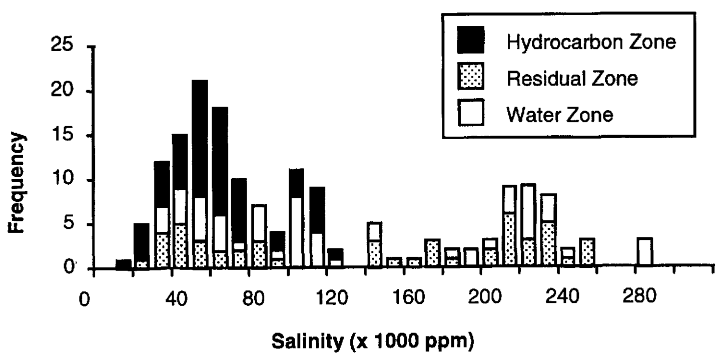

Fig. 6. Fluid inclusion salinities determined for aqueous inclusions from five Timor Sea hydrocarbon fields (from Lisk *et al.* 1997).

Significantly, these HRDZs can be detected remotely as velocity anomalies on seismic data, potentially allowing seal integrity of prospective hydrocarbon traps to be evaluated predrill (O'Brien & Woods 1995; O'Brien *et al.* 1996). GOI mapping has been used extensively to validate this system by allowing the complete charge history of hydrocarbon fields such as Jabiru to be described and the original OWC identified for assessing the net loss of hydrocarbons due to fault breach (O'Brien *et al.* 1996; Lisk *et al.* 1997).

Oil-leg prediction

The sedimentary basins of the North West Shelf contain oil-prone source rocks and the likelihood of discovering oil as opposed to gas is commonly a function of thermal maturity and the efficiency of migration paths, rather than the availability of an oil-prone source. Oil-prone source rocks that are now over-mature will have generated liquids in the past and structures that are presently gas-bearing may have once contained oil columns. Understanding the timing of oil migration relative to gas charge is critical for the determination of oil-leg potential. Appraisal drilling, designed specifically to locate an oil-leg, has been difficult to plan effectively, since to date there has been no way of demonstrating unequivocally what volume of oil was once reservoired. Conventional PVT measurements showing that gas is at dew point, or recognition of oil shows from fluorescence and extraction techniques, or Rock-Eval pyrolysis results (S1 peak and Iatroscan data), are all indicators that an oil leg may have been present, although these methods are rarely conclusive and many are often unreliable. Significantly, none of these approaches is particularly useful for identifying original OWCs and so they provide little constraint on the volume of oil once present. Consequently, decisions regarding additional drilling to locate a possible oil leg are taken with limited control on the critical risk of oil charge.

Collection of GOI data allows the extent of prior oil accumulation to be determined, thereby providing the opportunity for explorers to make a more informed assessment of oil-leg potential (Lisk *et al.* 1996*b*).

Oliver-1, Vulcan sub-basin

The Oliver oil and gas discovery, located in the Vulcan Sub-basin (Fig. 2), was drilled in 1988 by BHP Petroleum Ltd and encountered a 178.5 m gross hydrocarbon column in Jurassic sandstones (Fig. 3), comprising 164 m of gas over a 14.5 m oil leg. A combination of the offshore location of the field and the thin oil leg resulted in insufficient reserves to justify development and the well was suspended without further appraisal drilling. The risk of late gas charge also downgraded the prospectivity of nearby traps which have volumetric capacities to support an oil play but are too small to represent an economic gas development. Consequently, the area has seen only light exploration activity since 1992.

GOI analyses at Oliver-1 indicate that the oil leg was once significantly larger, thereby enhancing the liquid prospectivity of surrounding traps. Samples taken from between 2946 m and 3045 m and within the present gas leg have GOI values that are more than two orders of magnitude higher than values recorded over the

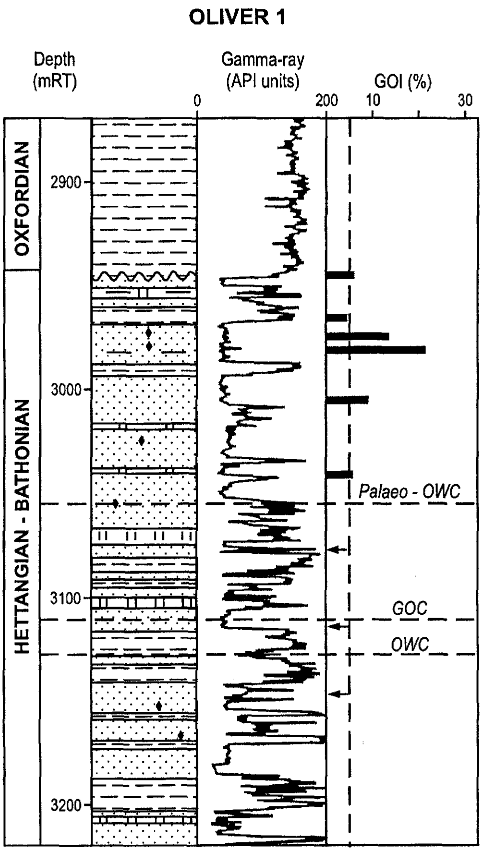

Fig. 8. GOI results from Oliver-1. Arrows indicate samples with GOI values < 1%. Present and palaeofluid contacts are shown while the vertical dashed line represents an empirical threshold for oil accumulation as derived from data shown in Fig. 1. Modified from O'Brien *et al.* (1996).

