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SESSION 1B—SAFETY REGULATION AND MANGEMENT

Offshore petroleum safety—a vision for the future

P. Wilkinson

Presenter: Peter Wilkinson.
Department of Industry, Tourism and Resources.

Session 1B: 2:00 pm, Hall D.

Over the last few years there have been a number of reviews of the adequacy of the offshore petroleum regulatory structure which demonstrates a healthy desire on the part of industry and governments to continually improve. The Piper Alpha disaster in the North Sea, in which 167 men died, led to the Australian industry and governments getting together and looking at what could be done to further improve offshore safety. This led to the modernising of the safety legislation by replacing the increasingly outdated, inflexible and highly detailed, prescriptive law with the much more flexible system based on the concept of safety cases. This approach is widely credited with improving offshore safety, partly as a result of giving the industry more power and responsibility to identify its own hazards and controls for those hazards. Company safety cases are of course subject to challenge from the three main specialist offshore regulators off Western Australia, Victoria and the Northern Territory.

To date the Australian offshore petroleum industry, thankfully, has been free of the disasters which have occurred and continue to occur worldwide in this intrinsically hazardous industry. As well as Piper Alpha, many still remember the Alexander Keilland disaster (123 dead) and the Ekofisk blowout both in the North Sea. Also in the Northern Hemisphere, the Ocean Ranger disaster offshore Canada resulted in over 80 fatalities. More recently Petrobras lost the P36 floating production system offshore Brazil, shortly after installation with the loss of eleven lives and a reported financial loss of over US $800million, excluding loss of production, increased oil imports and asset replacement. Numerous serious incidents occur each year, which do not get into the headlines. Nearer home, hydrocarbon leaks continue to occur, fortunately in small numbers but there is no room for complacency.

Governments and industry have not been idle. Following concerns raised by a number of parties, including the workforce and industry, the Commonwealth carried out a major review of offshore safety. (All of the petroleum beyond the 3-mile limit is in the Commonwealth's jurisdiction, although the State and Territory governments currently carry out the regulation of the Commonwealth safety legislation). This review, which included an international team of offshore safety experts, found that:

- **The legal and administrative framework and its day to day application is complicated and insufficient to ensure effective and cost-efficient regulation,**
- **State/NT regulators lacked capacity, skills and consistency,**
- **The Commonwealth did not have sufficient resources, technical expertise, credibility and authority to drive the required changes.**

At the inaugural meeting of the Ministerial Council on Mineral and Petroleum Resources on 4 March 2002 the Commonwealth and State/Territory Ministers agreed to implement a work programme to examine how best to improve offshore safety primarily through a single joint national safety agency. This session will provide a vision of the future for offshore safety. It will set out what needs to be done by industry and government, if our shared view of a continued safe, healthy and productive offshore petroleum industry is to be achieved.

This paper will appear in Part 2 of the APPEA Journal 2002

The human factor: A benchmark of worker attitude to health, safety and environment in the Australian oil and gas industry 1999-2001

B. Safari

Presenter: Mark Cully
National Institute of Labour Studies (NILS),
Flinders University.

Session 1B: 2:25 pm, Hall D.

Between 1999 and 2001, the National Institute of Labour Studies conducted surveys of workers attitudes to—and opinions of—Health, Safety and Environment (HSE). We surveyed 1618 employees and 717 contractors in seven companies operating in Australia: Apache, BHPP, Chevron, Esso (Bass Strait platforms), Newfield, Santos and Woodside.

The benchmark is based on 84 survey statements common to all company surveys. We grouped the statements into 10 'Scales': Communication and Worker Involvement, Environmental Commitment, Equipment and Maintenance, Incident Report and Investigation, Individual and Teamwork, Job Satisfaction, Leadership, Risk Management, Systems and Processes of Work; and Training. The Scale's average favourable score is the key statistic we use throughout the benchmark. The benchmark consists of comparing the company results of

employees and contractors as well as a disaggregation of employees' results by supervisory responsibility, technical discipline, workplace (office or production facility), age group and tenure.

The results indicate that, generally speaking, respondents are satisfied with the HSE climate in their companies. In particular, they are motivated and confident about their personal and team skills and attitude toward HSE. While the general picture is satisfactory, there are opportunities for improvement, mostly in the planning and design of safety systems and processes, the timely and regular maintenance of equipment, as well as the management's attitude towards workers' safety and follow-up on reported incidents. A particular effort would be welcome in making workers feel that they are valued and that their health and safety is central to the companies' business objectives. Finally, workers indicated that the HSE climate could be improved by an increase in staffing levels, as this would ease deadline pressures and reduce the incentive to cut corners. The results suggest that policies for improvement are likely to be more effective if they are tailored to each particular company or group of workers.

It is hoped that the benchmark – a first of its kind in Australia - will encourage information sharing between companies. This dialogue will lead to an overall improvement in HSE within the industry as a whole.

This paper will appear in Part 2 of the APPEA Journal 2002

Bass strait offshore facility safety Cases: a case study on effective workforce involvement in the modern safety case regime

M.C. Greenwood, M.A. Newton, N.V. Clarke, D.C Tyler, C.L. Turner.

Presenter*: *Michael Greenwood
Esso Australia

Session 1B: 2:50 pm, Hall D.

In 2001, Esso obtained regulatory acceptance Safety Cases for each of its 18 Bass Strait offshore facilities. To reach this important milestone, a number of significant challenges had to be overcome. This paper discusses these experiences and seeks to provide insight into the strategies that can be successfully adopted to develop "a living Safety Case" that delivers improved safety performance.\

Acceptance of the safety cases was the culmination of a planned and disciplined approach that incorporated key learnings and experiences arising from a major incident in 1998 at Esso's Longford Gas Plant. An iterative safety case development, review and continuous improvement process was implemented and over the ensuing three years this has significantly improved the understanding of the unique hazards, risks and associated control measures across each of the eighteen facilities.

Extensive and highly effective strategies for employee involvement were integral to all stages of the safety case development process. This paper discusses how increased expectations under the onshore Victorian Major Hazardous Facilities Regulations 1999 have been adopted in the preparation of Esso's offshore facility Safety Cases. It examines how a skilled team comprising a Health and Safety Representative, an Offshore Installation Manager and specialist Safety Professionals collaborated to deliver a true program of workforce involvement and buy-in that establishes a culture for a true "living safety case" workplace culture.

Esso's approach to develop the Safety Case as a "shop-floor friendly" tool and establish simple linkages between the Safety Case Formal Safety Assessment (FSA) and Safety Management System have delivered significant benefit in improving workforce awareness of risks and their associated control measures. This has been supported by a competency based interactive scenario-solving Safety Case training module in an approach that has commenced integrating Safety Case understanding into a behavioural modification program. This paper explores the successful planning, development and implementation of these innovative measures which have been recognised by regulators and sectors of industry.

An effective Safety Case regime is underpinned by three core aspects: management commitment; employee involvement and effective regulatory enforcement. Preparation of Esso's Bass Strait Safety Cases has been driven through management commitment to achieving and sustaining a living Safety Case regime. Strong workforce involvement has facilitated support for the safety case development approach and contributed valuable anecdotal knowledge and expertise pertinent to the facility and its inherent hazards and risks. Regulatory enforcement, the third core aspect of a safety case regime, establishes expectations for continual improvement and the ongoing reduction of risks to ALARP. This paper discusses Esso's experiences in relation to each of these dimensions.

This paper will appear in Part 2 of the APPEA Journal 2002

SESSION 2B—VALUE DRIVERS: COMMERCIAL TAX CONSIDERATIONS

Tax reform in the oil industry

M.Williamson

Presenter: Max Williamson
Wiltax Consulting Pty Limited

Session 2B: Hall D, 3:45 pm

Following the return of the Liberal National Country Party for its second term of office under the Prime Minister, Mr John Howard, the Federal Government established a committee headed by a business executive Mr John Ralph. This Committee produced an extensive report recommending substantial changes to the Australian tax legislation. Following consideration of the report by the Federal Government, substantial amendments were proposed in September and November 1999. Many of these proposals have now been legislated and several remain in the pipeline awaiting Parliament scrutiny.

This paper covers the practical aspects of the changes to the tax legislation, along with examination of particular issues associated with new developments in matters such as gas banking. Particular focus has been made on the new Uniform Capital Allowances Provisions and the deductions which will be available to the industry against upstream project development expenditures.

Adding value through mergers and acquisitions

M.Alciaturi

Presenter: Martin Alciaturi
Ernst and Young Corporate Finance Pty Ltd

Session 2B: 4:10 pm, Hall D.

Many market commentators are forecasting increased corporate merger and acquisition activity in the Australian oil and gas sector. This activity presents industry participants with significant opportunities to increase shareholder value.

An effectively designed acquisition approach (business process) assists in establishing strategic objectives to maximise value and returns to a company. Steps in a structured process include assessing the acquirer's strengths and weaknesses, defining the strategy, identifying the range of possible targets and evaluating the preferred target prior to negotiating and completing the acquisition.

Observed market evidence supports the theoretical notion that market participants determine the value of E&P companies with primary reference to the NAV (DCF) methodology. The benefits of this valuation methodology are that it attempts to rigorously capture the effect of large changes in production over time and the irregular nature of E&P companies' capital expenditure programs.

Effective due diligence supports the decision-making process by identifying the risk factors that can make or break a deal and assists to clarify the transaction whilst effective structuring of the acquisition will minimise value-loss through tax leakages etc.

Portfolio risk management at BHP Billiton

J.F.McCarthy

Presenter: Jane McCarthy
BHP Billiton

Session 2B: 4:35 pm, Hall D.

BHP Billiton has implemented a portfolio risk management strategy. The strategy is based on extensive quantitative analysis of the risks and opportunities in the BHP Billiton portfolio and applies leading financial markets thinking to a portfolio of natural resource assets. It enables BHP Billiton to more rigorously manage the risks within its portfolio.

This paper will discuss the portfolio modelling process supporting Portfolio Risk Management. The process involves detailed modelling of changing financial markets (i.e. commodities, currencies, interest rates), the implications for the financial strength of the company (i.e. interest cover, liquidity profile, credit rating, gearing) and, ultimately, the implications for the business strategy (i.e. financial targets, growth aspirations, capital investments, acquisitions, share buybacks). This will illustrate how quantitative tools become building blocks for decision making beyond the market risk strategy and strengthen capital disciplines.

SESSION 3A—GAS RECOVERY, MARKETING AND REINJECTION

Latest Asia-Pacific LNG developments: How Australia can benefit

W.H. Grasso

Presenter: Wim Hein Grasso
Shell Development (Australia) Pty Ltd

Session 3A: 11:00 am, Hall E.

Australia has ample gas reserves to meet the growing demands of domestic markets to well beyond 2020. Even if Australia were to supply all of its domestic electricity market for the next 20 years by natural gas, vast untapped reserves would still remain. Australia needs to export its surplus gas to monetise it within a reasonable timeframe, and LNG is still the most cost-effective way of doing this.

This paper examines the potential supply factors that Australia must contend within an increasingly deregulated and competitive export world. Innovative ideas are required to keep Australia at the forefront of the LNG market, ahead of competitors in the Asia-Pacific and Middle East. The opening up of the west Americas for Australian LNG, along with reduced manufacturing and shipping costs and the establishment of alliances with LNG consuming countries are all positive and necessary factors to ensure that Australia's gas resources are developed within an acceptable timeframe.

The development of Gorgon area gas

Ian Grose

Presenter: Ian Grose
Gorgon Development Team leader.

Session 3A: 11:25 am, Hall E.

Australia will increasingly need to turn to natural gas to offset declining oil production and meet an expanding global need for clean energy. The Gorgon Project Joint Venture Participants, (ChevronTexaco/ExxonMobil/Shell), are poised to develop the significant Gorgon gas reserves located 130km offshore the north west Australian coast to help fulfil this need.

The Gorgon Project has access to extensive proved reserves of 13.8 Tcf and a development plan that can supply gas to a Barrow Island landfall at world competitive prices. Several concepts are being considered for development of the Gorgon reserves.

Technology will play a key role, with the extensive use of subsea production facilities and innovative LNG design concepts being considered. The focus is on a design that would have a low unit cost and also provide new benchmarks in safety and environmental performance.

The development of the Gorgon reserves could also facilitate the establishment of other gas based industries in Western Australia and offers the opportunity for new Gas-to Liquid (GTL) plants to lead Australia's transition to a gas based economy.

The Gorgon Project is expected to attract nearly A$4 billion investment for an LNG development and a further A$2 billion for a major industrial gas consumer. Total export income could reach A$2500 million per year for 30 years.

This paper will appear in Part 2 of the APPEA Journal 2002

The potential for geological sequestration of CO_2 in Australia: preliminary findings and implications for new gas field development

J. Bradshaw, B.E. Bradshaw, G. Allinson, A.J. Rigg, V. Nguyen and L. Spencer

Presenter: Dr John Bradshaw
Geoscience Australia

Session 3A: 11:50 am. Hall E.

Many industries and researchers have been examining ways of substantially reducing greenhouse gas emissions. No single method is likely to be a panacea, although some options do show considerable promise. Geological sequestration is one option that utilises mature technology and has the potential to sequester large volumes of CO_2. This technology may have particular relevance to some of Australia's major gas resources that are relatively high in CO_2. In Australia, geological sequestration has been the subject of research within the Australian Petroleum Cooperative Research Centre's GEODISC program. A portfolio of potential geological sequestration sites (sinks) has been identified across all sedimentary basins in Australia, and these have been compared with nearby known or potential CO_2 emission sources, including natural gas resources. These sources have been identified by incorporating detailed analysis of the national

greenhouse gas emission databases with other publicly available data, a process that resulted in recognition of eight regional emission nodes. An earlier generic economic model for geological sequestration in Australia has been updated to accommodate the changes arising from this process of source to sink matching. Preliminary findings have established the relative attractiveness of potential injection sites through a ranking approach. It includes the ability to accommodate the volumes of sequesterable greenhouse gas emissions predicted for the adjacent region, the costs involved in transport, sequestration and ongoing operations, and a variety of technical geological risks. Some nodes with high volumes of emissions and low sequestration costs clearly appear to be suitable, whilst others with technical and economic issues appear to be problematic. This assessment may require further refinement once findings are completed from the GEODISC site-specific research currently underway.

SESSION 3B—NEW PETROLEUM MODELS

New petroleum models in the Pedirka Basin, Northern Territory, Australia

G.J. Ambrose[1], K. Liu[2], I. Deighton[3], P.J. Eadington[2] and C.J. Boreham[4]

***Presenter*: Greg Ambrose**
Northern Territory Geological Survey

Session 3B: 11:00 am, Hall E.

The northern Pedirka Basin in the Northern Territory is sparsely explored compared with its southern counterpart in South Australia. Only seven wells and 2,500 km of seismic data occur over a prospective area of 73,000 km^2 which comprises three stacked sedimentary basins of Palaeozoic to Mesozoic age. In this area three petroleum systems have potential related to important source intervals in the Early Jurassic Eromanga Basin (Poolowanna Formation), the Triassic Simpson Basin (Peera Peera Formation) and Early Permian Pedirka Basin (Purni Formation). They are variably developed in three prospective depocentres, the Eringa Trough, the Madigan Trough and the northern Poolowanna Trough. Basin modelling using modern techniques indicate oil and gas expulsion responded to increasing early Late Cretaceous temperatures in part due to sediment loading (Winton Formation). Using a composite kinetic model, oil and gas expulsion from coal rich source rocks were largely coincident at this time, when source rocks entered the wet gas maturation window.

