GEOSCIENCE AUSTRALIA

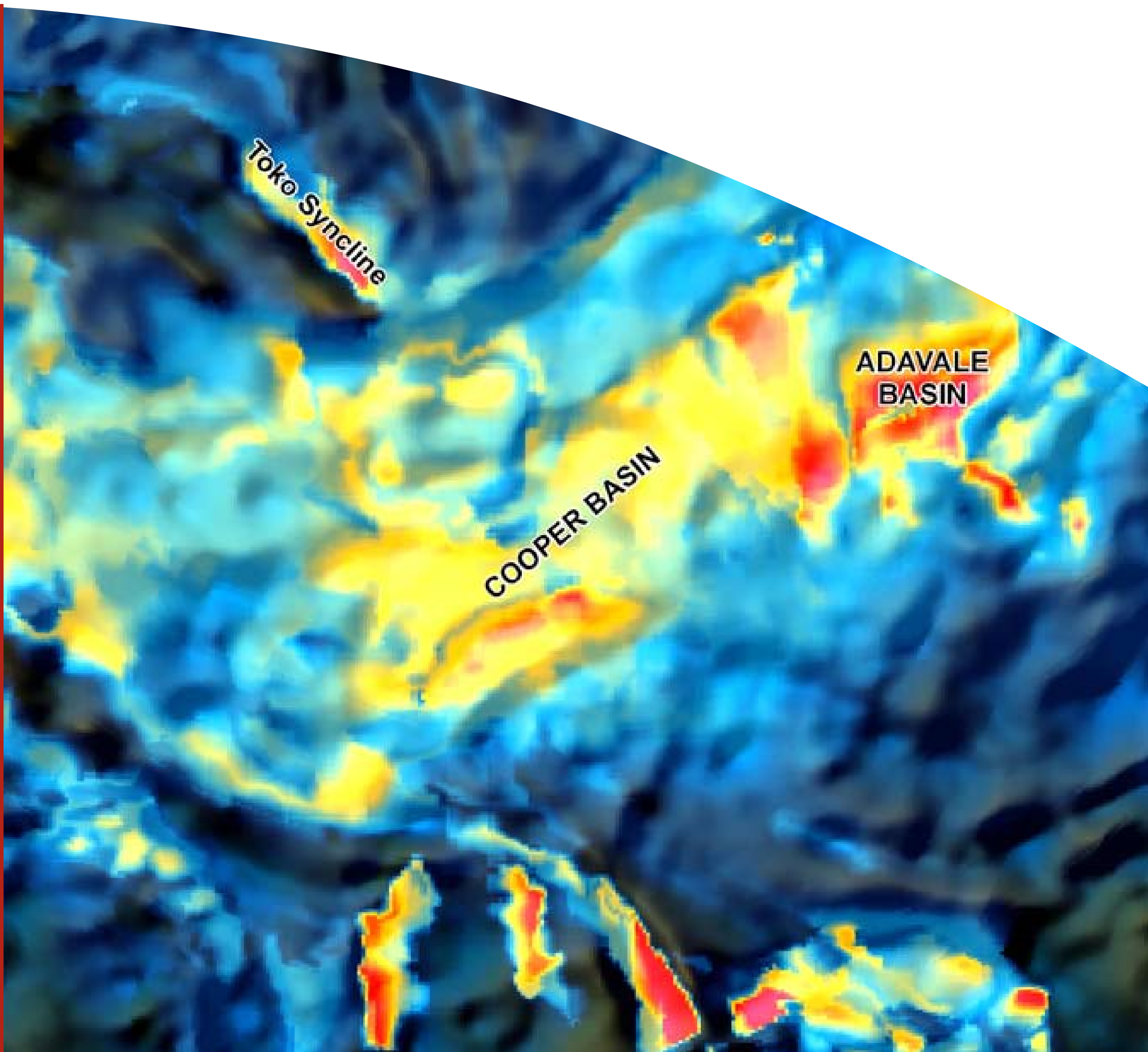
Australian Government
Geoscience Australia

Hydrocarbon & Geothermal Prospectivity of Sedimentary Basins in Central Australia

Warburton, Cooper, Pedirka, Galilee, Simpson & Eromanga Basins

Bruce Radke

Record
2009/25



APPLYING GEOSCIENCE TO AUSTRALIA'S MOST IMPORTANT CHALLENGES

Hydrocarbon and Geothermal Prospectivity of Sedimentary Basins in Central Australia

Warburton, Cooper, Pedirka, Galilee, Simpson and Eromanga Basins

GEOSCIENCE AUSTRALIA
RECORD 2009/25

by

Bruce Radke[1]

Australian Government
Geoscience Australia

1. 'Eungella', 908 Farringdon Road, Braidwood, NSW, 2622

Department of Resources, Energy and Tourism
Minister for Resources and Energy: The Hon. Martin Ferguson, AM MP
Secretary: John Pierce

Geoscience Australia
Chief Executive Officer: Dr Neil Williams PSM

ISSN 1448-2177
ISBN 978-1-921672-03-3 Print
ISBN 978-1-921672-01-9 Web
ISBN 978-1-921672-02-6 CD-ROM

GeoCat # 69150

Bibliographic reference: Radke B, 2009, *Hydrocarbon and Geothermal Prosepctivity of Sedimentary Basins in Central Australia; Warburton, Cooper, Perdirka, Galilee, Simpson and Eromanga Basins.*Geoscience Australia Record 2009/25

Cover image:

Total sedimentary thickness of the Central Basins region and surrounds (from FrOG Tech, 2005) superimposed on crustal structure at about 7-12 km depth as indicated by gravity (15-25 km upward-modeled slice of M. Morse, pers.comm, 2007). Deep depocentres of the Amadeus and Officer Basins lie on the western boundary, and the Belyando-Drummond Basins to the extreme northeast.

Contents

FIGURES

28 Under-explored terrain along the southern margin of the Mt Isa Block: (a) Combined gravity (colour)/magnetics (shadow) image and (b) Magnetics (TMI rtp) image, both with superimposed seismic survey lines and exploration wells.

29 Depth to magnetic basement (spot determinations from forward modelling by Meixner, pers. comm., 2007). Circles are depth (m) with high confidence; triangles are depths (m) of lower confidence.

30 Detail of TMI rtp image showing: 1) isolated bright spots (green arrows) – possible palaeo-hydrocarbon seepage sites, and 2) palaeodrainage lines (red arrows) - possibly within Cretaceous Winton Fmn or younger Paleogene fluvials – that could be foci of uranium roll-front deposits induced by hydrocarbon seepage and/or groundwater migration.

31 Groundwater flow lines within the Eromanga Basin main aquifer, showing recharge, vertical leakage, and progressive salinisation along flowlines [colour change from blue (low salinity) to red (high salinity)] under the present hydrodynamic regime. At 10-15 Ma prior to uplift of the Great Dividing Range, dewatering of the basin was predominantly by radial expulsion of connate fluids towards basin margins (from Radke *et al*., 2000).

32 First vertical derivative of aeromagnetics indicates probable sedimentary residual magnetic (SRM) anomalies over known hydrocarbon fields in the Cooper Basin. Untested SRM anomalies adjoin this region.

33 Geothermal highs as contours of predicted temperature at 5km depth, superimposed on gravity, with selected wells in the Eromanga Basin. The temperature contours contained in this figure have been derived from proprietary information owned by Earth Energy Pty Ltd ACN 078 964 73. (Contour interval 20^{o}C above a base contour at 200^{o}C).

34 Gravity lows defined beneath the Eromanga Basin, with intercepted granites, and hot siliciclastics (from Somerville *et al*, 1994).

35 The Innamincka Hot Fractured Rock Project of Geodynamics Ltd.
a) The Innamincka Granite with projected bore field size required to generate 275 MW.
b) Recorded microseismic events in the hot granite during hydraulic stimulation from Habanero 1 shows the lateral extent and horizontal tabular nature of the developed subsurface heat exchanger.
c) Extent of subsurface heat exchanger relative to existing wells (grid is 500m).
d) Modeled temperature drawdowns of proposed production fields in triangular and square well patterns after 20 years production for 43 and 41 wells respectively. Note temperature breakthrough between injection and production wells has not yet occurred
(From Geodynamics Annual Reports, 2004 & 2006; Wyborn *et al*., 2004).

36 Comparison of electricity generation costs from fossil fuels and HFR sources (from Geodynamics Pty Ltd, 2004 Annual Report).

37 Relatively high temperatures over basement granites on the Birdsville Track Ridge and over the Big Lake Granitoids. Crustal temperatures extrapolated to 5 km depth (from Earthinsite.com, Chopra and Holgate, 2005).

APPENDIX FIGURES

TABLES

Executive Summary

Within the Central Australian region, nominally constrained by 22.5°S 134°E and 31.5°S 144°E for this study, lie several systems of stacked basins beneath the extensive Mesozoic Eromanga Basin. Remnants of Proterozoic basins are largely inferred from gravity, unexplored, and are not everywhere differentiated from an extensive cover of the lower Paleozoic Warburton Formation. This sequence is the central link between the contiguous Amadeus, Officer and Georgina Basins, and the Thomson Fold Belt.

Since the Carboniferous, the region has largely experienced intracratonic sag and has accumulated continental sediments, including thick coal measures, with intermittent tectonism and uplift. In late Early Cretaceous, marine conditions briefly invaded this subsiding region, but continental sedimentation resumed in the Late Cretaceous. Tectonism occurred in the Paleogene with basin inversion and subsequent formation of the Great Artesian Basin. In the Cainozoic, the region is again in subsidence and accommodating fluvial and aeolian sediment slowly into the Eyre Basin. The preserved depocentres of the Carboniferous-Permian-Triassic Cooper, Pedirka-Simpson, and Galilee Basins are spatially separate, although all contain comparable, largely organically-mature continental coal measure sequences.

Only the Cooper–Eromanga Basin system produces gas and oil. The Mesozoic Eromanga Basin blankets the entire region but has deep depocentres overlying and offset from the underlying Carboniferous-Triassic basins. The Eromanga Basin sequence is the main oil producer of the couplet, with the dominant source from underlying Cooper sources. Ever-improving techniques for the differentiation of petroleum systems indicate that Mesozoic sources can contribute significantly where of sufficient thermal maturity. Even where these sequences are under-mature from insufficient burial, Coal Seam Gas remains a major potential resource that is only beginning to be investigated.

This region is the most productive onshore petroleum province of Australia, but also features world class geothermal resources contained in underlying high heat producing (HHP) granites. Collectively, the geothermal and sustained petroleum potential of the Cooper–Eromanga Basin points to it being the energy centre of Australia. The geothermal industry has reached ‘proof of concept’ for extracting energy from hot fractured rock. With all the unknowns and uncertainties of a new technological frontier, confirmed estimates of investment costs for development and sustainable production are eagerly awaited.

The petroleum industry in the Cooper–Eromanga basins system has well-established exploration, development, production and pipeline infrastructure in place, and there is an ever-continuing discovery of new fields, but these are generally smaller and in subtler structure. Cooper Basin gas is high in carbon dioxide, averaging 17% basinwide, and gas production alone contributes annual emissions to the atmosphere in the order of 1.8 million tonnes CO_2. Political and economic policies in Australia have begun to respond to the national and worldwide demand for reducing the footprint of greenhouse gas emissions, and this may soon shift the economic balance for each of these industries in opposite directions.

The Cooper–Eromanga Basin system has current recoverable reserves of gas and oil equal to its total production since the 1960s, and was recently in the throes of an exploration miniboom with improved discovery success rates. Contributing to this success are improved 3D seismic technologies that allow better structural definition and well positioning on subtle structural and stratigraphic plays. Since the first commercial discoveries of gas at Gidgealpa in 1963, and commercial oil at Strzelecki in 1976, regional exploration in the adjoining comparable basins has slowed to a virtual standstill.

Only recently, with complete stakeout of the Cooper–Eromanga Basin and with the recognition of Coal Seam Gas as a viable commercial commodity, has industry resumed exploration in surrounding basins for oil, gas, and methane deposits. This renewed activity may be more vulnerable to implosion again unless exploration is sustained and successes are achieved in the near future. Immediately apparent is the lack of infrastructure away from Cooper Basin facilities, and this forebodes much higher costs for exploration and future development for higher risk explorers than those continuing exploration in the Cooper–Eromanga Basin system. The expectation of discovery of large highly profitable fields away from this producing area is much lower given the current knowledge of these other basins, which is basic and incomplete when compared to the Cooper–Eromanga couplet. However the projected market price of commodities still makes any exploration attractive for higher risk investment in the longer term.

The Central Basins region straddles the jurisdictions of South Australia, Queensland and Northern Territory, an unfortunate geographic reality which has contributed to impeding a balanced regional appraisal of basement structure and basin architecture.

RECOMMENDATIONS FOR FUTURE ACTION AND RESEARCH

Pedirka-Simpson-Eromanga Basins in the Eringa-Madison-Poolowanna Troughs

This region offers the greatest potential for new petroleum discoveries, including Coal Seam Gas. All requisite ingredients exist for significant gas and oil accumulations in the late Paleozoic and Mesozoic sequences of the region but earlier exploration was largely over thermally immature regions. Exploration now has to now target deeper thermally mature source areas in the troughs and in structures overlying them. Source rock and thermal maturity characteristics of the deeper early Paleozoic sequence- have yet to be investigated. This sequence was previously regarded as economic basement.

Structural plays are numerous but many appear to be of subtle relief in faulted terrain. Effective and unambiguous delineation of these demands closer spacing of seismic grids, and better resolution of stratigraphic reflectors. Paleogene faulting has apparently breached many potential prospects. An understanding of the degree of its overprint on the sedimentary column would be a critical objective of improved seismic and structural interpretation.

The Toko Syncline to Cooper Basin, Arunta Block Margins, Muloorinna Ridge Margin, Southwestward extension of the Lovelle Depression

Large tracts are virtually unexplored with no seismic coverage and previously acquired gravity and magnetic data indicate many preserved sediment accumulations, presumably mainly Proterozoic, but additional remnants of more prospective Paleozoic and Triassic sequences may also exist, as well as local depocentres of thicker Eromanga Basin cover. The resolution of enigmatic gravity anomalies through the use of deep seismic and TMI modelling would offer the significant differentiation between possible small depocentres and granitic bodies. As many granites have HHP potential, seismic resolution offers a necessary advance for both geothermal and petroleum exploration.

Lower Paleozoic Warburton Basin

Regional resolution of lithofacies, organic content, thermal maturation history and/or metamorphic grade of the Warburton Basin sequence could resolve hydrocarbon prospectivity of provinces in the overlying Eromanga Basin sequence outside of the main depocentres.

Regional airborne surveys

With many defined areas of interest, regional airborne surveys for high resolution magnetics, hydrocarbon sniffing, and high sensitivity/quick response radiometrics could be a cost effective first pass to prioritise lines for a regional deep seismic program.

National Forum

Creation of a National Petroleum Exploration Accord, along the lines of NGMA, could offer a forum for improved liaison and cooperation between State and Federal petroleum interest groups on many common issues.

National Database standardisation

Geoscience Australia currently has a unique PTAG Database with design features offering improved contextual support for information, and historical tracking of all data acquisition and licensing to a graticular level of resolution. To enable wider access and usage of this unique facility requires solving the issues of confidentiality rights versus multi-levels of access to information. Adequate dedicated storage capacity for such a database is required. The best professional appraisal and resolution of these issues is paramount.

1 Introduction

The Cooper/Eromanga region is the most prolific hydrocarbon province in onshore Australia having produced over 5.5 Tcf of gas and 255 million barrels of oil since the 1970s. The remaining resources are estimated to be over 7 Tcf of proven gas and 320 million barrels of recoverable liquids. Such optimistic forecasts have resulted in a more or less exclusive focus on this province for ongoing and future exploration. Seismic coverage over the region is extensive and drilling success rates have remained high over the last decade. All commercial discoveries are readily marketable due to an existing infrastructure that allows delivery of oil and gas to expanding markets in SE Australia. For all these reasons, only very little exploration has occurred in surrounding basins leaving large areas of potentially high hydrocarbon prospectivity relatively unexplored.

Clearly, exploration away from existing infrastructure in unproven basins entails much higher risk. However, given the latest technological advances, increasing local demand for liquid hydrocarbons and the projected rising global oil price translate to a greater viability. These regions have had little new exploration data acquired in 30 years since the accelerated development of the Cooper–Eromanga fields. Exploration technologies have advanced dramatically in this time and as such, the outer regions require upgrading to 'state of the art' data acquisitions to enhance their attractiveness for exploration and hopefully, success with discoveries.

The aim of this report is to document the context and characteristics of all related basins and their petroleum potential, to identify information gaps that remain as critical uncertainties that have suppressed exploration interest in these areas.

The region for this study nominally lies within the coordinates 22.5ºS 134ºE and 31.5ºS 144ºE **(Figure 1)**.

This report addresses: the exploration history of the Cooper–Eromanga fields as a lesson for the future, basement and structural context, and the spatially-separate stacked basin systems. Summaries of individual basins and their statistics are provided as appendices for reference.

The Central Basins region transgresses the corner boundaries of South Australia, Queensland and Northern Territory, and as such, understanding of some areas has been largely blinkered by the individual limits of state and territory jurisdictions. The earlier NGMA Cooper and Eromanga Study was a major advance to integrate, standardise, and present seismic coverage for the Cooper Basin. This also stimulated comparable burial and thermal maturation modeling studies in each state. This study attempts to provide a unified overview of the lesser-explored region around the Cooper–Eromanga Basin system.

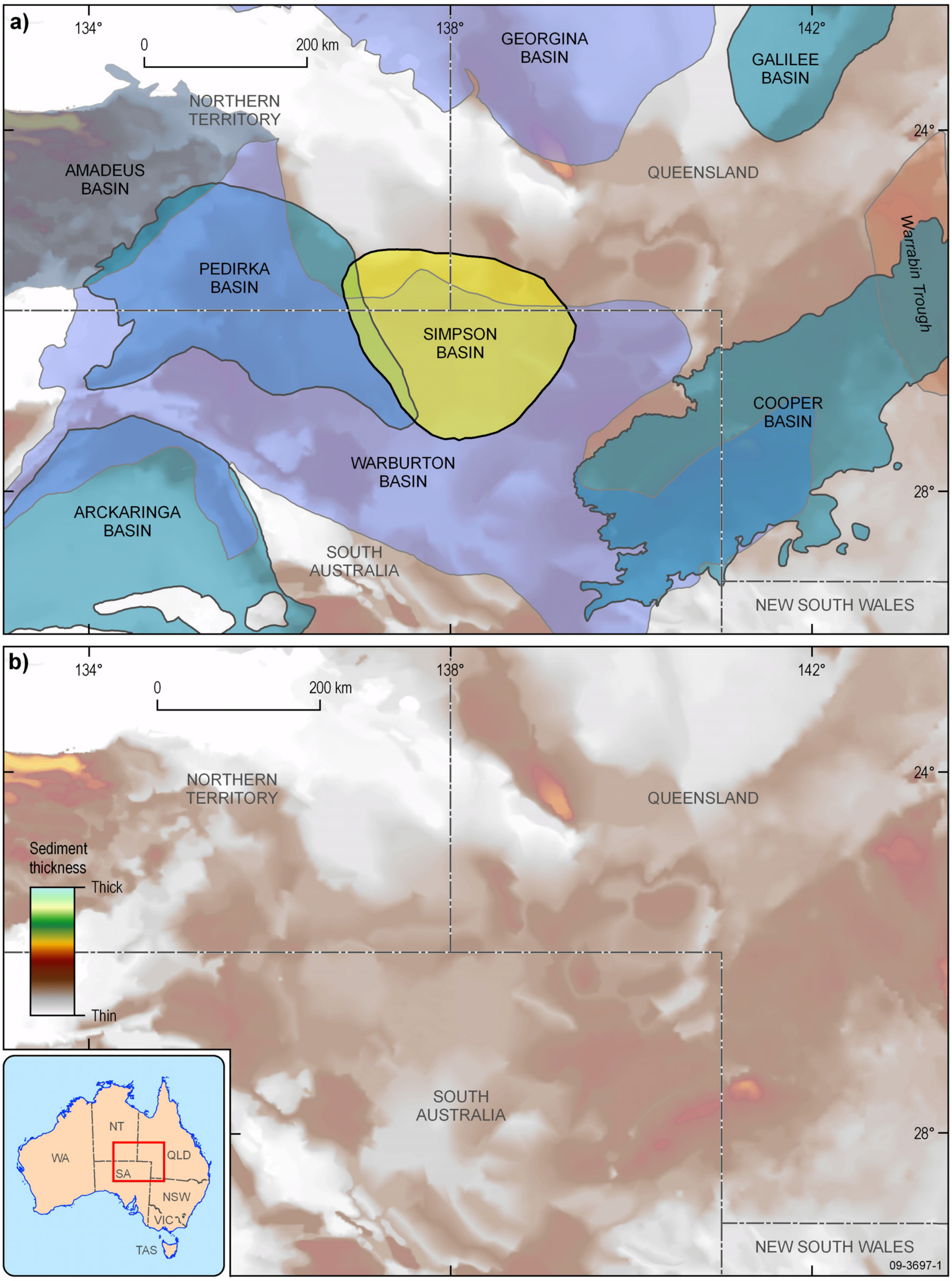


Figure 1: *(a). Phanerozoic sedimentary basins (boundaries of Geoscience Australia) superimposed on the known (b)Phanerozoic and Proterozoic sediment thickness (from modeling by FrOG Tech, 2005) within the Central Basins region. Relatively thick sedimentary successions extend between and beyond delineated basins. These areas indicate either possible extension to these Phanerozoic basins and/or undiscovered underlying Phanerozoic and Proterozoic basins.*

1.1 TOPOGRAPHY

The Central Basins region has surface expression as the Lake Eyre Basin Catchment, a subtle depression of internal drainage that is contained by the Mt Isa Inlier to the north, the Arunta Block to the northwest, the Musgrave Block and Petermann Ranges to the west, with the western margin defined by a slight uplift along and west of the Muloorina Ridge.

The central and northern-eastern extent of the Cooper Basin has expression as gently folded lateritic surfaces. The central-western region contains deserts with longitudinal dunes covering two featureless tracts, the Strzelecki Desert over the lower southwestern end of the Cooper Basin, and the Simpson Desert to the north and west of the Birdsville Track Ridge. A broad elongate region of no outcrop extends southwest from a NNW – SSE line extending from the Toko Thrust Fault in the northwest. This line generally demarcates to the east, raised lateritic expression of Cooper Basin structure. Slight topographic expression on the Birdsville Track Ridge crosses this region, and Lake Eyre lies near this western margin against the Muloorina Ridge.

Topographic expression of the region, including domes, folding and lineaments is evident in the DEM (**Figure 2**).

