POSTERS CONTENTS

The role of carbon isotope stratigraphy as a correlation tool about the Permian–Triassic boundary in the Perth Basin

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The negative shift in carbon isotope values in confirmed Permian–Triassic marine carbonate sections around the world is well documented and appears to be a global phenomenon. This is true even to the point where the negative carbon isotope shift has been suggested as an auxiliary marker of the Permian–Triassic boundary.

Although carbonate sections across the boundary are missing in Australia there is an apparent negative shift in carbon isotope values in total organic matter from siliciclastic sediments in sections that traverse the Permian–Triassic boundary. These documented sections are interpreted to be marine-influenced and non-marine. The Permian sediments are generally characterised by more positive carbon isotope values; the Triassic sediments have more negative carbon isotope values. This consistency of the negative carbon isotope shift in organic matter has been interpreted as analogous to the shift in carbon isotope values that occurs in marine carbonates and therefore to show the approximate transition from Permian to Triassic sediments. Recently this interpretation has been called into question following the discovery that some samples from acritarch-rich and woody debris-poor samples of apparent Permian age have organic carbon isotope signatures that are as negative as typical organic carbon from early Triassic sediments.

We present new carbon isotope data from the Perth Basin (Dongara–4, –12, –24, –25, Yardarino–1, –2 and Ejarno–1) that shows a well defined negative carbon isotope shift at within the zone of the Permian Triassic boundary as determined by palynology. This data set is consistent with all other organic carbon data sets published from sections across the Permian–Triassic boundary from around the world.

We suggest that, although the cause of the negative carbon isotope shift in organic matter from generally more positive values in the Permian to more negative values in the Triassic is still a matter under debate, the phenomenon is a real one. Furthermore, this variation in carbon isotope values shows potential as a correlation tool with significant precision. The relative ease with which the carbon isotope signature from total organic carbon can be determined, even in samples where positive age correlation using conventional palaeontological techniques has proven difficult, further suggests the potential of carbon isotope stratigraphy as a tool that can be used for time correlation on a regional or local scale.

Neogene structural history of the Barcoo Sub-basin, Browse Basin, Western Australia

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The Barcoo Sub-basin hosts the 180 km-long Barcoo Fault System, which varies in width from 2–20 km and comprises a series of enechelon overlapping faults offset from one another. The deformation style changes dramatically along strike, from broad, net contraction, through strike-slip, to broad net extension. Changes in structural style along the fault system result from control by restraining and releasing bend geometries.

The southern end of the fault system displays significant inversion and uplift in a restraining bend configuration near the Lynher–1 well. Zones up to 20 km wide of reverse-offset faults disrupt the sea-floor, indicating that fault reactivation occurred recently or is ongoing. Along strike to the north, the deformation style becomes dominated by narrow (2 km-wide) strike-slip zones, with fault showing inversion and evidence of reactivation. Deformation in this central part of the fault zone does not offset the sea floor. Towards the northern end of the fault zone, a broad deformation zone (20 km wide) displays both net normal and net reverse motion, with evidence of significant fault reactivation, consistent with formation in a releasing bend geometry. Reactivation and inversion may have been diachronous along the fault, as uplift at the southern end exceeds that at the northern terminus of the system.

Deformation along the fault zone, consistent with right-lateral oblique slip deformation, reactivated the original basin margin, in response to the Neogene collision of the Australian continent with the southern margin of the Eurasian continent. Zones of high strain along the fault system do not affect adjacent areas, indicating that reactivation and inversion, tightly confined to certain zones of weakness, may have been channelled into weaker parts of the basin, adjacent to basement uplifts.

The oblique, right-lateral displacement is consistent with predicted geometries from plate collision, and agrees well with known present-day stress from borehole breakout analyses.

2D and 3D structural restoration, trap integrity, and fluid migration in the Vulcan Sub-basin, Timor Sea, Australia

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Depth conversion, balancing and restoration using Geosec™ were carried out on six regional seismic lines across the Vulcan Sub-basin to improve our understanding of hydrocarbon migration history and trap integrity of this basin and adjacent areas. Compilation with the rest of the AGSO VTT–163 seismic lines across the Vulcan Sub-basin allows a fully balanced and restored 3D geometrical model of the area to be constructed using 3DMove™.