The Purni Formation coals provide the richest source rocks and equate to the lower Patchawarra Formation in the Cooper Basin. Widespread well intersections indicate that glacial outwash sandstones at the base of the Purni Formation, herein referred to as the Tirrawarra Sandstone equivalent, have regional extent and are an important exploration target as well as providing a direct correlation with the prolific Patchawarra/Tirrawarra petroleum system found in the Cooper Basin.

An integrated investigation into the hydrocarbon charge and migration history of Colson–1 was carried out using CSIRO Petroleum's OMI (Oil Migration Intervals), QGF (Quantitative Grain Fluorescence) and GOI (Grains with Oil Inclusions) technologies. In the Early Jurassic Poolowanna Formation between 1984 and 2054 mRT, elevated QGF intensities, evidence of oil inclusions and abundant fluorescing material trapped in quartz grains and low displacement pressure measurements collectively indicate the presence of palaeo-oil and gas accumulation over this 70 m interval. This is consistent with the current oil show indications such as staining, cut fluorescence, mud gas and surface solvent extraction within this reservoir interval. Multiple hydrocarbon migration pathways are also indicated in sandstones of the lower Algebuckina Sandstone, basal Poolowanna Formation and Tirrawarra Sandstone equivalent. This is a significant upgrade in hydrocarbon prospectivity, given previous perceptions of relatively poor quality and largely immature source rocks in the Basin.

Conventional structural targets are numerous, but the timing of hydrocarbon expulsion dictates that those with an older drape and compaction component will be more prospective than those dominated by Tertiary reactivation which may have resulted in remigration or leakage. Preference should also apply to those structures adjacent to generative source kitchens on relatively short migration pathways. Early formed stratigraphic traps at the level of the Tirrawarra Sandstone equivalent and Poolowanna Formation are also attractive targets. Cyclic sedimentation in the Poolowanna Formation results in two upward fining cycles which compartmentalise the sequence into two reservoir–seal configurations. Basal fluvial sandstone reservoirs grade upwards into topset shale/coal lithologies which form effective semi-regional seals. Onlap of the basal cycle onto the Late Triassic unconformity offers opportunities for stratigraphic entrapment.

Structural evolution and thermal maturation modelling of the Bass Basin

A. Cummings, R. Hillis, and P. Tingate

Presenter: Aaron Cummings. NCPGG

Session 3B: 11:25 am, Hall D.

The Bass Basin has been the focus of sporadic hydrocarbon exploration since the mid – 1960s, from which, the potentially commercial Yolla Field and a number of sub-commercial discoveries have been made. Despite this, exploration within the Bass Basin remains high risk. The success of future exploration within the basin is dependent on a greater understanding of the structural evolution of the basin and its relationship to the timing of hydrocarbon generation and migration.

Two regional seismic sections have been interpreted across structurally distinct regions of the Bass Basin. Sections were chosen on the basis of seismic quality and the suitability of their orientation for structural restoration. Both sections have been depth converted, structurally balanced, decompacted, and restored using the structural restoration software *2DMove*.

Restoration has been undertaken in order to constrain the timing of regional tectonic events responsible for basin structuring and to reconstruct the configuration of the basin during the main periods of hydrocarbon generation and migration. Results indicate a significant difference in the amount of brittle upper crustal extension that has occurred across the two sections of the basin analysed. The central Bass Basin has undergone approximately 12 % upper crustal extension since the early Cretaceous, whereas the Durroon Sub-basin has undergone approximately 22 % upper crustal extension. This highlights the difference in the structural evolution between the two regions and the increasing influence of Late Cretaceous Tasman Rifting towards the east of the Bass Basin.

Thermal history and maturation modelling is being carried out on 16 wells and on a number of pseudo-wells throughout the Bass Basin using BHT, vitrinite reflectance and apatite fission track data. Models are being constructed with the use of the 1D *BasinMod* program. The modelling constrains the relative amounts of subsidence and uplift across the basin as well as delineating the timing of hydrocarbon generation and migration. The integration of reconstructed sections and maturation modelling provides a snapshot of the geometry of migration surfaces present at the time of hydrocarbon migration, as well as an insight into how prospective traps have been modified over time

An understanding of early rift geometries, subsequent changes in basin architecture and thermal conditions is the key to defining new play concepts in this relatively underexplored, prospective basin.

This paper will appear in Part 2 of the APPEA Journal 2002

Carnarvon basin architecture and structure defined by the integration of mineral and petroleum exploration tools and techniques

L.L. Pryer, K.K. Romine, T.S. Loutit, and R.G. Barnes

Presenter: Lynn Pryer. SRK Consulting

Session 3B: 11:50 am, Hall D.

The Barrow and Dampier Sub-basins of the Northern Carnarvon Basin developed by repeated reactivation of long-lived basement structures during Palaeozoic and Mesozoic tectonism. Inherited basement fabric specific to the terranes and mobile belts in the region comprise northwest, northeast, and north–south-trending Archaean and Proterozoic structures. Reactivation of these structures controlled the shape of the sub-basin depocentres and basement topography, and determined the orientation and style of structures in the sediments.

The Lewis Trough is localised over a reactivated NE-trending former strike-slip zone, the North West Shelf (NWS) Megashear. The inboard Dampier Sub-basin reflects the influence of the fabric of the underlying Pilbara Craton. Proterozoic mobile belts underlie the Barrow Sub-basin where basement fabric is dominated by two structural trends, NE-trending Megashear structures offset sinistrally by NS-trending Pinjarra structures.

The present-day geometry and basement topography of the basins is the result of accumulated deformation produced by three main tectonic phases. Regional NE-SW extension in the Devonian produced sinistral strike-slip on NE-trending Megashear structures. Large Devonian-Carboniferous pull-apart basins were introduced in the Barrow Sub-basin where Megashear structures stepped to the left and are responsible for the major structural differences between the Barrow and Dampier Sub-basins. Northwest extension in the Late Carboniferous to Early Permian marks the main extensional phase with extreme crustal attenuation. The majority of the Northern Carnarvon basin sediments were deposited during this extensional basin phase and the subsequent Triassic sag phase. Jurassic extension reactivated Permian faults during renewed NW extension. A change in extension direction occurred prior to Cretaceous sea floor spreading, manifest in basement block rotation concentrated in the Tithonian. This event changed the shape and size of basin compartments and altered fluid migration pathways.

The currently mapped structural trends, compartment size and shape of the Barrow and Dampier Sub-basins of the Northern Carnarvon Basin reflect the "character" of the basement beneath and surrounding each of the sub-basins. Basement character is defined by the composition, lithology, structure, grain, fabric, rheology and regolith of each basement terrane beneath or surrounding the target basins.

Basement character can be discriminated and mapped with mineral exploration methods that use non-seismic data such as gravity, magnetics and bathymetry, and then calibrated with available seismic and well datasets. A range of remote sensing and geophysical datasets were systematically calibrated, integrated and interpreted starting at a scale of about 1:1.5 million (covering much of Western Australia) and progressing to scales of about 1:250,000 in the sub-basins. The interpretation produced a new view of the basement geology of the region and its influence on basin architecture and fill history. The bottom-up or basement-first interpretation process complements the more traditional top-down seismic and well-driven exploration methods, providing a consistent map-based regional structural model that constrains structural interpretation of seismic data.

The combination of non-seismic and seismic data provides a powerful tool for mapping basement architecture (SEEBASE™: Structurally Enhanced view of Economic Basement); basement-involved faults (trap type and size); intra-sedimentary geology (igneous bodies, basement-detached faults, basin floor fans); primary fluid focussing and migration pathways and paleo-river drainage patterns, sediment composition and lithology.

SESSION 3C—IMPROVED SEISMIC TECHNIQUES

Multi-component seismic— the tool for all reasons

F.L. Engelmark

Presenter: Folke Engelmark.
WesternGeco–Seismic Reservoir Services

Session 3C: 11:00 am, Hall C.

Marine multi-component seismic, known as 4C, is an emerging seismic technology providing improved and sometimes unique solutions to many common problems. In the marine environment the seismic sensors have to be placed on the sea-floor to capture converted or shear wave modes that cannot propagate through liquid media. Although this means increased acquisition cost, the improved information content makes it money well spent to better image and characterise reservoirs.

The 4C solutions fall into two major groups of five. First there are the imaging solutions:

- Improved standard P-wave imaging.
- Improved converted wave (P-S) resolution in the shallow sediments.
- Converted wave imaging through gas clouds.
- Converted wave imaging of low impedance contrast reservoirs.
- Improved sub-salt and sub-basalt imaging with converted waves.

The second group consists of the five characterisation solutions:

- Improved fracture characterisation by means of P-S waves.
- Qualitative 4D or time-lapse characterisation of fractured reservoirs with low intrinsic permeability.
- Improved lithology and fluid characterisation by combining the information in the two wave modes.
- Improved quantitative time-lapse evaluation of pressure and saturation changes.
- Improved characterisation of drilling hazards by combined evaluation of the two wave modes.

So far the most popular 4C solutions are imaging through gas and improved P-wave imaging of Jurassic reservoirs in the North Sea, for example the Statfjord, Brent and Beryl fields. However, as the technology is developing and maturing, the characterisation solutions will probably be the most common applications of 4C in the near future.

The use of seismic modelling when designing onshore 3D and 4D surveys

M.S. Egan and P. van Baaren

Presenter*: *Mark Egan,
WesternGeco

Session 3C: 11:25 am, Hall C.

There are many parameters to consider when designing acquisition geometries for onshore 3D and 4D seismic surveys. Plots of attributes, such as fold and offset distribution, are necessary in the design process but they are not always sufficient. For instance, they fail to predict the bandwidth and signal-to-noise ratios associated with various candidate designs. Properly crafted synthetic seismograms, however, can be used to yield these predictions. Downhole and surface seismic measurements are needed to drive this. The downhole measurements—primarily well logs—are used to create stratified earth models for input to ray trace calculations and reflectivity modelling. The surface seismic measurements-including finely sampled noise tests-are needed to derive intra-array statics distributions, ambient noise distributions, ground roll characterisations and other descriptions. These empower modelling routines to contaminate and perturb the synthetic signal in prospect-specific fashions. Results from Middle East studies typically show that survey designs that are best suited for addressing one particular issue might not be best for addressing others. Incorporation of digital group forming algorithms within the modelling process allows prediction of results that would be obtained from new high channel-count, single-sensor systems.

Acquisition technology opens up difficult data areas for 3d exploration

C.R.T Ramsden and A.S Long

Presenter*: *Charles Ramsden
Petroleum Geo-services Asia Pacific Pty Ltd

Session 3C: 11:50 am, Hall C.

3D seismic technologies have advanced rapidly during the 1990s. The new generation of seismic vessels such as the *Ramform* design with their massive towing capacities has changed the way in which modern seismic data is acquired. This has resulted in a large increase worldwide in the use of 3D seismic data during the exploration phase because of the reduction in the cost of 3D data. A statistical database has emerged showing that drilling on 3D data will double the commercial success rate compared to drilling on 2D data.

Historically, dual-source acquisition has dominated exploration (by comparison to single-source acquisition) due to cost savings associated with the fact that single-source acquisition implies a geophysical requirement to tow the streamers at half the separation of dual-source acquisition. Data quality associated with single-source acquisition, however, is typically much superior to dual-source data. The ability now to tow 12–16 streamers has reduced costs so that single-source acquisition is now cost effective. The surveys using single-source acquisition allow 3D data to be acquired with significantly higher trace densities and crew efficiencies than industry standard, and are called High Density 3D or HD3D. These surveys have benefits of increased fold, improved spatial resolution and improved imaging quality, and can now be routinely conducted, especially in difficult data areas.

The North West Shelf of Australia is a difficult data area because of the presence of strong multiple noise trains that often mask or interfere with the primary reflections (Ramdsen et al, 1988). Standard multiple attenuation techniques have had only limited success. HD3D with its higher trace density and 40% improvement in signal-to-noise ratio has resulted in improved data quality in difficult data areas, and should result in data improvements on the North West Shelf as well.

Furthermore, the Continuous Long Offset (CLO) recording technique using *Ramform* technology is a dual-vessel operation that has demonstrated significant operational efficiency improvements in long offset (typically deep water/targets) 3D seismic acquisition. Survey turnaround times can be reduced by as much as half of those using conventional techniques. The CLO technique is particularly well suited for deepwater recording.

SESSION 4A—GAS TO LIQUIDS

Australian GTL fuel—A strategic opportunity for Australia's stranded gas reserves

W. Higgs and Paul Prass

Presenter*: *Bill Higgs
Sasol Chevron Consulting Ltd

Session 4A: 2:00 pm, Hall E.

Australia's lack of gas supply infrastructure and market opportunities means that in the north-west of our nation more than 100 trillion cubic feet of gas remains uncommitted to customer contracts.

Because of Australia's relatively small domestic gas markets, the belief has been that only the LNG industry has the scale to monetise the large volumes of gas required to underpin greenfield developments and the expansion of gas supply infrastructure.

Changing fuel specifications around the world, combined with the limited opportunities for new LNG contracts, has renewed interest in gas-to-liquids (GTL) technology as an alternative to crude oil refining as a source of clean and efficient transport fuels. GTL is an exciting new market opportunity for Australian gas.

Exploration in Australia is waning due to declining opportunities for oil discoveries and the lack of markets for natural gas, which make investments in Australia's upstream sector unattractive.

In addition, Australia has dwindling crude oil supplies and faces the prospect of increasing reliance on imported crude oil and refined products. An Australian GTL Fuel industry can help overcome these hurdles by creating a designer blendstock and a valuable new GTL Fuel export industry.

A GTL Fuel industry would not only help resolve many of Australia's current upstream and downstream problems in the petroleum industry, but would also provide massive economic benefits to Australia.

This paper will look not only at the making but also the marketing of this fuel of the future.

This paper will appear in Part 2 of the APPEA Journal 2002

Potential impacts of Gas-to-Liquids on the oil and gas industry

P.D. Patterson, R. Payne and S.S. Tam

Presenter*: *P. Dee Patterson,
Moyes & Co., Inc.

Session 4A: 2:25 pm, Hall E.

Over the past decade interest in gas-to-liquids (GTL) technology within the oil and gas industry has been on the rise. Depending on the level of cost reductions obtained, this technology has the potential to create a significant change in the oil and gas industry. In an effort to consider these changes, this paper will address the following issues:

Can GTL technology redefine the energy industry's present structure and give rise to a broad range of new competitors and/or products? If so, how and when is it likely to happen?

Our answer to the first part of the question is, simply, yes. GTL technology certainly has the potential. However, the depth and breadth and timing of GTL's penetration into the industry will be driven by forces of cost, price and environmental regulations. The depth of penetration depends on the answers to the following questions: Can GTL plants be built for US$25,000/bpd or less? What impact will scale and learning curve have on cost reductions? What premium will the consumer market give for GTL products? Is the peak production for conventional oil production on the horizon?