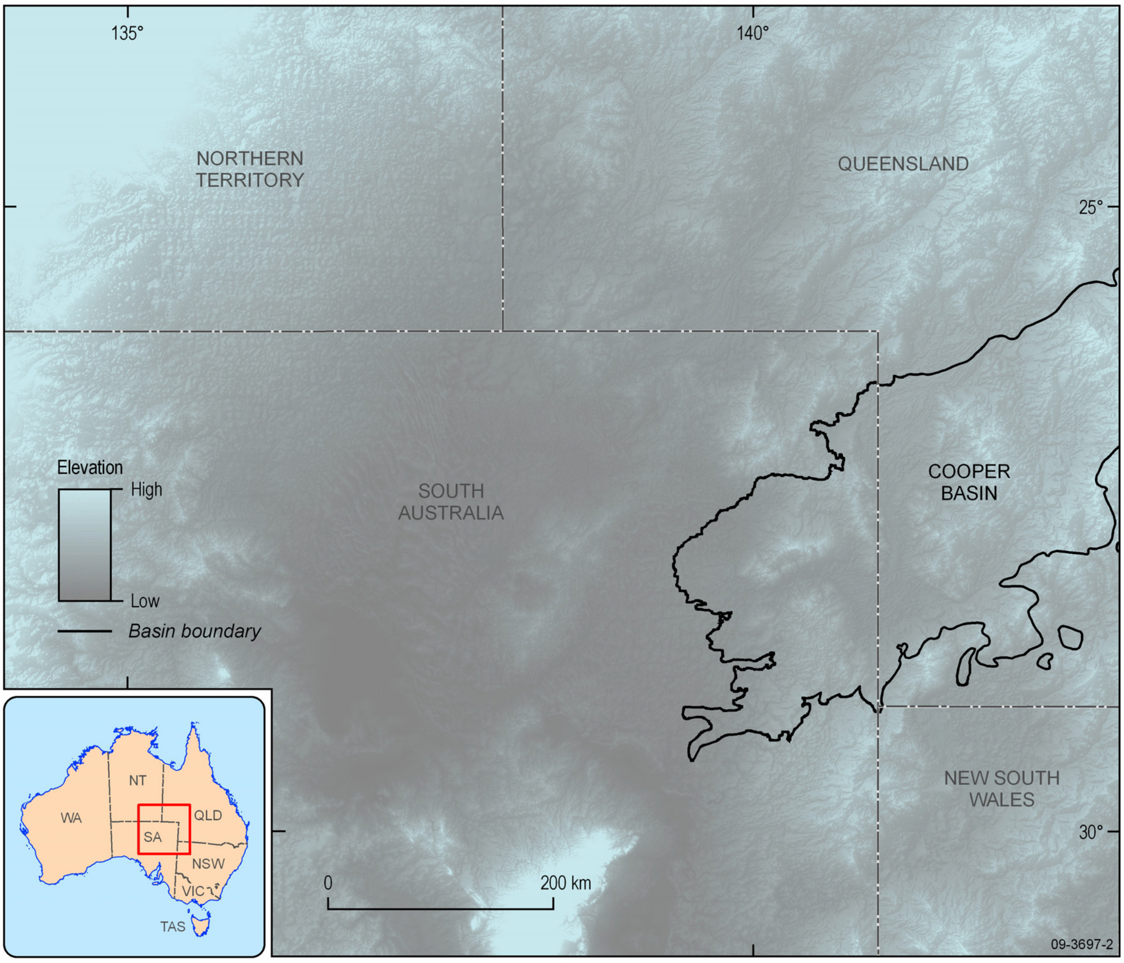


Figure 2*: Digital terrain model of the project area reveals the surface expression of the limited geology known at the outset of earliest petroleum exploration. The Lake Eyre Basin is surrounded by Precambrian terrain around the southwest, west and north. Seif dune terrain predominates in the lower western region of the basin while breached domes and folds of Eromanga Basin sequence dominate the terrain to the northeast and east.*

1.2 EXPLORATION HISTORY

In 1924, the Deputy State Government Geologist in South Australia, R.L. Jack conducted surface mapping while investigating groundwater supplies in the Great Artesian Basin (GAB). He mapped a fold structure and noted the presence of gentle folds in the Cordillo Downs area. His work on sedimentary basins in 1930 produced detailed cross sections of the GAB, based on this surface geology and water bore data. This provided the first reliable preview of Mesozoic-Paleogene geology across South Australia, later to be an invaluable foundation on which to base petroleum exploration.

The remoteness of the GAB had meant cost of exploration and development was prohibitive for such a distant and seemingly unpromising area. The lack of oil seeps and only some shows of gas in the artesian waters were taken to suggest that the area was unprospective.

The GAB attracted serious attention for petroleum during World War II with a search in the Frome Embayment. Zinc Corporation was hopeful, working in this area. Small quantities of natural gas had been reported from several widely separated artesian bores and in 1940, the company commissioned a report on the petroleum potential of the northeast and adjoining states. This assessment was pessimistic, but another report in 1944 drew attention to the reported gas in artesian bores within the Frome Embayment. The first OEL under the Petroleum Act in SA was for an area of 10,000 km^2 in the southern part of the GAB, east of Lake Frome. In 1947, the Australian Mining and Smelting Corporation (an associate of the Zinc Corporation) was granted an OEL of 127,000 km^2 including the area of the known Cooper and Eromanga Basin. From subsequent gravity and magnetic surveys, a gravity anomaly immediately south of Patchawarra Bore was considered unique in that it was not reflected as a magnetic minimum, and was considered worthy of further exploration. These exploration licences were then transferred to the Frome-Broken Hill Co. (formed from Zinc Corporation, Vacuum Oil Co., and D'Arcy Exploration Co.), thereby introducing international expertise and assistance into the endeavour. Six wells were drilled using an oil field rotary rig for the first time in Australia. The first well at Kopperamanna on the Birdsville Track ceased at 992 m with drilling difficulties. Some methane was detected in the subsequent wells, but was considered insubstantial, and the prospect of finding commercial oil was downgraded and the area relinquished.

The perceived importance of Australia having its own domestic supply of oil and gas grew to a more critical degree than it had been prior to World War II. The incentive offered by the Rough Range oil discovery in Western Australia in 1953 also provided a revised approach to exploration thinking, with the subsequent formation of Geosurveys of Australia and Santos in 1954. The Suez crisis, which climaxed in 1957, was a further stimulus for home exploration.

Santos – South Australian and Northern Territory Oil Search – took up the role of exploration in South Australia. This company grew out of an earlier association of J.L. Bonython and R.F Bristowe who both maintained an interest in the possibility of oil in South Australia. Bonython had not forgotten a view expressed by one grand-uncle that oil would be found in the GAB, if at all, in Australia. Bristowe had flown over this terrain on trips to and from Darwin, and found it interesting that the country from the top of Spencer Gulf to the Flinders Ranges was similar to the oil-bearing regions he had observed between Iran and Russia in his role as a King's Messenger. While these laymen's views may be seen as far too simplistic, their convictions had practical consequences. They pooled their ideas in 1954, studied relevant available literature, and were advised by M.F. Glaessner of Adelaide University to see R.C. Sprigg in the Mines Department.

Sprigg's open-mindedness about oil prospects in the state had led him to clash with the Director of Mines at that time. He had tried unsuccessfully in 1952 to persuade the Director for an assessment of petroleum possibilities in the GAB. His earlier interest in oil and the efforts of Frome-Broken Hill's investigations had been further stimulated by interactions with a Russian hydrogeologist, I. Chebotarev. Chebotarev had re-examined the geochemical records of old bores while pondering theories of oil migration, and had told Sprigg that from his experience in Russia, the northeast of South Australia was the place to look for oil (Sprigg, 1983a, O'Neil, 1995). The coincident requests for information from Bonython and Bristowe helped precipitate Sprigg's resignation from the department in 1954. Less than a week before Santos was incorporated, Sprigg registered his own exploration company, Geosurveys of Australia, which was founded as a consulting firm. Sprigg engaged R.O. Brunnschweiler as a senior petroleum consultant to manage the contract between Geosurveys and Santos. By this time, revitalized interest by industry saw a miniboom in exploration acreage being taken up. Geosurveys and Santos aspired to acquire all of the northeast of the state. However, after Santos floated on the stock exchange in 1955, this partnership started investigations north of Port Augusta at Wilkatana where traces of subsurface oil were reported two decades earlier. Sprigg, whose interests lay elsewhere, went along with Santos in the short-term as it intended to concentrate on that area. Drilling recovered traces of oil in dolomitised Early Cambrian limestones – but not in economic quantities.

In 1953, the SA Premier of that time - T. Playford, had witnessed seismic crews in operation in America, and given its proven success in exploration, he resolved that South Australia should run its own seismic surveys. He was to subsequently provide a forceful and persistent interest in seeing through his vision for State production of petroleum. There were no commercial seismic services available in Australia, only BMR had seismic capability. This stimulated Playford to approve acquisition of the equipment and capital funds for field activities. Seismic surveying began in 1955 at Wilkatana.

1.2.1 Cooper–Eromanga Basin system

In 1956, Geosurveys had undertaken gravity and magnetic surveys in the GAB between Birdsville and Maree. One of their geologists, H. Wopfner, mapped some large anticlinal structures near Oodnadatta and Jack's earlier observations were recalled. The Australian visit of the world-renowned geologist A.I. Levorsen in 1957 was instigated by a request by Bonython. In an overview of all State (Wilkatana and surrounds) and Territory prospects (Amadeus Basin to Melville Island), Levorsen was not overly impressed. He is said to have remarked that Santos would need the Bank of England to fund work at Wilkatana which had the potential for 'Fords and Chevvies', whereas with proven anticlines in the GAB, the 'Cadillacs and Champagne' lay further north of Wilkatana. He recommended Santos increase its holdings and focus attention in the northeast, even extending into southwest Queensland. His positive and public support for the prospect of oil in that huge region where Santos had been reluctant to venture provided a fresh impetus to exploration. Sprigg rushed Wopfner immediately to investigate the outcropping anticlines in the GAB. Wopfner and Brunnschweiler made a detailed air reconnaissance over the region, logging an incredible 136 hours of flight time over 11 days. From this they added several likely surface anticlinal structures and Wopfner mapped the fold deformations in the Cordillo Downs-Innamincka-Morney area. Within the first two weeks, he had identified and mapped major structures, and then produced the first structure map of this part of the basin. Sprigg then visited the area for the first time to reconfirm that the mapped structure was in Cretaceous and not in basement.

It was subsequently realized that earlier drilling for artesian water had targeted the water courses along synclines and thus anticlinal features such as Innamincka and Cordillo Domes had never been assessed. Late in 1957, after Santos had drilled Oodnadatta 1, a BMR seismic crew was moved from northwest Oodnadatta to Cordillo Downs. These were the first seismic surveys in the western and central GAB. Prior to this, only gravity and magnetics surveys existed. Geosurveys, on behalf of

Santos, drilled five shallow structural-stratigraphic holes (458 m max.) in the Haddon Downs area to traverse the Nappamilkie Anticline and Haddon Syncline.

The vast area and their limited petroleum-geological knowledge taxed Santos fully. Levorsen realized that Santos lacked the resources and finance to explore properly and his business acumen extended to introducing Santos to Delhi-Taylor Oil Corporation (later Delhi International Oil Corp.) of Dallas, Texas. Delhi had the reputation for excellent seismic exploration, unsurpassed well site technology, and a determination to break new ground. Consequently Delhi Australia Petroleum was incorporated, and its partnership with Santos became known as Delhi-Santos. Despite its earlier lack of success, Frome-Broken Hill soon joined as an equal partner in 1959.

Levorsen had additionally recommended that encouragement be offered to the petroleum industry through government subsidies for exploration (Gibbs, 1988, Passmore, 1994). While South Australia was proactive in oil search through its legislation, the Federal Government acted on his suggestion that stratigraphic drilling in approved Australian Basins be subsidized on a £ for £ basis. The Petroleum Search Subsidy Scheme under the Petroleum Search Subsidy Act 1957 subsidised stratigraphic drilling by private companies in some sedimentary basins to the tune of £500,000 initially, and then £1 million from 1959, when a second Act allowed for subsidies for geophysical work. Tax concessions were also provided to investors in oil exploration companies and for the companies themselves.

On the advice of Geosurveys, Delhi-Santos drilled Innamincka 1 to a depth of 3852m, the first well to penetrate the full Eromanga sequence into the Cooper Basin and to bottom in Ordovician beds which at that time were questionably assigned Devonian - an assignation that remained unchallenged for the next 30 years. Hydrocarbon prospectivity was suggested by minor shows within the Mesozoic succession. Cores and DSTs provided evidence of gas with water and oil-cut mud in both Permian and Mesozoic, and encouraged further exploration. Despite State jurisdictions, the South Australian Mines Department participated in the drilling of Betoota 1 in Queensland in 1960. That well penetrated the same sequence as Innamincka 1 but on the flank of a structure where it was terminated in conglomerate. Frome-Broken Hill then withdrew from its farmin agreement with Delhi-Santos. Surface structures at Innamincka and Betoota were bald-headed: the Permian sequence did not extend over the crest of the structures.

The general mineral boom of the 1960’s brought many large and small overseas and Australian companies onto the petroleum scene. Sprigg, with others, formed and promoted Beach Petroleum in 1960. In 1962, Total Exploration, a subsidiary of the French Petroleum Company, injected capital into Delhi-Santos. After a gas discovery in 1963, more international and interstate capital investment occurred, with Burmah Oil joining the search in 1965. From 1960, aeromagnetic and gravity became better coordinated and systematicised, along with new seismic techniques and exploration strategies. The SA Mines Department conducted seismic work for Delhi near Birdsville, Durham Downs and Innamincka Dome, as well as shooting from Birdsville to Maree. The discovery of the Moonie oil field in 1961 added further encouragement. Results of seismic work by the SA Mines Department between 1960 and 1964 helped to define the Gidgealpa- Merrimelia-Innamincka (GMI) Ridge, with the consequent discovery of natural gas. After 1964, as this State seismic work was scaled down, the effort was transferred to foreign seismic contractors such as Namco, United Geophysical and Geophysical Services International.

Following seismic in 1960-1961, a large subsurface structure without surface expression and located 65 km south of Innamincka was drilled in 1962. Dullingari 1 was the first well sited using seismic interpretation, and it penetrated thick Eromanga and Cooper Basin sequences, and showed unmetamorphosed sediments unconformably underlying the thick Permian strata. Gas shows were encountered in the Permian but equipment problems meant the reservoirs were not evaluated. Delhi-Santos wells in 1963, Pandieburra 1 and Putamurdie 1 (SA) and Orientos 1 and Naryilco 1 (Qld) revealed sediments with petroleum potential. All were on-structure where Permian was missing so it was decided to test off-structure.

The first off-structure well was drilled in 1963 on the eastern flank of the GMI Ridge. Gidgealpa 1 penetrated a thick Permian section with several sands with good reservoir properties. A fossiliferous Cambrian carbonate sequence with porous zones tested gas-cut salt water. Drilling had focused on the early Paleozoic and Permian section which contained gas shows. The well was so badly washed out and caved that it could not be tested and Santos was reluctant to proceed. On the advice of Wopfner, the State Government and Premier insisted that the Permian sands be tested at any cost – or another well be drilled on the same structure. Delhi's view to drill prevailed within the partnership, despite the financial constraints to do so. Gidgealpa 2 was drilled on-structure with drillstem tests in the Permian sands – resulting in a gas flow of 56,634 cumd (2 mmcfd). On completion, the well produced gas and condensate. Five subsequent wells established the Gidgealpa field to be 18 x 6.5 km in extent. Delhi-Santos primary objective had been oil – gas was a secondary consideration. The impact of the Gidgealpa discovery led to most of SA being under licence for petroleum exploration.

The Petroleum Search Subsidy Act was a major stimulus for exploration, but over time there were numerous revisions and refinements to the scheme. Some amendments in 1964 adversely affected exploration in the Cooper Basin. There was removal of subsidy for borehole surveys and detailed structure drilling, a reduction in subsidy for test drilling and stratigraphic drilling, and the introduction of an exclusion circle concept (Passmore, 1994). The latter circles were defined as areas around discovery wells and fields. The 64 km circle imposed around Gidgealpa and Moomba entrained the most significant discoveries in the basin to that stage. Additionally, by this stage of exploration in the region, the Mesozoic sequence was apparently no longer considered prospective by Government assessors so there was no subsidy incentive for investigating this part of the sequence, and Santos chose to not fully log wells until into the Paleozoic section (R. Temple, pers.comm, 2007).

Assessment of the Gidgealpa Field and further exploration in the region occupied much of 1964. Four wells were drilled on the Merrimelia structure in 1964 and 1965 and the first recorded sign of oil in Triassic sediments, apart from dull yellow fluorescence, was made in Merrimelia 2. A non-commercial gas flow was discovered in Merrimelia 4, but perceived lack of porosity and effective permeability strengthened an argument against this area containing commercial hydrocarbons. More significantly, the Delhi-Santos discovery of natural gas at Moomba 1 in 1966 vindicated the optimists including those in the State Department. Several exploration wells at Moomba, 30 km south of Gidgealpa, proved the existence of large widespread gas reserves, hence establishing a base for the viable development of the Cooper Basin.

In 1969, Owen Nugent, a senior geologist with Delhi, alluded to the possibility that stratigraphic traps in the Jurassic Hutton Sandstone might host oil because of it overlying the prospective Triassic and Permian sediments. This perception in its time seemed radical, and was only seriously returned to 20 years later. Now it is the prevailing (and perhaps limiting) paradigm for oil exploration in the Eromanga Basin sequence.

In 1970, more than 5000 km of seismic data were recorded and 20 exploration wells drilled in the Cooper Basin region. The Della gas field was discovered that year by Pursuit-Delhi-Santos-Vamgas with their first well on the Nappacoongee-Murteree Ridge. In 1969, Alliance had earnt a 50% interest in the Merrimelia-Innamincka Block through an agreement with Delhi-Santos-Vamgas. Alliance drilled Merrimelia 5 which was completed as a gas producer in 1970. Other discoveries in 1970 were Packsaddle, Tirrawarra, Mudrangie and Strzelecki. Also in that year, Bridge Oil announced a gas flow from the Patchawarra Formation and light crude oil in the Tirrawarra Sandstone (Tirrawarra 1). This discovery indicated that the long search for oil might at last pay dividends. However, the extent of the reservoir, and how it might best be brought to market remained to be established.

The Tirrawarra discovery further stimulated exploration fervour, with gas being found at Big Lake, Coonatie, Dullingari, Burke, Brumby and Kanowana in 1971 and 1972, as well as oil and gas at Fly Lake and Moorari. Additionally, the gas reserves were revised and upgraded in several instances, as at Toolachee, Della and Tirrawarra. Between 1970 and 1972, a further six wells were drilled on structure at Della where five of the seven wells produced gas.

In late 1972, R.F.X. Connor became the Federal Minister for Minerals and Energy. His resolute pursuit of his own and ALP policies wrought havoc with the resources sector. Included in these policies, he advocated a national natural gas pipeline grid across the continent, a government Petroleum and Minerals Authority (PMA) to undertake mineral, oil, and gas searches. To fund the PMA, he advocated abolishment of both the Petroleum Search and Subsidy Scheme and tax concessions to mining companies controlled by overseas interests. He placed export controls on mineral and energy resources, and banned the export of LPG in 1974 because he wanted it marketed locally. Additionally he insisted on 50% Australian equity in uranium, natural gas and coal projects. The net outcome of these new policies was the decline in exploration and development. In SA in 1973, one well was drilled, and none in 1974, 1975, with few seismic surveys. The PSSS was closed in 1974, but with any proposed work approved before then, this continued through to 1976. In 1975, an additional levy was introduced on all old oil production once more than 318,000 kl/year (2MMbbl/year) were produced. These political Federal directives collectively slowed exploration. In 1975, the High Court of Australia adjudged the formation of the PMA to be illegal and the new coalition Fraser Government sought a buyer for the interest.

Drilling activity recommenced in 1976 and Namur 1, which discovered gas in the Jurassic Namur Sandstone, focused attention to the Eromanga sequence and a change of thinking about its prospectivity. In 1978, the first commercial oil was discovered in the Hutton Sandstone at Strzelecki 3 – the field came on stream in 1983. The well was intended to test the Permian, following up gas shows which had been detected in Strzelecki 1 in 1970, with a secondary Jurassic target - the Cooper Basin was still considered the prime target. This well established the potential of the Eromanga sequence and encouraged similar targets to be drilled. Dullingari North 1 was spudded in 1979 to test the gas potential to the north of the Dullingari field. Dullingari 1 had penetrated shallow Eromanga oil and Permian gas but neither was recognized and it was completed as a water bore. The gas discovery well, Dullingari 2, was not drilled until 1972 and was followed by gas appraisal wells Dullingari 3, 4, the latter revealing some oil.

These discoveries led to both an upgrading of the oil prospectivity of the region, and a reappraisal of known structures. Changes in exploration paradigms and drilling practices were pivotal to new finds. Initial search in the region was stimulated by mapped structure in Mesozoic rocks, but the subsequent drilling had been on structures where the Permian was thin and thus targeted the early Paleozoic sequence. In 1963, the search shifted to the Permian following the Gidgealpa 2 gas discovery. The overlying Mesozoic sequence was penetrated with little regard before testing would commence in the Gidgealpa Group.

The PSSA subsidy was apparently inadequate for funding any additional Mesozoic investigation, and as a result, the explorers rarely electric logged this upper sequence. This collectively contributed to the overlooking of the main oil resources in the region for almost 20 years.

From the earliest time of Santos exploration, the Cambrian was always a target, and eventually oil turned up with gas in the Permian. The Mesozoic through all this time had been disregarded and it was only because of oil escaping from some of the existing holes – a phenomenon at the time that mystified people as to where it was coming from – that the potential of oil in the Mesozoic was finally realised and a whole new era of exploration emerged. The irony is that the whole impetus for exploration in the Cooper region came from the convictions of the early prospector Bonython, who helped precipitate State oil search through the formation of Santos, and Sprigg, who had always favoured the Great Artesian Basin sequence.

Systematic sampling and description of cuttings, and the use of full electric log suites over the Mesozoic sequence were finally commenced in the Moomba area with the drilling of Moomba 42 in 1978. However, even in 1987, a proposal was put forward by Delhi Petroleum for an oil exploration well to test log anomalies that indicated a 7 m oil column. This was rejected as the evidence for presence of oil was considered insufficient. Additionally, during a proposed work over of Moomba 2 in 1989, a cased hole test of the Hutton Sandstone was proposed but rejected on safety/engineering grounds, and this log anomaly remained untested for a further 11 years. Exploration in the SA sector of the Cooper/Eromanga Basin since 1960 has resulted in the discovery of 70 oil fields (the majority in Eromanga reservoirs) and 124 gas fields (Morton, 1996).

In 1997, after 31 years of gas production and 89 wells, oil was finally confirmed in the Jurassic-Cretaceous Eromanga sequence overlying the Moomba gas field. The decision to finally assess the Eromanga potential was mainly prompted by the prolific number of residual oil shows encountered throughout Moomba in the previous 19 years. By this time, the 2D seismic grid over much of Moomba was down to 500 m spacing. By 2001, 22 wells had targeted oil accumulations in the Mesozoic sequence (Menpes, 2001). By 2007, the oil drilling program had accelerated with a target of some 1000 wells by 2010. The extent of seismic coverage, exploration and production wells in the region is shown in Figure 3.

1.2.2 Pedirka-Simpson-Eromanga Basin system

Initially this region was perceived as having similar potential to the Cooper–Eromanga Basin system, but after a series of eight dry holes up to the drilling of Poolowanna 1 with the first good indications of oil in the Eromanga sequence, more attractive successes back in the Cooper–Eromanga Basin system drew exploration attention away from this region.

This Pedirka-Simpson-Eromanga Basin system has been largely underestimated for the last 20 years and during the 1990s it suffered from a complete absence of exploration activity- a period when new exploration axioms were evolving in the analogous Cooper–Eromanga Basin system. Recent exploration in this latter region has largely succeeded because of the application of new technology, including 3D seismic, and the fine-tuning of models on petroleum expulsion and migration pathways. It is the opinion of Ambrose (2006) and P. Boult and E. Alexander (pers. comm., 2007) that a similar approach and effort in the Pedirka Basin could yield similar successes.

Exploration licences first covered the Pedirka Basin in South Australia in 1959, when Delhi-Santos targeted Cambro-Ordovician sediments of the Warburton Basin in the Innamincka area. In the

Cooper Basin, the first petroleum well was drilled in 1959 and then gas discovered in 1963. This changed the focus regionally from Early Paleozoic to the Carboniferous-Permian basins.

Exploration in the Pedirka-Simpson-Eromanga Basin system commenced after Delhi-Santos farmed out part of its licence to French Petroleum Company (FPC, now Total) in 1963. Acquisition of gravity and seismic data was followed by the drilling of four wells in SA to test Permian targets. Over the next five years, other companies farmed into this acreage - such as Vamgas and Western Mining Corporation. During this same period, Beach Petroleum drilled two exploration wells in the Northern Territory part of the Basin but by late 1966, without any encouragement from drilling results, interest in the area waned.

1976 in the Cooper Basin area saw the first significant flow of gas from a Mesozoic reservoir in Namur 1 (later to be shown to be of Permian source). In 1977, oil was discovered in Poolowanna 1, in basal Jurassic and Triassic, with an initial flow to surface of 15 kL/day (96 bbl/day) – the first flow of oil from the Eromanga Basin. The well also confirmed a thick Triassic sequence in the Poolowanna Trough. This discovery later proved to be uneconomic, but in the same year, commercial oil was discovered in Strzelecki 3 back in the Cooper–Eromanga Basin system, with a flow of 382 kl/day (2400 bbl/day) from the Jurassic Hutton Sandstone (Alexander & Jensen-Schmidt, 1995). The discovery of the large Jackson Field in the Eromanga Basin sequence also confirmed that Middle and Late Jurassic objectives were also valid and important. Prior to these discoveries, it was widely believed that any trapped oil and gas had been flushed out by the flow of artesian water. A pivotal change in this conceptual thinking was challenged at this time by several explorers, and Senior and Habermehl (1980) advocated petroleum accumulations behind structural disruptions and impediments to flow in the main artesian aquifers in Queensland.