interval 3078–3150 m (Fig. 8). A sharp reduction in GOI values from 5.7% at 3045 m to less than 0.1% at 3078 m is interpreted to reflect the crossing of a palaeo-OWC. Given that the top of the reservoir occurs at about 2940 m, these data delineate a palaeo-oil column measuring between 99 m and 132 m (median thickness = 115.5 m) at the Oliver-1 well location (O'Brien *et al.* 1996). The sequence of high GOI values overlying low GOI values which define a palaeo-OWC within the present gas leg is significant as it suggests that the oil column was hydrodynamically stable. This precludes the gradual smearing of an originally much smaller oil column during gas charge or episodic displacement where high GOI values would be expected to extend to the current gas–oil contact. Further, the absence of high GOI values in samples from the current oil leg suggests that most of the oil inclusions are formed during initial charge and not during subsequent modifications. Consequently, episodic cycles of displacement followed by periods of quiescence are not seen as opportunities for establishing zones of high GOI that may be wrongly interpreted as one continuous oil column. In addition, episodic displacement is unlikely to result in continuous zones of high GOI; rather, fluctuating values ranging from low (< 1%) to high (< 5%) GOI would be expected.

A gross palaeo-oil column of 115.5 m, taken together with relevant information on rock volumes and reservoir parameters (O'Brien *et al.* 1996), suggests that the Oliver trap contained between about 150 and 200 MMBBL of oil prior to gas charge (Fig. 9). In contrast, the present 14.5 m oil leg equates to approximately 45 MMBBL suggesting that in excess of 100

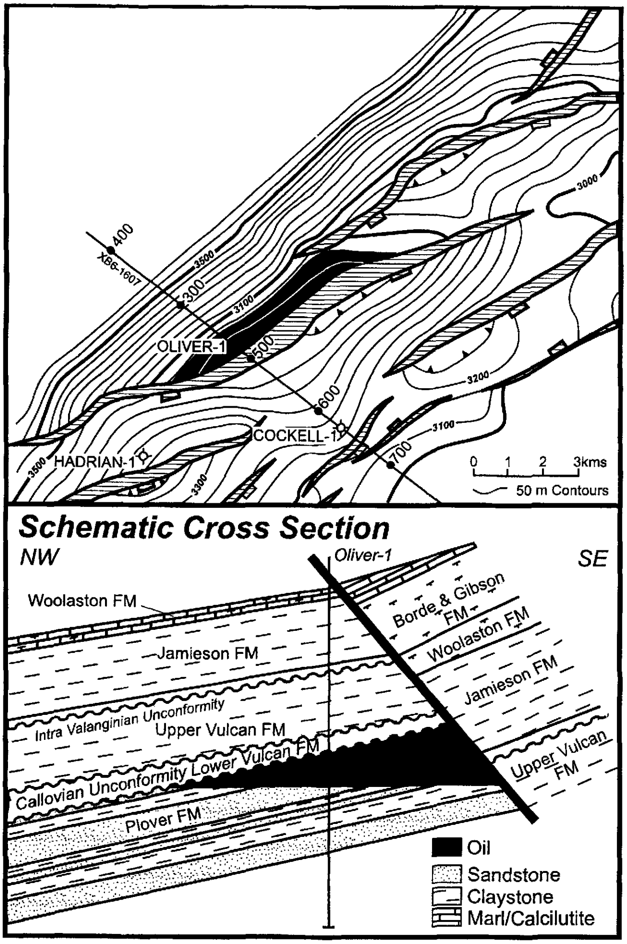

Fig. 9. Depth structure map for the Oliver field at Callovian unconformity level (Evans *et al.* 1995) showing the extent of the palaeo-oil column defined by GOI data. Modified from O'Brien *et al.* (1996).

MMBBL of oil has been lost from the Oliver trap (O'Brien *et al.* 1996).

The displacement of significant volumes of oil provides an opportunity for this oil to charge nearby structures, especially those that may be in the shadow of regional migration fairways and may not previously have been regarded as prospective. However, several issues impact upon a conclusion of gas displacement including loss of oil due to seal failure, biodegradation of the early oil charge and changes in the PVT state of the reservoir after initial oil charge.