The sections were restored to the following horizons: Top Miocene, Top Eocene, Top Paleocene, Top Upper Cretaceous, Top Mid-Valanginian, Top Tithonian, Top Kimmeridgian, Top J/T, and Top Permian. The results of sequential decompaction and restoration were assembled and plotted. Restoration results of the six regional lines, which cover the main structural elements of the area, confirm that the evolution of the Vulcan Sub-basin and its adjacent areas occurred in four stages: pre-Jurassic and syn-Triassic rift, Late Jurassic rift, post-Jurassic rift margin subsidence, and Timor Collision. From the Permian to Recent, the maximum observable brittle extension of 5.5–8.28% occurred during the Triassic, which led to the formation of the proto-Swan Graben in the southwest and proto-Cartier Trough in the northeast. The Londonderry High was uplifted and eroded so that it contains no Jurassic or Triassic section. On the Ashmore Platform a 2–3 km sediment blanket is preserved, and in the Vulcan Sub-basin there are 6–9 km of Jurassic/Triassic section. From the Callovian to the Tithonian, extension was focussed in the Swan Graben in the southwest and in the northeast in the central part of the Cartier Trough with an observable brittle extension of 1.5–3%. Extension was shifted to the Skua Syncline in the southwest in contrast to northwest basin-bounding faults in the Cartier Trough.

During the post-Jurassic rift, the sub-basin initially subsided towards the Australian mainland in the Late Cretaceous, and then flipped to margin subsidence towards the Timor Trough until the Recent. This change in subsidence patterns had a marked effect on sediment distribution patterns and upon migration paths. The patterns were again disrupted in the Mio-Pliocene by arc-collision in Timor. Mio-Pliocene subsidence of the Vulcan Sub-basin continued, with similar regional subsidence in the Cartier Trough. However, modelling suggests that the Ashmore Platform was uplifted at this time, which both defined the Trough and dramatically changed the migration pathways.

The recognition and alleviation of near-wellbore fracture complexity in central Australia

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Increasingly demanding contractual obligations and more cost-effective technology have lead to the widespread use of hydraulic fracture treatments of wells in central Australia. Whilst historically confined to low permeability, marginal fields, the majority of natural gas wells in central Australia are now routinely fractured. However, an increasing number of wells in localised regions have displayed treatment difficulties, such as the inability to inject the required proppant concentrations without exceeding surface injection pressure limitations. Fracture width restrictions due to complex fracture geometry has been recognised as the origin of these anomalies. Near-wellbore tortuosity refers to convoluted fracture shapes, such as multiple or twisted fractures, connecting the far-field fracture to the wellbore. The propensity for fracture tortuosity is a direct function of the in situ stress regime, wellbore completion and treatment schedule.

Naturally fractured formations are most susceptible to multiple fracturing. The identification and characterisation of natural fractures is best performed using more than one method, such as combining FMS image analysis with mud loss data. In addition, wells subject to reverse fault stress regimes will also be subject to severe near wellbore tortuosity.

The presence of near-wellbore fracture complexity is betrayed by injection pressure anomalies, such as excessive shut-in pressure drops, 'pressure kicks' upon proppant injection, and large shut-in pressure declines. Injection rate changes provide the best means of diagnosing the presence and severity of near wellbore fracture complexity. Hindsight fracture pressure analysis using conventional hydraulic fracture design models is a powerful diagnostic method, which can establish both

the presence and extent of multiple fracturing. Fracture models are used to generate simulated treatment pressure records for a number of likely fracture geometries, including an estimated number of multiple fractures. These simulated injection pressure records may be then compared with those measured in the field.