Following these discoveries, exploration effort focused on Eromanga Basin oil in the Cooper, Simpson and Pedirka Basin (Poolowanna Trough) areas. Delhi-Santos had seismic and drilling programs in the Poolowanna Trough 3 wells in 1981, 4 wells in 1985 and 3 wells in 1987-89, but no further discoveries were made. In 1989, Santos relinquished part of its acreage over the Pedirka Basin region, and then fully withdrew in 1994. In an attempt to maintain interest in the area, MESA extended the regional seismic grid across the Eringa Trough to investigate Early Paleozoic and Permian sediments and structure in 1994-95. In 1997, MESA promoted and offered three blocks for release between the Eringa Trough and depocentre/eastern flank of the Poolowanna Trough to encourage continued exploration of the whole Pedirka-Simpson-Eromanga region. Dry hole analysis of the earlier seven unsuccessful wells in this release area in South Australia indicated that only two wells were drilled within closure or to have tested closure in optimum conditions (Carne & Alexander, 1997). Recent exploration by Central petroleum culminated in the drilling of 2 wildcat wells in 2008. It remains uncertain if Blamore 1 tested closure as prognosed depths were at odds with drill intersections. Discovery of very thick coal sequences in the Purni Formation led to a following and successful well for coal bed methane.

Hammersley 1 in 1988 demonstrated that the Permian sequence thickened rapidly into the Eringa Trough. Several earlier wells, including McDills 1 (1966) that was drilled along the Dalhousie-McDills-Mayhew Trend on the eastern edge of the trough, demonstrated that a thick Early Paleozoic sequence correlated with the Amadeus sequence, and should also be present in the Eringa Trough (Questa, 1990).

Geochemical and reflectance information has shown that apparent lack of organic maturity may also have been a major reason for lack of exploration success in the Pedirka Basin region, as many of the wells drilled to date have evaluated structurally shallow parts of the basin. The need for testing deeper-buried reservoir/source rock couplets is obvious, but efforts in the Poolowanna Trough had given no encouragement since oil was discovered at Poolowanna 1 (Questa, 1990). Ambrose *et al.* .(2002, 2007) identified post-Miocene reactivation of some structures and proposed that this may have breached many formerly-charged reservoirs. However maturation analysis (Questa, 1990; Carne and Alexander, 1997) suggests petroleum generation and migration was in at least two pulses, the second at about this mid Paleogene period.

1.2.3 Galilee-Eromanga Basin system

Exploration in the northern Galilee Basin was in two phases, 1959-74 and 1980-88, with drilling peaking in 1964 (6 wells) and 1988 (6 wells). The termination of the first phase of exploration was largely due to the withdrawal of income tax concessions for explorers, and the termination of the Federal petroleum search subsidy scheme in 1974. The second phase of activity was dominated by the regional exploration program of Esso Australia Ltd in the northern Galilee Basin with a philosophy to understanding the regional tectonic and structural framework. In addition to Esso, Crusader Ltd and Minora Resources NL were also active in the Lovelle Depression. Despite this renewed exploration activity, no economic hydrocarbons were discovered. Towards the end of this phase of exploration, the Queensland Geological Survey maintained deep stratigraphic drilling to resolve stratigraphic relationships within the basin sequence (Hawkins and Green, 1993).

1.2.4 Warburton Basin

Seismic surveys led to the drilling of Innamincka 1 in 1959, the discovery of Permian non-marine sediments, as well as a thick succession of redbeds (Innamincka Formation) now known to be Early Ordovician. Seven dry holes were drilled, including Gidgealpa 1 which tested gas-cut salt water from Cambrian dolostone and recorded fluorescence at several levels. An updip test of the dolostone led to the discovery in 1963 of commercial Permian gas in Gidgealpa 2 (the dolostone was faulted out). Consequently, subsequent exploration focused on the Permian Cooper Basin in preference to the deeper structurally complex early Paleozoic sequence.

Despite extensive seismic surveys, the structural definition of the Warburton Basin in key regions is hampered by high structural dip, the masking effects of Permian coals, and a thick alteration zone at the top of the Warburton sequence. Exploration drilling through the 1970's and 1980's was met with no commercial success. However, the discovery of commercial gas in Moolalla 1 and Lycosa 1, and oil in Sturt 6, all drilled in 1990, led to renewed interest in the early Paleozoic 'economic basement' – not for indigenous petroleum but for oil and gas trapped up dip from Permian source rocks. Early in 2001, Challum 19 in southwest Queensland flowed gas at 211,000 m^3/d (7.5 MMcfd) from the carbonate Kalladeina Formation.

1.2.5 Summary

The lessons from this history of exploration are not unique. If data are not acquired, or are misinterpreted due to the tenets of the day, significant petroleum accumulations may be completely overlooked or not recognized for what they are (Menpes *op cit.*). Whatever the exploration paradigm of the day, one must always be prepared to expect the unexpected, and to re-evaluate acquired information periodically with 'fresh eyes'.

Good exploration management should creatively and effectively optimize the dynamic of communication between all facets of its divisions towards effectively addressing its mission statement.

1.3 PRODUCTION AND KNOWN EXTRACTABLE RESERVES

The Cooper–Eromanga Basin system is the principal onshore hydrocarbon province in Australia at present. Gas is the main resource, with a cumulative production as at 2005 totalling 155.8 Bcm (approx. 917 MMbbl oe), and with proven reserves 195.3 Bcm (approx.1150 MMbbl oe). However, oil production is not insignificant - cumulative production to 2005 was at 40.64 Gl (255.6 MMbbl) with known recoverable reserves at 51 Gl (320.6 MMbbl) (S. Le Poidevin, Pers Comm, 2007).

1.3.1 Gas

Gas is derived predominantly from reservoirs within the Cooper Basin sequence which account for 96.7% production to date, and 98.6% of known recoverable reserves. The basin contains 28 times more gas (as oil equivalents) than oil.

Producing reservoirs in the Cooper Basin are:

	Production	Reserves
Early Triassic Arrabury Formation	1%	1%
Late Permian Toolachee Formation	56%	55%
Early Permian Daralingie Formation	1%	1%
Early Permian Epsilon Formation	4%	4%
Early Permian Patchawarra Formation	32%	31%
Early Permian Tirrawarra Sandstone	6%	7%

Current gas production from reservoirs in the Eromanga Sequence accounts for less than 1.4% total production from the Cooper–Eromanga Basins, and is derived principally from the Hutton Sandstone (61%) and Namur Sandstone (30%), and the balance mostly from the Poolowanna Formation (6.3%). Gas is also produced from the Cambro-Ordovician Pando Formation in the Warburton Basin but where recognized as a separate reservoir component, this accounts for only 0.3% of total gas production from the Cooper–Eromanga sequence.

1.3.2 Oil

In contrast, the Eromanga Basin sequence is host to most of the oilfields, containing 107 times more oil than gas (as oil equivalents). Oil from this basin accounts for 86.5% of total production and 85% of proven oil reserves in the basin couplet. Approximately 40% of production comes solely from the Hutton Sandstone in the Jackson field which covers 21 km^2. The next largest producing field is Kenmore at 25% of Jackson production, followed by Naccowlah West and Bodalla South, all on or away from the southeastern margin of the Cooper Basin in Queensland.

Producing reservoirs within the Eromanga sequence are:

	Production	Reserves
Early Cretaceous Wyandra Sandstone	2%	3%
Early Cretaceous Murta Formation	10%	15%
Early Cretaceous McKinlay Member	1%	2%
Jurassic-Cretaceous Namur Sandstone	15%	14%
Jurassic Westbourne Formation	4%	4%
Jurassic Adori Sandstone	0.2%	0.2%
Jurassic Birkhead Formation	6%	8%
Jurassic Hutton Sandstone	57%	51%
Jurassic Poolowanna Formation	5%	4%

Oil in the Cooper Basin sequence, provides the balance of 14% of total production and 15% of total reserves, and is reservoired in:

	Production	Reserves
Middle Triassic Tinchoo Formation	3%	6%
Early Triassic Arrabury Formation	1%	1%
Late Permian Toolachee Formation	0.6%	0.6%

Early Permian Patchawarra Formation	5%	12%
Carboniferous-Permian Tirrawarra Sandstone	90%	77%
Late Carboniferous Merrimelia Formation	1%	1%

With late gas generation in the Patchawarra Formation, oil has been displaced from intraformational reservoirs within the Cooper Basin sequence and migrated predominantly up dip out of basin margins, as well as upward into overlying stacked traps in Eromanga reservoirs. This displacement has included some downward migration into the Tirrawarra Sandstone and the now oil-saturated Merrimelia Formation. Because of poor porosity/permeability characteristics of these glacigene sediments, recovery is difficult and ethane injection has been used with some success in the Tirrawarra Sandstone pools.

1.4 EXPLORATION TODAY

Exploration activity in the region remains predominantly within the Cooper–Eromanga Basin system (**Figure 3**). A revival of drilling in the Pedirka– Simpson- Eromanga (Poolowanna) Basins has outlined a coal seam gas resource with significant potential but hydrocarbon pools remain elusive. There is no other significant activity in adjoining basins.

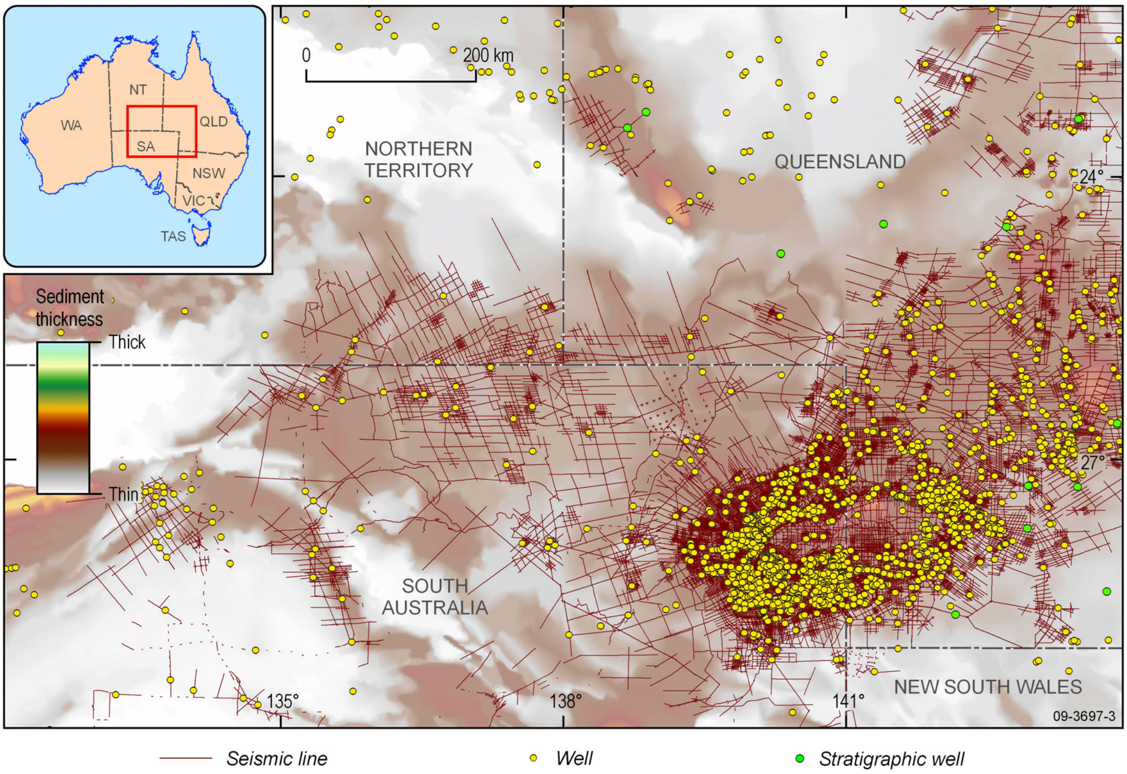


Figure 3*: Seismic coverage with stratigraphic, exploration and production wells within the Central Basins region.*

1.4.1 Cooper – Eromanga Basin system

Since late 2006, Beach Petroleum has apparently maintained an overall success rate of 76% with 38 wells. Similarly, Santos had drilled 108 wells in 2006 with a 79% success rate (using truck-mounted rigs to target relatively small and shallow pools of oil in infill drilling and near-field exploration). In this program, Santos is planning on up to 250-280 wells per year for a target of 100 wells to be drilled by 2010. Although targets are generally low yield, this project is low-cost and low-risk, and has a high success rate. It is predicted that the current rate of production at 30,000 barrels per day will treble by 2010 (John Young in PNN News 12 July, 2007).

An earlier perception was that migration pathways was the main risk. Today the identified main risk is locating wells on structure. The more obvious and larger structures have already been drilled so now the targets are more subtle structural closures where relief on some of these closures is the same as the mis-ties between 2D seismic lines (E. Alexander and P. Boult, pers comm., 2007). 3D seismic is being increasingly used to minimise this risk.

Traditionally the Cooper region has been typified by simple anticlinal features, but in close analysis, the structural geology is very complex. The region has been subject to significant stresses over time, and this dynamic structural history has affected thermal maturation, migration and trapping mechanisms. Understanding the structural geology and structural history is critical to this objective. Advanced seismic processing has greatly assisted in increasing success rates in drilling.

Seismic can be used to identify the direction of stresses, to help in drilling wells so that stresses are uniform. It can also help to plan optimum directions for exploration and production wells, predict which sets of natural fractures will be open, and assist in planning frac programs. It has been used to identify lobes and pockets in oil fields to deliver success in near-field development programs and to drive an increase in the reserves base of existing fields (T. Guglielmo, in PNN News, 12 July 2007). 1-3 MMbbl targets are not huge, but with Cooper oil light and sweet, the rewards are material to efficient operators.

Recent exploration around and beyond the western periphery of the Cooper Basin has led to the repeated discovery of oil pools hosted in the stacked Jurassic-Cretaceous Sandstone reservoirs. The uppermost Namur Sandstone has the best reservoir characteristics and the main Jurassic contribution is from Birkhead sources. Two areas of exploration success are to the west-southwest (Parsons, Carrawonga, Christies, Silver Sands and Perlubie fields) and northwest (Charo, Growler, Wirraway, Warhawk and Tigercat) are up to several tens of kilometres beyond the northwestern erosional limit of the Cooper Basin. This recent string of discoveries indicates the attractiveness of a region now coined the 'Jurassic Oil Fairway'. This adjoins but lies outside of the Cooper Basin limits. The western extent of this fairway has yet to be defined but approaches a region where the shales seals/aquicludes that separate these sandstone reservoirs, thin and pinch out onto the Birdsville Track Ridge, a region covered by the thicker Algebuckina Sandstone. This reservoir is a higher permeability conduit with increased groundwater flow from northeast to southwest (Radke *et al.,* 2000). Current exploration models for these discoveries are based on the understanding that the trapped petroleum has migrated predominantly from a Patchawarra source in the Cooper Basin (Altmann and Gordon, 2004) with an additional component from lateral updip migration from Birkhead sources within the Eromanga sequence (Errock, 2005). Oil characteristics become increasingly water-washed and gas-poor with the distance of the fields away from the known source kitchens, indicating the increased interaction with artesian groundwater.

1.4.2 Pedirka-Simpson-Eromanga (Poolowanna) Basin system

Although much of the region is covered by exploration licences, exploration has been minimal compared to the Cooper Basin region, with only one company drilling in 2008, the first activity for decades. In Blamore 1, disparities between prognosed and drilling intercepts imply poor seismic definition of structure. With technical drilling problems in subsequent wells, it has left the potential of the deeper sequence unresolved. However, cumulative coal bed thickness in the Permian Purni Formation is much greater than previously known and the coal seam gas potential of shallower regions has been demonstrated with a potential producer in CBM93001.

1.5 CRUSTAL FEATURES

The Central Basins region covers the South Australia (Proterozoic) mega-element and Tasman (Paleozoic) mega-element of Shaw *et al*. (1995) and Shaw & Palfreyman (1995). It is probable that the South Australia and Central Australia (Proterozoic) mega-elements underlie the younger Tasman mega-element beneath the Cooper Basin (Draper, 2002) **(Figure 4).**

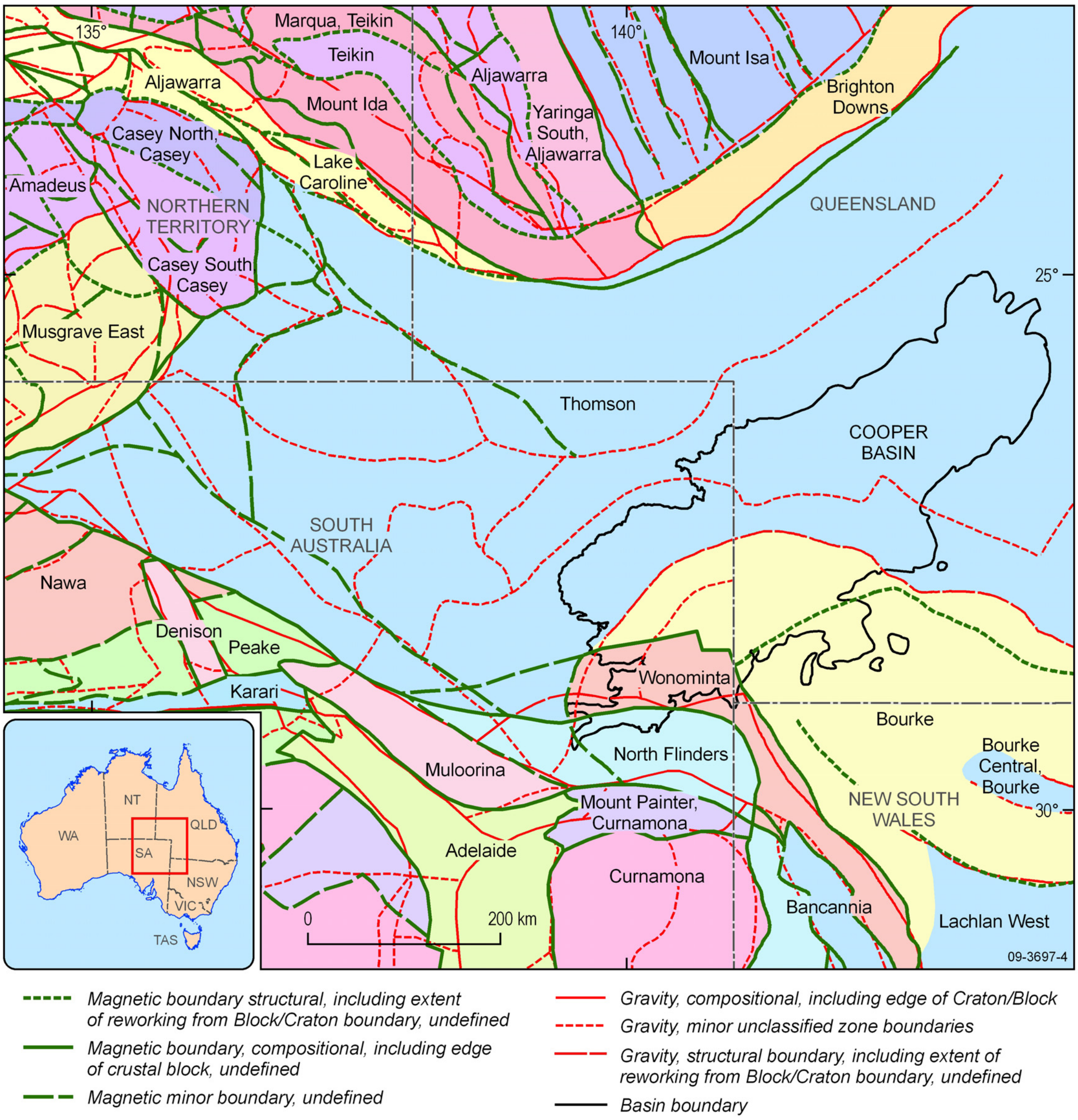


Figure 4*: Crustal mega-elements comprising groups of crustal elements, as delineated by gravity (red) and magnetics (green) (from Shaw & Palfreyman, 1995).*

Several stacked Phanerozoic basins, including the prolific oil and gas-producing Cooper Basin, cover the region that straddles the South Australian – Northern Territory and Queensland borders. These basins are underlain by different provinces of Proterozoic basement, including the Willyama Supergroup, Curnamona Craton and Arunta Block, and other unknowns.

A predominant underlying element to the east is the Thomson Fold Belt, and a distinctive Bourke province lies to the south. This has a younger overprint than the Thomson Fold Belt, and separates it from the Lachlan Fold Belt to the east. The Worominta Province underlies the Cooper Basin in South Australia. The gravity trend that demarcates the Thomson-Bourke contact coincides with the Gidgealpa-Merrimelia-Innamincka (GMI) trend and the Jackson-Naccowlah-Pepita (JNP) trend. On the basis of borehole, magnetic and gravity data, Meixner *et al*. (1999, 2000) identified differences in the basement type over the GMI trend that formed by a 3.5km throw by steep thrusting from the southeast.

1.5.1 Basement to the Cooper Basin

The oldest rocks beneath the Cooper Basin are those of the Arunta Complex within the Central Australia mega-element (Parker, 1993). The GMI thrust (Meixner *et al.,* 1999, 2000) may be the contact between the Arunta Complex and the Curnamona Craton. Little is known about pre-Paleozoic rocks under the Thomson Fold Belt in Queensland.

The Worominta Province extends northwards to near the southern preserved margin of the Cooper Basin. This province is part of the Kanmantoo Fold Belt (Scheibner, 1974) of the Tasman Fold Belt System. The Kanmantoo Fold Belt contains Neoproterozoic to Ordovician sedimentary and volcanic rocks deformed by the Delamerian Orogeny and modified by subsequent orogenies.

Immediately underlying is the Warburton Basin which contains a sequence of similar age to the younger rocks of the Kanmantoo Fold Belt, but is less deformed. The Warburton Basin is seen by Parker (1993) as the transition from deeper marine sediments of the Kanmantoo Fold Belt and the intra-continental basins to the west, such as the Amadeus Basin.

In Queensland, most of the Cooper Basin is underlain by the Thomson Fold Belt which comprises two sequences, Neoproterozoic to Middle Cambrian, and the Early Cambrian- Late Ordovician Warburton Basin. An upper age limit for the Thomson Fold Belt east of the Warburton Basin is Late Cambrian, constrained by Late-Ordovician post-orogenic granites, and folding and metamorphism preceded emplacement of these granites (Draper, 2005). Two phases of deformation are evident in the fold belt- Middle to Late Cambrian, and Silurian. If the deformation was late Middle to Late Ordovician, it is probable that at least part of the Warburton Basin was affected by this deformation.

The dating of granites below the Cooper Basin has increased differentiation of igneous suites on either side of the state border. Dates of the Big Lake Suite in South Australia are 323±5 Ma from Moomba 1 and 298±4 Ma from MacLeod 1, both SHRIMP determinations (Gatehouse *et al.,* 1995). Dates of Queensland granites are K-Ar dates on muscovite. The age in Ella 1 is 408±2 Ma and in Roseneath 1 is 405±2 Ma (Murray, 1994). Subsequent Shrimp U-Pb dates of granites now indicate ages from as old as Early Ordovician (Carlow 1, Adavale Basin) through Middle Ordovician (Toobrac 1), Middle Silurian (Ella 1), and Middle to Late Devonian (Towerhill 1) (Draper, 2005). All dated granites beneath the Cooper Basin are S-type granites. An I-type granite at Tibooburra, New South Wales, has an age of 410 Ma (Scheibner, 1996). The Queensland granites are Early Devonian while the granites in South Australia are mid- to latest Carboniferous. The regional gravity data indicate that these different-aged granites lie in discrete but separate arcuate belts (Meixner *et al.,* 2000).

The Early Devonian granites coincide with widespread extension in the Thomson Fold Belt (Evans *et al*., 1990) with the formation of the Adavale Basin and the Warrabin and Barolka Troughs. The earliest sequences in the Adavale Basin are intermediate continental volcanics and red beds. Finlayson *et al.* (1990) suggest the possibility of mafic underplating of the crust during this extensional phase. The basin was subsequently deformed in the Middle Carboniferous (J. Draper, pers. comm., 2007) although Finlayson *et al.* (1990) have described the Quilpie Orogeny as occurring during the Early to Middle Carboniferous when movements of tens of kilometres occurred along westward dipping mid-crustal ramps.

Despite the rudimentary knowledge of basement events beneath and adjacent to the Cooper Basin, the area has had a complex history. The structural grain that developed during this earlier time has imposed an influence on the formation of, and subsequent tectonism in the Cooper Basin.