If the development of the LNG industry is representative of the potential growth in the GTL industry, we could project a GTL production rate of 1,000,000 bpd in 2025, or about 1.3% of the world's current production rate.

A new process for converting natural gas into hydrocarbon liquids

K.R. Hall, A. Akgerman, R.G. Anthony, P.T. Eubank, J.A. Bullin, J.G. Cantrell, B.R. Weber, Jr. and J. Betsill

Presenter: Kenneth Hall.
Chemical Engineering Department, Texas A&M University

Session 4A: 2:50 pm, Hall E.

Gas-to-liquids technology has become an intensely investigated field in the petrochemical industries. The obvious reason is the vast reserves of stranded natural gas (currently flared, reinjected or not produced) and the desire to monetise these resources. Conventional wisdom has gravitated to some variation of Fischer-Tropsch technology to produce hydrocarbon liquids from natural gas. We have developed an entirely different approach for this conversion and licensed the technology to Synfuels International of Dallas for commercialisation.

The new process has several advantages: it is simple; it should be economical for flows ranging from 10 MMSCFD through 500 MMSCFD; it can be skid-mounted (at lower flow rates) for transportation to site; it appears that the cost of fluids produced would be less than $20 per barrel; it is nearly energy self-sufficient; water can be a by-product; and the nominal product is a light gasoline with about a C_7 molecular weight that can be converted into a heavier fraction with extra processing. This paper presents some details of the process and discusses results from a 100 MSCFD pilot unit.

SESSION 4B—NEW PETROLEUM MODELS

Oligo-Miocene canyons in the Gambier Sub-basin, Southern Australia—deepwater analogues for petroleum exploration

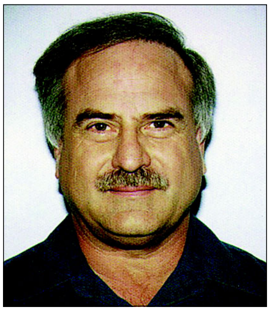
R.M. Pollock, Q. Li, B. McGowran and S.C. Lang

Presenter: Rosalie Pollock,
National Centre for Petroleum Geology and Geophysics,

Session 4B– 2:00 pm, Hall D.

The Gambier Sub-basin lies on the southern Australian passive continental margin that formed during continental breakup and seafloor spreading between the Australian and Antarctic plates. In addition to the numerous modern submarine canyons reported on the southern Australian margin, three palaeo-canyon systems have been identified within the Gambier Limestone of the South Australian Gambier Sub-basin. Favourable environmental conditions during the Oligocene and Early Miocene led to deposition of the Gambier Limestone, a widespread, prograding extra-tropical carbonate platform. A world-wide glacio-eustatic sea level fall in the Early Oligocene exposed the shelf in the Gambier Sub-basin, causing widespread erosion and minor fluvial incision on the shelf and subsequent formation of nick points at the shelf edge. During the following marine transgression later in the Oligocene, the shelf was inundated and the nick points provided conduits for erosive turbidity currents to enlarge the canyons to the spectacular dimensions observed on seismic data. No less than 20 successive canyon cut and fill events ranging from Late Oligocene to Middle Miocene have been observed and mapped on seismic data across the shelf in the Gambier Sub-basin. The thick, dominantly fine-grained carbonate sheet logically represents a potential regional seal to underlying clastic reservoirs. However, the possibility exists for carbonate reservoir sands to be present within the palaeo-canyons, sealed by surrounding fine-grained carbonates. Although no hydrocarbons have yet been identified in the carbonates of the Gambier Sub-basin, the canyons provide an analogue useful for establishing the scale, internal architecture and geometry of canyon fill systems.

New Zealand's Taranaki Basin: giants in the graben?



A.W. Hart

***Presenter*: Alan Hart,**
Golden Downs Consulting Ltd.

Session 4B– 2:25 pm, Hall D.

During the past 50 years of utilising modern techniques in New Zealand's Taranaki Basin, explorers have both been rewarded by its bountiful accumulations and frustrated by its complicated morphology. Numerous superimposed sub-basins, depocentres, areas of uplift, interbedded volcanic edifices and recent volcanism contribute to the complexity of New Zealand's only producing province. Exploration has been successful along the flanks of the basin, but the time has come to focus on the numerous grabens forming the Taranaki Basin.

The basin is a Late Cretaceous rift more than twice the size of the North Sea's prolific Viking graben, but only 120 wildcats have been drilled since 1955, with only 50 offshore. Horst, tilted fault block, inversion features and thrust anticlines have been the traditional targets, but companies are showing increased interest in relatively more difficult plays involving turbiditic, volcaniclastic and diagenetic reservoirs.

The axis of the 6,000 km^2 Northern Taranaki graben, the northern part of the Taranaki Basin, has not been penetrated by the drill bit and offers numerous exploration opportunities for basin floor and slope fans of Eocene and Miocene age. Acoustic scattering, diffraction and absorption within a chain of buried Miocene stratovolcanoes inhibit seismic energy from passing into the older sequences, which consist of numerous basin floor fan sequences. Long avoided by exploration programs, volcanic edifices were found to possess good reservoir characteristics and entrap hydrocarbons at Kora–1. The 7000+ km^3 of layered extrusive volcanic rock in the graben cannot therefore be discounted as potential reservoir. Another play developed by Miocene magmatism is the doming of potential turbidite reservoirs by underlying igneous feeder dyke systems. In addition, the wells drilled at Kora identified a more elusive play concept—that of potentially large petroleum accumulations stratigraphically trapped downdip from diagenetically altered reservoirs, serving as sealing lithologies, near the igneous feeder dyke systems.

As most seismic records in the Northern Taranaki graben were acquired more than a decade ago, modern seismic acquisition and processing technologies are needed to penetrate the buried volcanic edifices and unlock the basin's story. A better understanding of the basin's complexities, more cost-effective drilling techniques and a willingness to explore for targets in the source kitchens may finally expose the true potential of the Taranaki Basin.

The petroleum potential of East Timor

T.R. Charlton

***Presenter*: Tim Charlton,**
University of London

Session 4B: 2:50 pm, Hall D.

The hydrocarbon prospectivity of East Timor is widely considered to be only moderate due to Timor island's well-known tectonic complexity, but in the present study a much higher potential is interpreted, with structures capable of hosting giant hydrocarbon accumulations. High quality source rocks are found in restricted marine sequences of Upper Triassic-Jurassic age. The most likely reservoir target is shallow marine siliciclastics of Upper Triassic-Middle Jurassic age encountered in the Banli–1 well in West Timor, comparable to the Malita and Plover Formations of the northern Bonaparte Basin, and sealed by Middle Jurassic shales of the Wai Luli Formation. The Wai Luli Formation also forms a major structural décollement level which detaches shallow level structural complexity from a simpler structural régime beneath.

The principal exploration targets are large, structurally simple inversion anticlines developed beneath the complex shallow-level fold and thrust/mélange terrain. Eroded-out examples of inversion anticlines, such as the Cribas, Aitutu and Bazol anticlines, are typically several tens of kilometres long and up to 10 km broad. Comparable structures in the subsurface of southern East Timor are interpreted north of Betano, and probably also near Suai, Beaco, Aliambata and Iliomar. Other potential targets include a possible non-inverted rollover anticline at Pualaca, stratigraphic and structural traps in the south coast syn/postorogenic basins, and possibly large structural domes beneath extensive Quaternary reef plateaux in the extreme east of the island.

SESSION 4C—IMPROVED SEISMIC TECHNIQUES

Vector wavefield-separation techniques for improved multi-component seismic exploration

N. Hendrick and S. Hearn

Presenter:* *Natasha Hendrick, *MIM Exploration and University of Queensland.*

Session 4C: 2:00 pm, Hall C.

Analysis of multi-component seismic data commonly involves scalar processing of the vertical component to provide a conventional P-wave image, and scalar processing of the horizontal component(s) to yield an S-wave image. A number of convincing examples now exist where such S-wave imagery has significantly enhanced hydrocarbon exploration.

There is potential to achieve cleaner P- and S-wave images by more fully exploiting the true vector nature of multi-component reflection data. The simplest form of vector analysis, termed polarisation analysis, allows identification of different wave types. It does not, however, generally lead to effective wavefield separation, due to significant interference between the different waves in a typical exploration-seismic recording.

More effective vector separation is possible if the particle-motion information from polarisation analysis is coupled with the more familiar tools of frequency and velocity filtering. Three related separation algorithms, termed MUSIC, IWSA and PIM are considered here. These techniques all utilise a parametric approach whereby wavefield slowness and polarisation are modelled simultaneously in the frequency domain.

Synthetic and ocean-bottom cable examples are used to demonstrate practical issues relating to the use of these tools. The PIM algorithm is considered to be the most generally useful of the three multi-component wavefield separation algorithms. Implementation of these tools in a highly automated production environment is considered non-trivial. Hence, it is envisaged that such vector separation schemes will have most application for specialised data processing over identified target zones. Vector wavefield separation has the potential to amplify the considerable success already achieved with integrated P- and S-wave exploration.

Extracting sub-surface information from long offset p-wave data—a cheaper alternative to multi-component OBC for exploration?

R.G. Williams, G. Roberts and K. Hawkins

Presenter:* *Gareth Williams, *Veritas DGC.*

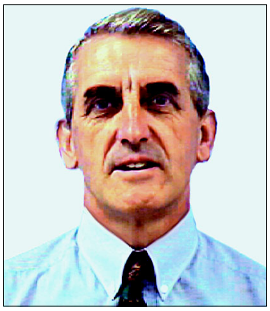
Session 4C: 2:25 pm, Hall C.

Seismic energy that has been mode converted from p-wave to s-wave in the sub-surface may be recorded by multi-component surveys to obtain information about the elastic properties of the earth. Since the energy converted to s-wave is missing from the p-wave an alternative to recording OBC multi-component data is to examine p-wave data for the missing energy. Since p-wave velocities are generally faster than s-wave velocities, then for a given reflection point the converted s-wave signal reaches the surface at a shorter offset than the equivalent p-wave information. Thus, it is necessary to record longer offsets for p-wave data than for multi-component data in order to measure the same information.

A non-linear, wide-angle (including post critical) AVO inversion has been developed that allows relative changes in p-wave velocities, s-wave velocities and density to be extracted from long offset p-wave data. To extract amplitudes at long offsets for this inversion it is necessary to image the data correctly, including correcting for higher order moveout and possibly anisotropy if it is present.

The higher order moveout may itself be inverted to yield additional information about the anisotropy of the sub-surface.

The next generation spatial data warehouse



A.J. Yardley

***Presenter:* Alan Yardley,**
Woodside Energy Ltd

Session 4C: 2:50 pm, Hall C.

Woodside Energy, based in Perth, Western Australia, has commenced the implementation of its next generation spatial data warehousing and visualisation system. The warehouse facilitates access to data in various corporate geoscience data sets, as well as up-to-date cultural and environmental data. It expands the capabilities of the existing geoscience database by providing a facility to handle spatial data at the database level rather than in files and maps. Spatial data can now be kept in the database, in its correct spatial location, and with a known provenance.

Woodside's worldwide exploration, development and production activities require the use of a wide variety of geographic data such as seismic, bathymetry, wells, permits, coastlines, political boundaries, navigation charts, remote sensing and geological interpretations.

Geo-spatial data comes to Woodside in a variety of formats, datums and conditions. The Geomatics Department, through the Geoscience Database and Spatial Information Management teams, loads, maintains and manages all data considered to be corporate. It is quality controlled and placed into the warehouse, where it is readily accessible to technical and administrative staff.

Location is an essential element in most Woodside decisions. Because of the new spatial capabilities, a number of geographic information processes are now possible. Additionally information can also be made available through the internet if required.

Reliable geographic information will become more widely available in the organisation, and be more easily merged with traditional data types, enhancing the decision-making process.

SESSION 5A—INTEGRATED STUDIES AND EXPLORATION

High resolution palaeogeographic mapping of the fluvial-lacustrine Patchawarra Formation in the Cooper Basin, South Australia

P.C. Strong, G.R. Wood, S.C. Lang, A. Jollands, E. Karalaus, and J. Kassan

***Presenter:* Paul Strong,**
Santos Limited.

Session 5A: 3:45 pm, Hall E.

Fluvial-lacustrine reservoirs in coal-bearing strata provide a particular challenge for reservoir characterisation because of the dominance of coal on the seismic signature and the highly variable reservoir geometry, quality and stratigraphic connectivity. Geological models for the fluvial gas reservoirs in the Permian Patchawarra Formation of the Cooper Basin are critical to minimise the perceived reservoir risks of these relatively deep targets. This can be achieved by applying high-resolution sequence stratigraphic concepts and fine-scaled seismic mapping. The workflow begins with building a robust regional chronostratigraphic framework, focussing on widespread lacustrine flooding surfaces and unconformities, tied to seismic scale reflectors. This framework is refined by identification of local surfaces that divide the Patchawarra Formation into high-resolution genetic units. A log facies scheme is established based on wireline log character, and calibrated to cores and cuttings, supported by analogue studies, such as the modern Ob River system in Western Siberia. Stacking patterns within each genetic unit are used to determine depositional systems tracts, which can have important reservoir connectivity implications. This leads to the generation of log signature maps for each interval, from which palaeogeographic reconstructions are generated. These maps are drawn with the guiding control of syn-depositional structural features and net/gross trends. Estimates of fluvial channel belt widths are based on modern and ancient analogues. The resultant palaeogeography maps are used with structural and production data to refine play concepts, as a predictive tool to locate exploration and development drilling opportunities, to assess volumetrics, and to improve drainage efficiency and recovery during production of hydrocarbons.

Seismic to simulation: integrated reservoir model for the Patricia Baleen gas field

P. Fink, M. Adamson, F. Jamal and C. Stark

Presenter: Paul Fink,
OMV Australia Pty Ltd.

Session 5A: 4:10 pm, Hall E.

The Patricia and Baleen offshore gas fields are located in the northeastern part of the Gippsland Basin in southeast Australia. Although discovered by two exploration wells almost a quarter of a century ago, the two gas fields only recently have again become the focus of appraisal and subsequent development activity through OMV's acquisition of Cultus in 1999.

After the drilling of a successful appraisal well in late 1999, a high resolution 3D seismic survey was acquired in early 2000. No further data acquisition will be undertaken. Special emphasis was therefore put on maximising the value of the 3D dataset by integrating the PreSTM (Pre–Stack Time Migration) seismic and several Elastic Impedance attributes with all other available subsurface data prior to building a sophisticated stochastic reservoir model for simulation.

This paper describes how the integration of leading edge seismic technology with unconventional geological modelling was used to overcome a number of major challenges in order to build a coherent static reservoir model and constrain resource uncertainty given the limited amount of wireline and core data:

- A large proportion of the gas fields is strongly affected by seismic tuning which would introduce significant uncertainties on GRV and GWC estimations from seismic, if not accounted for properly. Likewise all seismic and to a somewhat lesser extent basic inversion based attributes used for reservoir property determination are strongly affected by this geophysical artefact: These challenges (and seismic pitfalls) were met by inverting the conventional 3D seismic for P- and S- wave impedances and generating a set of Elastic Impedance Cubes, difference cubes and LRM Cubes (standing for the elastic constants Lambda (λ), Rho (ρ) and Mhu (μ)), defining petroacoustic properties of the reservoir rocks. These cubes were tested for mathematical dependency and used for the conditioning of the facies and porosity models.
- The glauconitic Gurnard reservoir contains a high fraction of conductive minerals and is almost completely bioturbated. Conventional saturation estimations based on wireline-logs and conventional sequence stratigraphic facies description did not deliver a reliable picture: Instead a facies model based on ichnofabric analysis was built and constrained with data available at the three well locations. Saturation height functions were applied separately for each facies type. The Rho-Lambda ($\rho\lambda$) cube was used to condition facies distribution away from the wells.