Absorption of oil into an under-saturated gas phase that charges the trap subsequent to the accumulation of an oil column can account for some of the lost oil, as the capacity of gas to absorb oil increases with higher pressure and temperature (Fig. 10). The maximum loss of oil by this mechanism can be calculated crudely from the condensate–gas ratios measured on recovered gas. At Oliver-1, these ratios range from 35 to 39 barrels per million standard cubic feet (BBL/MMSCF) (BHP Petroleum Ltd 1988) for gas recovered by repeat formation tester (RFT). When combined with an estimate of gas in place at Oliver of some 300 billion cubic feet (BCF), and assuming later gas charge consisted purely of methane (i.e. the greatest gas absorption effect), then the maximum loss of oil through absorption is placed at about 10–12 MMBBL. This reduces the net loss of oil from the Oliver trap to about 90 MMBBL.

Biodegradation can result in the loss or reduction of an early oil column before the arrival of late gas. However, geochemical analysis of presently reservoired hydrocarbons can be used to recognize prior biodegradation (Williams & Poynton 1985; Lisk *et al.* 1996*a*). In Oliver-1 geochemical analysis of recovered of oil and gas (BHP Petroleum Ltd 1988) shows no evidence of biodegraded residues and consequently loss of the original oil charge through this mechanism is considered unlikely.

Fault seal integrity has been recognized as an issue which adversely affects the preservation of hydrocarbon charge in the Timor Sea. However, seal integrity studies conducted by O'Brien & Woods (1995) & O'Brien *et al.* (1996), and discussed earlier, categorized the Oliver structure as a high integrity trap with no evidence to support significant vertical leakage. Indeed, almost all of the gas fields in this region lack the diagenetic effects which are characteristic of breached oil fields (Fig. 7). Further evidence of high seal integrity for the Oliver trap is provided by the absence of the high salinity fluids seen in all of the Timor Sea residual zones (including Oliver-1) where salinity data have been collected (Fig. 6).

Having excluded alternative mechanisms for the loss of oil from the Oliver trap the exploration implications arising from the displacement of a large palaeo-oil column can be explored with greater confidence. The spill point of the Oliver trap is structurally controlled, with loss of oil expected from the eastern side of the field (Fig. 11). Mapping of remigration pathways has allowed the prospectivity of adjacent traps to be addressed by controlling the oil charge risk. Significantly, the presence of an oil leg within the present-day Oliver structure suggests that no gas has been spilled, and consequently the likelihood of these adjacent traps also having been gas-flushed is low.

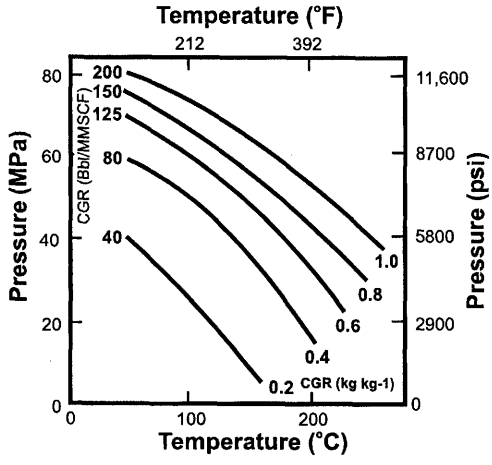

Fig. 10. Variation in the predicted condensate–gas ratio (CGR) for an oil-saturated gas as a function of pressure and temperature (from Price *et al.* 1983).

Identification of structural tilting

Basin-ward tilting of hydrocarbon traps has been frequently documented on the North West Shelf (Lisk *et al.* 1996*a*; Beales & Howell 1992; Osborne & Howell 1987), with the tilting thought to be in response to the differential loading of the rifted margin during progradation of sediments in a passive margin setting (Kopsen & McGann 1985). These structural modifications are especially significant when they postdate oil charge, resulting in the progressive loss of hydrocarbons as the spill point of the trap changes through time (Fig. 12). Accurate identification of original fluid contacts allows the relative timing of structural tilting to be constrained, and is critical if the oil charge potential created by these movements is to be fully recognized.