Controlling hydraulic fracture initiation is the key to eliminating near-wellbore tortuosity. By minimising the presence of flaws intersecting the wellbore (natural fractures or perforations), multiple fracturing can be reduced. As the hydraulic conductivity of fractures is a function of fluid viscosity, multiple fracturing can be substantially reduced, if fracture treatments are initiated using cross-linked gels, as opposed to linear gels or slick water. In formations with a history of fracture tortuosity, 'proppant slugs', which are pills of high proppant concentration slurry, are invaluable in screening out unwanted multiple fracture branches early in the course of fracture treatments.

The WA Data Management Group—issues and concerns

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The WA Data Management Group was formed in 1997 to provide a forum for data management within the petroleum industry. It has grown to include a unique membership of exploration and service companies together with government representatives. Members have a wide range of academic and technical qualifications and experience, comprising information management, computer and geoscience specialists, showing the diversity of interests in data management.

The group aims to provide a forum and network for the petroleum industry and government to exchange information, and to strive to increase the efficiency and effectiveness of data management processes in these organisations, through guidelines and recommendations. To facilitate the workings of the group it typically meets as two sub-groups: data management and data content.

Issues and concerns of the data management sub-group are focussed on how information is handled and disseminated within a company, the industry and government. The data content group concentrates on information required to load and manipulate the data. For both groups, the recognition of and adherence to standards is a priority issue, as this is the only way to ensure that data can be easily exchanged between companies and also be of value to future users. International and Australian/New Zealand standards are used as benchmarking tools.

Common standards within the industry are SEGY for seismic data and UKOOA for well logs. However, often these standards are disregarded resulting in information being lost and other companies being unable to use the data at a later date. The Development of Minerals and Energy in Western Australia is considering rejecting tapes submitted without adherence to the standards.

Most companies have experienced receiving unreadable and unusable data. With older data, the cause is often the deterioration of the tapes or earlier versions of data storage not being readily compatible with new software. In other cases, the data is readable but unusable because headings are incomplete or relevant data has been left out.

Today, electronic data is almost the norm. Intranets and internets allow reports, well logs and other graphic data to be transmitted around the world. This data still has to be captured, processed and stored, otherwise it can be easily lost. For each company, data is a core asset. On an industry level, millions are spent each year on exploration and the petroleum industry generates billions per year for the economy. These dollars are represented by the data we manage. As industry members it is in our interests to ensure that the information we provide is of the highest standard, that it is an asset for the future and not a liability.

Shelf growth and the evolution of submarine canyon morphology: a key to velocity problems in the offshore Gippsland Basin

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The Seaspray Group in the offshore Gippsland Basin records the evolution of a cool-water carbonate shelf during the last 36 million years. In this time, submarine canyon growth and decay has been pervasive, with several canyon-types preserved within the Seaspray Group. Sonic velocity changes associated with some Miocene canyons have created problems in the seismic interpretation of the underlying Latrobe Group structures.

The modern environment of the offshore Gippsland Basin has several canyon types including: a) dendritic canyon-head structures developed on the outer shelf; b) multiple, small linear canyons developed on the relatively steep (~11°) portion of the slope with distinctive 'ridge and runnel'-type morphology; c) large continous, sinuous canyons developed on gentle gradient (2–3 degree) slopes; and d) a large straight stem canyon (Bass Canyon) developed on the basin floor. Several of these canyon types can be recognised from seismic in the Tertiary and

Quaternary of the Seaspray Group. The Bass canyon and its tributaries are largely cut into the Seaspray Group and Latrobe Group or older sediments. There is very little evidence for modern sedimentation in the Bass Canyon and erosion appears to have dominated its history since the mid-Miocene.

Zones of high velocity are associated with major mid-Miocene canyon systems for which there appears to be no modern analogue. High velocity facies are best developed above a major erosion surface where down-lapping reflectors are present. Simple cut and fill canyons do not contain well developed high velocity fill sequences. The high velocity facies is predominantly restricted to mid-Miocene sediments and is best developed in the deeper portions of the Seaspray Group. Two hypotheses can be used to account for the high velocity facies: 1) the high velocity facies is the product of a laterally migrating meadering canyon system, with the high velocity zones being equivalent to 'point bar' sequences in fluvial systems; 2) the high velocity facies represents a package of sediments that progrades from the northeast and southwest and are related to basin geometry and the change from a ramp to shelfal architecture.