1.5.2 Geophysical interpretation of basement

The best-studied part of the region is over the Cooper Basin, where the sources of all magnetic anomalies occur at or below base of the Cooper sequence (Meixner *et al*., 1999). The Patchawarra Trough has a large magnetic anomaly but no distinct gravity low, and this implies the presence of a deep homogenous dense body, consistent with mafic/ultramafic intrusives. In the Tirrawarra Field area, the causative body has a circular intrusive character, modeled at 15 km depth and probably extends much deeper but in the anomalously high geothermal gradient of ~38^{o}C/km, such deep extent would exceed the Curie Point and erase magnetic signatures. This body may have resulted from magma formed by decompression processes associated with crustal extension related to basin formation. Another possibility is that the magma originated from hot spot activity and there has been subsequent thermal subsidence. This sub-Patchawarra trough magnetic body is below seismic basement and probably deeper than the base of the eastern Warburton Basin. The southeastern edge of this anomaly appears fault-bounded with 3.5km uplift on a reverse fault – the GMI Ridge. The broad gravity low in the Nappamerri Trough corresponds to the Big Lake Suite Granodiorite, and intense gravity lows are coincident with subcrops interpreted to be cupolas emanating upwards from the deeper batholithic mass.

1.6 STRUCTURAL SETTING

The Cambro-Ordovician Warburton Basin overlies Proterozoic basement. The entirely non-marine Late Carboniferous-Triassic Cooper Basin is an intracratonic depocentre overlying the eastern Warburton Basin in the southwest which is transitional with the Thompson Fold Belt towards the northeast into Queensland **(Figure 1)**.

Prominent northwest- southeast and northeast-southwest trending lineaments have been documented by Campbell & O'Driscoll (1989), Gravestock (1995), Apak *et al.* (1997), Boucher (1998). Major magnetic trends support the presence of northeast trending lineaments. However, regional gravity trends suggest arcuate zones as well as lineaments. The former may reflect previous thrusting as well as a pre-existing basement fabric.

The Warburton Basin is the oldest Paleozoic basin of the central region and shows direct morphological responses to the structural influences of the fundamental NNE (GD and G8) and WNW (T-C and NB-CR) continental lineaments. The structural foundations of the basin become clearer when the WNW lineaments, including RD5 and RD6 can be seen to coincide with a predominance of Cooper–Eromanga petroleum occurrences (Campbell and O'Driscoll, 1989).

Both the Cooper and Eromanga Basins are intracratonic features. The Cooper Basin comprises a Middle Triassic to Permian non-marine sequence, and immediately overlies the Cambrian-Ordovician Warburton Basin as well as Cambrian-Ordovician meta-sedimentary rocks of the Thomson Fold Belt.

The Cooper Basin is approximately rectangular with its long axis trending northeast-southwest. A prominent east-southeast striking series of faults and fault-bounded anticlines separates the basin into northern and southern parts. Various names have been applied to this feature which lies on the continental-scale G3 structural corridor (Campbell and O'Driscoll, 1989); these include the Arrabury-Naccowlah Trend (Kantsler *et al.,* 1983); Pepita-Wackett-Nockatunga Trend (Kuang, 1985) and Jackson-Naccowlah-Pepita Trend (Heath, 1989).

A G3 corridor separates the arcuate northeast-trending structures in the southern Cooper Basin from approximate meridional trends in the northern sector and corresponds to changes in pattern and trend of geothermal gradients (Pitt, 1986). The Southern Cooper Basin contains the thickest (1600 m) and most complete Permian succession, whereas the Permian is thin (300m), and the Triassic sediments considerably thicker in the northern Cooper Basin. Most hydrocarbon discoveries lie within the G8 corridor (Campbell and O'Driscoll, 1989).

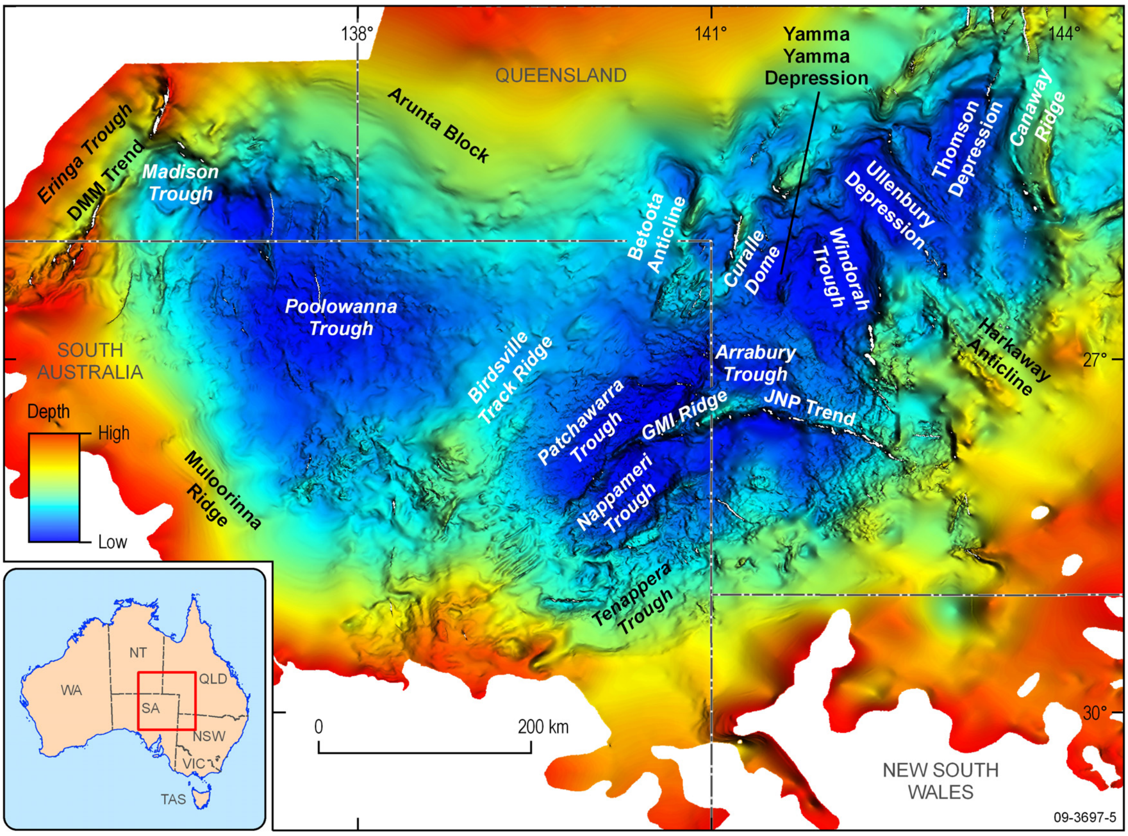


Figure 5:*Regional structural features expressed in the structural depth of the Cretaceous 'C' seismic horizon (Cadna-owie Formation) (after NGMA)*

The southern Cooper Basin is divided into the Patchawarra, Nappamerri and Tenappera Troughs separated by the structurally elevated Gidgealpa-Merrimelia- Innamincka (GMI) and Murteree Ridges **(Figure 5).** In cross-section these ridges of faulted anticlines are markedly asymmetrical, with thick Permian sediments faulted against their northwestern margins, and thinner sediments onlapping their southeastern flanks (Heath *et al*., 1989; Apak *et al.,* 1993). Anticlinal crests are frequently devoid of Early Permian sediments, although Late Permian strata are locally continuous.

In contrast, the Eromanga Basin is more extensive, fully overlying the Cooper Basin, Thomson Fold Belt, Adavale Basin, Warrabin and Barolka Troughs, Simpson Basin, and covers the Pedirka and Warburton Basins. The Eromanga sequence comprises Jurassic non-marine and Cretaceous non-marine to marine sediments.

1.7 TECTONIC HISTORY AND DEPOSITION

In this region, the structural grain has developed from a series of deformations and epeirogenic movements since the Cambrian. The Central-Northern Arunta Province underwent high grade metamorphism in an extensional setting during the Ordovician (480-460 Ma).

The Warburton Basin was not severely deformed everywhere by the Late Cambrian Delamerian Orogeny. The eastern region of this basin that adjoins and underlies the Cooper Basin in South Australia appears to have been least affected. Although with significant thrusting, the metamorphism of this sequence reached zeolite facies. Into Queensland, the degree of metamorphism increased, possibly to lower greenschist facies and is comparable with equally metamorphosed rocks in the Thomson Fold Belt. To the north and west of the Birdsville Track Ridge, the intensity of metamorphism probably exceeded zeolite grade, with chlorite and sericite frequently reported. This structural grain of both the Pedirka and Cooper regions has been profoundly influenced by northwest-southeast oriented compression and uplift associated with the Devonian-Carboniferous Alice Springs Orogeny (**Table 1**). Overthrusts in Cambrian rocks beneath the Cooper Basin (Roberts *et al.,* 1990) form northeast-southwest arcuate domal trends such as the Gidgealpa-Merrimelia-Innamincka (GMI) Ridge, Dalhousie-McDills-Mayhew Ridge, and the Birdsville Track Ridge. This deformation event also affected the Arunta Province but its southern region had cooled through 350-420^{o}C by 350 Ma. Ductile deformation and metamorphism had ceased by the end of the Devonian, a time when widespread brittle faulting was widespread through this province (Scrimgeour and Raith, 2001).

There was active convergent plate-margin tectonism in eastern Australia from at least 490 to 90 Ma (Veevers *et al*., 1991; Gravestock 1996). The apparent eastward migration of successive volcanic arc complexes resulted in the superposition of intracratonic sag basins on formerly active foreland and back-arc basins **(Figure 6).** The Drummond and Adavale Basins are thus interpreted as Lower Paleozoic foreland basins (Moore *et al.,* 1986) whereas the overlying Cooper and Galilee Basins are regarded as Upper Paleozoic, predominantly intracratonic sag basins. The Bowen Basin is considered to be part of a north-south, 2000+ km long foreland basin system that extended from just south of Townsville to south of Sydney (Elliot, 1993; Baillie *et al.,* 1994). Both the Mesozoic Eromanga and Surat Basins are interpreted by Moore (1986) as intracratonic sag basins with the development of mild Paleogene to present-day folding (Sprigg, 1986; Moore *et al.,* 1986). However, the Surat Basin is regarded as a foreland basin that was contiguous with the Papuan Basin (Veevers, 1984). The connection between the Surat and Papuan Basin has now been obliterated by the uplift of the Great Dividing Range in northern Queensland, but marked geological similarities are compelling (Veevers, 1984). The Carpentaria Basin is an intracratonic sag basin associated with the Mesozoic foreland Papuan Basin. The present-day Karumba Basin, which overlies the Carpentaria Basin, is the present intracratonic sag basin associated with the Paleogene to Recent foreland Papuan Basin centred on the Aure Trough (Boult, 1997).

Figure 6*: Phanerozoic basins of eastern Australia with an earlier interpretation of the Tasman Line (Veevers, 1984) that purportedly separates Precambrian terrain to the west (from Boult et al., 1998).*

Throughout the period 490 to 90 Ma (Late Cambrian to Late Cretaceous) there was a balance of sediment supply between successive volcanic arcs to the east of the Tasman Line (Veevers, 1984) and stable cratonic terrain to the west. Nd/Sm dating of these contrasting sediment types indicates the volcanic source provenances are from 900 Ma crust and cratonic sources from 1600 Ma crust (P. Boult, pers.comm, 2007). During the Upper Paleozoic, the Canaway Ridge between the Cooper and Galilee Basins was a significant barrier to sediment supply. It prevented volcanic arc-derived (VAD) sediment being supplied to the Cooper Basin while both Galilee and Bowen Basins are dominated by VAD sediments **(Figure 7)**. During the Mesozoic, uplift on the Canaway structure was less of a barrier to sediment supply and the distribution of VAD sediment across the interior became more widespread. The Birkhead Formation represents the distal extent of VAD sediment across interior Australia until the onset of Marine conditions during the Cretaceous (Boult *et al.*, 1998).

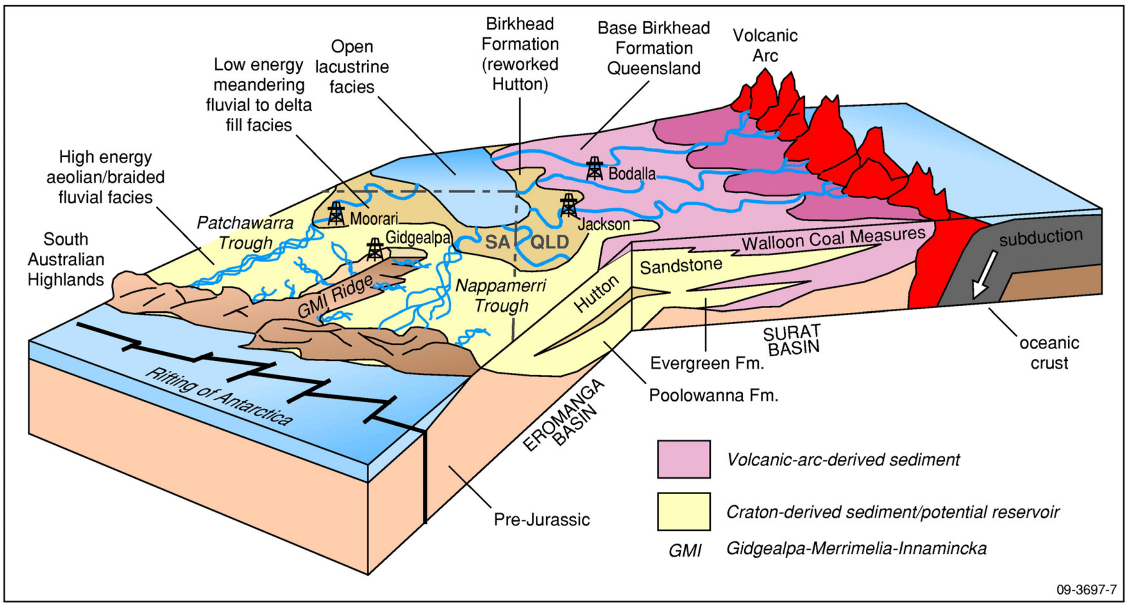


***Figure** 7: Palaeogeography and sediment provenances during the early depositional phase of the Birkhead Formation (from Boult et al., 1998).*

The intracratonic Cooper Basin contains Late Carboniferous to Middle Triassic rocks. Deposition commenced with the late Paleozoic glaciation and ceased at the end of the Middle Triassic due to widespread compressional or transpressional deformation, regional uplift and erosion. The stratigraphic succession comprises three upward-fining, non-marine sequences restricted to the subsurface, 1250-3670 m below sea level. They make up the Late Carboniferous to Late Permian Gidgealpa Group and Late Permian to Middle Triassic Nappamerri Group. Stratigraphic successions which span the Permian and Triassic without a major break are also recorded in the Pedirka, Bowen, Galilee and Sydney Basins. The ages of the various groups and their formations are derived from palynological studies.

In the Cooper Basin region, pronounced Paleozoic tectonism created compression during the latter part of the Alice Springs Orogeny (Late Devonian to Mid-Carboniferous), folding Neoproterozoic/Paleozoic sediments in the Warburton Basin. This rejuvenated terrain was then truncated by erosion resulting in moderately-undulating topography which was infilled by Permo-Carboniferous sediments. Mild tectonism at the end of the Early Permian was accompanied by regional easterly tilt with local basin sag occurring in the Eringa, Madigan and Poolowanna Troughs

- the latter being the major focus of Mesozoic sedimentation. Permian structuring in the Cooper Basin region is evidenced by a regional disconformity which separates the Late Carboniferous to Early Permian Gidgealpa Group and Late Permian to Middle Triassic Nappamerri Group. However, erosion was minimal across this basin compared to adjoining depocentres. The oldest Simpson Basin sediments were deposited on a gently undulating Permian surface, under the influence of mild regional subsidence.

Uplift of the GMI Ridge has been recognised as resulting from late Early Permian diastrophism (Kapel, 1966) but the tectonic history of the basin is still much debated. Battersby (1976) and others regarded the basin as an intracontinental downwarp, punctuated by uplift of the GMI and Murteree Ridges. Reverse faults along the GMI Ridge and offsets of possible strike-slip origin resulted from Permian reactivation of faults penetrating the underlying Warburton Basin (Stuart, 1976). Wopfner (1985) envisaged a general compressional tectonic regime for the basin and Kuang (1985)

Table 1: Phanerozoic tectonic history across the Central Basins region.

		Western Pedirka Basin		Poolowanna Trough		Cooper Basin		Windorah Trough and to the east		Galilee Basin	
AGE	**Age Ma**	**Event**	**Deformation**	**Event**	**Deformation**	**Event**	**Deformation**	**Event**	**Deformation**	**Event**	**Deformation**
Late Miocene - Recent	**10- present**	epeirogenic	N-S compression- thrust faulting, earthquakes								
Middle Miocene	**15-10**	epeirogenic	N-S Compression, uplift of Northern Flinders, Dalhousie/McDills trend, folds & faults (350-500m)		Continent-wide structural movements formed traps		Continent-wide structural movements formed traps		Continent-wide structural movements formed traps		Continent-wide structural movements formed traps
Late Eocene-Oligocene	**34-25**	top Eyre unconformity	N-S compression		uplift of Birdsville Track Ridge		N-S compression, uplift of Innamincka Dome, Birdsville Track Ridge				
Late Cretaceous	**90-60**	top Winton unconformity	E-W compression				E-W compression	(800m)		(800m??)	
Late Triassic	**205-193**	base of Eromanga unconformity	tilting to east (?200m locally)				plate margin stresses		intraplate tectonic		
Early-Middle Triassic					Regional uplift & tilting, erosion terminates deposition		Regional uplift & tilting, erosion terminates deposition				
Late Permian	**264-250**	top Pedirka unconformity	epeirogenic uplift (100m)		Poolowanna Trough initiated by tilting, uplift, erosion		regional disconformity, peneplanation				Compression
					Dalhousie-McDills high develops						regional downwarp
Middle-Late Carboniferous	**330-300**					granite intrusions		Kanimblan Orogeny	E-W Compression	Kanimblan Orogeny	E-W Compression
Late Devonian-Early Carboniferous	**360-330?**	Alice Springs Orogeny	NW-SE compressions 20km crustal shortening, thrusting at McDills - Dalhousie (3000m)		Birdsville Track Ridge formed		NW-SE compression and uplift . Overthrusts form GMI Ridge				
Late Silurian-Early Devonian	**415-375**	Rodingan Event	regional tilting (500m)								
Middle-Late Cambrian	**505-500**	Delamerian Orogeny	NW-SE compression		Warburton not severely						
Neoproterozoic	**600-550**	Petermann Ranges Orogeny	compression with dextral shear (2000m)							Alexander & Jensen-Schmidt (1995)	

interpreted three phases of crustal shortening by fault reactivation. Others interpret the basin as extensional (Heath, 1989). Generally the intracratonic sag model is proposed. Growth faulting culminating in uplift at the end of the early Permian (Daralingie Unconformity) did not elevate the GMI and Murteree Ridges in their present form. An alternative model may be that uplift followed older Paleozoic or even Proterozoic northwest meridional and northeast trends, as indicated for the GMI Ridge by Apak *et al*., 1993). Early Permian depositional facies were also governed by these older structural trends. Elevation of the GMI and Murteree Ridges took place at the close of Cooper Basin deposition, marked by the Middle Triassic unconformity.

A prominent northeast-trending structural grain was inherited during deposition of the Cooper Basin. Lower crustal or upper mantle material was emplaced in the upper crust beneath the Patchawarra Trough. Reverse faulting along the southeastern edge of this area created block uplift to form the GMI Ridge during Cooper Basin deposition. A prominent gravity low underlying the Nappamerri Trough is due to the Early Carboniferous Big Lake Suite granodiorite. These granites have intruded strata of the Warburton Basin. Cupolas of this granite suite form pre-Permian palaeotopographic highs. Permian sediments have draped over these to form important petroleum traps. The northeast-south western alignment of the Big Lake granite cupolas under the Nappamerri Trough could indicate a parallel aligned belt of older Early Devonian granites to the southeast. A gravity low over the Tenappera Trough (to the southeast of the Nappamerri Trough) indicates an Early Devonian granite which intrudes Proterozoic basement. Additionally the Early Devonian granites in Queensland and highly magnetic Cambrian basalts define a middle Cambrian rift system (Meixner *et al.,* 1999).

West of the Birdsville Track Ridge, the Poolowanna Trough was initiated by tilting, uplift and erosion of the western Pedirka Basin during the Permian (Hibburt and Gravestock, 1995).

The Dalhousie-McDills-Mayhew Trend is a large scale structural high which originated during the Permian. Sediment was shed into the Poolowanna Trough where 300 m of Triassic sequence is now preserved (Moore, 1986). Comparable to the Cooper Basin, the Triassic-Jurassic Depocentre of the Poolowanna Trough lies considerably to the east of the Permian depocentre, and Triassic-Jurassic sediments progressively onlap Permian sediments in a westwards direction. Regional uplift, tilting and erosion terminated deposition in the Pedirka/Simpson and Cooper basins at the end of the Early to Middle Triassic.

Deposition in the Eromanga Basin was initially controlled by the topography of the Triassic unconformity surface, especially for the Poolowanna Formation and lower Hutton Sandstone. No major depositional breaks occur in the Eromanga Basin, indicating a period of tectonic quiescence (Carne and Alexander, 1997). Structuring during the Jurassic was subtle and largely a function of drape and compaction over older Paleozoic highs. Structural closures formed at this time are believed to be prime oil targets (Ambrose *et al*, 2007).

Through the Cainozoic, the continental compressive stress field evolved from east-west to north-south as the Australia plate drifted in a north easterly direction from Antarctica towards collision with the Southeast Asian and Pacific Plates (Smith, 1990). Events on the margins of the plate strongly influenced Cainozoic deposition and structuring in the interior of the continent. Early Paleogene compression enhanced closure on pre-existing structures and created other structures independently within the Cooper Basin. Continent-wide Miocene structural movements formed traps and influenced hydrocarbon migration in a number of Australian basins. In the Eromanga Basin region, during the Oligocene, major surface anticlines were formed (Wopfner *et al.,* 1974; Moore and Pitt, 1984).

Intense east-west compression and local wrenching at this time resulted in severe structural rejuvenation, and in some cases structural inversion, along most major faults (Hibburt and Gravestock 1995; Ambrose *et al*. 2002; Ambrose *et al*, 2007). This second phase of compression reactivated pre-existing faults and produced localised uplift and erosion with folding and faulting (Santos, 1988). Uplifts in the order of 350-500 m occurred near the margin of the basin (Foster *et al*., 1994; Krieg, 1985; Alexander and Jensen-Schmidt, 1995). Cainozoic uplift affected groundwater flow in aquifers within the Great Artesian Basin and may have influenced hydrocarbon migration and remigration in the region. A widespread increase in geothermal gradient in the Eromanga Basin has occurred recently in the last 5 Ma, linked to the flow of hot groundwater. This recent heating has not had sufficient time to increase the thermal maturity of Eromanga Basin source rocks over structural highs, but has probably caused recent petroleum generation in troughs within the Cooper Basin and the Poolowanna Trough (Tingate and Duddy, 1996).

2 Regional Overviews

2.1 WARBURTON BASIN

The Warburton Basin is an Early Paleozoic pericratonic basin containing an Early Cambrian and Ordovician sequence, with possible Devonian rocks as observed in the Pedirka Basin and inferred in the Boorthanna Trough. The Warburton Basin is bounded on the southwest by the Muloorinna Ridge, Musgrave Block to the west and Arunta Block to the northeast (**Figures 8a, b**). The metamorphic effects of the Cambrian Delamerian Orogeny (520 to 500 Ma) extended over the NT portion, south to just over the SA-NT border, and eastwards into Queensland. Within South Australia the sequence was apparently unaffected (Gatehouse, 1986). The Warburton Basin underlies the Cooper, Pedirka and Eromanga Basins in northern South Australia and Northern Territory (**Figure 1**), and lies within the southwestern edge of the Thomson Fold Belt (Murray and Kirkegaard, 1978; Gatehouse, 1986). Early Cambrian rocks in the Arrowie Basin, eastern Officer Basin, and at McDills 1 may be marginal to the Basin.

A nominal subdivision of the basin into eastern and western portions is demarcated by an uplifted Precambrian block that is basement to the Birdsville Track (BT) Ridge. The eastern Warburton Basin unconformably underlies the gas and oil producing Cooper and Eromanga Basins (**Figure 9**) and is generally considered economic basement to the Cooper Basin. However, four commercial wells produce Permian-sourced oil and gas from within the eastern Warburton sequence, and more than 90 wells have petroleum shows from penetration of the uppermost part of this basin. Over 600 wells have penetrated up to 40 m into the basin.