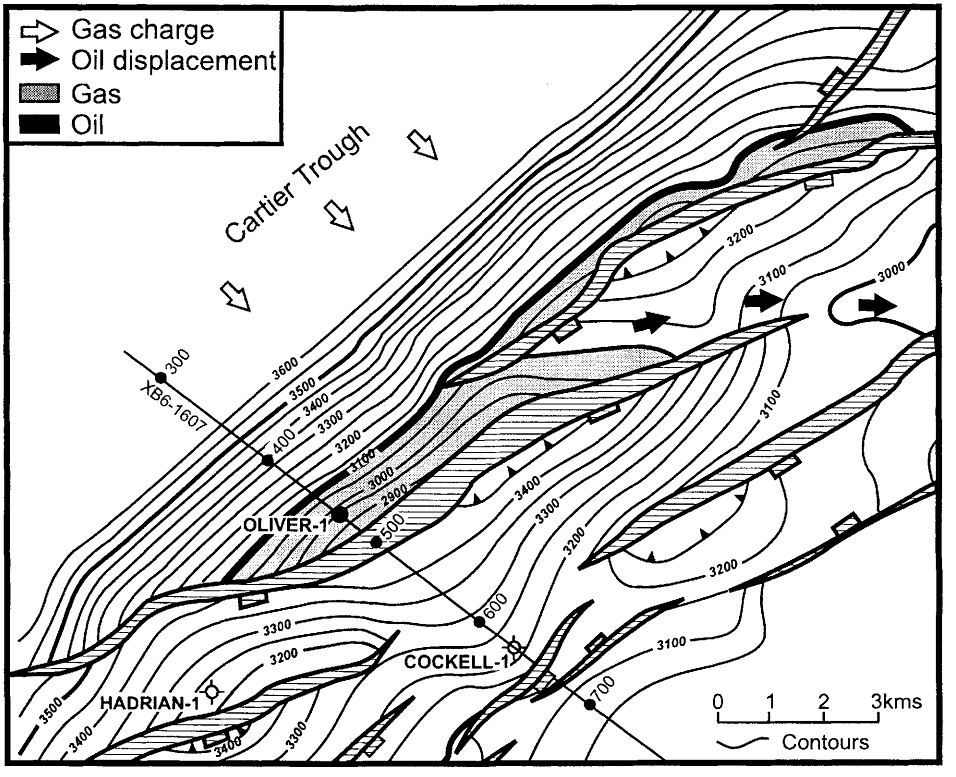

Fig. 11. Callovian unconformity depth structure map showing the likely remigration pathways for oil spilt from the Oliver trap during gas flushing (from Lisk *et al.* 1997).

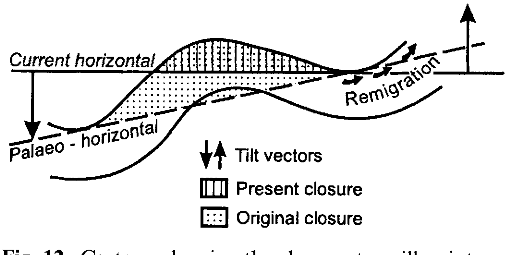

Fig. 12. Cartoon showing the changes to spill point induced by altering the geometry of hydrocarbon traps through tilting.

East Spar Gas Field, Barrow sub-basin

The East Spar gas field, discovered in 1994 by Western Mining Petroleum Pty. Ltd, is located in the northern Barrow Sub-basin, a thick Jurassic and Cretaceous depocentre that hosts numerous significant hydrocarbon discoveries (Fig. 2). The gas is reservoired in massive to cross-bedded, deltaic sandstones of the Barrow Group, which exhibit good reservoir quality: porosities are as high as 24%, with permeabilities reaching 4000 mD (Pitt *et al.* 1996). Appraisal drilling has identified proven and probable gas reserves for the field of 834 BCF, with no associated oil leg (Pitt *et al.* 1996).

The wetness of the gas (condensate yield of 69.1 stock tank barrel (STB) MMSCF), taken together with the oil-prone nature of adjacent source rocks, suggest that the trap may have once contained liquid hydrocarbons. Consequently, a sampling programme was undertaken to assess the oil charge history of the field (Lisk 1995). Confirmation of a prior oil charge was sought to enhance the prospectivity of a new exploration play, which was targeting a separate culmination located to the east of the East Spar field (Pitt *et al.* 1996). This feature, known as Area C, was considered too small, and was thus uneconomic if it contained gas; drilling of the prospect could be justified, however, if the trap contained oil rather than gas.

The results of GOI mapping conducted on East Spar 4AST1 revealed a zone of high GOI values at the top of the Barrow Group (Fig. 13). A sharp reduction in GOI values from