The Seaspray Group in the offshore Gippsland Basin—its stratigraphy, submarine canyons and velocity problems

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The Seaspray Group in the offshore Gippsland Basin records the evolution of a cool-water carbonate shelf over the last 36 million years. It disconformably overlies and forms the major seal to the Cretaceous to Eocene clastic sediments of the Latrobe Group. During the evolution of the shelf, submarine canyon growth and infill has been pervasive, with several canyon-types preserved within the Seaspray Group. Sonic velocity changes associated with some Miocene canyons creating problems in the seismic interpretation of the underlying structures.

The Seaspray Group can be divided into two megasequences based on seismic character, wire-line logs, velocity profiles, carbonate content, petrological character and fossil age. The lower Megasequence A comprises a semi-conformable package of pelagic marls that thins down-basin and into the middle of the basin from 1.2 ms to 0.3 ms two-way time. In morphological shape it represents the proto-Bass Canyon. It shows upper reflector truncation and erosion on the canyon sides and stratigraphic condensing towards the canyon centre over the middle of the basin. This unit is disconformably overlain by Megasequence B along a prominent seismic boundary. Megasequence B comprises a seismically chaotic series of bioclastic marls that infill the proto-Bass Canyon and showing complex channel cut and fill, with a dominant direction of downlap and channel migration from north to south and down-basin. The boundary between the two megasequences approximates the D1–D2 zone of early Middle Miocene age, which could become younger from north to south.

Zones of high velocity are predominantly restricted to the deeply buried parts of Megasequence B at two-way times greater than 0.8 ms, and where it overlies areas of thin Megasequence A. The highest velocity facies of Megaseqence B immediately overlies the boundary between the two megasequences and consists of a sequence with upward-decreasing carbonate, up to 1 km thick. The chief characteristics of the high-velocity facies are: 1) fine grained bioclast-rich packestones and wackestones with less than 10% quartz silt that is more prone to cementation and is visibly more stylotised at depths greater than 0.8 ms; 2) it is age independent and cuts across seismic boundaries within Megasequence B; 3) velocities progressively increase with depth within Megasequence B so that higher velocities occur in the thicker the unit towards the middle and down the basin; and 4) laterally within the highest velocity zone, velocities increase with steepness of angle on the downlap surfaces due to coarser grain sizes, probably due to greater initial porosity.

Transfer zones in extensional basins and their control on structural style and stratigraphy—implications for hydrocarbon exploration

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Extensional strain in rift basins during the stages of active rifting is generally dispersed between a number of normal faults of varying throw. The strain is conserved in three dimension through a coordinated system of transfer zones (accommodation zones) which influence the boundary fault configuration in a variety of ways. Transfer zones accommodate displacement and elevation differences between adjacent blocks through a wide range of features at various scales including discrete faults affected by normal slip, oblique slip or strike-slip or wide complex zones of pure normal faulting, transtension or broad warping.

The fundamental unit of any extensional basin is a half-graben. Each half-graben may display differences in fault dip, throw or polarity (dip facing or tilt). Individual half-graben link along strike through a series of transfer zones which accommodate the differences between adjacent blocks. The resulting rift is a complex of smaller units, each conceivably with a unique character.

The linking of the half-graben units along strike in an extensional basin interwoven with these transfer zones will determine the evolving topographic disposition during the initial evolutionary history of the rift basin. The transfer zones may also continue to influence later basin evolution in the post rift stages. They will control the development of the drainage patterns and sediment transport direction and dispersal. Major inter-basin transfer zones may act as conduits for large rivers transporting sediments to the adjacent depocentres. Small-scale intra-basin transfer zones linking individual fault segments within a half-graben may control local sediment character and distribution. Transfer zones are generally sites of large-scale accumulation of coarse clastics whereas the down-thrown border faulted margins are sediment starved bypass zones and therefore, preferential sites for organic-rich lacustrine source rocks.