More specifically, the results presented in the paper are:

- Elastic Impedance inversion provided vertical seismic resolution in the order of 4 m to 10 m, thereby allowing a more accurate seismic estimation of GRV and the GWC. Lamés' Constants were extracted from seismic in order to classify lithology.
- A realistic facies model was built utilizing the Rho-Lambda ($\rho\lambda$) cube combined with ichnofabric analysis tied to permeability and water saturation distributions.
- Elastic Impedance Difference cubes were successfully calculated to eliminate tuning even further and condition the stochastic porosity model.
- Connected volume maps were used to optimise the production well paths
- The GIIP upside volume has been upgraded compared to that based on an earlier simplistic geological reservoir model used for simulation. A more realistic P10/P90 reserves range is now supported by a number of deterministic and stochastic reservoir models.

Management of uncertainty and risk in offshore petroleum development

P. Behrenbruch

Presenter: Peter Behrenbruch,
School of Petroleum Engineering and Management, Adelaide University.

Session 5A: 4:35 pm, Hall E.

Uncertainty in petroleum development projects is most often associated with petroleum reserves. It is the limited amount of subsurface data typically available during the time of development planning that creates this situation. Risks are associated not only with reservoir uncertainty but also with wells and production facilities. Risks for offshore projects, as compared to those onshore, are further compounded by very large capital expenditures and less flexibility in catering for subsurface surprises, or remedial action in case of engineering blunders.

These concepts are illustrated using case histories of successful and failed projects. Lessons learned from these and other projects are then summarised and processes for uncertainty and risk management are outlined. Risk and uncertainty cover a wide range of issues, and relate to geoscience, reservoir engineering, well technology, facilities engineering, operations, and project planning and evaluation.

SESSION 5B—OIL GENERATION AND MIGRATION

Evaluation of hydrocarbon seepage in the Great Australian Bight

H.I.M. Struckmeyer, A.K. Williams, R. Cowley, J.M. Totterdell, G. Lawrence and G.W. O'Brien

Presenter*: *Heike Struckmeyer,
Geoscience, Australia.

Session 5B: 3:45 pm, Hall D.

The regional assessment of hydrocarbon seepage is built around a combination of Radarsat and ERS Synthetic Aperture Radar (SAR) data, acquired during 1998 and 1999, as part of a collaborative project between Geoscience Australia, Nigel Press Associates, Radarsat International and AUSLIG (specifically the Australian Centre for Remote Sensing). In total, 55 Radarsat Wide 1 Beam Mode scenes and one ERS scene from the Great Australian Bight (GAB) region were analysed. The data were integrated with regional geological information, and other hydrocarbon migration and seepage indicators such as reprocessed and reinterpreted legacy Airborne Laser Fluorosensor (ALF) data, to provide an assessment of the possible charge characteristics of the region.

The results of the study suggest that active, though areally restricted, liquid hydrocarbon seepage is occurring within the Bight Basin. The majority of seepage slicks occur along the outer margin of the major depocentre, the Ceduna Sub-basin, in areas where significant Late Tertiary to Recent faulting extends to the seafloor. Very little evidence of seepage was observed on the SAR data above the main depocentre, which is an area of minimal Late Tertiary to Recent faulting. Reprocessed ALF data reveal three main areas with relatively dense fluors. Although they are not directly coincident with locations of seepage interpreted from SAR data, their distribution support the pattern of preferred leakage along the basin margins.

Integration of regional geological models with the results of this study suggests that structural features related to active tectonism have focused laterally migrating hydrocarbons to produce active seepage at specific locations in the basin. Where these features are absent, seepage may be passive and/or be governed by long distance migration to points of seal failure. Together with oil and gas shows in exploration wells, observations from this study provide further evidence that liquid hydrocarbons have been generated in the Great Australian Bight.

Evidence for a new oil family in the Nancar Trough area, Timor Sea

S.C. George[1], H. Volk[1], T.E. Ruble[1] and M.P. Brincat[2]

Presenter*: *Simon George,
CSIRO Petroleum

Session 5B: 4:10 pm, Hall D.

Geochemical evidence is presented for a previously unrecognised oil generative source rock in the Nancar Trough area. This source rock supplements the middle to late Jurassic source rocks, which have previously been shown to have generated most of the oils in the northern Bonaparte Basin and the Vulcan Sub-basin. Fluids with a strong contribution from this new source rock, defined here as the Nancar oil family, have an unusually high abundance of mid-chain substituted monomethylalkanes. In comparison, oils from the Vulcan Sub-basin contain mostly terminally substituted monomethylalkanes and the overall abundance is much lower. Oils from the Laminaria High and some from the northern Vulcan Sub-Basin show intermediate characteristics and may be co-sourced. Evidence from the analysis of fluid inclusion oils was important in establishing the presence of the new oil family because interference from drilling mud contaminants could be excluded. The detailed geochemistry of Ludmilla–1 fluid inclusion oil suggests the source rock for the Nancar oil family was deposited in a marine environment under sub-oxic conditions with limited sulphur content, a low contribution of terrestrial organic matter and a high contribution of organic matter from bacterial activity. Since monomethylalkanes are typical biomarkers of cyanobacteria, the source rock that gave rise to the new oil family may be rich in cyanobacterial organic matter. Further studies on sediment extracts are needed to establish an explicit oil-source rock correlation and to identify the stratigraphic location/palaeo-environment of the source rock. Such information will be valuable in determining the prospectivity of the large and relatively unexplored province draining the Nancar Trough kitchen.

Exploring the potential for oil generation, migration and accumulation in Cape Sorell–1, Sorell Basin, offshore west Tasmania

C.J. Boreham, J.E. Blevin, I. Duddy, J. Newman, K. Liu, H. Middleton, M.K. Macphail and A.C. Cook

Presenter: Chris Boreham,
Geoscience Australia

Session 5B: 4:35 pm, Hall D.

Given the underexplored nature of the Sorell Basin, offshore Tasmania, the reported presence of oil stains and shows in the Late Cretaceous sequence below 3,000 m in Cape Sorell–1 is seen as encouraging evidence of an effective petroleum system. To investigate the significance of these shows, an integrated palynological, geochemical and burial history analysis of Cape Sorell–1 has been undertaken. New data have been collected on palynology, potential source rocks (biomarker and chemical kinetics), oil migration indicators (quantitative grain fluorescence—QGF, and grains–with–oil–inclusions—GOI) and thermal history parameters (vitrinite reflectance—VR, vitrinite–inertinite reflectance and fluorescence—VRF® and apatite fission track analysis—AFTA®). A synthesis of these analyses has resulted in a model that suggests that the terrestrial organic–rich potential source rocks in Cape Sorell–1 are very labile for hydrocarbon generation and are presently at the initial phase of oil generation. The model also indicates that increasing hydrocarbon generation with time reflects a progressive increase in temperature reaching maximum temperatures at the present–day. According to the model, accelerated rate of oil generation from the Maastrichtian potential source rock interval at ~3,200 m in the lower Sherbrook Group Equivalent occurred at ~48 Ma and is in response to the maximum burial heating rate in the Early Eocene, during rapid deposition of the thick Wangerrip Group Equivalent. This heating event may have been related to gateway opening along the Otway coast and west Tasmanian margin. Although there was a declining heating rate since the Early Eocene, gas and oil may continue to be generated to the present–day at Cape Sorell–1.

The low content of mobile oil below sealing facies higher in the section negates a pervasive oil migration phase sourced down–dip from the basin centre, or from older sedimentary sequences below TD in Cape Sorell–1. However, the possibility that Cape Sorell–1 is in a migration shadow cannot be excluded. The restricted areal extent of the depocentre associated with Cape Sorell–1, together with thin, isolated potential source beds at the well site, would indicate the major risk for hydrocarbon occurrences in the local region is limited source rock volume. However, seismic evidence suggests the possible presence of similar facies within the deeper syn–rift succession below TD at Cape Sorell–1. The labile nature of the organic matter would support oil generation and migration at maturities lower and depths shallower than traditionally viewed. This work provides evidence to support a possible oil play from terrestrial source rocks in the Sorell Basin, and may also provide useful insights into recent large offshore gas discoveries to the north in the adjacent Otway Basin.

SESSION 5C—PORE PRESSURE

Seismic expression of abnormal geo-pressure in the Barrow Sub-Basin

M. Urosevic, Li-Yun Fu and K.J. Dodds

Presenter: Milovan Urosevic,
Australian Petroleum CRC.

Session 5C – 3:45 pm, Hall C.

Drilling uncertainties related to abnormal geopressure are common in the Barrow and Dampier Sub-basins of the North West Shelf. These uncertainties contribute to increased drilling risk and costs. There have been a number of published studies in this area which have been directed towards understanding the mechanisms and modelling of the expected pressures. These studies, however, have been in general isolated and have concentrated on non-seismic related methods. This paper provides an empirical analysis of the seismic response in an area with known variation of overpressure, and critically is integrated with a comprehensive research effort looking at aspects of overpressure from a laboratory, empirical and theoretical perspective.

The study was conducted using data taken from permit WA-25-P (P25) in the Barrow Sub-basin. These data included 3D surface seismic and VSP, well logs, mud weight and pressure data from the wells. The results of a mineralogical analysis conducted on core samples and basin-wide geological modelling studies were also incorporated into the study. The Muderong Shale, which comprises the principal seal in the area and is believed to be overpressured was selected as the prime target for the analysis. Initially we assess the potential of existing methods, such as velocity-based methods, for remote prediction of excessive pore pressure in the area P25. This is extended to amplitude related effects involving an analysis of reflectivity in the presence of a velocity transition zone over the overpressured interval. Finally the relationship of well data, VSP and surface seismic derived attributes is described.

The available data in the P25 area was sparse and consequently we could not rely on statistical based associations. Current industry methods that rely on a limited number of calibration points suggest that the application of either velocity or AVO based methods may produce unreliable predictions of pore pressure. Ambiguities in inferring overpressure introduced by a variable mineral composition of shales and the presence of a strong velocity gradient, which distorts the wave shape, reduces the reliability of these methods.

A detailed analysis using VSP data acquired in a highly overpressured well was found to be crucial for understanding the response of various seismic attributes to changes in effective stress. This enabled us to propose a new qualitative, but efficient approach for remote prediction of overpressure, particularly suited for under-explored areas such as P25. The applicability of the method, which uses single and combined seismic sequence and trace multi-attributes to predict overpressured zones, is demonstrated with the Venture-Carey 3D data recorded in the Barrow Sub-basin.

Detecting overpressure using porosity-based techniques in the Carnarvon Basin, Australia

P.J. van Ruth, R.R. Hillis and R.E. Swarbrick

Presenter:* *Peter van Ruth,
National Centre for Petroleum Geology and Geophysics

Session 5C: 4:10 pm, Hall C.

Overpressure has been encountered in many wells drilled in the Carnarvon Basin. Sonic logs are used to estimate pore pressure in shales in the Carnarvon Basin using the Eaton and equivalent depth methods of estimating pore pressure from velocity data with reference to a normal compaction trend. The crux of pore pressure estimation from the sonic log lies in the determination of the normal compaction trend, i.e. the acoustic travel time (Δt)/depth (z) trend for normally pressured sediments. The normal compaction trend for shales in the Carnarvon Basin was established by fitting an Athy-type exponential relationship to edited sonic log data, and is:

$$\Delta t = 225 + 391\exp^{(-0.00103\,z)}$$

Vertical stress estimates are also needed for the Eaton and equivalent depth methods used herein. A vertical stress (σ_v) relationship was obtained by fitting a regression line to vertical stress estimates from the density log, and is:

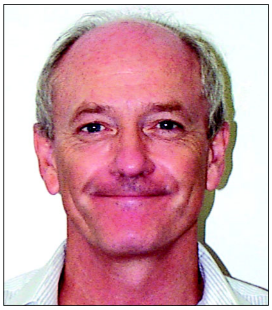
$$\sigma_v = 0.0131\, z^{\,1.0642}$$

The Eaton and equivalent depth methods yield similar pressure estimates. However, the equivalent depth method can only be applied over a limited range of acoustic travel times, a limitation that does not apply to the Eaton method.

The pressure estimates from the Eaton method were compared to pressures measured by direct pressure tests in adjacent permeable units. There is a good correlation between Eaton and test pressures in normally pressured intervals in three wells and overpressured intervals in two wells. Eaton pressure estimates underestimate overpressured direct pressure measurements in four wells by up to 13 MPa. This is consistent with overpressure being generated (at least in part) by a fluid expansion mechanism or lateral transfer of overpressure. The Eaton pressures in one well are, on average, 11 MPa lower than hydrostatic pore pressure recorded in direct pressure measurements below the Muderong Shale. The sediments in this well appear to be overcompacted due to exhumation.

Mud weights can be used as a proxy for pore pressure in shales where direct pressure measurements are not available in the adjacent sandstones. The Eaton pressure estimates are consistent with mud weight in the Gearle Siltstone and Muderong Shale in 4 of the 8 wells studied. The Eaton pressures are on average 10 Mpa in excess of mud weight in the Muderong Shale and Gearle Siltstone in three wells. It is unclear whether the predicted Eaton pressures in these three wells accurately reflect pore pressure (i.e. the mud weights do not accurately reflect pore pressure), or whether they are influenced by changes in shale mineralogy (because the gamma ray filter does not differentiate between shale mineralogy). Several kicks have been recorded in adjacent wells within the Muderong Shale and Gearle Siltstone, and this interval is overlain by significant sediment thickness in these three wells. These observations are consistent with the existence of overpressure due to rapid burial-related disequilibrium compaction in the Muderong Shale and Gearle Siltstone.

The seismic reflection response to changes in pressure



B. Evans and A. Pauli

Presenter*: *Brian Evans,
Australian Petroleum CRC and Department of Exploration Geophysics, Curtin University.

Session 5C: 4:35 pm, Hall C.

Hydrocarbons are often interpreted using seismic attributes, the most common being high anomalous amplitudes or bright spots. Seismic data processing and interpretation is involved in enhancing such anomalies, thereby improving the interpretation for both optimised drilling and volumetric assessment. However, not all bright spots are hydrocarbons since there have been occasions when an economically drillable bright spot unexpectedly produces a dry hole. This paper discusses the first laboratory-based experiments aimed at understanding seismic reflection effects caused by changes in pressure. Water-saturated unconsolidated sand in an unconfining container was pressured from room pressure to over 2 MPa in step manner and then reduced back to room pressure. After each step in application of overburden pressure change, a zero offset 3D seismic survey was performed using ultrasonic transducers. This approach was repeated after the injection of air, to observe the seismic response to gas under changing pressure.