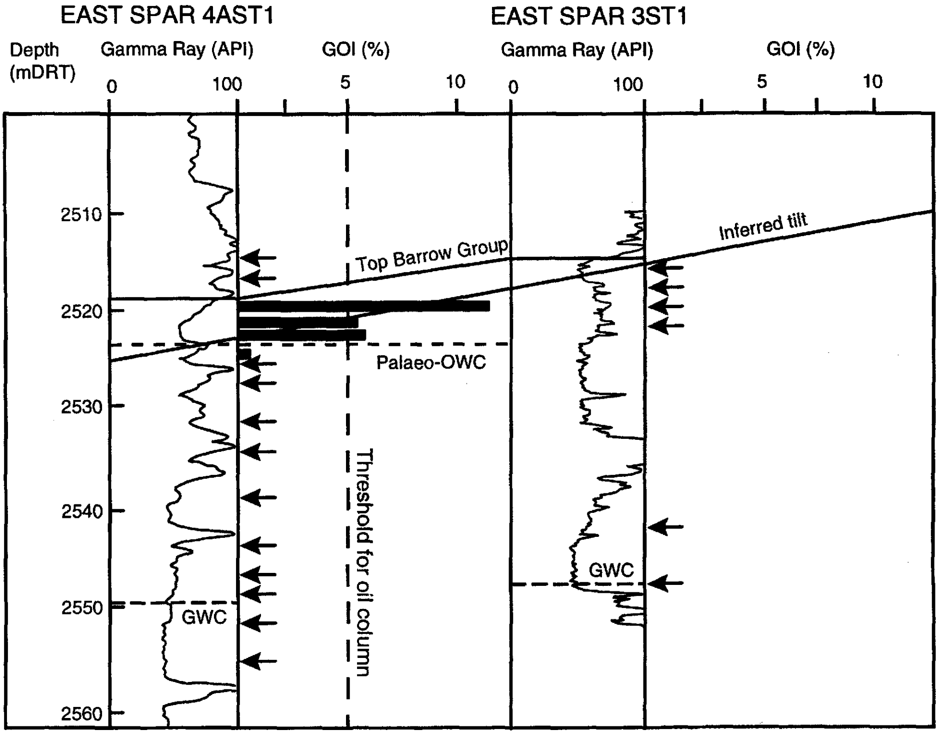

Fig. 13. GOI results obtained from East Spar 4AST1 and East Spar 3AST1. Arrows denote GOI values <0.5%.

6.4% at 2517.6 m true vertical depth (TVD) to 0.5% at 2518.5 mTVD is interpreted to reflect the crossing of an original OWC and confirms the presence of 5–6 m palaeo-oil column within the presently gas-bearing sandstones intersected in East Spar 4AST1.

Subsequent sampling of East Spar 3AST1 was undertaken in an attempt to further define the extent of the East Spar palaeo-oil accumulation. This sampling programme did not encounter elevated GOI values (Fig. 13) and the absence of high palaeo-oil saturation in stratigraphically equivalent samples is interpreted to reflect that they were located either outside structural closure or below the palaeo-OWC at the time of oil charge. Given the interpreted structure map as it presently stands, this would have required East Spar 4AST1 to have been structurally higher than East Spar 3AST1 at the time of oil charge. Sedimentation through the Tertiary comprised a westerly prograding, carbonate wedge which is thought to have induced subsidence in a west–northwest direction; this would be consistent with tilting of the structure down towards East Spar 4AST1 (Fig. 13). The minimum amount of tilting required to accommodate the GOI data is calculated to be about 3°. Tilting is unlikely to have been solely responsible for the loss of oil from the East Spar structure, since East Spar 4AST1 lies within present closure. Given that the East Spar structure is presently gas-bearing, a combination of gas displacement and structural tilting was probably responsible for the loss of oil across the spill point. Tilting of the East Spar trap down towards the west, as inferred by the GOI data, would have resulted in a loss of closure on the eastern side of the field, favouring remigration of oil toward Area C (Fig. 14).

The timing of this tilting event could be addressed by flattening individual seismic or stratigraphic surfaces until a horizontal OWC is obtained. Fluid inclusion palaeotemperature data available to this study (Lisk 1995) also provide an opportunity to address this issue by constraining the time of initial oil charge. Aqueous fluid inclusions located within quartz overgrowths have homogenization temperatures which range from 95°C to 128°C (Lisk 1995). When these palaeotemperature data are reconciled with palaeoformation temperatures derived from a default basin model, the trapping of fluid inclusions by quartz overgrowth crystallization is inferred to have occurred from about 35 Ma (Fig. 15). Petrographic data, which detail the location of oil inclusions relative to authigenic