Changes in minor fault dip direction and variations in the orientation or the intensity of faulting can occur in transfer zones because these zones represent a change from more or less two-dimensional extension to oblique-slip fault systems associated with three-dimensional extension. Such conditions may generate traps of different structural style or larger size than elsewhere in the rift.

The literature shows that a large number of oil and gas fields in various rift systems around the world (viz. the North Sea, the Reconcavo Basin of Brazil and the Gulf of Suez) are focussed around transfer zones. Careful study of these zones will improve the understanding of the syn-rift stratigraphy and help in predicting hydrocarbon accumulations.

Hydrocarbon potential of the Drummond Basin, central Queensland—a reassessment based on seismic, aeromagnetic and geochemical data

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The Late Carboniferous–mid Triassic eastern Galilee Basin overlies the latest Devonian–Early Carboniferous Drummond Basin that does not contain significant source rocks. Small amounts of gas and oil were recovered from tight sandstones in the Lake Galilee Sandstone in ENL Lake Galilee–1 well and small amounts of gas from FPN Koburra–1 and MON Carmichael–1 wells. These hydrocarbons in the lowermost unit of the Galilee Basin are stratigraphically below identified source rocks. Middle Devonian (Emsian) clastics, carbonates and volcanics occur beneath the Drummond Basin and regional seismic lines indicate a thick sedimentary sequence underlying the Drummond Basin at depth.

The structure of the basin has been delineated using seismic and airborne magnetics. Multiple reactivation of structures is a major feature of the tectonics of the area. Vulcanism affected the eastern Drummond Basin area between Middle Devonian and latest Carboniferous. The vulcanism was associated with extension in the unnamed underlying Early to Middle Devonian basin, latest Devonian to Early Carboniferous Drummond Basin and the Late Carboniferous to Early Permian lower Galilee Basin. The extensional episodes were followed by folding events and the upper Galilee Basin (Late Permian to mid Triassic) was deposited in a flexural setting and folded by the culmination of the Hunter–Bowen Orogeny.

The oil from ENL Lake Galilee–1 well has isotopically light alkanes within the range of carbon isotopic composition for oils from the Larapintine–3 (Devonian) Petroleum System, but outside the range for oils from the Larapintine–4 (Carboniferous) Petroleum System. The unnamed basin beneath the Drummond Basin is the probable source for the ENL Lake Galilee–1 oil.

If a widespread source rock unit is present beneath the Drummond Basin, potential exists for a previously undetected petroleum system. Traps could therefore occur within the Middle Devonian sequence and in sub-unconformity traps against the basal Drummond Basin and the basal Galilee Basin. Migration up-dip within the Drummond Basin would make the shallow anticlines on the eastern side of the Drummond Basin attractive targets. Migration into the basal Galilee Basin has occurred, albeit into tight sandstones.

Clastic depositional modelling with Sedsim: recent innovations and sensitivity tests

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The clastic depositional model Sedsim has undergone massive change in the last year, which has made the code more robust, versatile and accurate. The major changes will be presented here in detail. The sensitivity of the

numerical model to a range of possible input parameters has also been investigated.

Sediment depositional models are gaining a wide acceptance in the oil industry as a valuable tool in determining the sediment distribution in depositional basins at all scales. The Sedsim program models the movement of clastics over geological time periods and provides a sediment profile to match existing seismic records, as well as providing valuable insight into the physical mechanisms controlling basin development.

Changes made to Sedsim in the last year have concentrated on improving the correlation of the numerical code and the physics of sediment transport and deposition. These features included improved sediment deposition controls, fluid dynamics, fluid element positioning, and stability criteria (in what way were these improved?).

In order to demonstrate Sedsim's versatility and stability, a series of sensitivity tests have been conducted. These numerical experiments examined the models reaction to features such as changes in resolution, fluid source input, wave motion, sea level change, compaction, and tectonic activity. The results show SEDSIM's ability to produce results with a high fidelity under a range of conditions.