The velocity of sand increased as a function of pressure until a value of approximately 1 MPa was attained, when fracturing became apparent. Upon pressure reduction below 2MPa, fracture healing became apparent; there were also rapid changes in reflection amplitudes due to changes in pressure. It is under high pressure that preferential alignment of parallel grains at specific distances relative to the seismic wavelength may result in 'seismic tuning', and apparent bright spots. It was noted that a pressure increase caused anti-clockwise rotation of the AVO fluid line; this may provide an indication of whether a change in seismic character is a result of a pressure or gas reduction. Some apparent bright spots within sand/shale sequences may also result from seismic tuning effects developed at specific seismic wavelengths, rather than from the presence of hydrocarbons; the sense of rotation of the fluid line may also help to differentiate between a pressure change or gas reduction.

SESSION 6A—ENVIRONMENTAL REGULATION AND MANAGEMENT

Overview and review of the Commonwealth Environment Protection and Biodiversity Conservation Act, 1999

K. Heiden

Presenter: Karl Heiden,
Environment Australia

Session 6A: 11:00 am, Hall E.

This paper provides a brief overview of the Environment Protection and Biodiversity Conservation Act 1999 (the Act) and discusses the operational performance of the Act in the first 18 months.

The introduction of the Act on 16 July 2000 has created a new environmental assessment and approval regime at the Commonwealth level. Proposals are no longer referred for assessment on the basis of government decisions, but on the basis of the potential for a proposal to impact upon a matter of National Environmental Significance (NES). An analysis of projects that have been referred, assessed and approved provides a useful guide to the types of activities, and the circumstances under which proposals are captured by the Act. This exercise is particularly valuable for the oil and gas sector.

With a significant proportion of referrals received being generated by the petroleum industry, many issues with the administration of the Act have been identified. Environment Australia has undertaken a number of initiatives to address these concerns. Examples include involvement in the Strategic Assessment being conducted by the Department of Industry Tourism and Resources (DITR), a review of the Referral form and an undertaking to provide a more industry-specific form, and regular, high level meetings between Environment Australia, the DITR and APPEA to facilitate and streamline the working arrangements between parties.

The paper also identifies areas where industry can work closely with the Commonwealth Government in new ways to achieve a balance between environmental protection and the continued development of the oil and gas industry.

Changes to the environmental management of produced formation water, offshore Australia

G.L. Cobby

Presenter: Graham Cobby,
WA Department of Mineral and Petroleum Resources

Session 6A: 11:25 am, Hall E

Under Australian offshore petroleum legislation, produced formation water (PFW) shall not be discharged into the sea unless there is an approved method. Where approval is granted, the concentration of petroleum in any PFW discharged to the sea shall not be greater than 50 mg/l at any one time and the average content over each 24 hour period shall be less than 30 mg/l unless otherwise approved.

The introduction of the Commonwealth Petroleum (Submerged Lands) (Management of Environment) Regulations 1999 has changed the way PFW is regulated. The operation of a facility is defined under regulation 4 as a petroleum activity. Regulation 13(3) requires operators to assess the environmental effects and risks of a petroleum activity. The assessment of a facility operation should include the effects and risks associated with PFW discharge.

This paper considers how these new requirements affect petroleum operators and what this means for existing and future production facility PFW management. Information is provided regarding assessment tools that are available to measure environmental effect and risk and attempts to describe their ecological relevance and role in decision-making.

Environmental regulation of the upstream petroleum industry in South Australia

R.A. Laws, T. Aust and M. Malavazos

Presenter: Terry Aust,
Primary Industries and Resources South Australia.

Session 6A: 11:50 am, Hall E.

South Australia has adopted a regulatory framework for the upstream petroleum industry within which environmental objectives are established through a consultative process. A principal focus of the new regime is the building of community confidence in the environmental performance of the industry and the capability of its regulator. Without such confidence, restrictions on access to land can be expected to grow. Denial of access will result in resources lying undiscovered and undeveloped to the economic detriment of the industry and the community.

The development of the new legislative framework was underpinned by modern regulatory principles and practices with particular regard to applying the principles of certainty, openness, transparency, flexibility, practicability and efficiency. Transparency and consultative processes were considered particularly important in addressing concerns of conflict of interest and the risk of regulator capture.

The new Act provides that no activity can occur unless it is covered by a statement of environmental objectives (SEO), developed on the basis of an environmental impact report (EIR). SEOs also contain the methodology by which compliance with achievement of objectives is assessed. Once an SEO is in place, it can be used throughout the industry for like activities. Compliance costs for both government and industry will be reduced as a result. Approval time frames and the potential for delays will also be significantly improved. SEOs are now in place for all normal Cooper and Otway Basin seismic, drilling, pipelining and production activities, although some are in interim form and are under review.

Public consultation on the EIR and draft SEO is undertaken for significant activities. Criteria to assist determination of the degree of significance of proposed activities have been established. Based on the degree of predicability and manageability of the likely impacts of the activity, these criteria provide a useful framework within which the necessary value judgements can be made.

Consultation is confined within government for non significant activity proposals. Inter-agency agreements have been put in place to facilitate this process.

Copies of all EIRs, SEOs and significance assessments are made available via the World Wide Web. Company annual licence environmental compliance reports plus summaries of results of audits by inspectors are also made public in the same way.

The Act includes the concept of the enforcement pyramid in which a range of actions escalating in severity can be applied to suit any degree of non-compliance. In addition, companies who exhibit a history of compliance, plus a capacity to comply in the future, are rewarded by up to a 50% reduction in licence fees and do not need to seek approval for routine activities.

SESSION 6B—METHODOLOGIES FOR MORE EFFECTIVE E&P

The John Brookes gas discovery—an evolving story

K. Auld, B. Thomas, J. Goodall, and J. Benson

Presenter: Kerri Auld,
Santos Limited

Session 6B: 11:00 am, Hall D.

John Brookes–1 was drilled as part of a work commitment for the WA-214-P Joint Venture in 1998 and discovered an 85 m gross dry gas column. The objective of the well was to test a structural closure at the base of the Muderong Shale regional seal on the Tryal Rocks anticline, up-dip from Tryal Rocks–1, drilled in 1970. Tryal Rocks–1, the 31st offshore well to be drilled within the Carnarvon Basin, WA, was initially considered a dry hole. However, a review of the well data in 1997–98 suggested that Tryal Rocks–1 might contain a hydrocarbon column. The mapping of the structure using initially 2D seismic data acquired post Tryal Rocks–1, then 3D data, indicated that Tryal Rocks–1 was drilled within closure, but off crest, and that significant closure existed up-dip. The John Brookes–1 location was selected to test this up-dip potential. The John Brookes–1 discovery confirmed the validity of the structural mapping. However, the unexpected nature of the reservoir, interpreted as a well developed turbiditic channel of Birdrong Sandstone age, changed the emphasis from purely structural to a play with structural/stratigraphic potential. An amalgamated turbidite complex model was invoked which infers that the John Brookes–1 reservoir represents a confined channel system cut into the underlying substrate. This model explains the results to date, with the John Brookes–1 gas reservoir being in direct continuity with the sandstones at Tryal Rocks–1. A review of the 3D seismic data across the field and seismic modelling support the stratigraphic model developed from the palynological interpretation.

A revised depositional model for East Spar and its impact on field performance

N.P. Tupper, E.F. Tadiar, D.L. Price and J.D.S. Goodall

Presenter: Neil Tupper, Santos Ltd

Session 6B: 11:25 am, Hall D.

The East Spar gas condensate field is located in production licence WA-13-L in the offshore Carnarvon Basin. Production commenced in 1996 with two subsea wells linked to processing facilities on Varanus Island via a multi-phase pipeline. The pressure performance of the field has been significantly different to pre-development expectations. This prompted a re-examination of the seismic and well data to investigate the potential for alternative reservoir models.

Integrated stratigraphic and seismic interpretation reveals that the Barrow Group reservoir sands were deposited within an incised valley of limited lateral extent. Sea level fall instigated erosion of a valley that on transgression was filled with successive fluvial, estuarine and marine sediments. Good quality sands are expected to be limited to this valley, the upper part of which can be mapped on seismic. Poor sand development in East Spar–2ST is consistent with its location at the edge of the incised valley.

Before development, the primary production mechanism was expected to be a strong bottom water drive comparable with other Barrow Group fields in the Carnarvon Basin. The revised depositional model, however, and the observed decline in reservoir pressure, indicate that connection to this regional aquifer is limited. This implies that water influx will probably be later, and ultimate recovery higher, than previously anticipated.

An integrated petrophysical workflow to generating fluid substituted logs for AVO characterisation—Gipsy and North Gipsy fields case study, North West Shelf, Australia

D.L Clarke and A.P Clare

Presenter: Zachariah John Schlumberger Oilfield Services

Session 6B: 11:50 am, Hall D.

As part of a multi-well field study an integrated petrophysical workflow was developed to include the generation of fluid substituted logs for AVO characterisation.

The workflow relied upon the construction of a multi-mineral model that best approximated the actual mineral content of the reservoir. Any limitations or assumptions were noted and taken into account when creating the multi-mineral model. Other petrophysical results were derived from the same model to validate its consistency such as intrinsic permeability, porosity, water saturation, etc. Iteration between the model and the results was required until a consistent model was achieved.

The estimation of an intrinsic permeability log was based upon the k-Lambda method that uses the multi-mineral model and porosities.

The estimation of a shear slowness log and the fluid substituted logs was based upon elastic rock properties derived from the multi-mineral model and the acquired compressional slowness log and bulk density log.

This integrated approach provides a higher confidence in the derived results, which are then used as input into the reservoir model, thereby improving the reserve calculations.

The interdependence of each derived result on the same input multi-mineral model ensures consistency and predictability in a complex geological environment, which captures all available information.

The method is demonstrated with the Gipsy–1 and North Gipsy–1 wells, which were part of the original field study.

SESSION 6C—TRAPPING OIL: SEALS AND FAULTS

3D Fault modelling and assessment of top seal structural permeability—Penola Trough, onshore Otway Basin

P.J. Boult, B.A.Camac and A.W. Davids

Presenter: Peter Boult,
SA Department of Minerals and Energy.

Session 6C: 11:00 am, Hall C.

Many of the commercial hydrocarbon accumulations discovered to date within the Pretty Hill Formation in the onshore Otway Basin of southeastern Australia rely on a semi-brittle top seal and fault seal. Therefore a detailed and integrated fault, stress field and fracture analysis is fundamental to prospect evaluation.

A syn-kinematic interpretation of the 3D seismic data set, using variance cube and visualisation technology was augmented with interpretation of the dip-meter and high-resolution borehole images. This resulted in the interpretation of a more complex fault history than previously inferred from 2D seismic mapping and dip-meter analysis alone.

There are two major prospect/field bounding fault sets within the Penola Trough. Northwest-trending faults are associated with two commercial fields and several palaeo-accumulations. East-west trending faults are associated with three major fields, two uneconomic fields and two possible palaeo accumulations.

Hydrocarbon leakage is probably caused by the creation of structural permeability across the regional seal. The location of leakage depends on the interaction between the seal, associated faults, and the regional stress field. Faults deflect regional stress trajectories within the top seal, creating local areas of high differential stress which enables brittle failure and the development of structural permeability. Predicting stress trajectories, the magnitude of differential stress and thus the location of structural permeability within the top seal to the underlying Pretty Hill Formation reservoirs, will reduce exploration risk uncertainty.

Microstructural and geomechanical characterisation of fault rocks from the Carnarvon and Otway Basins

D.N. Dewhurst, R.M. Jones, R.R. Hillis and S.D. Mildren

Presenter: David Dewhurst,
CSIRO Petroleum.

Session 6C: 11:25 am, Hall C.

The results of natural and laboratory-induced fault behaviour from wells in the Otway Basin are compared with sample material from a producing Carnarvon Basin field where rocks from a fault zone have been cored. Capillary pressure, microstructural and juxtaposition data obtained from these fault rocks indicate a capability to hold back gas columns in excess of 100 m, yet many fault closures are found to contain only palaeo-columns. Trap failure is usually attributed to reactivation of trap-bounding faults, often during Miocene-Recent times in these basins. Faults susceptible to reactivation can be predicted by geomechanical methods involving the determination of the in-situ stress field and the orientation and dip of faults with respect to that stress field. Failure envelopes of fault rocks have been determined to estimate reactivation potential in the present day in-situ stress field. This approach works well where fault rocks are weaker than the host reservoir sandstone, but may not be applicable where fault rocks are stronger. In fields where the latter is the case, intact hydrocarbon columns are present, irrespective of whether faults are optimally oriented for reactivation. This indicates that the assumptions of zero cohesive strength and constant friction coefficient for predicting the reactivation potential of fault rocks may not be completely reliable.

Calibrating predictions of fault seal reactivation in the Timor Sea

S.D. Mildren, R.R. Hillis and J.Kaldi

Presenter: Scott Mildren, NCPGG

Session 6C: 11:50 am, Hall C.

Predictions of the likelihood of fault reactivation for five fault-bound prospects in the Timor Sea are made using the FAST (Fault Analysis Seal Technology) technique. Fault reactivation is believed to be the dominant cause of seal breach in the area. Calculations are made using a stress tensor appropriate for the area, a conservative fault-rock failure envelope and the structural geometries of each prospect. A depth-stress power relationship defines the vertical stress magnitude based on vertical stress profiles for 17 Timor Sea wells.

Empirical evidence of hydrocarbon leakage at each trap is used to investigate the accuracy of the fault reactivation-based predictions of seal integrity. There is a good correlation between evidence of leakage and the risk of reactivation predicted using the FAST technique. Risk of reactivation is expressed as the pore pressure increase (ΔP) that would be required to induce failure. This study allows the fault reactivation predictions to be calibrated in terms of risk of seal breach. Low integrity traps are associated with ΔP values less than 10 MPa, moderate integrity traps correspond with values between 10 and 15 MPa and high integrity traps correspond with values greater than 15 MPa. Faults with dip magnitudes greater than 60° in the Timor Sea area are likely to have a high risk of reactivation and shear failure is the most likely mode of reactivation.

SESSION 7A—STAKEHOLDER ISSUES/NATIVE TITLE

Management of environmental and stakeholder issues for offshore exploration activities in the Otway Basin

J.G. Colman, A. Grubisa and R.S. Millhouse

Presenters: Jeremy Colman and Annalisa Grubisa, Woodside Energy Limited

Session 7A: 2:30 pm, Hall E.

Woodside has been managing seismic acquisition and drilling operations as part of a gas exploration program in the offshore Otway Basin in southwest Victoria since July 1999. There are a number of sensitive and complex environmental and multiple-use issues facing companies undertaking exploration activities in these waters, including a seasonal aggregation of feeding blue whales, winter calving and breeding habitat for southern right whales and a productive rock lobster fishery. Recent changes to the legislative regime for environmental approvals of petroleum activities in Commonwealth waters has introduced further complications for operators in this area. Consequently, a key aspect of this exploration program has been the pro-active management of environmental and stakeholder issues.

A comprehensive management strategy addressing these issues was developed for seismic acquisition and drilling operations, with the key objectives of ensuring regulatory compliance and facilitating a process where all stakeholders were fully informed about proposed activities. This process focussed on informing stakeholders of the potential impacts of seismic acquisition and drilling, and how Woodside intended to manage those impacts. This approach was driven by a desire for continuous improvement of performance, over and above compliance with all regulatory requirements. It also recognises the legitimacy of stakeholder risk through social, environmental and political values, and has had environmental and economic benefits for the project.