Wopfner (1974) defined the Warburton Basin as mainly the Cambrian to Devonian successions in the northeastern area of South Australia. Gatehouse (1983) formally defined three major stratigraphic units: the Mooracoochie Volcanics, Kalladeina Formation, and Dullingari Group (**Figure 10**). The Mooracoochie Volcanics embrace all the major volcanics encountered in the basin, including trachyte, rhyolite, and possibly andesite in Murteree 1. The Kalladeina Formation comprises limestone, dolomite, shale, siltstone and sandstone, and minor tuffs. The Dullingari Group includes pyritic shale, siltstone and minor sandstone characterised by a high degree of induration, probably zeolite grade metamorphism, and also glauconitic bioturbated sandstone and siltstone. More recently a new stratigraphic unit was identified – the Pando Formation. This consists of clean quartzose sandstone to bioturbated, glauconitic sandstone, interbedded siltstone and shale (Gatehouse *et al*, 1995). Additionally, two igneous units have been named **-** Big Lake suite and Jena Basalt (Boucher, 1991).

Because these stratigraphic units were named from different wells, no direct contacts between them have been observed within cores except for an unconformable contact between Mooracoochie Volcanics and Kalladeina Formation (**Figure 11a**).

The western Warburton Basin is the larger portion that extends westward and northwestward from the BT Ridge below Eromanga Basin cover. This vast region has attracted less seismic and little exploration drilling because of an absence of any known Late Paleozoic accumulations between the Cooper and Pedirka regions. Tirari West 1, Lake View 1, and Poonarunna 1 tested structures overlying a large negative Bouguer anomaly (Santos, 1988 a, b). This area lies immediately west of the BT Ridge and the Lake Blanche Lineament (Pre-Jurassic palaeohigh) (**Figure 11b**). In the Eringa-Madigan-Poolowanna Troughs, many exploration wells bottomed in presumed Amadeus/Warburton rocks, but no systematic study is known that assesses the degree of metamorphic overprint or maturation, source, and reservoir characteristics of these rocks.

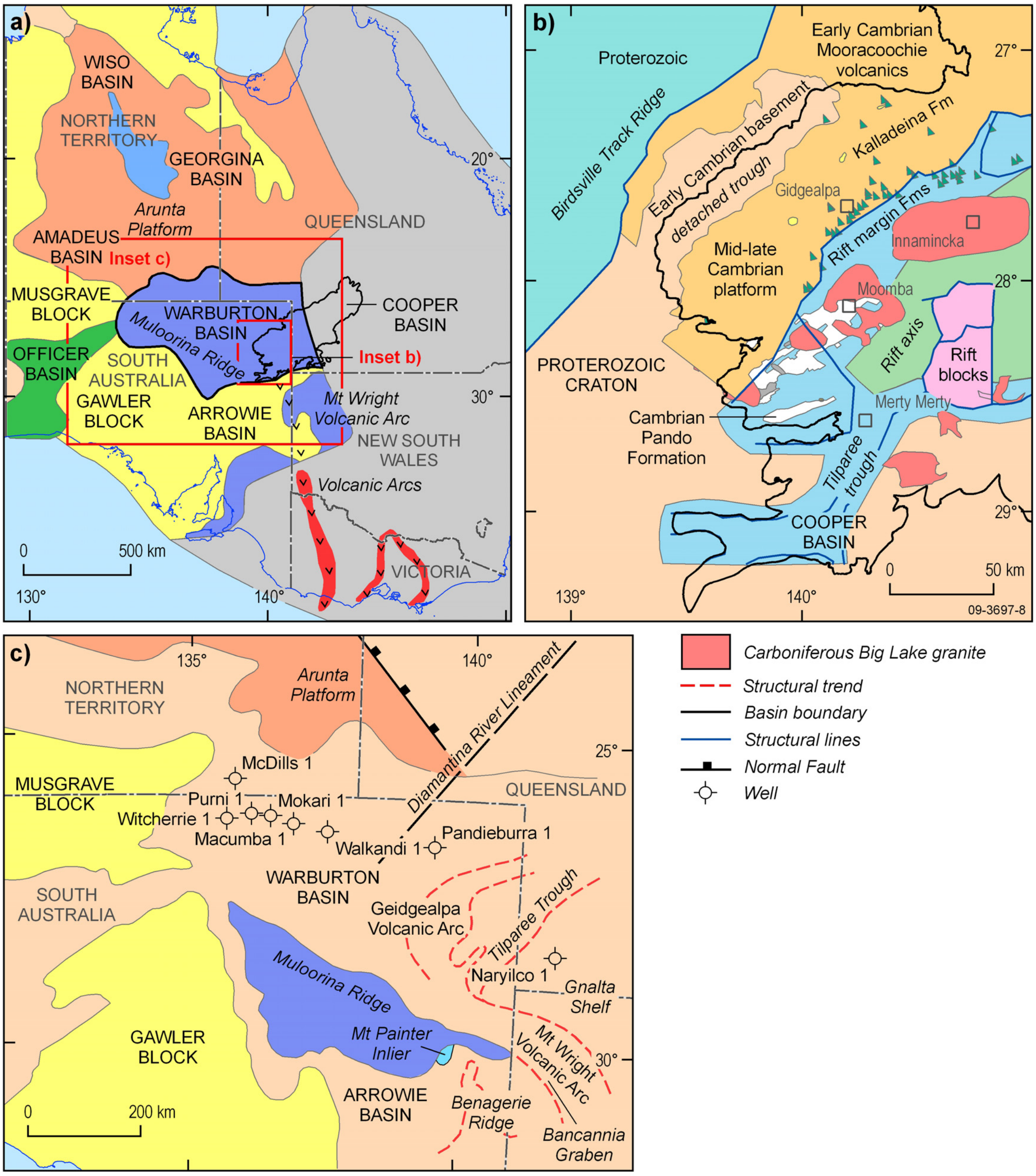


***Figure 8**: Warburton Basin: (a) in Cambrian palaeocontext (from Roberts et al, 1990); (b) configuration of the detached rift and rift producing the Tilparee Trough (from Boucher, 2001 a); and (c) within surrounding Precambrian terrain (from Gatehouse, 1986)*

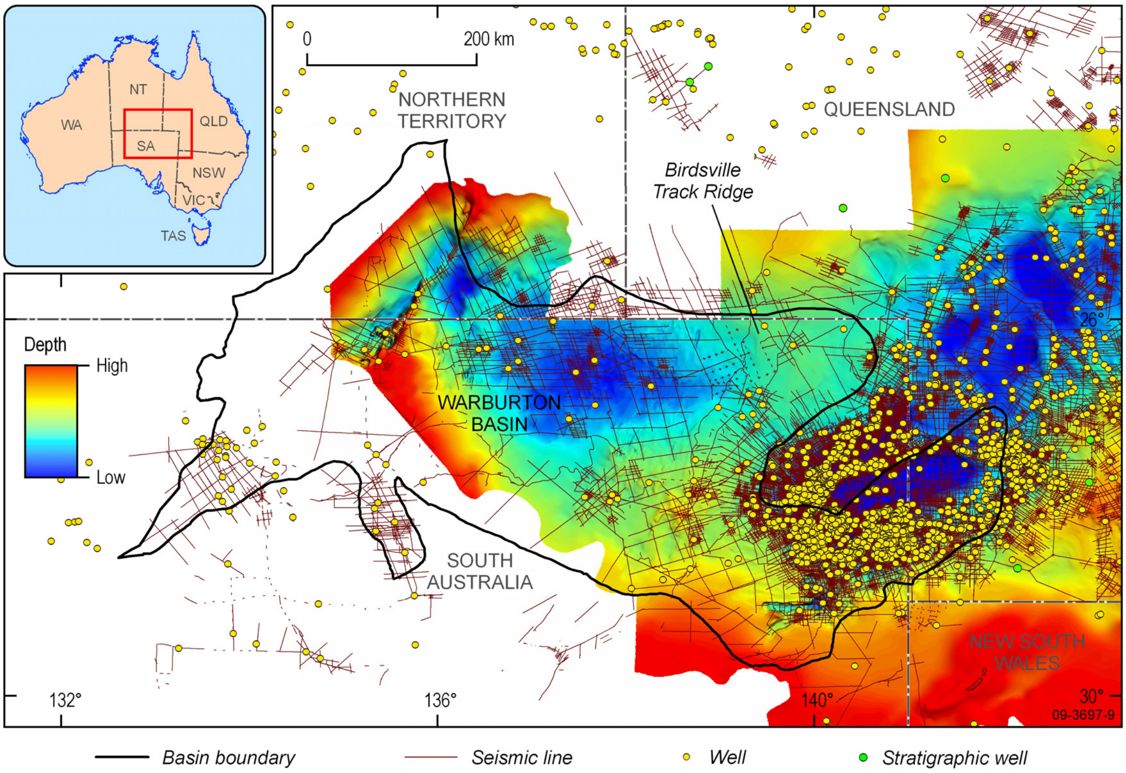


Figure 9: *Known extent of the Warburton Basin on the structure of the 'Z' seismic horizon (pre-Permian basement). The Birdsville Track Ridge divides the eastern and western provinces of this basin (after NGMA).*

2.1.1 Metamorphic grade

Many Warburton rocks have been referred to as metasediments, and where intercepted in the western region, they are significantly tectonised with dips >45 to 75°. Most of the wells bottomed in indurated dense quartzites, sometimes with minor black shales, carbonate, or fractured siltstones. In Purni 1 and Mokari 1, the presumed Ordovician rocks are dark shales or slate. Well log documentation of presence of chlorite or sericite appears generally east from Mokari 1 in this western part of the basin.

Preservation of the sequence in the South Australian part of the eastern Warburton Basin, adjacent to or below the Cooper Basin, appears to be the exception in metamorphic overprint. Most of the Dullingari Group shale has undergone only low grade metamorphism with stress and compaction-related deformation, including weak mineral alignment and foliation (Sun and Gravestock, 2001). Recognition of Warburton equivalents extending northeastwards into Queensland **(Figure 9)** is generally based on carbonate/calcareous components in otherwise greenschist-grade siliciclastics of the Thomson Fold Belt (C. Murray and J. Draper, pers. comm., 2007). In the Pedirka region, probable Devonian and Ordovician rocks within the DMM Trend are redbeds with apparent chloritic sediments (Questa, 1990). Eastwards from here and across into Queensland on the northern flank of the Cooper Basin, are steeply-dipping fractured siliciclastic sediments with traces of chlorite or sericite. These are collectively assigned as economic basement, remain undated, and could be either Warburton-Georgina equivalents where some carbonates are present, possible Proterozoic Field River Beds or older rocks. Flat-lying siliciclastics intersected below the Eromanga sequence in Marduroo1 have been ascribed to the Proterozoic Field River Beds (Magnier, 1965).

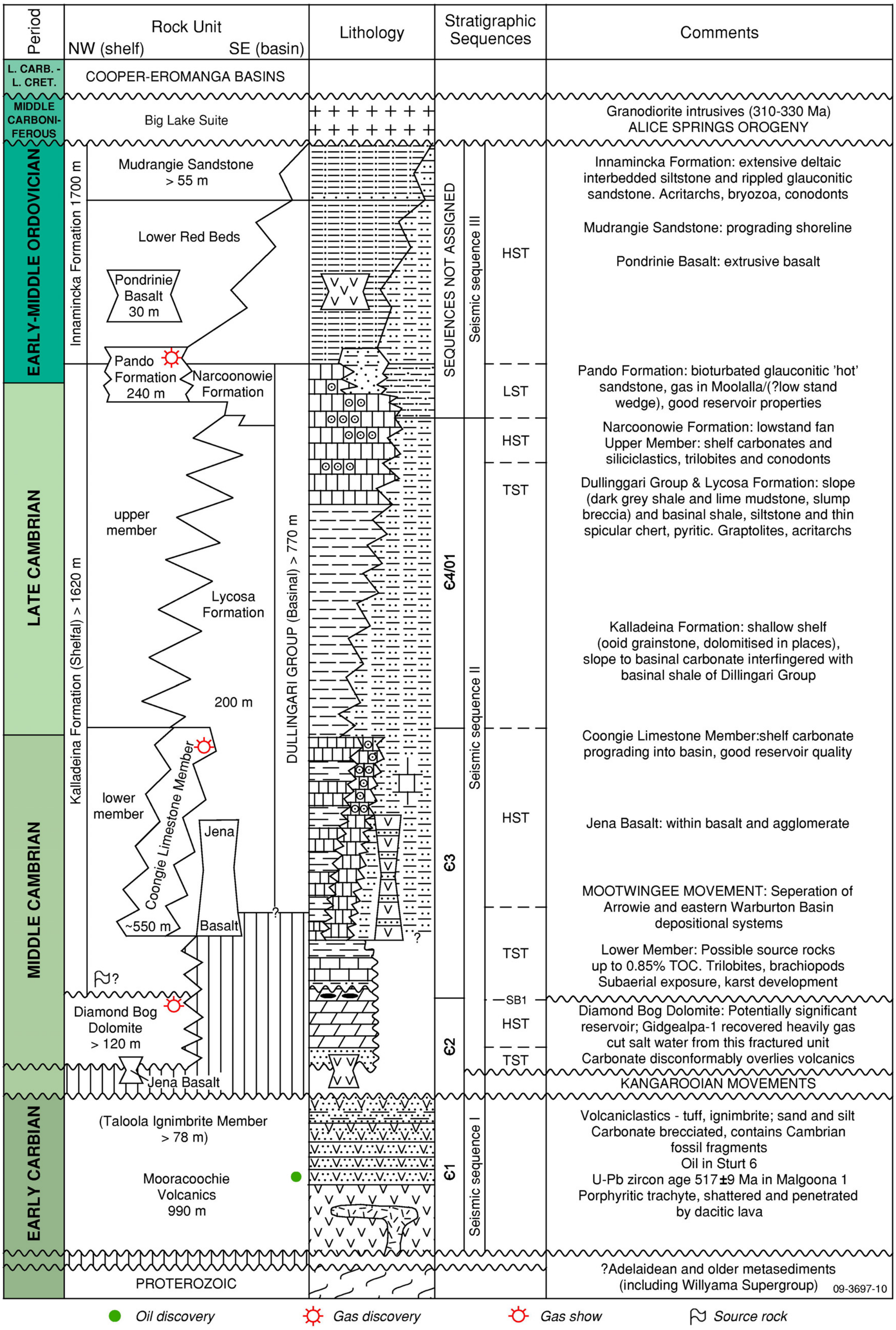


***Figure 10**: Summary of the eastern Warburton geology and stratigraphy (from PIRSA2007).*

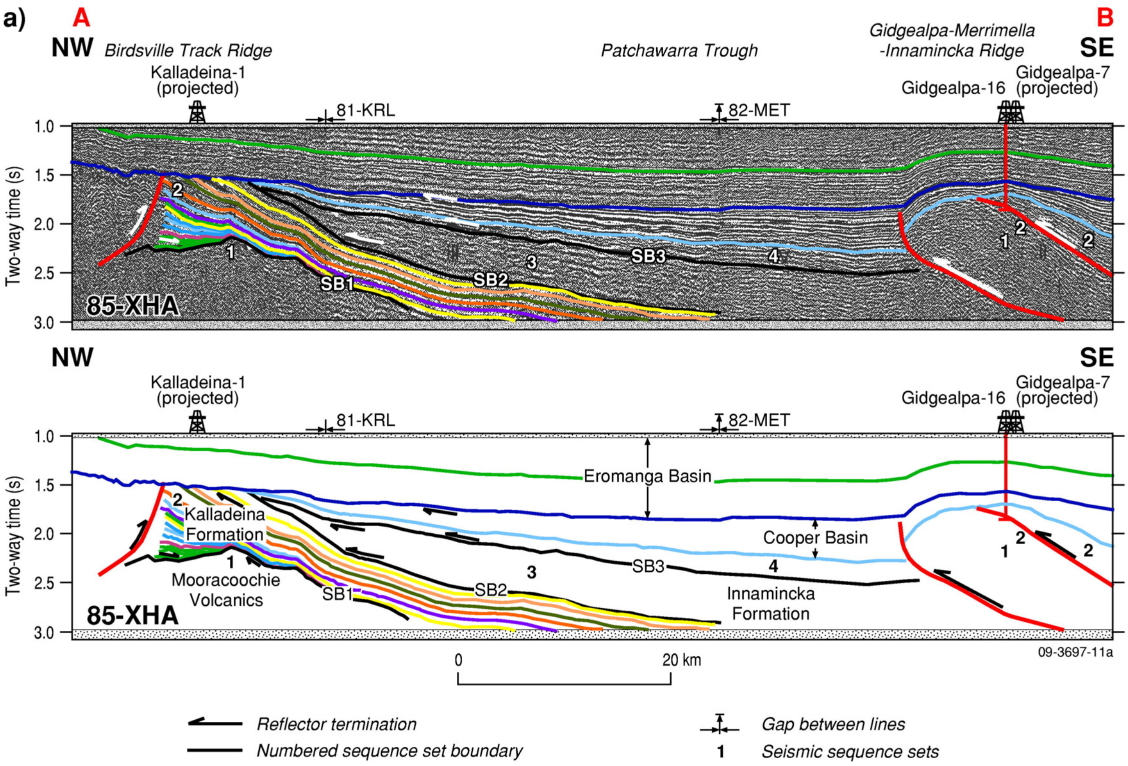


__Figure 11__: Warburton Basin: (a) section across the Patchawarra Trough from Birdsville Track Ridge to GMI Ridge (from Sun, 1998)

2.1.2 Tectonic and depositional history and structural setting

Sometime between 600 and 500 Ma, the Pangaea supercontinent broke up through global rifting and extension into many smaller continents including Gondwana (Veevers, 1984). A back-arc rift basin is interpreted under the Cooper Basin. Volcanics along the Mt Wright volcanic arc and in the Gidgealpa areas imply the existence of a subduction zone east of Gidgealpa at this time. The continental side of this arc and subduction zone is inferred to have experienced extension due to heating and thinning of the crust, and then developed into a backarc basin. A rift formed (**Figures 8b**, **8c)** and crustal blocks rotated and tilted to accommodate the stretching. Syn-rift deposition was restricted to half grabens and the basal sediments included volcanics, non-marine shales and sandstones which formed potential reservoirs, seals and source rocks.

Continued subsidence and increased marine influence promoted carbonate deposition on a stable platform to the east. In the rift zone, the carbonates graded into continental-derived clastics, and the carbonate units alternated with thick shales. The rapid thickening of the sediment package west of Kalladeina 1 is most apparent in the lower syn-rift sequence. Overlying sediments here also appear thicker west of Kalladeina 1, possibly due to post-rift subsidence as a result of earlier sediment loading **(Figure 11a)**. Following the extensional phase (after the early Ordovician), there was compression and uplift of the Kalladeina Formation sequence, an event possibly related to the Delamerian Orogeny which apparently youngs northward from the Adelaide region.

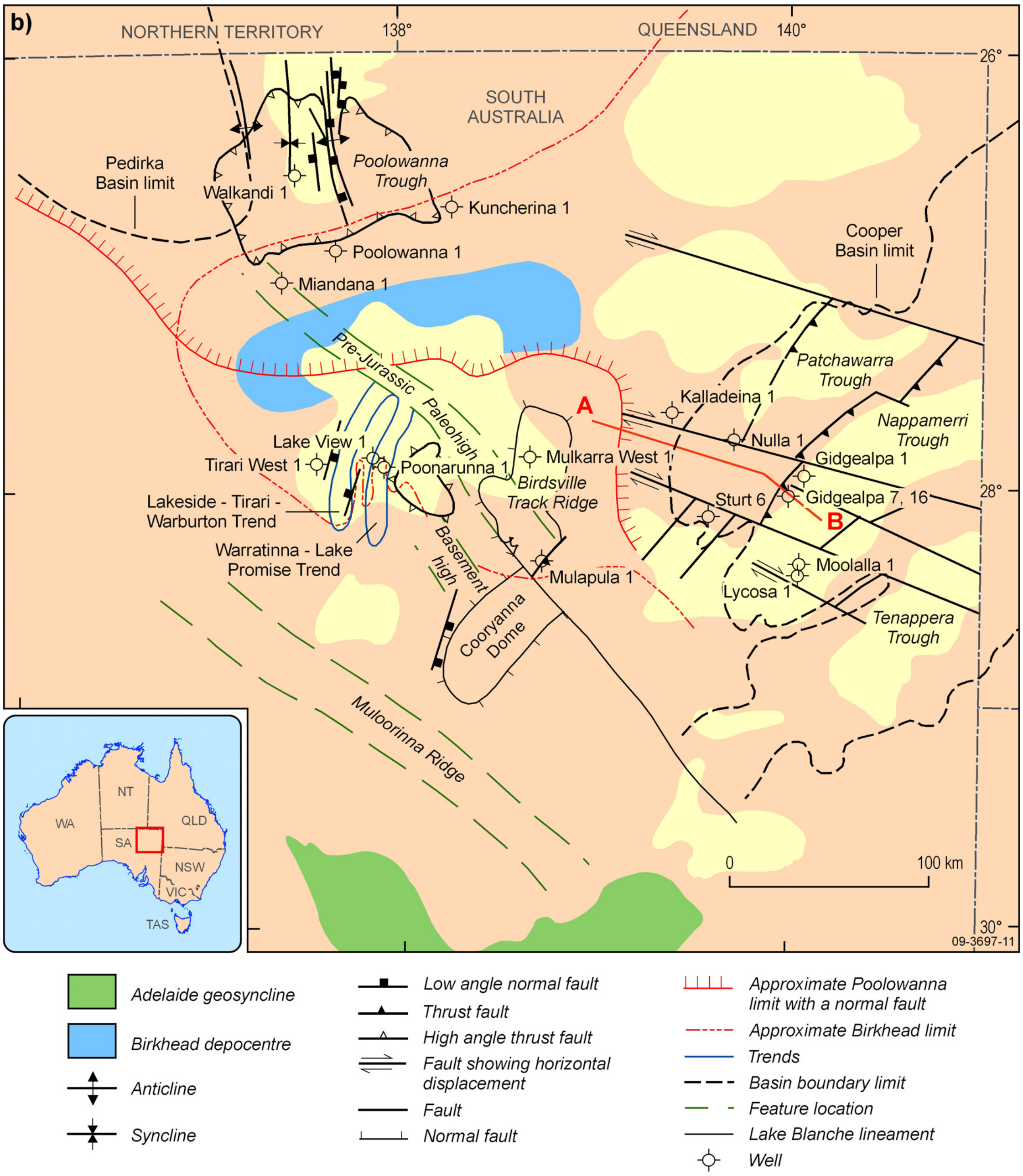


Figure 11: *(b) Structural elements in the western province (from Alexander and Hough, 1990).*

More than 1700 m of carbonate shelf sediments were deposited from Early Cambrian to Early Ordovician in a basin consisting of half grabens on the continental side of an active margin. The thicker syn-rift sediments west of Kalladeina 1 are more extensively deformed than the stable carbonate succession, tight folding and faulting are indicated by seismic data. A westward jump of the subduction zone is postulated to explain the structural complexity observed. A western plate boundary at a subduction zone close to the Precambrian craton would cause the more severe deformation on that side of the basin close to the Precambrian craton, leaving the more distal sediments to the east relatively intact. One effect of this deformation may also have thrust the frontal section of the craton over the Warburton rift sediments.

2.1.3 Stratigraphy

The stratigraphy of the Warburton Basin, as summarised by PIRSA 1997, is shown in **Figure 10**. Two stratigraphic units define the Early Cambrian-Early Ordovician successions in stratigraphic ascension: Mooracoochie Volcanics and Kalladeina Formation. These strata were deformed by a series of episodic fault movements through time, especially along the main GMI trend. This deformation has created high reservoir potential of mainly complicated fracture porosities.

The Kalladeina 1 sequence, the type section of the Kalladeina Formation, provides the most complete section, being more than 1700 m thick. The established biostratigraphic framework, based on eight trilobite and three conodont assemblages from ten key wells, indicates the strata cover a range from Middle Cambrian-late Templetonian to the early Ordovician Warendian stages, and provide reliable well correlation across extensive areas, especially across the GMI Trend region. Recovered conodont assemblages from four wells in the eastern Warburton Basin allow correlation to be made with the classic sea level curve for the Late Cambrian to Early Ordovician (Miller *et al*., 2003).

Four seismic sequence sets are recognised by Sun (1998) in the eastern Warburton Basin between the eastern flank of the BT Ridge and the eastern flank of the GMI Ridge (**Figure 11a**). These sequence sets are differentiated by regional reflection terminations and configuration. Biostratigraphy has assisted well correlation. Distinct among them, the high amplitude set II was either folded or abruptly truncated by a complex fault zone (Roberts *et al.,* 1990) on the eastern flank of the BT Ridge. Seismic reflections dip southeast and lose quality below the deep part of the Patchawarra Trough. A series of imbricate thrust faults elevated sequence sets I and II along the GMI Ridge. The three sequence boundaries SB1, SB2, SB3 also have different characteristics.