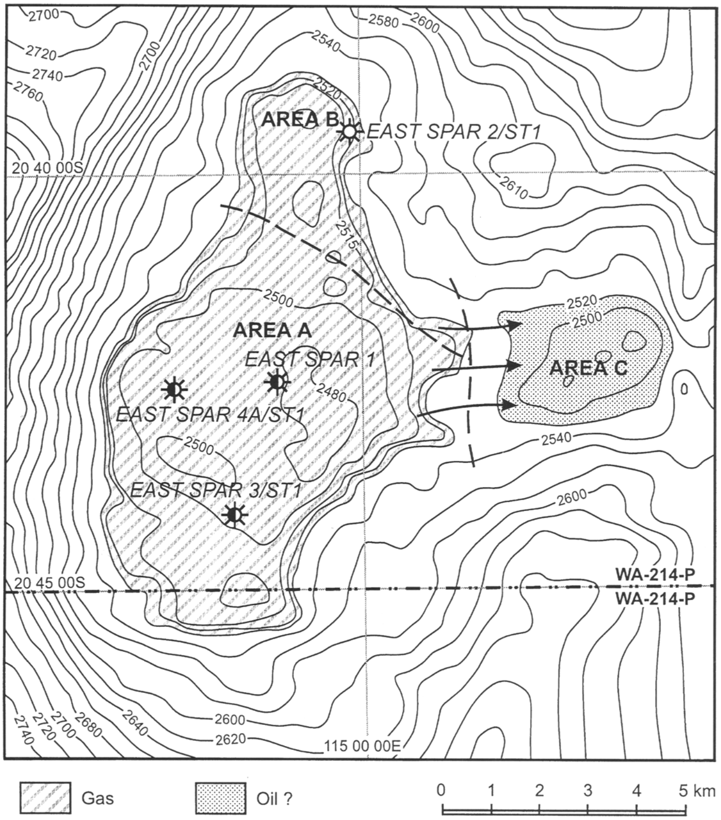

Fig. 14. Interpreted depth structure map for the East Spar feature at top Barrow Group level (modified from Pitt *et al.* 1996) showing anticipated remigration directions for displaced oil.

minerals, show that some oil inclusions occur within quartz overgrowths (Fig. 16), suggesting that oil migrated during the formation of this diagenetic cement. However, most of the oil inclusions occur on fractures in detrital quartz and feldspar, and this is interpreted to reflect the attainment of high oil saturation after the formation of quartz overgrowths. An abundance of oil inclusions within quartz overgrowths, reflecting the coating of many detrital grains with residual oil, would be expected if high oil saturation was synchronous with, or preceded, quartz overgrowth crystallization. Consequently, these data constrain the tilting event to after 35 Ma which is consistent with an increasing thickness of postrift sediments during the Middle to Late Tertiary.

Collectively, the results obtained for the East Spar field lend considerable support to Area C being an oil, rather than sub-commercial gas, play. However, two further issues need to be addressed before this conclusion can be fully supported. First, the volume of oil displaced will play an important role in justifying a new drilling decision. Given evidence for modification of closure through time, only limited control can be placed on the area of palaeoclosure, which influences any calculation of original oil in place. However, if an assumption is made that these modifications have rotated the geometry of the trap, but have not significantly altered its volumetric capacity, then an estimate of original oil in place can be made.

Volumetric calculations based on height of palaeo-oil column (6 m), area of closure assuming a flat OWC (15.1km^2), published net to gross ratio (Pitt *et al.* 1996; Craig *et al.* 1997), average porosity (10%) and an assumed water saturation of 50%, indicate that the East Spar trap once contained about 9–10 MMBBL of oil prior to gas charge. This value is less than would be required to produce an economically viable field in this basin. Consequently, unless the assumptions inherent in the calculation are flawed, the exploration potential of Area C would appear to be small.

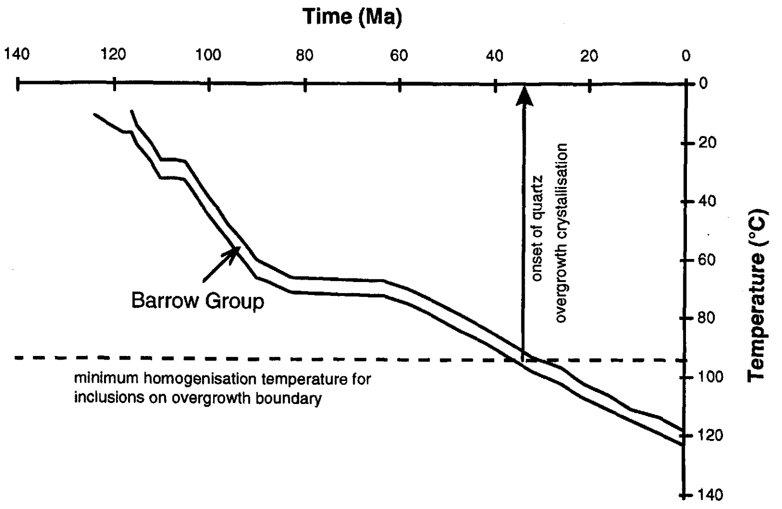

Fig. 15. Modelled formation temperatures in the Barrow Group versus time. The onset of quartz overgrowth crystallization is based on the minimum homogenization temperature recorded on aqueous fluid inclusions within quartz overgrowths from East Spar 4AST1.