Environmental benefits included early identification and assessment of potential environmental impacts resulting from the different phases of exploration, development of management strategies to control and mitigate these potential impacts, and improved environmental awareness across the project team, joint venture partners and external stakeholders. Prevention of delay or denial of regulatory approvals for exploration activities had significant economic benefits to Woodside and the joint venture partners. The development and implementation of a stakeholder involvement process, involving explorers, external affairs and environmental advisers, was an innovative approach that has application across other Woodside activities and the industry generally, particularly for projects in locations with a high level of environmental sensitivity, multiple-use and stakeholder concern.

Developments nationally in native title and cultural heritage

D. Young and S. McGregor

***Presenter:* Doug Young,**
Blake Dawson Waldron

Session 7A: 2:55 pm, Hall E.

This year is the 10th anniversary of the High Court's decision in Mabo [No 2]. This paper presents a potted version of what has occurred over the past decade and then a more detailed summary of what has happened over the past year including, recent native title and cultural heritage cases and legislative amendments and their impact on both onshore and offshore petroleum explores and producers. It also looks at the issues likely to be considered by the High Court in the long awaited decision in the Miriuwung Gajerrong (Ward) case.

This paper will appear in Part 2 of the APPEA Journal 2002

The Cooper Basin Native Title Agreements—an explorer's perspective

N.W. Martin

***Presenter:* Neville Martin,**
Minter Ellison.

Session 7A: 3:20 pm, Hall E.

On 22 October 2001 in Adelaide, the successful bidders for the 1998 First Round Cooper Basin Acreage Release, the South Australian Government, and various native title claimant groups completed the signing of historic and long awaited native title agreements. A few days later, the Petroleum Exploration Licences (PEL) were issued in respect of the blocks covered by those agreements, and so commenced a new era of oil and gas exploration in South Australia.

This paper examines the process that led to the finalisation of negotiations and the signing of the agreements, from the perspective of one of the exploration companies that participated in the negotiations.

SESSION 7C—METHODOLOGIES FOR MORE EFFECTIVE E&P

Drill cuttings analysis—a new approach to reservoir description and characterisation; examples from the Cooper Basin, Australia

S. Tiainen, H. King, C. Cubitt, E. Karalaus, T. Prater, and B. Willis

***Presenter:* Sharon Tiainen,**
Santos Ltd

Session 7B: 2:30 pm, Hall D.

In the absence of conventional core data, drill cuttings provide a continuous, independent and relatively inexpensive data source. Data collected from this often under-utilised resource can be used to determine permeability, provide information on diagenesis, stratigraphy and sedimentology, locate natural fractures, discriminate between genuinely poor reservoir and under performing assets and assist with petrophysical characterisation. Data can also be acquired in real time at the wellsite.

Drill cuttings analysis or rock typing is a visual method of semi-quantitatively describing rock and pore characteristics from drill cuttings. More specifically it partitions rocks into distinct permeability groups according to their petrophysical properties as observed under high-powered stereo microscope. Based on the observation of key visible attributes, the rocks are assigned to one of six rock types equivalent to the following permeability ranges; 1A (>100mD ambient), 1B (10-100 md ambient), 1C (1-10 mD ambient), 1D (0.5-1 mD ambient), type II (0.5-0.07 mD ambient) and type III (<0.07 mD ambient).

One of the major strengths of rock typing is it can be used to provide an estimate of in-situ permeabilities. As rock type categories are related to ambient permeability classes an algorithm has been developed to take these ambient range estimates to single in-situ values for permeability and then taking into consideration the lithology in the sample, calculates a permeability height (kh) for the interval. The algorithm corrects for overburden, klinkenberg and relative permeability effects.

A comparison of kh derived from rock typing with kh derived from production and test data indicates a strong correlation between the two datasets. Results indicate that the kh sources are consistently similar and fall within one third of an order of magnitude of each other. As both of these data sources are independently derived it suggests both are realistic derivations of the actual kh of the reservoir interval. Consequently, once calibrated to all data sources, rock typing is considered capable of providing a robust estimate of in-situ kh for a specified reservoir interval.

High resolution sequence stratigraphy, reservoir analogues, and 3D seismic interpretation—application to exploration and reservoir development in the Baryulah Complex, Cooper Basin, Southwest Queensland

S.C. Lang, N. Ceglar, S. Forder, G. Spencer and J. Kassan

***Presenter*: Simon Lang,**
NCPGG

Session 7B – 2:55 pm, Hall D.

Gas exploration and reservoir development in the Baryulah area, Cooper Basin, southwest Queensland has focussed on the fluvial-lacustrine, Permian coal-bearing Patchawarra Formation, Murteree Shale, Epsilon and Toolachee Formations. Geological interpretation of drilling and 3D seismic data has benefitted from integration of sequence stratigraphic concepts with the judicious use of reservoir analogues and seismic attribute mapping. Initially, a coherent regional chrono-stratigraphic framework was established, based on broad palynological zonations, and correlating extensive lacustrine flooding surfaces and unconformities, tied to 3D seismic reflectors. This framework was subdivided by using local key surfaces identified on wireline logs (usually high-gamma shaly intervals overlying coals), resulting in recognition of numerous high-resolution genetic units. Wireline log character, calibrated by cores from analogous fields around the Cooper Basin and supported by analogue studies, forms the basis for a log-facies scheme that recognises meandering fluvial channels, crevasse splays, floodplain/basin, and peat swamps/mires. Fluvial stacking patterns (aggradational, retrogradational or progradational), produced by the ratio of sediment supply to accommodation within each genetic unit, were used to help determine depositional systems tracts (alluvial lowstand, transgressive, or highstand) and likely reservoir connectivity. Log signature maps for genetic intervals form the basis of palaeogeographic mapping. Modern and ancient depositional analogues were used to constrain likely facies distribution and fluvial channel belt widths. Syn-depositional structural features, net-to-gross trends, and seismic attribute mapping are used to guide the scale, distribution and orientation of potential reservoir trends. When used in conjunction with structural and production data, the palaeogeographic maps help develop stratigraphic trap play concepts, providing a predictive tool for locating exploration or appraisal drilling opportunities.

Selecting the winning bid

E. Alexander and J. Morton

***Presenter*: Elinor Alexander,**
Petroleum Group, Primary Industries and Resources South Australia

Session 7B: 3:20 pm, Hall D.

Work program bidding is established as the favoured method of allocating petroleum exploration tenements in offshore Australian waters and most of onshore Australia. However, the selection of winning bids can be complicated by the ranking of 2D versus 3D seismic, seismic versus drilling, program timing issues etc. On occasion the selection of the winning bids has been contentious. This paper summarises the process developed by the Petroleum Group in South Australia to select the winning work program bids for prospective onshore blocks for which bids have been gazetted. No other Australian jurisdiction has yet publicly released their detailed bid assessment processes.

Onshore acreage releases with work program bidding have been used in South Australia since the 1980s by Petroleum Group to:

- focus industry onto specific prospective areas of the State (e.g. the Cooper Basin post expiry of PELs 5 and 6 in 1999);
- maximise exploration commitments; and
- achieve competition policy.

The South Australian Petroleum Act 2000 allows cash or work program bidding to be used depending on the acreage. Acreage releases are announced by Ministerial press release. Associated clear bid assessment criteria are published together with promotional material to aid applicants. The date and time for close of bidding are also established, usually allowing a 6–9 month acreage evaluation period, the timeframe depending on the volume of data involved, i.e. the exploration maturity of the area.

Applications received as a result of a gazettal process (i.e. competing bids) are assessed by a process designed to ensure probity and to achieve the over-arching aim of the bidding process i.e. the suitability of the applicants proposed work program for evaluating the prospectivity of the licence area and discovering petroleum.

A scoring system has been developed which establishes, for each bid what is effectively a risked net present value in well equivalents. In this system, guaranteed work scores higher than non-guaranteed work; early work scores higher than later work; wells with multiple targets are scored higher than single target wells; 2D and 3D seismic and other exploration activity is converted into well equivalents; and loading of the later, non-guaranteed years of work programs are heavily discounted.

The scoring system may also take into account differences in the amount and density of exploration data and minor variations may be made to the system to take this into account. It is intended that details of the scoring system to be used in bid assessment will be published each time bids are sought to ensure transparency and a level playing field.

Comparisons are made with acreage management philosophy and processes used by other regulatory regimes in Australia and internationally.

SESSION 7C—TRAPPING OIL: SEALS AND FAULTS

Seal potential in Cretaceous and Late Jurassic Rocks of the Vulcan Sub-basin, North West Shelf, Australia

T. Kivior, J.G. Kaldi and S.C. Lang

Presenter*: *Tom Kivior,
National Centre for Petroleum Geology and Geophysics and Australian Petroleum Cooperative Research Centre.

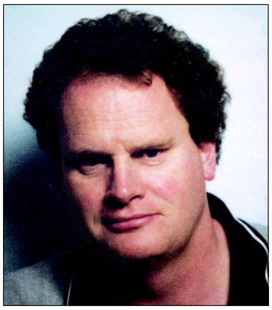
Session 7C: 2:30 pm, Hall C.

The occurrence of palaeo-oil columns in Late Jurassic and Cretaceous reservoirs in the Vulcan Sub-basin suggests that hydrocarbon accumulations have leaked. It is unclear whether accumulations have leaked through breach of top seal or fault seal. This paper evaluates the top seal potential for hydrocarbon accumulations in the Vulcan Sub-basin. Seal potential (SP) combines seal capacity (the hydrocarbon column height that can physically be held back by a seal), seal geometry (the areal extent and thickness of the seal) and seal integrity (rock mechanical properties of the seal). Seal capacities are measured using mercury injection capillary pressure calculations. Areal extent is evaluated using sedimentological and sequence stratigraphic principles. Thickness is determined empirically from well logs and seismic data. Seal integrity is derived from a brittleness index. In addition, a component relating to data quality and quantity is included in seal potential evaluation.

Lower Vulcan Formation SP ranges from low to high due to variations in seal capacity and thickness risks as well as data quality and quantity. High SP occurs in the main depocentres and low SP occurs on palaeo-highs and basin margins. Upper Vulcan Formation SP ranges from low to moderate due to variations in seal capacity and data issues. Moderate SP occurs in depocentres and low SP on basin margins. In the Echuca Shoals Formation seal capacity, seal extent and integrity as well as data quality and quantity are good. Seal thickness, however, is inconsistent, resulting in SP variations from good to poor as a function of thickness. Jamieson Formation has high seal capacities, is thick and areally extensive. The seal potential, however, is locally moderate (e.g. on the Ashmore Platform) due to integrity issues. Woolaston, Gibson and Fenelon (WGF) Formations are grouped together as the regional seal and in this group SP varies from low to high. The WGF rocks have high seal capacities, are areally extensive and thick and the data quality and quantity is good. The main risk is integrity, which increases from northwest to southeast in the basin.

Based on the overall seal potential analyses, almost all seals in the area are capable of holding back hydrocarbon columns greater than present or paleocolumns encountered. This suggests that hydrocarbon leakage in the Vulcan Sub-basin was unlikely to have occurred as a result of top seal capillary failure.

Influence of hydrocarbon migration and seepage on benthic communities in the Timor Sea, Australia



G.W. O'Brien, K. Glenn, G. Lawrence, A.K. Williams, M. Webster, S. Burns and R. Cowley

Presenter: Geoff O'Brien, Geoscience Australia and now at NCPGG

Session 7C 2:55 pm, Hall C.

The Ashmore Platform–Timor Sea region of Australia's North West Shelf is an area of significant petroleum exploration potential, with several large commercial oil fields present. Moreover, exploration activity seems likely to continue at current levels for the foreseeable future, and may also extend into deeper water, given high oil prices and improved drilling technologies. The area is also one of high conservation value, with both the Cartier Marine reserve and Ashmore Reef (a Category 1 marine park), as well as numerous other genetically-rich carbonate seed bank systems, closely associated spatially with exploration activities. Balancing the conservation and resource values in this area will present a key challenge into the future.

The magnitude of this challenge has been highlighted by recent work undertaken by AGSO, which involved the acquisition and interpretation of assorted remote sensing data, such as high-resolution bathymetry (including side-scan sonar), satellite synthetic aperture radar (SAR), Landsat, water column geochemical sniffer, airborne laser fluorosensor, seismic data and seafloor sediment sampling. These studies have shown that, at both a regional and local scale, the development of these important carbonate systems appears to directly relate to the geological development of the area.

At a regional scale, the collision between the Australian and Eurasian crustal plates in the Pliocene (<5 MaBP) induced the formation of the Timor Trough. The rapid subsidence associated with the formation of the trough provided a range of ideal habitats within which rapidly growing carbonate communities could effectively out-compete other types of sediment deposition/accumulation processes on the continental shelf. Moreover, this trough focussed the location of (what would become) the Indonesian Through Flow (ITF). The conjunction of the ITF with the Indian Ocean ultimately provided a range of diverse genetic opportunities, a situation which reinforced the favourable growth conditions created by the rapid subsidence. As a result of these processes, reefal growth in the Timor Sea took place almost exclusively over the last five million years, with most occurring over the last three million years or so.

At a local scale, new data also strongly suggest that the locations of the majority of reefs and carbonate banks and build-ups in the area are associated with active and palaeo-hydrocarbon seeps. These seeps are localised over either fault systems which tap the reservoir, along migration fairways, or at the pinch-out of the regional Cretaceous top seal. Our interpretations suggest that the reefs and the build-ups formed by a sequential process. Firstly, hydrocarbon seepage (induced by collision-related faulting) localised small seafloor (chemo-lithotrophic) biological carbonate communities, which ultimately formed topographically positive features. These higher relief features were subsequently preferentially colonised by an assortment of reef-building biota, whose rapid growth progressively kept up with rising sea-level (which was driven principally by collision-related subsidence). The most favourable conditions for initial reef colonisation probably occurred during periods of relatively low sea-level, when the areas around the reefs were located at much shallower water depths (<40m) than today, and ample sunlight reached the seafloor.

Clearly, the fact that the genetically rich carbonate communities in this area are probably causally related to natural hydrocarbon seepage (and the attendant processes which drove that seepage) will present a series of almost unique exploration, development (especially engineering) and conservation challenges.

Acoustic properties of Muderong shale

D.N. Dewhurst, M.D. Raven, P. van Ruth, P.R. Tingate and A.F. Siggins

Presenter: David Dewhurst, CSIRO Petroleum

Session 7C: 3:20 pm, Hall C.