Sequence I is characterised by a thick vuggy and fractured dolostone unit, with palimpsest oncoid-intraclastic wackestone and packstone, indicating a possible peritidal environment (Sun *et al*., 1994). The dissolution event is from subaerial exposure (Gravestock, 1990). In the Gidgealpa area, a strong peak reflection represents this dolomite unit (Carroll, 1990) which is at least 120 m thick in Gidgealpa 1. Sequence I is absent in Kalladeina 1 and Coongie 1, possibly due to non-deposition or erosion, and supports the initial geometry of the Gidgealpa area as a caldera or being caused by syn-depositional rifting (Sun, 1996).

Sequence II onlaps the lowstand karsted surface of sequence I in the Gidgealpa area but sequence set I in both Kalladeina and Coongie areas has several interpreted volcanic mounds with upper erosional and truncated boundaries (Sun, 1998). Sequence II commenced with an Australia-wide maximum sea level rise. Open marine neritic environments are characterised by fine sandy wackestone, shale and organic-rich dark grey to black lime mudstone. Submarine hardgrounds, together with phosphate-impregnated breccias and bored surfaces are known in Kalladeina 1 and Gidgealpa 1 (Sun, 1996). These sediment-starved surfaces indicate a condensed section due to drowning of the platform during a rapid sea level rise.

Sequence III contains a lowstand systems tract in the Gidgealpa area, which is a basinal shale and siltstone unit lacking carbonates in both Gidgealpa 1 and 7. Fine-grained siliciclastics are interbedded with thin carbonate intervals in Kalladeina 1, and are predominant in the trough area to the west. This siliciclastics-dominated lowstand systems tract in the trough is similar to those reciprocal lowstand clastics in the Canning Basin (Southgate *et al*., 1993). With a relative sea level rise, transgressive systems tracts are indicated by starved condensed sections (in Gidgealpa area) and one or more reworked lag beds (Kalladeina 1). Three parts of a highstand systems tract are recognised from deep shelf to slope basin. Previous non-depositional areas (Coongie to Daer) and the platform edge became sites of subtidal deposition, and developed into ooid shoal complexes. In the Gidgealpa area, a carbonate slope apron environment started with a sediment-starved argillaceous mudstone, later receiving carbonate turbidites and finally debris flow deposits. Large quantities of basaltic lithic breccia, tuff, and mixtures of carbonates and volcaniclastics were also intercalated with deep water carbonates. A strong seismic reflector in the vicinity of Coongie 1 represents a thick ooid succession, extending towards the basin – and supports interpretation as a prograding phase during a highstand. This sequence ends with a shoaling-upward parasequence set of late highstand systems tract indicating a possible subaerial exposure surface recorded in both Kalladeina 1 and Coongie 1.

Sequence IV started with a flooding surface on the underlying subaerial-exposed altered zone, indicating a transgressive systems tract. It is characterised by stacked parasequence sets of late highstand systems tracts, an abrupt change of depositional style, sediment supply, and shallower setting. The regime is a mixed carbonate-siliciclastic system, comprising separate carbonate and siliciclastic shoals, and an offshore muddy shelf as seen in Kalladeina 1, Charo 1 and Coongie 1, and the Wantana to Innamincka areas to the east. These may suggest a stacked parasequence set of highstand systems tract with limited accommodation and influenced by relatively frequent sea level fluctuations, indicating termination of subsidence or uplift of the basin margin. There was a dramatic increase of siliciclastics and decrease of carbonates compared to the three earlier sequences. The shingled reflectors in the vicinity of Kalladeina 1 further support a prograding shallow marine nearshore setting (Sun, 1996).

2.1.4 Post-Ordovician history

Following a compressional phase, or possibly synchronous with it, the subduction zones moved predominantly to the east in a series of steps. Recent dating of granites and Nd/Sm dates of the Thomson Fold Belt indicate that this was a major step to east of the Adavale Basin (J. Draper and C. Murray, pers. comm., 2007). Gravity signatures of deep crustal domain boundaries (**Figure 4**) would support this assertion. Accretion of post-Ordovician age terranes continued eastwards as the Australian continent enlarged. Large scale erosion of Warburton sediments occurred. From the Permo-Carboniferous to Paleogene, two major intracontinental downwarps were centred to the southeast of the Warburton depocentre, causing the Warburton sequence to tilt gently towards these downwarps. The first downwarp then accommodated Cooper Basin deposition. The second downwarp was over a much broader area with its depocentre apparently offset to the northwest of the Cooper Basin axis. Here Eromanga deposition concealed all of the Warburton Basin. Reactivation and enhancement overprinted on some earlier Warburton Basin structures with northwest-southeast oriented compression during the early Paleogene (Roberts *et al*., 1990). Structure and isopach mapping indicates large scale thrusts and later wrench fault zones, high angle reverse faults and subcrop edges of the Kalladeina Formation.

Sun (1997) summarises the main structures of the eastern Warburton Basin in the region between the eastern flank of the Birdsville Track Ridge and the eastern flank of the GMI Ridge, classifying four categories: a complex deformation zone; reverse faults; folds; isolated thrust faults and an imbricate thrust system.

2.1.5 Hydrocarbon shows

The Warburton and associated lower Paleozoic units were the initial target for petroleum exploration in the northeast of South Australia and yielded the first hydrocarbon shows in carbonates intersected in Gidgealpa-1 in 1963. The wells Gidgealpa 3, 16 and 23 all encountered small gas shows in the pre-Carboniferous sequence. Hydrocarbons occur below the pre-Permian unconformity and organic geochemical evidence suggests oils derived from here contributed to the initial charge in Cooper Basin Reservoirs (Boreham and Summons, 1999; Hallmann *et al*., 2005). However, oil and gas commercially produced from fractured Warburton rocks within thrust structures and below this basin are of Permian origin (Kagya, 1997). This makes Early Paleozoic strata in the region potential exploration targets. Oil has flowed in commercial volumes from fractured Cambrian tuffs in Sturt 6 and 7, and gas has been tested in Moolalla 1 and Lycosa 1 in Ordovician sandstone and fractured siltstones respectively. In these wells, the origin of the hydrocarbons has since been ascribed to Permian sources (Sun and Gravestock, 2001). About half of the exploration wells drilled in the Cooper Basin penetrates pre-Carboniferous sediments (Gatehouse, 1986).

2.1.6 Source rocks

Potential source rocks were suggested to occur in a deep trough in the vicinity of Kalladeina 1 and the western area (Roberts *et al*., 1990) but Sun (1997) suggests that deep marine mudstone or shale tends to occur in the slope to basin facies of sequences II and III in the Gidgealpa area. The highest TOC obtained so far is 0.85% from Gidgealpa 7 (McKirdy *et al.,* 1987) from a lime mudstone and shale of the slope apron facies of sequence II. These slope- to basin facies are widespread and may contain excellent source rocks (Sun, 1997).

The quantity and quality of source rocks encountered to date within the Warburton sequence is low. From a total of 79 TOC analyses, 50% each of cores and cuttings, 65% have poor source potential (0-0.25% TOC), 24% fair (0.25-0.5% TOC), 9% good (0.5-1% TOC) and 2% very good (>1 % TOC).One 50 m horizon intercepted in Kalladeina 1 (3350-3400m) appears to be of moderate to very good source potential. Of a total of 42 Rock-Eval pyrolyses from 8 wells, 90% of these analyses indicate poor source quality, but the moderate source potential of 10% lies predominantly in the interval in Kalladeina 1 (Roberts *et al.,* 1990). Fine sapropelic material, a Type II kerogen of probable marine phytoplankton origin (algal/bacterial), has been preserved in reducing conditions. Biomarker distributions of this source rock suggest a major contribution from Rhodophyceae (Hallmann *et al.,* 2006). The marine shale of sequence II in Kalladeina 1 contains Type II-III kerogen

2.1.7 Maturity

Calculated maturities of the Kalladeina Formation in Gidgealpa 1 are within the lower part of the oil window.

Several different approaches yield a wide range of maturity estimates.

On the basis of MPI-calculated thermal maturities of residual oils from SFTE, Hallmann *et al.* (2006) suggest maturity from Warburton sources varies up to 1.6% R_c. This is in agreement with the best estimate of Roberts *et al.* (1990) for a maturity of 1.6% R_c for the source interval in Kalladeina 1. Estimation of maturity of the source sequence in this extended area (**Figure 12b**) was from burial history modelling, with maturity contours of an oil window (0.6-1.3% R_e), wet gas window (1.3-2.0% R_e), and dry gas window (2.0-4.0% R_e).

Evaluation of maturity of the sequence in these 8 wells within the Cooper Basin, is based on Rock-Eval pyrolysis parameters (T_{max} and Production Index), MPR, kerogen fluorescence, and from empirical basin modelling. Mature to post-mature rocks are indicated although the T_{max} for Kalladeina 1 indicates an anomalous low maturity.

Conodont alteration indices (CAI) (Epstein *et al.,* 1977) were used by Sun and Nicoll (2004) to indicate:

CAI 1.5 (50-90°C in the early part of the oil window) in Coongie 1 at 2627 m,
CAI 2 (60-90°C oil window) in Charo 1 at 2229 m,
CAI 3-4 (110-300°C, gas window) in Packsaddle 1 at 3157-3165 m,
CAI 4 (190-300°C dry gas to overmature) in Wantana 1 at 2935 m.

In this latter well, overmaturity is ascribed to high palaeotemperatures from proximity to nearby granite intrusives.

2.1.8 Thermal history

Basin modelling indicates that peak oil generation probably occurred during the Early Cretaceous. This study assumed an unchanged temperature gradient, removal of 1600 m of Ordovician sediments during the Late Ordovician, and further erosion of 350 m of Cretaceous sediments in the Paleogene. A synthesis of all maturity estimates for the best source interval in Kalladeina 1 indicates 1.6% R_c and kerogen extracts from around 3350 m are considered late to overmature for oil. The Gidgealpa kerogens indicate maturity equivalents of late oil to early gas generation.

This modelling by Roberts *et al*. (1990) assumed a uniform gradient through time. However, analysis of Ordovician sediments (Pando and Mudrangie Formations) from Daralingie 1 and Pando 2 wells suggest a provenance that was last uplifted and eroded during the Delamerian (510-490 Ma) orogeny, and possibly the Petermann Ranges (560-540 Ma) orogeny (Duddy, 2002).

2.1.9 Structural timing, hydrocarbon generation and migration

The depth structure map of the KAL5 event, the most consistent over the area, was used by Roberts *et al,* (1990) to outline current migration pathways (**Figure 12c**). Migration pathways within the overlying Eromanga sequence were based on the ‘C’ seismic horizon. Only the area beyond the KAL 5-6 subcrop was assumed to be a likely vertical leakage area of Kalladeina-sourced hydrocarbons. Sun and Gravestock (2001) have also proposed migration routes. Geochemical analysis of many oil Cooper Basin reservoirs suggests that although small in volume, often the first oil charge was contributed from the Larapintine Petroleum System (!) (Hallmann *et al*., 2005).

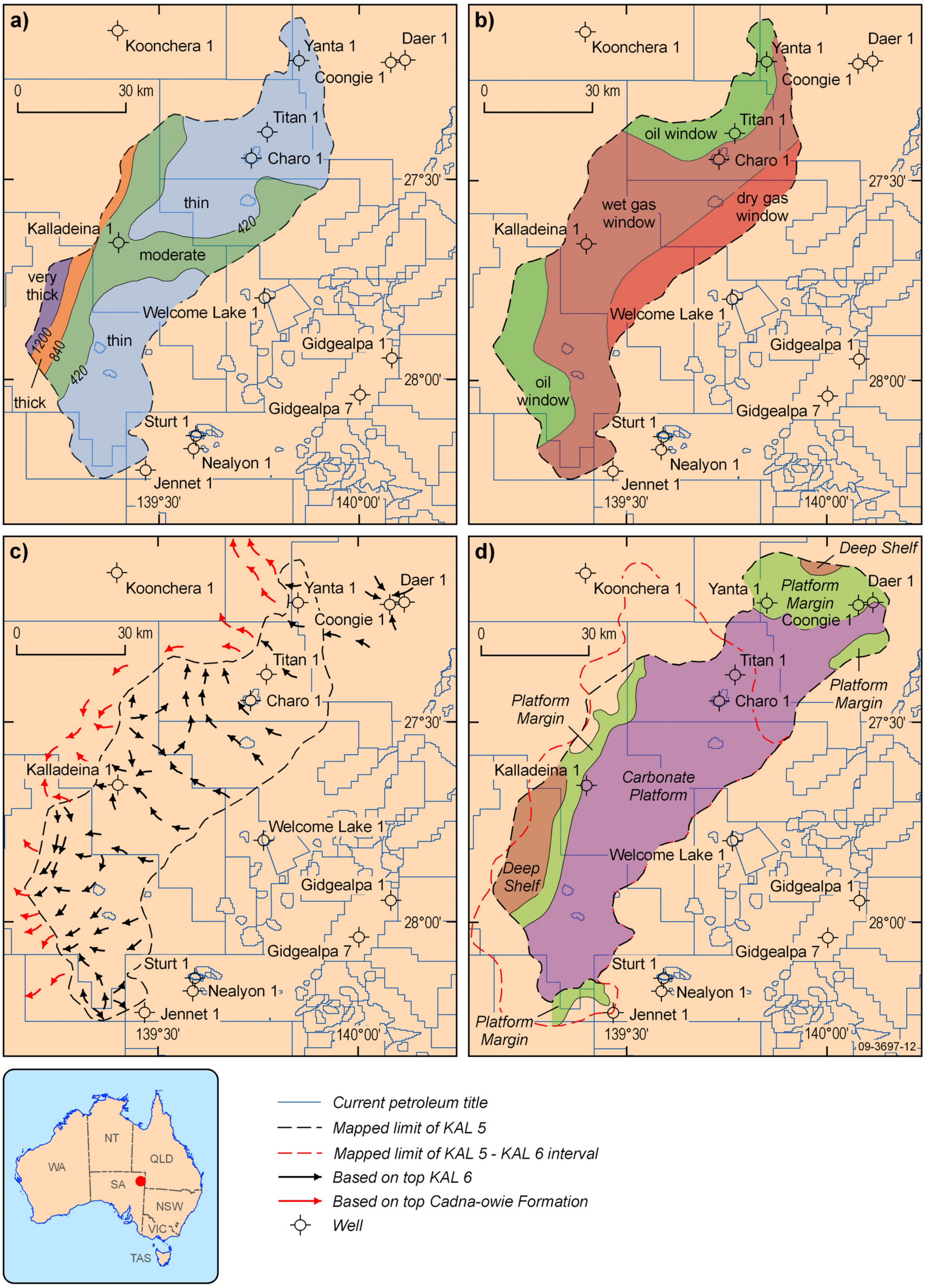


Figure 12: *Kalladeina Formation sourcing & migration: (a) source thickness of KAL5-6 interval; (b) source maturity of KAL5; (c) migration pathways based on structure of 'C' horizon and KAL5; (d) palaeogeography of intra-Kalladeina reservoirs in KAL5-6 and KAL 4-5 intervals (from Roberts et al., 1990).*

2.1.10 Reservoirs and seals

Stratigraphic framework and sequence analysis have improved understanding of the major facies distribution, subaerial solution surfaces, and as such the potential occurrence of reservoir, source and seal rocks. On this rationale, Sun (1998) predicted potential reservoir units to occur on the platform and immediately beneath sequence boundaries in the ramp to platform portion of the basin. Potential reservoirs can be predicted from well data to lie at the shelf edge and slope area.

Most primary porosity in carbonates of sequence II is occluded by cements but good secondary porosity occurs as moldic, vuggy, fracture, breccia and intercrystalline types. The vuggy fractured dolomite of sequence I was developed during a low sea-level stand related to subsequent exposure (Sun, 1997) and structurally favourable areas are on the eastern flank of the BT Ridge and on the GMI Ridge.

The Warburton sequence contains good reservoir units. Five potential reservoir sandstones were identified with the use of sequence stratigraphy, related mapping and petrography. These exhibit a combination of primary intergranular and secondary porosity, mainly from feldspar and carbonate cement dissolution, but matrix permeability is very low and fractures are required for enhancement. These units are: Pando Formation, upper member of the Kalladeina Formation, Mudrangie Sandstone Member, Narcoonowie Formation and Weena Sandstone (Sun, 1999). In this Warburton sequence, 32% of all recorded oil shows occur in the Pando Formation.

Secondary porosity can be as high as 20% as seen in Daralingie 1, but permeability is generally low. The interpreted turbiditic deposits of the Narcoonowie Formation and shale-dominated Lycosa Formations together represent 58% of total gas shows recorded in Warburton intersections in South Australia.

Potential carbonate reservoir units include the Diamond Bog Dolomite and Coongie Limestone Member. Any shallow-water carbonate or calcareous sandstone has potential to hold hydrocarbons where it lies immediately below unconformities and secondary porosity has developed through karstic processes (Sun, 1999). Porosity types in the Kalladeina Formation include vuggy fracture porosity (saddle dolomite linings) as observed at Gidgealpa; fractured dolostones, dolomitised oomoldic porosity (Coongie and Daer areas), and karst limestone reservoirs (interpreted to exist at Gidgealpa, based on log analysis). The thick vuggy fractured dolostone intersected at Gidgealpa is Floran, the same age as the source prone interval (Roberts *et al.*, 1990).

Fracture sets occur in brittle lithologies – from ignimbrite and tuffaceous sandstones (Sturt 7, 8, Boxwood 1, Gidgealpa 4), siltstones (Moolalla 1), dolomite (Gidgealpa 1, 5, 7), and sandstones (Beanbush 1, Meranji 2, Jennet 1, Merrimelia 6, 7). Depending on the local stress regime, specific component joint sets may be dilated. In an attempt to relate regional fracture patterns to potential production, Sun (1999) identified two groups of orthogonal fracture sets across local structures beneath the Cooper Basin:

> NNE-SSW (20-200^o) and ESE-WNW (110-290^o) similar in orientation to low frequency lineaments NNE8 and WNW9 of Boucher (1998), are possibly the younger set; and
> NE-SW (60-24^o) and NW-SE (150-330^o) where the NE-SW orientation is comparable to Lineament NE1 of Boucher (1998).

Open fractures in Lycosa 1 have azimuths WNW and NW and dip southwest (Sun, 1999).

2.1.11 Exploration potential

Three play types are presented in the context of structural setting and migration pathways:

I Kalladeina Formation source and reservoir

The best source interval in the Kalladeina 1, between 3350 and 3400 mKB is Floran age (Middle Cambrian), and another intersection of this unit is known at Gidgealpa. Seismic events KAL 5 and KAL 6 contain the source interval. On the assumption that these mappable events contain a time interval, then the KAL 5-6 isochron can be interpreted to reflect the quality and distribution of this source-prone interval and prospectivity. The elements of source, maturity, reservoir and structure, together with migration and seals are outlined in the prospectivity maps of Roberts *et al.* (1990) (**Figure 13**).

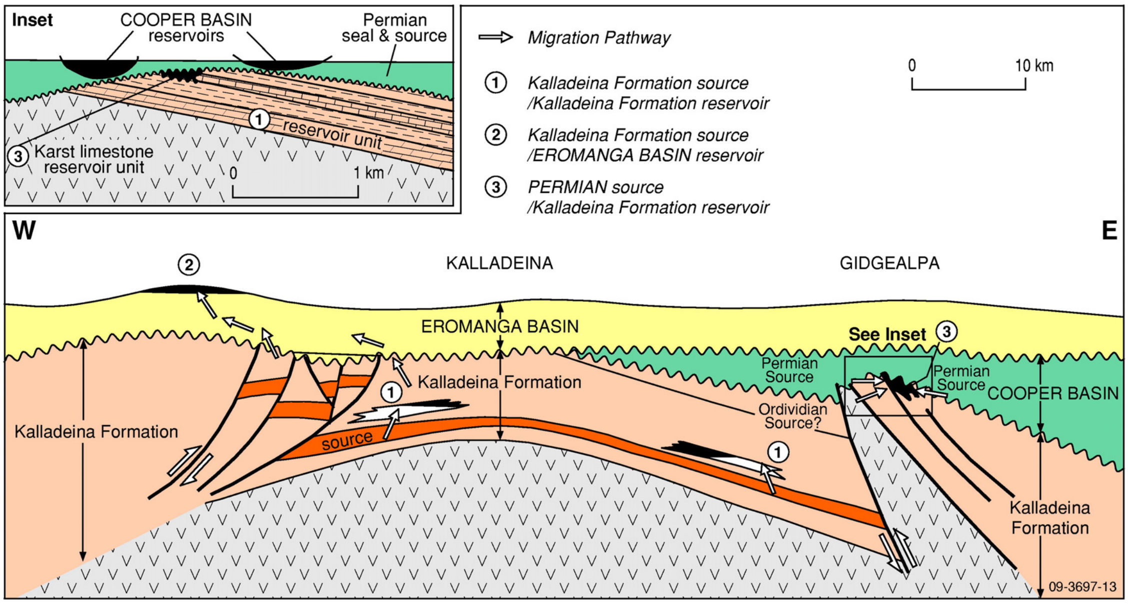


Figure 13: Migration pathways and play types for the eastern Warburton Basin (from Roberts *et al.*, 1990).

II Kalladeina Formation source and Eromanga Basin reservoir

This play shares a common source with type I, but with more extensive migration pathways.

III Cooper Basin source and Kalladeina Formation reservoir

This play accesses hydrocarbons sourced from the Cooper Basin sequence.

IIIa Karst

Irregular hill topography is interpreted on the upper unconformity of the Warburton sequence. If carbonates occur on or near this surface, then karst can be expected. A necessary requirement is that the blanketing sequence directly above is a good seal and, preferably, to also provide the hydrocarbon charge (Roberts *et al.*, 1990; Sun, 1998).

IIIb Fractured rock reservoirs

These are the current producers below the Cooper Basin, and are proposed for active exploration and exploitation by Sun (1999).

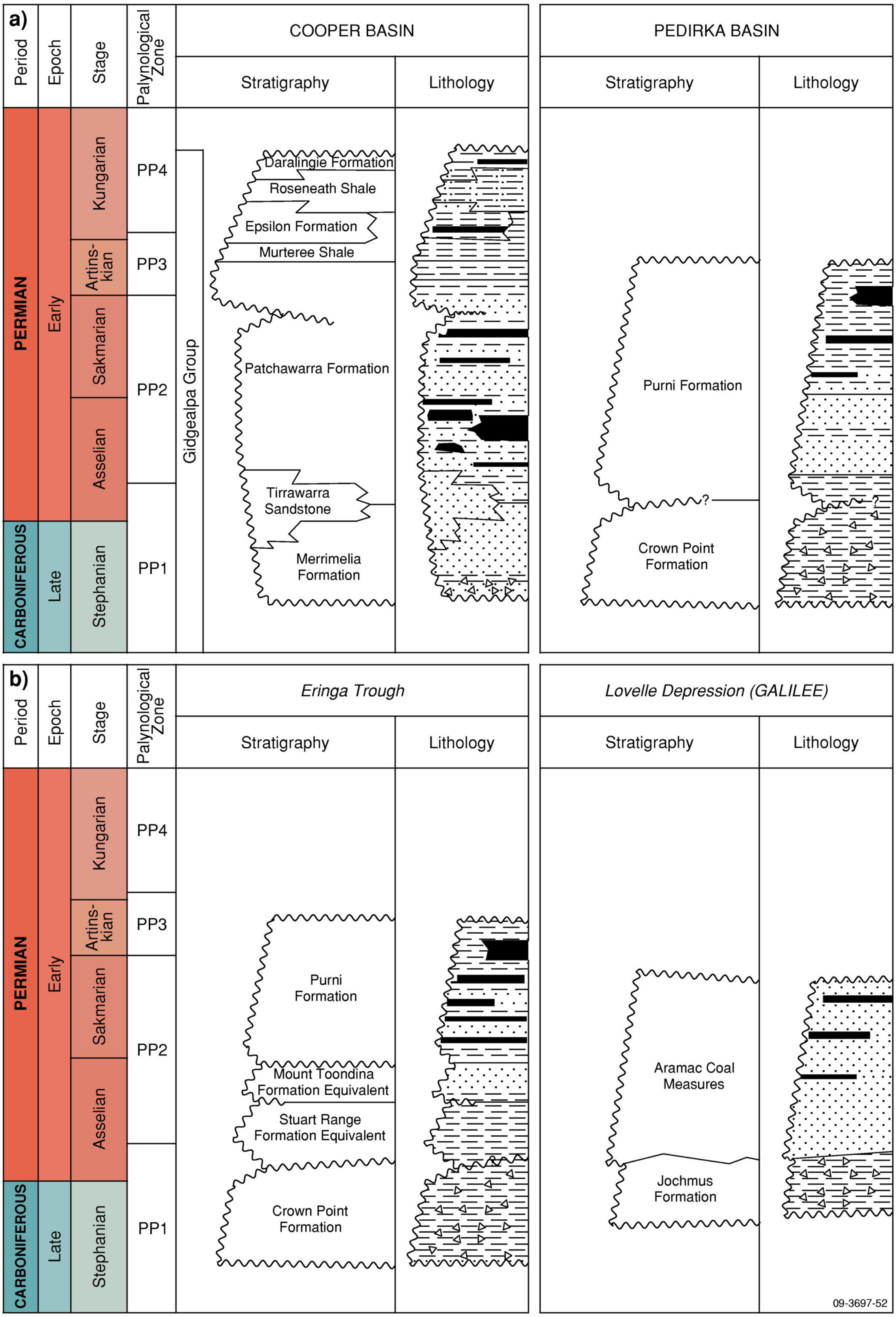


***Figure 14**: Early Permian correlations between Cooper, Pedirka and Galilee Basins (from Alexander and Jensen-Schmidt, 1995; Hawkins and Green, 1993; Evans, 1980).*

The delineation of an enigmatic and unique alteration profile at the base Cooper Basin unconformity indicates that Warburton reservoirs may be sealed by this alteration zone. Detailed maps of the thickness and extent of this potential seal are available in Boucher (2001c; 1997b).