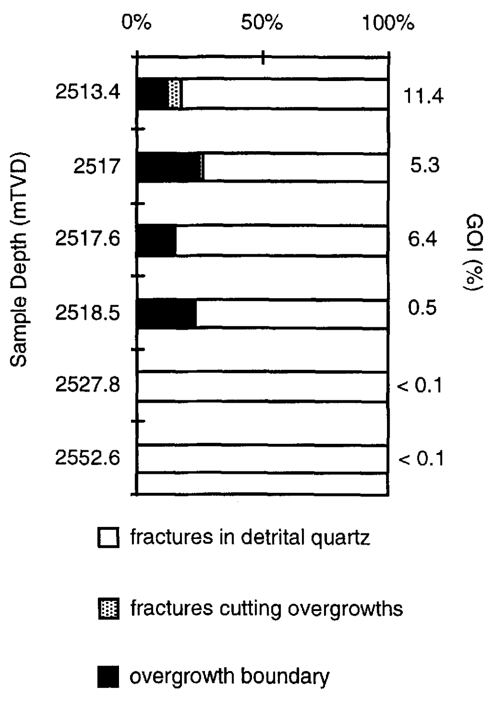

Fig. 16. Location of oil inclusions relative to quartz overgrowths in samples from East Spar 4AST1.

In addition, the high condensate yield exhibited by East Spar gas suggests there is opportunity that a late gas charge, under-saturated with respect to liquids, may have absorbed some of the palaeo-oil, resulting in a lesser proportion having been spilled up-dip. The likely wetness of gas entering the trap is difficult to assess, although maximum loss of oil can be estimated by assuming that any late gas consisted purely of methane. Given proven reserves at East Spar of approximately 834 BCF and a condensate yield for the gas of 69.1 STB/MMSCF, then the maximum loss of oil can be placed at 57.6 MMBBL. Calculations of oil in place prior to emplacement of the current gas column (10 MMBBL) clearly suggest that an absorption mechanism is a plausible one to account for the prior oil column and one which substantially reduces the likelihood of oil being displaced to Area C.

Conclusions

Reservoir filling histories can be complex and elusive. New methods such as GOI allow the charge history of hydrocarbon traps to be more fully described, which is critical to predicting present-day petroleum distribution. On the Australian North West Shelf, the application of these methods for mapping hydrocarbon charge has allowed the prospectivity of new plays to be addressed by constraining the timing of oil charge and by identifying changes in the configuration of hydrocarbon traps after initial charge. More importantly, this information, when collected on a regional basis, has allowed processes which influence the distribution of oil and gas in this region to be recognized and fully described with a consequent reduction in exploration risk.

Given the relatively low cost of the GOI and other fluid inclusion-based methodologies, relative to the large costs involved in drilling exploration wells, these new techniques have the potential to both reduce risk and improve exploration efficiency enormously, both in Australia and elsewhere.

This work forms part of the Fill-Spill project, a collaborative initiative between AGSO and CSIRO aimed at characterizing charge histories on the Australian North West Shelf. The authors wish to thank Dr Dan Carruthers and Dr Don Hall for their constructive review of this manuscript which has unquestionably improved this paper. Eva Mylka and Jane Michie are thanked for the drafting of figures while the assistance and comments of research and support staff at CSIRO and AGSO are also gratefully acknowledged.

References

BEALES, V. & HOWELL, E. A. 1992. Tanami Oil Discovery: Barrow Sub-basin. *APEA Journal*, **32**, 86–93.

BHP PETROLEUM LTD. 1988. Oliver-1 well completion report, unpublished.

BRADSHAW, M.T., BRADSHAW, J., MURRAY, A.P., NEEDHAM, D.J., SPENCER, R. E., SUMMONS, R.E., WILMOT, J. & WINN, S. 1994. Petroleum systems in West Australian basins. *In*: PURCELL, P.G. & PURCELL, R.R. (eds) *The Sedimentary Basins of Western Australia, Proceedings of the West Australian Basins Symposium*, Perth, 93–118.

CARRUTHERS, D. & RINGROSE, P. 1998. Oil-rock contact volumes during secondary oil migration. *This volume.*

CRAIG, A., SIT, H., SHERIDAN, P. & MACLEAN, L. 1997. A geophysical appraisal of the East Spar gas/condensate field. *APEA Journal*, **37**, 12–30.

EADINGTON, P.J., LISK, M. & HAMILTON, P.J. 1990. *Fluid history analysis of samples from Augustus-1, Douglas-1, Challis-1 & Jabiru-1A, Timor Sea.* CSIRO Report, unpublished.

——, —— & KRIEGER, F.W. 1996. *Identifying oil well sites.* United States Patent No. 5,543,616.

EVANS, B.J., OKE, B.F., Urosevic, M. & Chakraborty, K. 1995. A comparison of physical model with field data over Oliver Field, Vulcan Graben: *APEA Journal*, **35**, 26–43.

GEORGE, S.C., GREENWOOD, P.F., LOGAN, G.A. QUEZADA, R.A., PANG, L.S.K., LISK, M., KRIEGER, F.K. & EADINGTON, P.J. 1997. comparison of palaeo-oil charges with currently reservoired hydrocarbons using molecular & isotopic analyses of oil bearing fluid inclusions – Jabiru Oilfield. *APEA Journal*, **37**, 490–504.

HAGEMANN, H.W. & HOLLERBACH, A. 1985. The fluorescence behaviour of crude oils with respect to their thermal maturation & degradation. *Organic Geochemistry*, **10**, 473–480.