The presence of smectitic shales often causes serious problems for drillers in the form of both overpressures due to low permeability and wellbore stability problems resulting from the presence of swelling clays. Prediction of overpressures in such sediments is hampered by interlayer water in the mineral structure that is not accounted for in porosity determinations whether by wireline methods or laboratory drying techniques. This study looks at the detailed physical properties and microstructure in relation to acoustic response of the Muderong Shale, a smectitic shale from the Carnarvon Basin on the Northwest Shelf of Australia. Porosity determined from acoustic or standard drying techniques is far in excess of that determined by both helium and

mercury porosimetry, but correcting for interlayer water results in the values determined by the latter techniques. Physical properties are intimately tied to the acoustic response of the Muderong Shale at both sonic and ultrasonic frequencies. The presence of smectite results in anomalously low velocities in the Muderong Shale and the development of both compaction fabrics and induced microfracture generation result in significant acoustic anisotropy. Velocity variations from downhole shales in wells from the Carnarvon Basin can mainly be tied to smectite content but also to overpressure. The high degree of anisotropy of the Muderong Shale at ambient pressure can be related to the presence of both a sedimentary compaction fabric and high aspect ratio compliant microfractures. Determination of the relative contributions of these two causes of anisotropy in shales may provide a method by which to distinguish overpressure-generating mechanisms from acoustic data.

POSTERS

Macrocyclic alkanes: Markers for the freshwater alga *Botryococcus Braunii* in the Gippsland basin

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Macrocyclic alkanes are novel markers derived from the algaenan of *Botryococcus braunii* (*B. braunii*) independent of the race of *B. braunii*. Analysis of a crude oil (Leatherjacket–1, Cretaceous) and a sediment from the Gippsland Basin (Flounder–1 well, Cretaceous) reveal the presence of macrocyclic alkanes, suggesting an input to the organic matter from freshwater alga *B. braunii*. This is the first report of macrocyclic alkanes in Australian crude oils and in sediments other than torbanites. These compounds are important because they ultimately derive from the algaenan of *B. braunii* and are thus selectively preserved in crude oils unlike other *B. braunii* biomarkers that are not always preserved.

Post drill analysis of horizontal wellbores in Griffin field using true stratigraphic position modelling

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An analysis of two horizontal wellbores in Griffin Field utilising True Stratigraphic Position Modelling (TSPM) demonstrates a geologically intuitive method for the evaluation of horizontal wellbores. TSPM transposes LWD Gamma Ray to its True Stratigraphic Position (TSP), creating a simulated vertical log. The modelling process yields a very accurate profile of the apparent formation dip along the wellbore path, accurately determines the position of the wellbore relative to the stratigraphy, and identifies faulting with throws as small as 1 to 2 m. The method negates distortion of the LWD logs caused by structural, stratigraphic and wellbore geometry interaction. Once the TSPM interpretation is made the complete suite of log curves including resistivity, density porosity, and neutron porosity can then be plotted against TSP to document lateral changes in correlative penetrations of the reservoir. The models are then displayed to provide a comprehensive structural and stratigraphic picture of the reservoir along the wellbore path. The displays include a cross-section view which documents the structure, and apparent formation dip profile plotting the wellbore and the formation boundaries with TVD against lateral departure. The TSP log shows the detail stratigraphic correlation upon which the model was built showing data in respective fault blocks restored to True Stratigraphic Position. The calculated TSP curve is plotted along with vertical offset wells and the Stratigraphic Path Curve (TSP plotted against measured depth). Statistical analysis are displayed showing cross-plots of correlative petrographic zones in the wellbore.

Dedicated marine fauna monitoring program during a seismic survey in the Great Australian Bight

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Between December 2000 and May 2001 a dedicated marine fauna monitoring program was conducted during a large 2D marine seismic survey in the Great Australian Bight. The program involved three dedicated observers each spending five weeks aboard the survey vessel. Concentrating on a 2 km radius around the vessel, the dedicated observers visually monitored surface waters for 60 minute time periods covering daylight hours, and recorded any sightings of marine mammals, sharks and seabirds. Data on sightings, effort, seismic survey status, water temperature and salinity, weather and sea conditions, and animal behaviour were logged into a database together with GPS track and waypoint data for analysis and plotting with GIS software. Additional satellite derived sea surface temperature data were sourced to assist in interpretation of any spatial and temporal patterns in marine fauna diversity and distribution throughout the survey area, during the survey period.

Very few marine mammal sightings (10 sightings of five species totalling 148 individuals) were recorded. Most of the sightings were of pods of common dolphins and long-finned pilot whales. Only three sightings of large whales were recorded, including a southern right whale outside the survey area as the vessel transitted to

port. The number of sightings is very low compared to the results of other visual surveys conducted aboard operating seismic survey vessels and may be indicative of low population densities of cetacean species in the deep, offshore waters of the Great Australian Bight during the period of the survey. Given the low sample size no conclusions can be drawn regarding the behaviour of cetaceans observed when the air gun array was operating and when it was not. Nor can any conclusions can be drawn regarding the influences of oceanographic parameters. The most useful biological data from the monitoring program consists of more than 1,200 sightings of 17 seabird species.

Correlation of Permo-Triassic sandstones in wells Mondarra–1 and Mondarra–2, Perth Basin, based on quantitative mineralogical and petrographic data derived from cuttings and cores

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The accurate correlation of Permo-Triassic sandstone horizons between wells across the Perth Basin is vital to the understanding of the structure and stratigraphy within this major play. In particular, it is important to identify stratigraphic variations due to facies changes from those due to faulting.

This study documents the results of a collaborative project undertaken by Arc Energy NL and CSIRO Minerals, based on archived cuttings and core samples collected from wells Mondarra–1 and Mondarra–2, northern Perth Basin. The aim was to correlate distinctive sandstone horizons from one well to the other, and to test a structural model that required a part of the sequence to be faulted out of one of the wells.

All samples were analysed automatically by CSIRO's rapid analysis, SEM-based, quantitative mineralogical system, QemSCAN, providing both modal and textural data on the heavy mineral populations present in the cuttings and cores.

Results convincingly show that the sequence sampled in Mondarra–2 is correlated with the lowermost sequence analysed in Mondarra–1. The correlation is based on zircon, apatite, rutile and mica content, and is supported by trends in clay phases present.

The results from this study are encouraging given that previous correlation attempts, based on conventional cuttings analysis, wireline logs, and palynological studies, had been inconclusive.

The Legendre field development and geomechanical program: from exploration to drilling to production

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Exploration and appraisal drilling leading to the discovery of the Legendre Field in southeastern part of the Dampier sub-basin was accompanied by numerous and costly problems associated with wellbore stability. In order to understand the reasons for these failures and reduce the risk associated with the Legendre Field Development Program, an in-depth geomechanical analysis was carried out as a joint effort between Woodside Energy Limited and GeoMechanics International. The primary objective of the study was to improve our understanding of the in situ stress regime in the Legendre fields and then to apply these results to better assess the risks associated with development drilling risks and optimise, if necessary, the drilling program to maximise wellbore stability for avoiding costly operations. The analysis was able to identify optimal drilling trajectories using the minimal mud weight tolerances to avoid instabilities and circulation losses. The results of this analysis was also used to better understand the relationship between the stress state and the seismic fault and natural fracture network which has immediate implications for circulation losses, reservoir modelling and production performance of the field.

The Legendre geomechanical model was determined by reviewing available drilling and geologic information, pressure data and image data from the Jaubert–1, Legendre South–1 and Titan–1 wells. The results were a well-constrained estimation of the magnitudes of the principal tectonic stresses (SHmax, Shmin and Sv) and pore pressure (Pp) distribution within the Legendre North and South fields. The most difficult parameter, magnitude of the greatest principal horizontal stress (SHmax), was determined by modelling the complete stress tensor that would be consistent with the style of stress-induced compressive and tensile wellbore failure seen in these wells. Wellbore failure analysis based on high-resolution image logs indicates a SHmax stress direction of about 72°N ± 4°. Analysis of absolute stress magnitudes in the Legendre Field indicate is a strike-slip faulting regime (SHmax > Sv > Shmin) in which the vertical stress is the intermediate stress. Pressure data and drilling information indicates that the pore pressure regime within the reservoir is approximately hydrostatic throughout the area.

Mud weight programs were designed using the Legendre geomechanical model (stress and rock strength) for the five planned trajectories in the development program. Depending on the design tolerance for wellbore breakout development, a mud program was customised to allow some breakouts to form and still retain a low mud pressure. This was particularly important because there were some critically-stressed fractures in the area; if these were intersected with an elevated mud pressure, circulation losses would be likely to occur. The production wells were nearly all drilled in the most optimal trajectory that ensured the lowest mud weight could be deployed.

The Legendre drilling program was a geomechanical success in that it was possible to successfully drill and complete all the production wells using a mud weight range of 1.08–1.11 SG without encountering the mechanical instabilities associated with excessive hole enlargement, hole cleaning and excessive sidetracking.

(U-Th)/He thermochronology as a potential petroleum exploration tool: application to the Otway Basin, Southeastern Australia

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The novel thermochronological technique of (U-Th)/He dating is based on the accumulation and diffusive loss of helium produced by alpha decay of uranium and thorium impurities within apatite grains. Apatite (U-Th)/He ages are progressively reset by heating, due to the diffusive loss of the radiogenic helium (analogous to the "annealing" of fission tracks), with total loss occurring at temperatures around 80°C (for timescales involving millions of years). When integrated with information from AFTA and other thermal indicators (e.g. vitrinite reflectance – VR), this technique allows more precise thermal history constraints to be established at relatively low temperatures (50–80°C).

A number of tectono-thermal events are known to have affected the Otway Basin of southeastern Australia, including mid-Cretaceous, Early Tertiary and Late Tertiary episodes. Here, we illustrate how integration of (U-Th)/He dating of apatite with AFTA and VR data in a number of Otway Basin wells provides much tighter constraints on the lower temperature history, and provides improved precision on the timing of basin inversion during Tertiary times.

For example, AFTA and VR data in the Anglesea–1 well show two paleo-thermal episodes with cooling beginning from maximum paleotemperatures in the Early Cretaceous (110–95 Ma), and from a lower paleo-thermal peak in the Tertiary (beginning between 50 and 0 Ma). Assuming that heating was due to burial, the Tertiary stratigraphy further constrains the most recent cooling episode to post-35 Ma. Using the framework provided by AFTA (above), we have modelled (U-Th)/He ages in samples within the Early Cretaceous section, using various timings for the onset of cooling within the allowed range (making appropriate allowance for the influence of grain size on diffusion rates). Comparison of modelling results with measured (U-Th)/He ages allows refinement of possible thermal history scenarios. A scenario involving rapid cooling beginning at close to 10 Ma gives the best fit to the measured He ages. This timing is consistent with the regional geology, characterised by a widely recognised Late Miocene unconformity. Thus application of (U-Th)/He dating provides increased precision in determining the timing of the most recent cooling episode, which allows much tighter integration with geological information. Results from other wells confirm the occurrence of a number of cooling episodes at different times within the Tertiary.

Other parts of the Basin have been sheltered from the effects of these episodes and have undergone simpler burial histories. Results from these locations provide a test of helium diffusion systematics, suggesting that systematics based on laboratory heating can be extrapolated with confidence to geological situations.

Integration of (U-Th)/He dating of apatite with existing thermal history reconstruction techniques in this way provides more a reliable basis for constraining thermal histories in sedimentary basins. This in turn allows improved understanding of the thermal evolution of potential hydrocarbon source rocks, particularly in relation to the time at which source rocks reach their maximum maturity levels. In basins with complex histories, knowledge of this factor in relation to the time of structure-forming events can significantly reduce exploration risk by targetting regions where hydrocarbon generation post-dates structuring.

Estimating porosity and permeability from calibrated image logs

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Porosity and permeability determine the potential storage volume and rate of hydrocarbon extraction respectively. In carbonate rocks, porosity-permeability cross plots show large variability, and factors other than porosity are needed to model permeability (Lucia, 1999). Lucia (1999) also states that pore space must be defined and classified in terms of rock fabrics in order to integrate the geological and engineering information of the rock.

Image logs (eg. STAR) have been used to classify carbonate rock fabrics over intervals of interest in a number of wells in a field under study. A substantial length of core was taken from one of the wells, over which porosity and permeability measurements were routinely taken, providing a statistically viable dataset.

Over the cored interval, the image fabrics were correlated to the core. The measured porosity and permeability over the cored interval for each image fabric was then isolated into separate data-sets. From this information a standard deviation plot was generated from which the mean value of porosity and permeability was obtained, as well as the standard deviation, giving a minimum and maximum value for each image fabric. The calculated mean, maximum and minimum values for each image fabric were then used as a template that could be applied to similar image fabrics in intervals with no available core.

Using this image-based classification methodology of carbonate fabrics, an extrapolation of porosity and permeability in zones with no measured data can be made with reasonable confidence. It must be noted that such an image-based fabric classification is restricted to a particular field and cannot be extrapolated to other fields. A fabric classification would have to be generated specifically for each study area.

The Gippsland Basin enigma—Top Latrobe, and its expression in other SE Australia basins

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The Eocene is an important time in the tectonic evolution of the southeastern Australian Basins. It is during the Eocene that the present configuration of the Indo-Australian plate developed, with the onset of fast spreading beginning in the Southern Ocean around 40 Ma. Plate reshuffling during the Eocene appears to herald the onset of the Late Tertiary compressive tectonic regime in SE Australia. Significant unconformities exist within the Eocene of the Gippsland. Torquay and Otway Basins, and include the Top Latrobe Unconformity (Top Latrobe) that forms the major control to hydrocarbon accumulations in the Gippsland Basin.

Traditionally Top Latrobe has been picked at the first occurrence of a quartz sand body beneath marine marlstone and mudstone of the Seaspray Group. On seismic, (and where close spaced well data exists), a low angular unconformity exists between interbedded sand/shale/coal facies of the Latrobe Group and the Seaspray Group. Here, the unconformity is characterised by tectonic deformation and tilting, and always overlies and truncates marine filled Marlin and Flounder Channels (dated at 45 and 52 Ma respectively) where present. The angular unconformity produced can be up to 5 degrees.

The Top Latrobe in the Gippsland Basin shows large amounts of erosion with a maximum of up to 600 m in the Marlin Channel near the Marlin Field. The Top Latrobe is also characterised by resilient sandstone strike-ridges that result in a varied topography. Where sandstones are stratigraphically clustered together at the Top Latrobe subcrop, strike ridges are common. Where thick shale units occur at the Top Latrobe subcrop, topographic valleys are more common. Hence many oil fields have the bonus of a thick series of sandstone reservoir units located where topographic/structural culmination occurs.

Significant erosion and missing biostratigraphic zones occur below the unconformity particularly on the crests of structures, suggesting pre-existing topography and differential (subaerial?) erosion prior to progressive burial onlap by Seaspray Group units. Many faults terminate at the Top Latrobe although some anticlinal growth may have continued into the Miocene.

A study of 50 key offshore wells across the Gippsland Basin suggests that the best correlation between the seismic/synthetic Top Latrobe, and the litho-biostratigraphic Top Latrobe occurs around the Middle to Late Eocene boundary. This date applies the constraints of between 40 and 45 Ma when incorporating the age of Marlin and Flounder channelling. This unconformity occurs between the Eocene Lower and Middle N. asperus (40–45 Ma) palynology zones. The Lower N. asperus zone also corresponds to the marine Turrum Formation (the sedimentary fill of the Marlin Channel) and the Flounder Formation (fill of the Flounder Channel). The Middle N. asperus Gurnard Formation unconformably overlies both the Top Latrobe unconformity and the Turrum and Flounder Formations, and corresponds to the first open marine transgression in the Gippsland Basin.