Three-dimensional forward stratigraphic modelling on the North West Shelf—status and future plans

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The three-dimensional forward stratigraphic modelling program Sedsim has been used to model several areas and ages of deposition on the Australian North West Shelf and elsewhere since 1996. These include the Kendrew Trough (Oxfordian), the Browse Basin (Neocomian), West Dixon (Upper Jurassic), Barrow Delta (Neocomian), Yampi Shelf (Albian), Offshore Canning, and others. The areas modelled include a variety of shallow-to-deep marine siliciclastic environments at spatial scales from tens to hundreds of kilometres, and time scales from days to millions of years.

Sedsim models enable the depositional history of an area to be investigated relatively rapidly. All available knowledge concerning sea level variation, climate, basement topography, sediment input points, tectonic movement and subsidence can be incorporated in the simulation. The results are constrained by whatever information is available from cores, logs, and seismic stratal patterns.

Sedsim enables the three-dimensional aspects of sequence stratigraphic stacking patterns to be investigated for different ratios of sediment supply rates to rates of accommodation space change. The three-dimensional patterns are often at variance with published two-dimensional models. The program is being developed further to incorporate a wider variety of depositional environments, enabling a wider range of sequence stratigraphic models to be tested.

Seismic velocities in the Petrel Sub-basin from the ocean-bottom seismograph studies: implications for crustal structure and petroleum prospecting

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Refraction/wide-angle seismic studies with ocean-bottom seismographs (OBS) in the Petrel Sub-basin effectively supplement conventional reflection surveys. Interval velocities estimated from the conventional reflection data at two-way times (TWT) greater than 2 s appear to be up to 1 km/s lower than those derived from the OBS data. If the first are used to depth convert reflection data, then depth to seismic boundaries in the centre of the basin at TWT 6–9 s would be under-estimated up to 2 km. Consequently, there is a danger that the depth and amplitudes of oil/gas prospective structures may be biassed if velocities derived from stacking of the conventional seismic reflection data are used for depth conversion of these data.

To interpret the seismic velocity models we developed petrophysical modelling-based methodology. The key element of this methodology is the construction of the VDRT (velocity as a function of depth and rock type) map for the assumed modern PT-conditions in the crust. The measured seismic velocities are then compared to this map to obtain an estimate of the proportion of various rock types at certain depth ranges. An important feature of our approach is that we treat the crust as a mixture of a limited number of rock types represented by their end-members. The bulk geochemical composition within each type of rock is kept constant and the mineralogical compositions allowed to vary, accounting for equilibration at the pressures and temperatures likely to have existed when the rock was formed. VDRT map provides a systematic approach to translation of seismic velocities into compositional models of the crust; it also enables probabilistic solution of the problem of non-unique correlation between the seismic velocity and petrology of the rock. At this stage the method considers igneous rocks only.

A preliminary estimate of the petrology of the deep crust and upper mantle in the region shows that mafic underplate is unlikely to be present in the lower crust. Rocks of the ultramafic composition will have seismic velocities close to those observed underneath the Moho even where it is as shallow as 20 km depth. The seismic velocity model derived from the OBS data constrains subsidence and flexural isostatic modelling in the region, as well as estimates of heat production affecting maturation of hydrocarbons.

The Australian stress map

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The Australian stress map project has compiled 206 reliable stress orientations for the Australian continent, approximately doubling the number from the 1992 world stress map compilation. Most new data are from borehole breakouts. Regionally, maximum horizontal stress (SH) is oriented northeast–southwest from New Guinea along most of the North West Shelf, rotating to 100°N in the Carnarvon Basin. SH is oriented 010°N–020°N in the Amadeus and Bowen basins. In the Cooper–Eromanga basins SH is oriented broadly east–west, and in the Otway and Gippsland Basin it is oriented 130°N. The regional variation of stress orientation within the Australian continent distinguishes it from areas such as western Europe and midplate North America which show consistent SH orientations. This variability reflects, to a first order, forces acting along the complex convergent northeastern boundary of the Indo-Australian Plate.