HIRSCH, L.M. & THOMPSON, A.H. 1995. Minimum saturation's & buoyancy in secondary migration. *AAPG Bulletin*, **79**(5), 676–710.

KOPSEN, E. & MCGANN, G. 1985. A review of the hydrocarbon habitat of the eastern & central Barrow Sub-basin, Western Australia. *APEA Journal*, **25**, 154–176.

LISK, M. 1995. *Hydrocarbon & pore water migration history of the East Spar gas field.* Unpublished report to WMC Petroleum Ltd.

—— & EADINGTON, P.J. 1994. Oil migration in the Cartier Trough, Vulcan sub-Basin. *In*: Purcell, P.G. & PURCELL, R.R. (eds) *The Sedimentary Basins of Western Australia, Proceedings of the West Australian Basins Symposium*, Perth, 301–312.

——, HAMILTON, P.J., EADINGTON, P.J. & KOTAKA, T. 1993. Hydrocarbon & pore water migration history in relation to diagenesis in the Toro & Iagifu sandstones, S.E. Gobe-2. *In*: CARMAN, G. J. & CARMAN, Z. (eds), *Petroleum exploration & development in Papua New Guinea*; *Proceedings of the second PNG Petroleum Convention*, Port Moresby, 477–488.

——, GEORGE, S.C., SUMMONS, R.E., QUEZADA, R.A. & O'BRIEN, G.W. 1996*a*. Mapping hydrocarbon charge histories: Detailed characterisation of the South Pepper oil field, Carnarvon Basin. *APEA Journal*, **36**, 445–464.

——, EADINGTON, P.J. & KRIEGER, F.W. 1996*b*. Quantitative evaluation of oil-leg potential in gas reservoirs. *AAPG Annual Convention*, San Diego (abstract only).

——, O'BRIEN, G.W. & BRINCAT, M.P. 1997. Gas displacement: An important control on oil & gas distribution in the Timor Sea? *APEA Journal*, **37**, 259–271.

MACDANIEL, R.P. 1988. The geological evolution & hydrocarbon potential of the western Timor Sea region. *Petroleum in Australia, The First Century.* APEA publication, 270–284.

MCLIMANS, R.K. 1987. The application of fluid inclusions to migration of oil & diagenesis in petroleum reservoirs. *Applied Geochemistry*, **2**, 585–603.

NEDKVITNE, T., KARLSEN, D.A., BJØRLYKKE, K. & LARTER, S.R. 1993. The relationship between diagenetic evolution & petroleum emplacement in the Ula Field, North Sea. *Marine & Petroleum Geology*, **10**, 255–270.

O'BRIEN, G.W. & WOODS, E.P. 1995. Hydrocarbon related diagenetic zones (HRDZs) in the Vulcan Sub-basin, Timor Sea: recognition & exploration implications. *APEA Journal*, **35**, 220–52.

——, LISK, M., DUDDY, I., EADINGTON, CADMAN, S. & FELLOWS, M. 1996. Late Tertiary fluid migration in the Timor Sea: A key control on thermal & diagenetic histories? *APEA Journal*, **36**, 399–427.

OSBORNE, D. G. & HOWELL, E. A. 1987. The geology of the Harriet Oilfield, offshore Western Australia. *APEA Journal*, **27**, 152–163.

OXTOBY, N. H., MITCHELL, A. W. & GLUYAS, J. G. 1995. The filling & emptying of the Ula Oilfield: fluid inclusion constraints. *In*: Cubitt, J. M. & England, W.A. (eds) *The Geochemistry of Reservoirs*, Geological Society, Special Publication **86**, 141–157.

PITT, G. W., KURYLOWICZ, L. E. & CAMPBELL, P. F. 1996. East Spar field: from discovery to sales. *APEA Journal*, **36**, 30–50.

PRICE, L. C., WENGER, L. M., GING, T. & BLOUNT, C. W. 1983. Solubility of crude oil in methane as a function of pressure & temperature. *Organic Geochemistry*, **4**, 201–21.

SMITH, G. C., TILBURY, L. A., CHATFIELD, A., SENYCIA, P. & THOMPSON, N. 1996. Laminaria – a new Timor Sea discovery. *APEA Journal*, **36**, 12–29.

SYLTA, Ø., PEDERSEN, J. I. & HAMBORG, M. 1998. On the vertical & lateral distribution of hydrocarbon migration velocities during secondary migration. *This volume*.

WHIBLEY, M. & JACOBSON, E. 1990. Exploration in the Northern Bonaparte Basin, Timor Sea – WA-199–P. *APEA Journal*, **30**, 7–27.

WILLIAMS, A. F. & POYNTON, D. J. 1985-. The geology and evolution of the South Pepper hydrocarbon accumulation. *APEA Journal*, **25**, 235–247.