2.2 LATE PALEOZOIC-MESOZOIC BASINS

Because of the widespread intracratonic nonmarine deposition across this part of the continent, there is a striking lithostratigraphic equivalence in the preserved remnants of the Permo-Carboniferous sequences in the Cooper, Pedirka and northern Galilee Basins (Lovelle Depression) (**Figure 14**), and the Triassic of the Cooper, Simpson and north Galilee Basins. With subsequent tectonic movement, uplift and erosion outside of the main depocentres - Cooper Basin, Eringa Trough-Poolowanna Trough, and the Lovelle Depression- any pre-existing sequence continuity that may have existed has been lost.

Recognition of the Triassic sequence in the Eringa-Poolowanna Trough area as a separate basin is not complemented within the Cooper Basin. Here the accepted and widespread use of the Gidgealpa – Nappamerri Group stratigraphic subdivision masks this similarity. The northeastern extent of the Cooper Basin in Queensland is predominantly Triassic sediments only.

Preserved remnants of the Permo-Carboniferous and Triassic sequences are a possibility in the under-explored northern region that impinges on the Arunta and Mt Isa Blocks. Conventional paradigms imply that this region has thin and shallow cover of the Eromanga Basin sequence that lies directly over 'basement'. In much of this region this may be so, but gravity and magnetic data suggests the scattered presence of underlying thicker sedimentary remnants. Ambiguity remains with the differentiation between interpreted basement granites and localised thicker remnants of deeper basins on potential field data alone (**Figures 3**, **15c**). Much of the early seismic shot in this region did not have effective penetration through coal measures in the Eromanga sequence.

This chapter addresses the superimposed basin sequences in the context of regional depocentres:
Cooper–Eromanga Basin system in the Cooper Basin depocentre,
Pedirka-Simpson-Eromanga Basin system in the Eringa & Poolowanna Troughs,
Galilee-Eromanga Basin System in the Lovelle Depression.

Summaries of these individual basins are presented in Appendix 1.

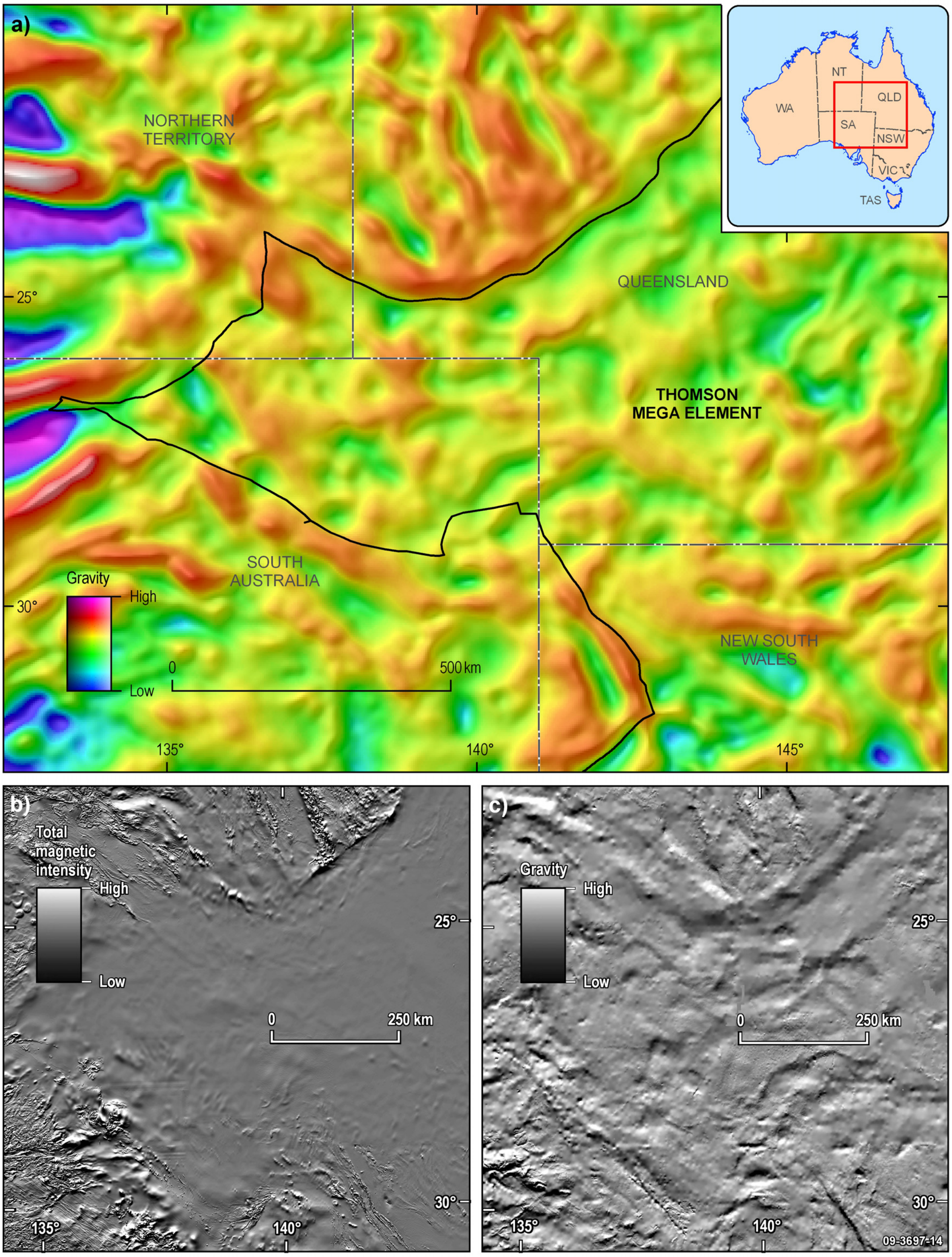


***Figure 15**: Potential Field Imagery: (a) Gravity slice (15-25 km upward slice -Morse, 2007) showing crustal structure at about 7-12 km depth. The main iden surrounding the Thomson Fold Belt supports granite dating of Draper (2005) that the Tasman Line follows around the eastern boundary of this mega-crustal iden; (b) TMI image shows Arunta Block trends extending under the Cooper Basin and also diffuse magnetic anomalies over this basin; (c) Gravity image (northern sun angle) highlights circular negative anomalies along the junction of Arunta and Lovelle Depression regions. Are these granites or small basins?*

2.2.1 Cooper–Eromanga Basin system

Although this system is currently the dominant onshore oil and gas producer in Australia, it is not addressed systematically or with any detail in this report. Exploration effort in this region has recently peaked again with almost complete stakeout **(Figure 16)** and unprecedented exploration drilling success rates.

The largest structures have already been tested but numerous smaller closures and stratigraphic plays remain to be explored. The increasing use of 3D seismic has greatly improved resolution of these subtler targets. Most significant is the exploration and success in discovery of oil in Eromanga Basin reservoirs, both beyond the extent of the underlying Cooper Basin, as well as directly over the existing Cooper Basin gas fields. The full potential of Eromanga oil directly overlying the Moomba gas field is now being addressed with a 1000 hole program scheduled to be completed by 2010.

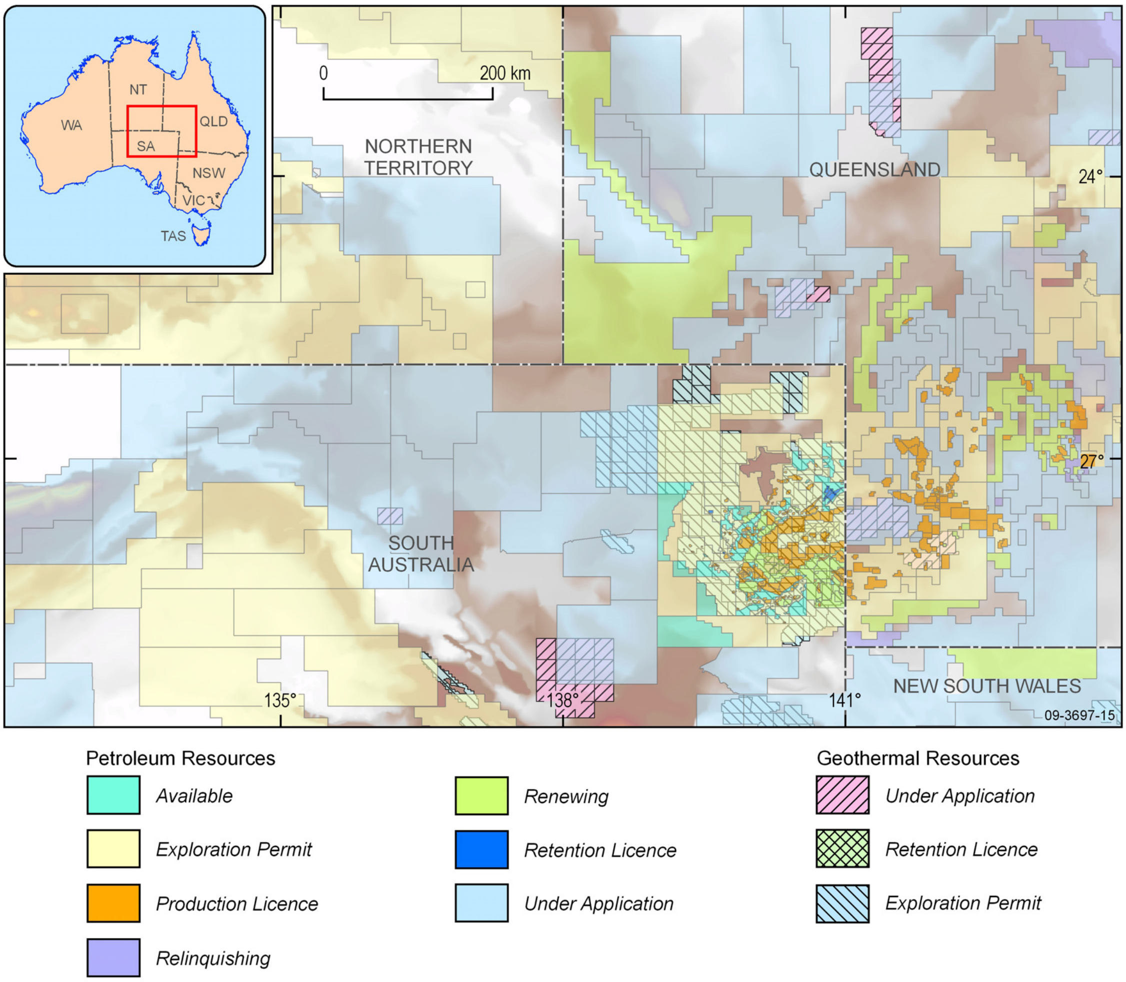


***Figure 16**: Petroleum and Geothermal exploration and production licence status (from PIRSA, 2007)*

The geology of The Cooper and Eromanga Basins is comprehensively addressed in the Petroleum Geology of South Australia, Volume 4 for the Cooper Basin (Gravestock *et al*., 1998) and Volume 2 2nd edition for the Eromanga Basin (Cotton *et al*., 2006). The Queensland sector of both basins is documented by Draper (2002).

2.2.1.1 Recognition of basement

The nature of a unique alteration profile at the basal Cooper Basin unconformity remains enigmatic. In most areas this profile appears to be a palaeosol of variable thickness and effect on different rock types in both the underlying Warburton Basin rocks and the intruding Big Lake Granites. However, this alteration zone is also known to extend upwards into the Cooper Basin sequence, a phenomenon that implies possible groundwater or hydrothermal alteration (Boucher, 1997b, 2001c).

2.2.1.2 Hydrocarbon Potential

The general view is that the system is awash with hydrocarbons that are in active migration because of the relatively recent phase of gas generation. This has been attributed to the recent increased geothermal anomaly. Gas generation within the coal measures, especially in the deeper Patchawarra Formation, is displacing oil out of Cooper reservoirs and into the overlying Eromanga reservoirs. Additionally, oil has been displaced downward into the underlying glaciogenic Tirrawarra and Merrimelia Formations. Because of this active migration event, seal integrity is not as critically important because recharge is concurrent with leakage migration (P. Boult, pers. comm., 2007).

2.2.1.3 Source rocks

Permian source rocks have average TOC and S2 pyrolysis yields of 3.9% and 6.9kg/t, respectively (excluding coals which are up to 30 m thick). Locally, the Toolachee Formation is the richest source unit. The Patchawarra Formation is considered the other major source unit, especially the lower shales and coals. The lacustrine Murteree and Roseneath Shales have relatively little source potential.

Alginites are a probable additional source to these thick coal measures. Algal source material is not distributed uniformly across the basin, but rather predominates in mud-free environments marginal to major coal accumulations - a distribution consistent with modern algal equivalents in that they required high light intensity and high nutrient environments in shallow pools or lagoons. Lindsay (2000) suggests that oil sources could be restricted to specific basinal settings lying between coal and mudstone depocentres. In the Cooper Basin, it is notable that gas shows are widespread but oil shows are areally restricted. In particular, oil shows occur on the Murteree Ridge adjacent to the main concentrations of algal material at the southeastern end of the Wooloo Trough, suggesting a local environmentally-specific source. These site specific environments could be determined to a large extent by basin dynamics (Lindsay, 2000).

2.2.1.4 Thermal history

Cumulative evidence from thermal modeling based on vitrinite reflectance, apatite fission track annealing (AFTA) and argon dating (Moussavi-Harami, 1996; Tingate and Duddy, 1996; Deighton and Hill, 1998) points to multiple oil expulsion episodes in the Cooper/Eromanga Basins. It appears that hydrocarbons were generated as a result of four main heatflow events:

Late Permian (250 Ma),
late Early Cretaceous (105 Ma),
Late Cretaceous (90-85 Ma), and
Late Neogene – present (5-2 Ma).

2.2.1.5 Structural timing, hydrocarbon generation and migration

Generation and expulsion of oil and gas in the Cooper and Eromanga Basins occurred predominantly in the mid-Late Cretaceous. In areas such as the Tirrawarra Field, additional oil was expelled in the late Paleogene. The Permian coal measures provide the bulk of the hydrocarbons generated because they contain rich source rocks that achieved suitable maturity levels. Jurassic source rocks are less rich and only achieve suitable maturity in deeper burial areas. The volumes expelled are theoretically large, up to 120 bbl/m^2 of kitchen area at Tirrawarra North (Deighton *et al.,* 2003). On the basis of geohistory modeling of burial, and palaeotemperatures, maturity, generation and expulsion maps were prepared for the Patchawarra and Toolachee Formations in the Cooper Basin, and the Poolowanna and Birkhead Formations in the Eromanga Basin (Deighton *et al.,* 2003).

The late Cretaceous event was probably the 'critical moment' that resulted in maximum expulsion from both the Permian and Jurassic source rocks in response to a combination of high heat flow and maximum burial. Oil produced in the first expulsion event can have been trapped only in the Cooper Basin sequence – as this event predated deposition of the Eromanga sequence - but possibly remobilized later because of restructuring and fault reactivation (Arouri *et al.,* 2004) and later gas generation. The main gas generation event in the Cooper Basin sequence is indicated from modeling to have peaked at 90 Ma. However, recent studies in charge histories of reservoirs would suggest considerable generation also during the most recent thermal event in the last 5 million years, with subsequent displacement and spilling of oil upsequence (P. Boult, pers comm., 2007). This would explain observations that oil is currently in active migration, with accumulations trapped beneath dynamic seals (Boult *et al*, 1998, Steve Le Poidevin pers.comm., 2007).

The predominant component of known oil in the Eromanga Basin sequence comprises up to 97% Permian oil. This compelling statistic reflects the prevailing exploration tenet of the past 30 years which has kept exploration of the Eromanga sequence focussed predominantly in areas that are underlain by Permian sediments. However, the recent Christies 1 oil discovery demonstrates that outside of the Permian Patchawarra edge, the Eromanga contribution increases significantly (Errock, 2005) **(Figure 17)**.

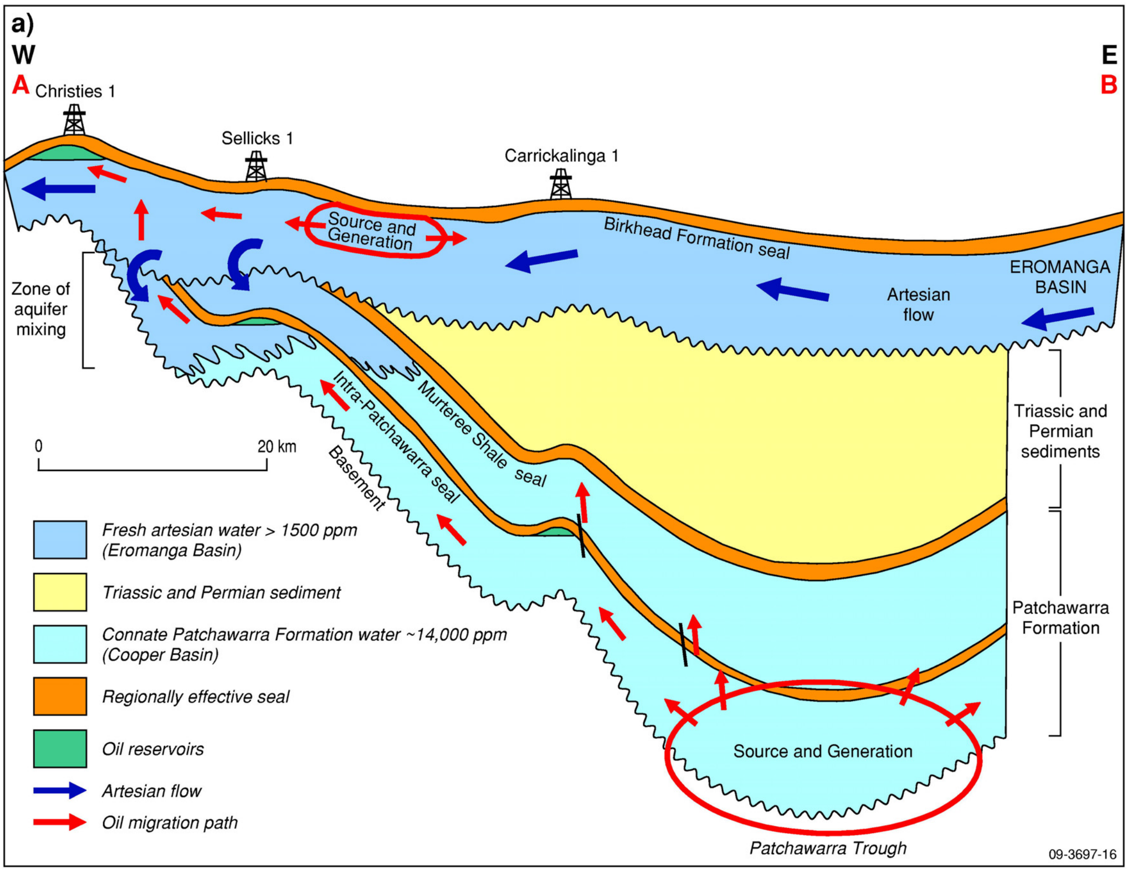


***Figure 17** :(a) Schematics of Permian and Jurassic source kitchens contributing to mixed charge accumulations in the Eromanga reservoirs (after Altmann and Gordon, 2004; Errock, 2005).*

2.2.1.6 Reservoirs and seals

Hydrocarbon discoveries have a wide stratigraphic distribution in the Cooper/Eromanga province, spanning almost the entire succession of both basins. The main producing reservoirs are the fluvial sands of the Patchawarra Formation and Hutton Sandstone, with the Birkhead and Poolowanna Formations hosting smaller oil pools (Gravestock *et al.,* 1998 a, b). Other important reservoirs include the Tirrawarra Sandstone and Toolachee Formation (Permian), Namur Sandstone (Jurassic-Cretaceous), the Murta Formation and its McKinlay Member (Cretaceous). These aforementioned accumulations are trapped by either regional or intraformational seals. The indicated stratigraphic levels are summarised in **Figures 18** and **19**.