In the onshore part of the Gippsland Basin, the Top Latrobe differs, and is placed within a semi-continuous series of coal measure units. It is now placed along the top of the Middle Eocene Traralgon 2 coal seam that is overlain (disconformably) by early Late Eocene-Oligocene Traralgon 1 coal measures and younger sequences. The Rosedale Fault controls the northern extent of the Traralgon 2 coal measures, and subsequent fault movements reverse this sense of throw after the Top Latrobe unconformity. Seismic resolution of this event onshore (unlike the offshore part of the basin) is hampered by the thick overlying Traralgon 1 coals.

In the Torquay Basin a low angular seismic unconformity is evident in the offshore basin between youngest (Middle Eocene) Eastern View Group beds and oldest (Late Eocene) Demons Bluff Group beds. In the Anglesea coal mine this boundary is exposed in the high wall of the open cut, as a low angle unconformity between the A Group coal seam and the overlying Boonah Formation. This represents the only outcrop example of this Eocene event.

In the onshore Otway Basin a similar low-angle unconformity can be demonstrated between top-Dilwyn Formation (Palaeocene-Early Eocene), and base-Nirranda Group (Late Eocene), suggesting the widespread nature of this unconformity in the SE Australian coastal basins. The timing appears to correspond to a rapid increase in spreading rates in the Australian-Antarctica breakup.

Most of the oil and gas bearing structures in Gippsland are directly attributed to this event. Their subsequent burial and seal has enabled entrapment of large quantities of hydrocarbons. In the Torquay and Otway Basin's inadequate burial of strata preserving this tectonic event makes the interval less favourable for hydrocarbon entrapment in these basins.

Pore pressure prediction from well logs, pitfalls and modifications

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Accurate knowledge of pore pressure is essential in drilling and production operations. Knowledge of stress and pore pressure history is also important to evaluate the effect of depletion on reservoir properties (e.g. porosity/ permeability, volume loss, and the effectiveness of a compaction drive). With the exception of a few models, existing pore pressure prediction techniques from well logs are based on a disequilibriom compaction mechanism in which there is a unique relationship between velocity and porosity that defines the compaction trend. Using such models it is impossible to distinguish between disequilibrium compaction and other sources of overpressure such as fluid expansion. Failure to account for such mechanisms leads to erroneous estimates of pore pressure and incorrect assessments of the effects of depletion.

The velocity-effective stress relation is controlled by the internal microstructure of the rocks and generally is independent of the rock porosity. If formation overpressure is not caused by an undercompaction mechanism, the porosity anomaly may be insignificant and the deviation of sonic log from a normal compaction trend could directly be used to quantify the abnormal pore pressure. When undercompaction drives overpressuring and rocks show anomalously high porosities, however, the sonic log may show a larger deviation since it will be responding to lower effective stress and the higher porosity. In this case if the influence of porosity anomaly on the sonic log is not carefully quantified there will be a risk of under- or over-estimating pore pressure. In areas where the normally pressured and overpressured zones have similar lithology and pore fluid, subtraction of the porosity anomaly (as derived from density log) from the apparent sonic porosity can be used to separate the porosity component from the pore pressure component of the sonic log reading in overpressured zones. This in turn leads to identification of the pore pressure history that is critical to understanding the response of the reservoir to depletion.

Stabilisation of offshore marine pipelines by dumped stone

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Tests were carried out on a scale model of a rock berm in a wave-current flume to determine the resistance of the berm to damage from combined wave and current action. The range of tests covered many of the situations possible in the field and serves to aid in the design of pipeline protection systems.

Two distinct mechanisms of berm damage were observed. The first was damage on the downstream face of the berm caused by the formation of a vortex and the second was damage due to excessive bed shear stress causing rocks to dislodge from the berm. These mechanisms can occur individually or simultaneously to cause unacceptable damage to the berm.

The results are presented as a design chart, indicating under what conditions damage to a rock berm can be expected to occur and the extent of the expected damage where it does occur.

Towards an efficient exploration frontier: constructing a portfolio of stratigraphic traps in fluvial-lacustrine successions, Cooper-Eromanga Basin

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In the Cooper-Eromanga Basin, the future of exploration lies in identifying an appropriate exploration portfolio consisting of stratigraphic traps in structurally low or flank areas. A variety of stratigraphic trap prospects in the Moorari and Pondrinie 3D seismic survey areas are identified in the Patchawarra, Epsilon, Toolachee and Poolowanna formations. To identify the stratigraphic traps, an integration of sequence stratigraphic concepts applied to non-marine basins and advanced 3D seismic data visualisation was employed. This paper focusses on estimating the chance of geologic success and the probabilistic reserves size for each prospect within its sequence stratigraphic context (lowstand, transgressive or highstand systems tracts). The geologic chance factors for an effective stratigraphic trap include reservoir, top seal, lateral seal and bottom seal within each depositional systems tract, the seal effectiveness of the adjacent depositional systems tracts and the appropriate spatial arrangement of these factors. The confidence values for the existence of geologic chance factors were estimated according to the distributions of the possible reservoir and seal rocks within each genetic-stratigraphic interval and the chance of geologic success of each prospect was calculated. For probabilistic reserves estimation, geologically reasonable ranges were estimated for each parameter employing Monte Carlo simulation to calculate the reserves distribution. When a series of possible exploration portfolios, including single or multiple prospects from the prospect inventory are plotted in terms of the chance of geologic success *vs.* the mean value of the reserves estimate, an efficient exploration frontier emerges. The portfolio candidates on the efficient exploration frontier were assessed with regard to chance of economic success and expected net present value (ENPV) using a simple cash flow model. The results indicate that appropriate portfolios include multiple prospect exploration especially with lowstand systems tract plays using single or multiple exploration wells. The portfolio construction approach for stratigraphic trap exploration should ultimately be made consistent with conventional play types, to enable an assessment of all exploration opportunities.

Use of 3D seismic proves vital in onshore Otway Basin exploration success

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The combination of commercial opportunity and technological advancements has revitalised hydrocarbon exploration in the onshore Otway Basin. Until 1999, relatively small field sizes and lack of markets allowed only modest drilling activity even in the prospective Port Campbell Embayment. Following the construction of the Iona to Geelong Gas Pipeline, exploration intensified to the point of drilling 6 wells during the first half of 2001, with each well resulting in a new discovery. In addition 188 sq km of 3D seismic data was acquired during this period. With such a success rate, high levels of exploration activity can be anticipated over the next few years.

The co-incidence of 3D seismic AVO and amplitude anomaly with structural closure has proven a key factor in the success within the productive Waarre Formation Play Fairway. In particular the use of near and far offset data has provided a high degree of confidence of geological if not commercial success. Low risk and a campaign drill program have allowed the commercialisation of even modest-size gas fields (less than 1 BCF) within small structures (less than 0.4 sq km).

Predictive structural model for the Barrow and Dampier Sub-basins

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The Barrow and Dampier Sub-basins of the Northern Carnarvon Basin developed by repeated reactivation, of long-lived basement structures during Paleozoic and Mesozoic tectonism. Inherited basement fabric specific to the terranes and mobile belts in the region comprise northwest, northeast, and north-south-trending Archaean and Proterozoic structures. Reactivation of these structures controlled the shape of the sub-basin depocentres, basement topography, and determined the orientation and style of structures in the sediments.

The Lewis Trough is localised over a reactivated NE-trending former strike-slip zone, the North West Shelf (NWS) Megashear. The inboard Dampier Sub-basin reflects the influence of the fabric of the underlying Pilbara Craton. Proterozoic mobile belts underlie the Barrow Sub-basin where basement fabric is dominated by two structural trends, NE-trending Megashear structures offset sinistrally by NS-trending Pinjarra structures.

The present-day geometry and basement topography of the basins is the result of accumulated deformation produced by three main tectonic phases. Regional NE–SW extension in the Devonian produced sinistral strike-slip on NE-trending Megashear structures. Large Devonian-Carboniferous pull-apart basins were introduced in the Barrow Sub-basin where Megashear structures stepped to the left and are responsible for the major structural differences between the Barrow and Dampier Sub-basins. NW extension in the Mid

Carboniferous to Early Permian marks the main extensional phase with extreme crustal attenuation. The majority of the basin sediments were deposited during this basin and subsequent Triassic sag phase. Jurassic extension reactivated Permian faults during renewed NW extension. A change in extension direction occurred prior to Cretaceous sea floor spreading manifest in basement block rotation concentrated in the Tithonian. This event changed the shape and size of basin compartments and altered fluid migration pathways.

The currently mapped structural trends, compartmentalisation and shape of basins reflect the basement fabrics. Each fabric can be discriminated and mapped using non-seismic data such as gravity, magnetics and bathymetry, and then calibrated with available seismic datasets. The combination of non-seismic and seismic data provides a powerful tool for mapping basement architecture, basement-involved faults (trap type and size), intra-sedimentary geology (igneous bodies, basement-detached faults, basin floor fans), primary fluid focusing and migration pathways, and paleo-river drainage patterns, sediment composition and lithology.

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Petroleum potential at the interface between the Cooper and eastern Warburton Basins

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The eastern Warburton Basin unconformably underlies the Cooper and Eromanga Basins in northeastern South Australia and extends to southwestern Queensland. Since the discovery of gas in Gidgealpa–2 in the Cooper Basin in 1963, the Warburton Basin has been regarded as economic basement and thus not explored seriously.

In the last decade a significant amount of research has been undertaken on the Cambro-Ordovician Warburton Basin and the interface between it and the overlying Cooper Basin. Petroleum potential at the interface is now better understood to warrant serious exploration. Key features include sources from the Cooper Basin, reservoirs from the Warburton Basin, and traps and seals from both basins. Exploration success has come from four wells that have tested commercial flows of hydrocarbons from Warburton Basin reservoirs: the fractured siltstone in Lycosa–1 has a maximum gas flow of 5.0 MMCFD (million cubic feet per day), the fracture-enhanced fine-grained sandstone reservoir in Moolalla–1 has a maximum gas flow of 9.6 MMCFD, the fractured tuff flowed gas at a rate of 1250 BOPD (barrels of oil per day) in Sturt 6 in 1990; in 2001, significantly the carbonate reservoir in Challum–19 flowed gas at a rate of 7.5 MMCFD in Queensland. Furthermore, 90 of the 600 wells that reached the Warburton Basin have hydrocarbon shows though limited testing has been conducted. Only 1.4% of the total drilled section in the Cooper Basin area has been intersected with the Warburton Basin and the majority of this drilling was into the main seal horizon rather than the reservoir.

One of the most significant recent discoveries was the recognition of an altered zone that is widespread within the uppermost levels of Warburton Basin strata beneath the unconformity with the overlying Cooper Basin rocks. Hydrocarbons were discovered in the reservoirs beneath this zone in Lycosa–1, Moolalla–1 and Farina–1. Less than 50% of wells that have been drilled into the Warburton Basin penetrated the altered zone to test the reservoirs beneath. Elsewhere, in Sturt 6 unaltered fractured acid volcanics are sealed by Cooper Basin siltstones.

Warburton Basin reservoirs rely on a down-dip Permian Cooper Basin source. No indigenous source has been proved in the Warburton Basin; most of the limited sampling, however, has occurred in altered lithologies in which the source is commonly biodegraded.

Clastic reservoirs within the Warburton Basin include shoreline, deltaic and turbidite sands. Fractures have assisted flows from shales in Lycosa–1, fine-grained sandstone in Moolalla–1, and acid volcanics in Sturt–6 and –7. Recent research has contributed a great deal to our understanding of the fracture systems and reservoir-effective fractures. A new unconventional reservoir rock is identified in altered granite.

Genuine structural traps within the Warburton Basin exist; the most reliable traps occur, however, in unconformity related structures. It does not matter if these ridges are of structural origin or palaeohighs, Warburton Basin reservoirs may be sealed by either Warburton or Cooper Basin seals or both while have access to migrating Cooper Basin sourced hydrocarbons.

It is critical to rectify the boundary between the two basins and identify locations where the more favourable Warburton Basin reservoir rocks have access to migrating down-dip Cooper Basin sources and to seals and traps from both basins. For the first time, a detailed study and reliable mapping techniques are emerging to accurately locate the top of the Warburton Basin to enable tectonically/unconformably related traps and migration pathways to be defined. It makes economic sense to drill deeper to reach these types of unconventional Warburton Basin reservoirs.

Field-scale hydrodynamics of Challis and Jabiru, Vulcan Sub-basin

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An evaluation of hydrodynamics at the field scale can provide information on the present day propensity of faults and cap rocks to be either sealing or leaky. The work presented in this poster is a contribution to the APCRC (Australian Petroleum Cooperative Research Centre) Seal Program. The hydrodynamic system presented here for the Jabiru and Challis Field areas is a detailed interpretation based on the North West Shelf Hydrodynamics and Fault Seal study as described by Otto et al. (2001).

The Jabiru Terrace is a series of horst blocks trending southwest–northeast. Pressure data from 14 wells in the Jabiru Field and surrounding region show a thick (>80 m) hydraulically continuous aquifer below about –1,620 mSS. The data define a formation water flow system oriented roughly perpendicular to strike. Flow is from high values of hydraulic head in the northwest to low values in the southeast. Although structural data is limited, it appears that hydraulic communication within the aquifer and the detailed flow paths are controlled by the fault distribution. At the ends of faults where structural displacement of the aquifer becomes zero hydraulic communication in the plane of the aquifer is maintained. Pressure data from the pooled hydrocarbon phases indicate that the faults themselves are sealing as indicated by different pressure gradients for pooled oil in each fault block. There is a range of oil densities with progressively heavier oil toward the southwest. With the exception of Jabiru–4, the oil column is about 80 m with a constant pressure gradient in each well. Jabiru–4 shows some vertical stratification above –1,624mSS defining several short hydrocarbon columns in sequence, each with its own pressure gradient. This stratification is likely related to the variable lithology and associated rock properties at this location.

The Challis Field pressure data features production induced draw down signatures for post 1990 wells (Challis–9–14). Significant drawdown is confined to the strata above –1,550mSS with post 1990 pressure data in the aquifers below this showing little or no effect. The pressure gradient in the Vulcan aquifer (1.44psi/m) defines the in-situ water salinity to be 46,000mg/l. The hydraulic head distribution shows a closed hydraulic head high against the south side of the main bounding fault and then an abrupt drop of 5m of hydraulic head across the main bounding fault to Cypress–1 in the north. The hydraulic head distribution suggests that the main bounding fault hydraulically separates the north and south sides but connects the Vulcan aquifer beneath the Challis Field (the south side of the fault) with a deeper aquifer. Subtle differences in the pressure gradient and oil-water contact elevation indicate that Challis–14 may separate the Field into two pools. The southern pool may extend southwest to include Cassini–1 considering that the oil pressure gradient and oil-water contact elevation exactly align with those of Challis–4. Minor cross faults near Challis–9 may control the northeast limit of the Field.

The hydrodynamic assessment of the Jabiru and Challis Fields described here represents the first step of an integrated process. A charge history based on GOI (Grain Oil Index) and a structural investigation of each field will be completed as a second step. At that time the hydrodynamic evaluation can be adjusted and incorporated into a multidisciplinary evaluation of each oilfield that will attempt to identify the geological factors contributing to cap and fault seal integrity and the current day distribution of hydrocarbons.