Vertical stress (Sv) gradient in the Bonaparte and Cooper–Eromanga basins increases with depth, being ~20 MPa/km at 1,000 m, and ~23 MPa/km at 3,000 m. The Amadeus Basin displays an overburden gradient of 25 MPa/km that is little affected by depth. Leak-off pressures suggest that the minimum horizontal stress (Sh) is the least principal stress (60–70% of Sv) in the Bonaparte and Cooper–Eromanga basins. Consideration of the frictional limits to faulting suggests that, if in a state of incipient faulting, the stress regime is approximately on the boundary between normal (Sv > SH > Sh) and strike-slip (SH > Sv > Sh) faulting in the Bonaparte Basin and strike-slip in the Cooper–Eromanga basins.

The key applications of stress data to hydrocarbon exploration pertain to wellbore stability and fluid flow directions. For example, in a transitional normal/strike-slip faulting environment (Sv > SH > Sh), horizontal wells deviated in the Sh direction are more stable (require lower mudweight to inhibit breakout) than those deviated in the SH direction. In situ stresses control natural fluid flow directions through the development of structural permeability (fluid flow along shear and extensional fractures). Hence in situ stresses can be analysed to avoid zones of enhanced structural permeability such as in the breached seals of the Timor Sea, and to target such zones in the tight gas reservoirs of the Cooper Basin. In situ stresses influence induced fluid flow directions through their control on the orientation, style and containment of hydraulic fractures.

The Australian Stress Map can be seen at: www.geology.adelaide.edu.au/~rhillis/ASM_fold/ASM.html.

Hydrocarbon reservoir potential of the Cambro-Ordovician Warburton Basin, South Australia

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The eastern Warburton Basin is considered to be the economic basement to the Cooper Basin and is practically unexplored. Three wells (gas in Lycosa–1 and Moolalla–1, and oil in Sturt–6) have tested commercial flows of hydrocarbons which migrated from Cooper Basin source rocks. Stratigraphy of the Warburton Basin from base to top consists of the Mooracoochie Volcanics (Sturt–6 fractured tuffaceous reservoir), Kalladeina Formation carbonate and siliciclastics (potential carbonate reservoir), Dullingari Group siliciclastics (Lycosa–1 fractured siltstone and mudstone), Pando Sandstone (Moolalla–1 sandstone reservoir) and Innamincka Formation redbeds and sandstone (potential sandstone reservoir). Some carbonates in the Kalladeina Formation are porous and permeable; a karst-related reservoir in Gidgealpa–1 tested gas-cut salt water.

A study of hydrocarbon reservoir potential of the Warburton Basin has been carried out by applying three approaches: 1) carbonate sequence stratigraphy results in recognition of three sequence boundaries where secondary porosity is enhanced, and two kinds of stratigraphic trap. One is associated with high-relief carbonate build-ups encased in lagoonal mudstone, and shelf-edge grainstone sealed by transgressive siltstone and shale. The other is a transgressive marine shale enclosing porous and karsted dolostone; 2) a systematic fracture study of 61 wells has located open and partially-open fracture systems within the Warburton Basin such as in Lycosa–1, Gidgealpa–1, –5, –7, and Merrimelia–2, –7. Core measurements are complemented by dipmeter,

FMS and FMI logs. Study of fracture chronology and fill cements is also underway to delineate tectonic phases and timing of opening and occluding of fractures. Microstructural attributes such as faults and folds recorded from the fracture study indicate a compressional, mainly southeast–northeast, structural style. At least four phases of fracture fill are differentiated from fracture stratigraphy. Most fractures are wholly or partly mineralised, with quartz, pyrite, calcite, dolomite, ankerite, siderite and kaolinite being the predominant minerals; and 3) sequence stratigraphy and facies analysis of reservoir sandstone from wireline logs, cores, cuttings, and 724 thin sections have helped qualify the reservoir quality of the Pando Formation and other potential sandstone hydrocarbon reservoirs. The Pando Formation occurs mainly in the Pando to Daralingie areas, and was probably deposited as a prograding lowstand wedge. A second sandstone unit from the upper part of the Innamincka Formation may be another potential reservoir, especially if fractured.

APPEA