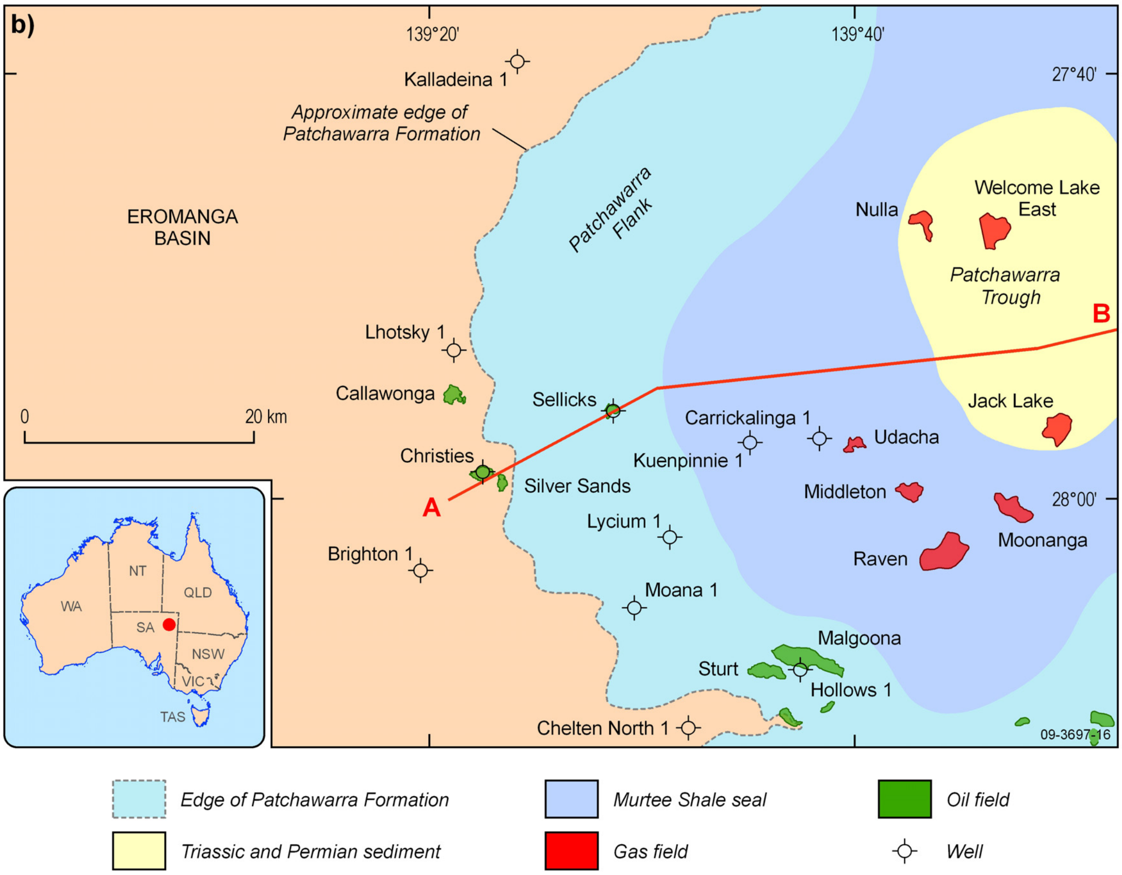


Figure 17: *(b) Schematics of Permian and Jurassic source kitchens contributing to mixed charge accumulations in the Eromanga reservoirs line location for part a. (after Altmann and Gordon, 2004; Errock, 2005).*

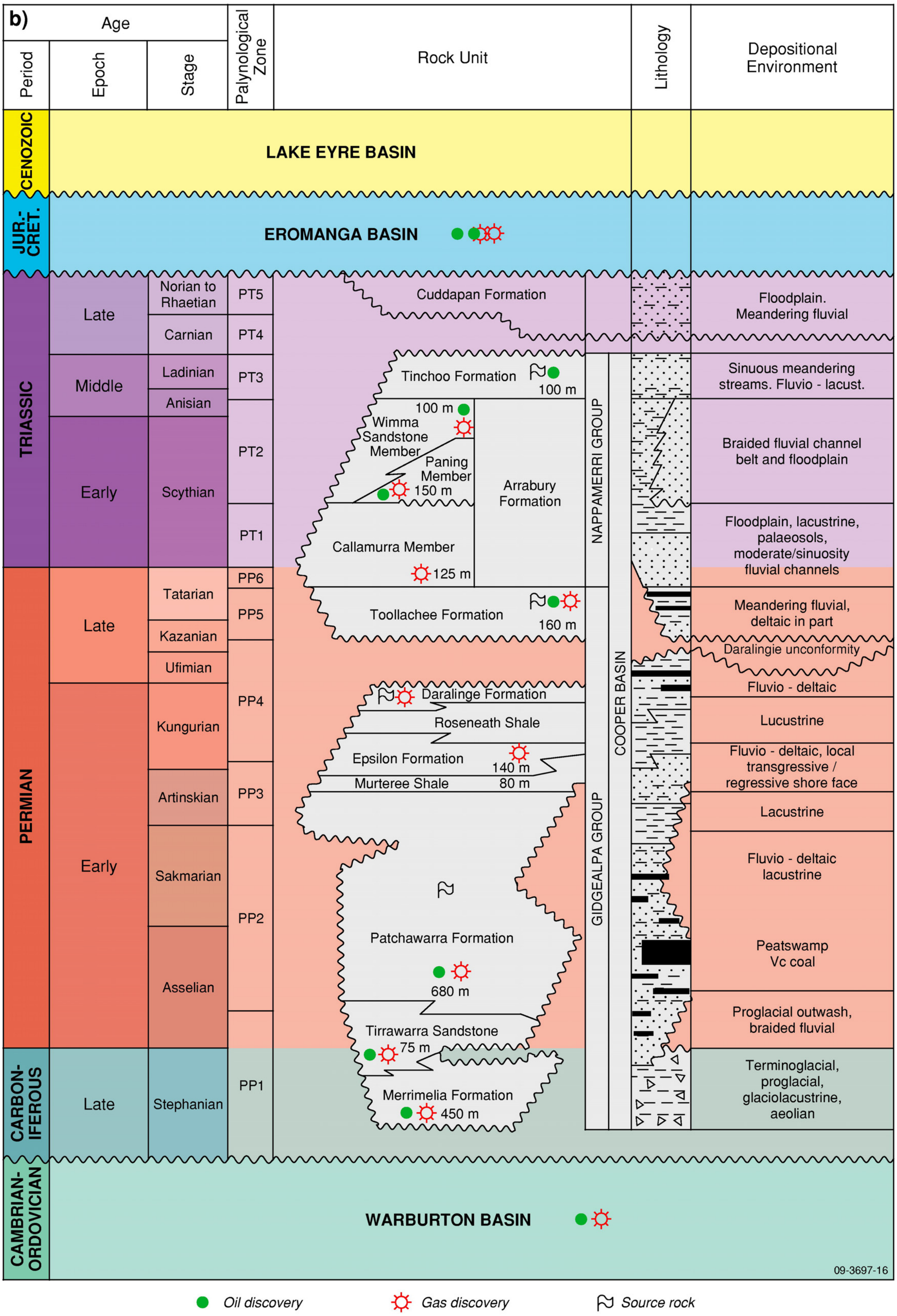


Figure 18 Stratigraphy of the Cooper Basin in South Australia (from PIRSA, 2007).

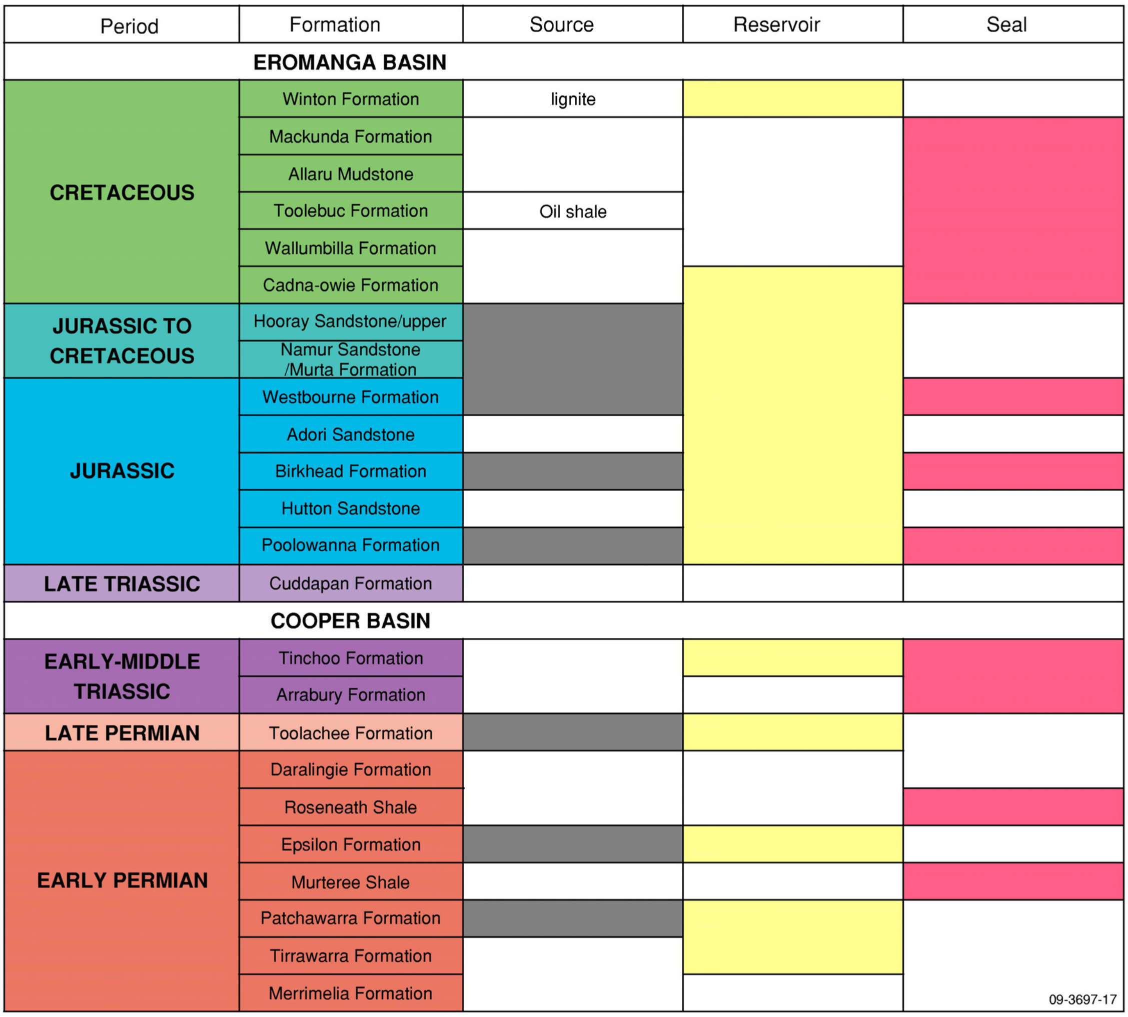


Figure 19: *Stratigraphic units and presence of source, reservoir and seal rocks in the Cooper–Eromanga Basins (from Deighton et al., 2003).*

Regional seals recognised within the Cooper Basin are the Permian Murteree and Roseneath shales, and the Triassic Arrabury Formation (Nappamerri Group). In the Eromanga sequence, seals are mainly carbonaceous shales of the Middle Jurassic Birkhead Formation, Early Cretaceous Murta Formation and the Bulldog Shale/Wallumbilla Formation. Fine-grained carbonaceous (in some instances coaly) lithofacies within the different reservoirs are relatively widespread and form effective intraformational seals that in fact cap the majority of the oil and gas fields in the Cooper Basin (Gravestock *et al*., 1998 a, b). Where regional seals pinchout on ridges or towards basin margins, or where intraformational seals are filled to spill point, stacked hydrocarbon pools can be expected (Heath *et al.,* 1989; Boult *et al*., 1998; Gravestock *et al*., 1998).

Mixing of Permian oil with younger hydrocarbons could have also been facilitated where the efficacy of the seal was inadequate to retain the hydrocarbon column until its structural spillpoint was reached (Boult *et al.,* 1998; Gravestock *et al*., 1998a, b). Jurassic-Cretaceous structuring with resultant drape over old structures is common, and there has been additional Late-Cretaceous-Paleogene structural reactivation.

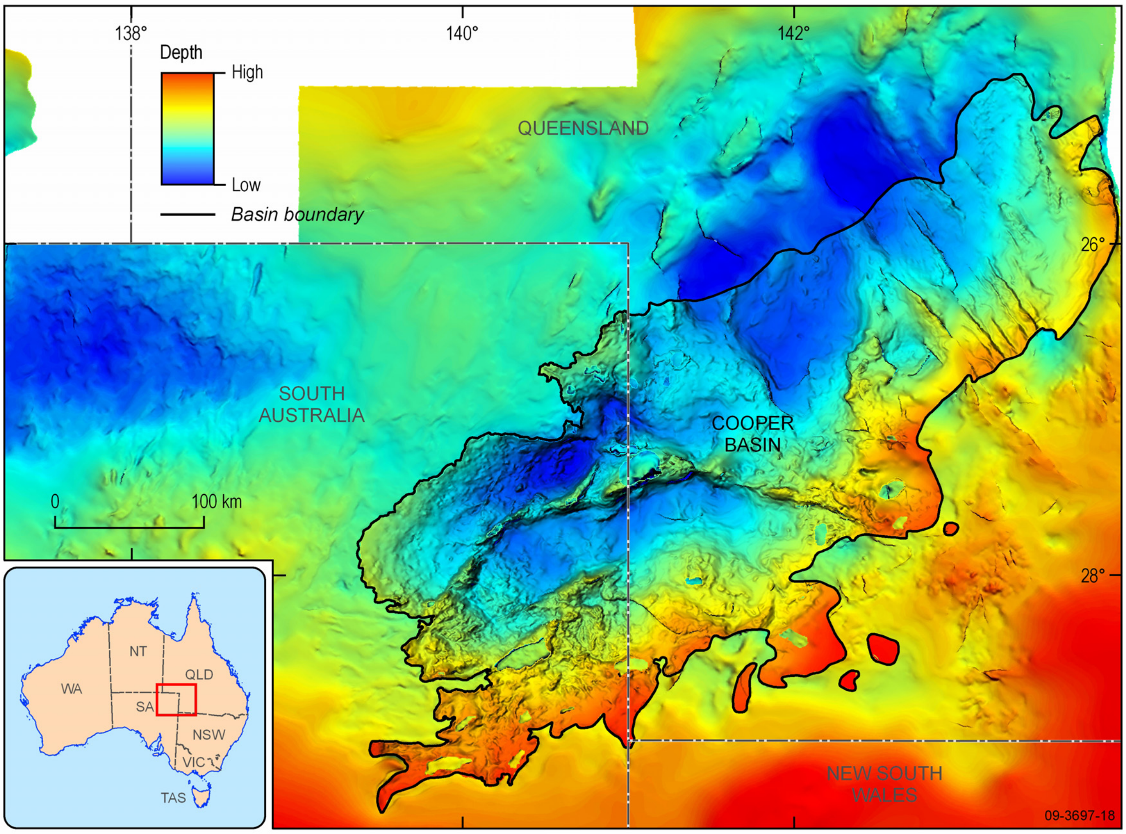


***Figure 20**: 'P' seismic horizon defines relationship of Permian Cooper Basin to the northwestern -offset Eromanga depocentre, which has created a tilted Cooper Basin. This surface of the 'P' seismic horizon is superimposed on a background surface of the 'Z' seismic horizon (pre-Permian) (from NGMA).*

2.2.1.7 Exploration Potential

Both Cooper and Eromanga Basin source rocks have contributed to oil accumulations in the region. Since this conceptual breakthrough of Heath *et al.* (1989), the commonly-accepted exploration paradigm is that oil hosted in the Eromanga reservoirs is predominantly Permian in origin; hence a Cooper substrate or migration pathway from this source sequence is required. The 'P' seismic horizon (near top of the Permian Toolachee Formation) in **figure 20** shows a regional asymmetric tilt to the remnant preserved basin, with higher flanks to the southeast. The axis of the Eromanga depocentre was apparently offset to the northwest of the Cooper Axis, especially in Queensland from the Yamma Yamma Depression and further northeast, thus creating the regional asymmetry of the Cooper Basin. This accounts for the largest known oil accumulations within the Eromanga reservoirs to lie on the southeastern flank of the Cooper Basin – such as seen in the fields on the Jackson-Naccowlah-Pepita trend, at Kenmore and at Bodalla in Queensland. To the southwest along this margin into South Australia, oil fields of comparable size are few. Structure is more complex within the Cooper Basin here, with numerous structural highs in the Tenappera and southwestern Nappamerri Troughs, and where local vertical migration of oil was apparently predominant. Consequently, the Eromanga sequence cover over the known oil and gas fields in this part of the Cooper Basin has high exploration potential, especially over the bald pre-Permian highs. A possible dearth of suitable traps in the Eromanga sequence around the southeastern margin has probably allowed any oil that migrated out and beyond Cooper Basin seals, to be largely lost to the system.

Along the northwestern flank of the Patchawarra Trough in South Australia, a similar Jurassic Oil fairway has been confirmed with many subtler and smaller structures.

Largely under-estimated is the recognition of the altered zone below the Cooper Basin as a potential seal for hydrocarbons within both the underlying Warburton Basin and the fractured Big Lake Granites.

Play concepts are too numerous to discuss here. There are many variants as illustrated in Gravestock *et al.* (1998) and Appendix 1. Stratigraphic traps have not been discussed as initial exploration almost exclusively targeted structure. As more detailed understanding of reservoir anisotropy develops for discovered fields, stratigraphic-lithofacies considerations become increasingly important to facilitate and optimise recovery.

2.2.2 Warburton/Amadeus -Pedirka-Simpson-Eromanga Basin system (Eringa, Madigan and Poolowanna Troughs)

Confusingly referred to as the Pedirka area is a region in the Simpson Desert that encompasses four superimposed sedimentary basins - parts of the Paleozoic Warburton/Amadeus Basins, the Permo-Carboniferous Pedirka Basin, the Triassic Simpson Basin, and the Jurassic-Cretaceous Eromanga Basin **(Figures 21, 22)**. This region straddles the jurisdictions of South Australia, Northern Territory and Queensland. The geology of the region is addressed by Questa (1990), Alexander and Jensen-Schmidt (1995), Ambrose *et al.* (2002, 2007), Cotton *et al.* (2006), and Draper (2002).

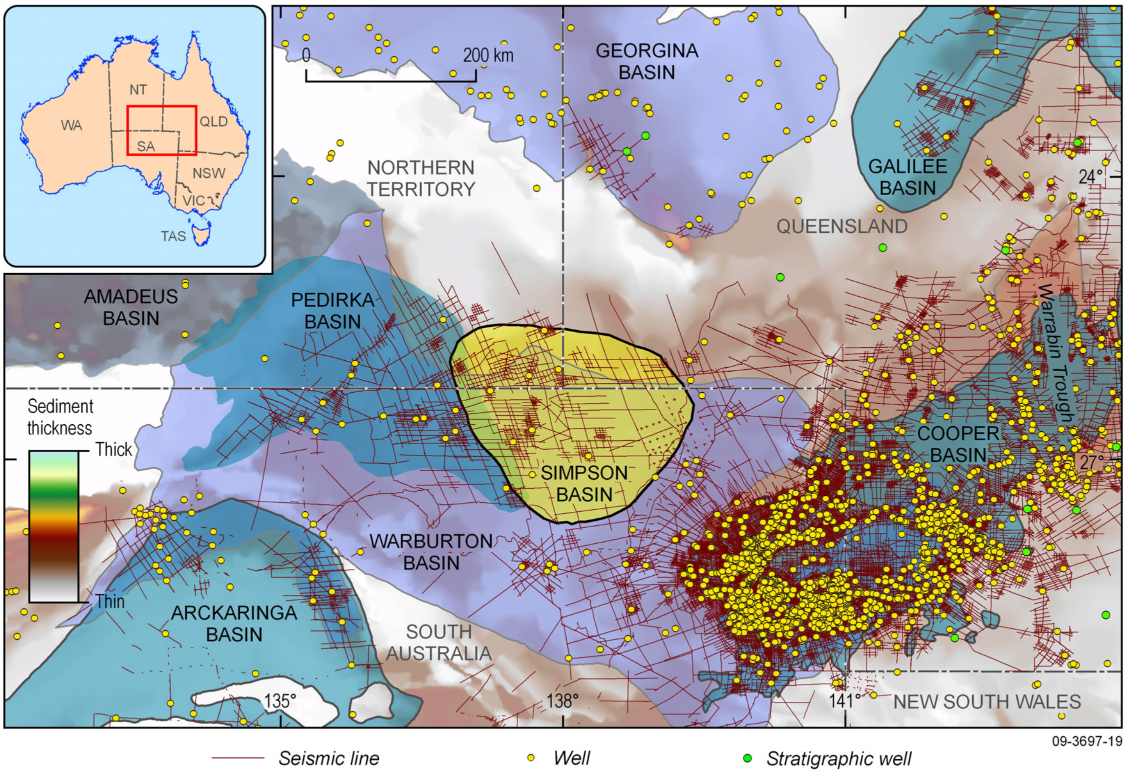


***Figure 21**: Relationship between Phanerozoic sedimentary basins over total sedimentary thickness (FrOG Tech, 2005), seismic and well data.*

2.2.2.1 Structural elements

The region can be divided into three sub-basins or preserved depocentres enclosed by the Arunta Platform to the northeast, Amadeus Basin to the northwest, Musgrave Block to the west-southwest, Muloorinna Ridge which demarcates the Officer and Arckaringa Basins to the southwest, and the Birdsville Track Ridge to the east. In this region and west of the Dalhousie-McDills-Mayhew (DMM) Ridge lies the north-northeast – south-southwest oriented Eringa Trough. Immediately east of the DMM Ridge and contained further east by the paralleling Border Trend is the Madigan Trough that is developed only in the Northern Territory. East of the Border Trend lies the much

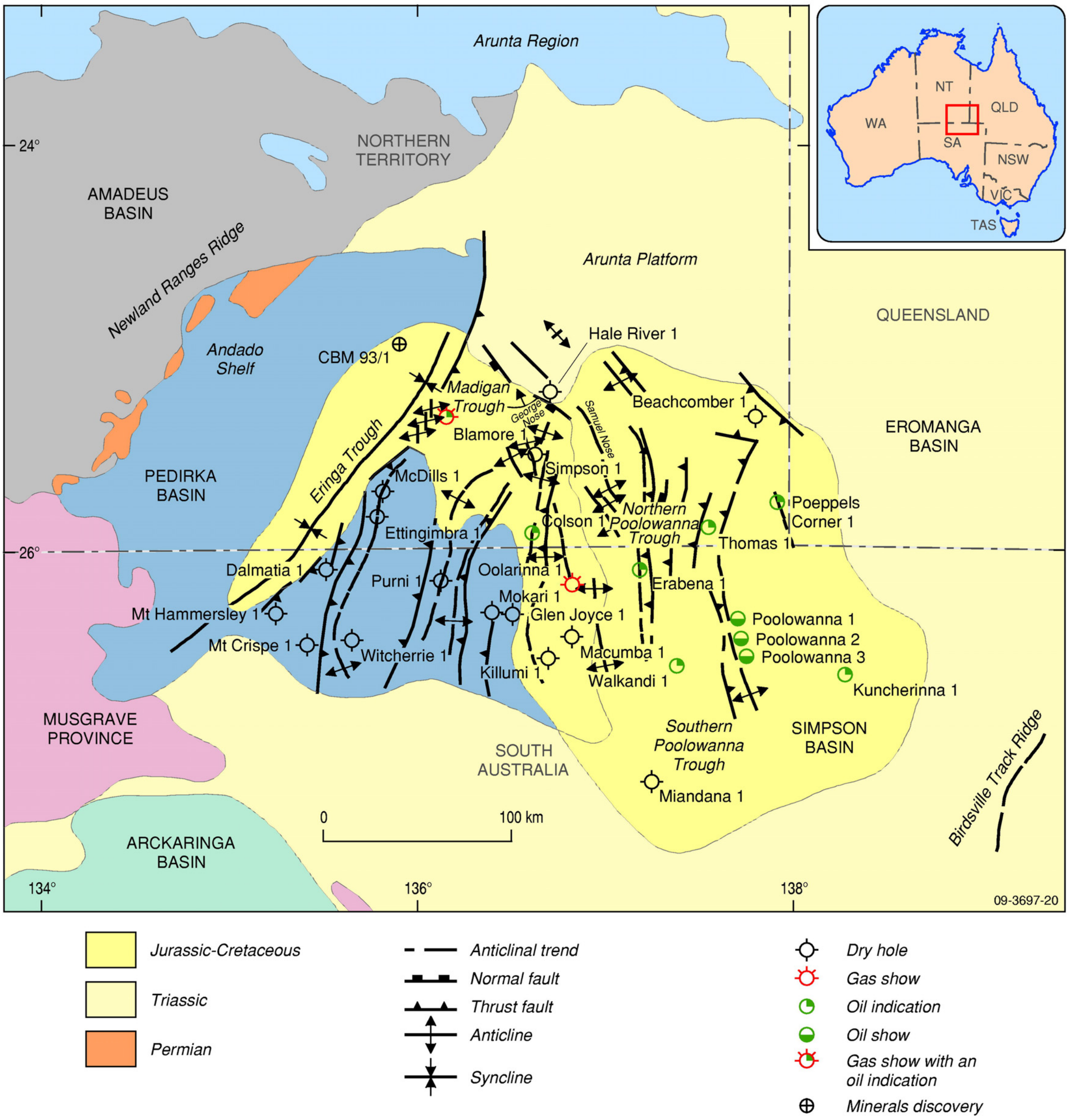


Figure 22: *Structural elements and relationship between the Pedirka, Simpson and Eromanga Basins (from Ambrose et al., 2007).*

larger Poolowanna Trough, bounded on its eastern flank by the Birdsville Track Ridge. This high separates this trough from the much deeper Cooper Basin. These ridges were initiated as overthrusts during the Devonian to Carboniferous Alice Springs Orogeny. They represent major pre-Permian tectonic boundaries but by Permian time had become relatively subtle features (Carne and Alexander, 1997).

The western Warburton Basin unconformably undelies the Pedirka-Simpson-Eromanga basins suite and was considered basement. Shelf and platform facies of the Cambrian sequence have been intercepted by wells. However, a depocentre with different structural grain and containing basinal facies is suspected in the region (Questa, 1990). The intercepted Ordovician siliciclastics have close similarities to the Amadeus sequence. Devonian and Siluro-Devonian rocks have been intercepted on the flanks of the DMM Ridge, and in parts of basement to the Poolowanna Trough.

The preserved sequence of the Carboniferous-Permian Pedirka Basin extends from the Newlands Ranges Ridge, the only region of surface exposure along the main southeastern margin of the Amadeus Basin, across the Andado Shelf and eastwards into the Eringa and Madigan Troughs. This basin has erosional thinning further east into the western quarter of the Poolowanna Trough. The Triassic Simpson Basin is preserved in the central parts of the Eringa, Madigan, and Poolowanna Troughs, and extends eastward onto the Birdsville Track Ridge (intersected in Pandieburra 1 and Koonchera 1). The whole region is covered by the Eromanga Basin which has depocentres in all three troughs **(Figures 23, 24).**

2.2.2.2 Hydrocarbon Potential

The evidence for petroleum generation is compelling. High quality oil-prone source rocks have been identified in enough wells to imply their development over a wide area of the western Eromanga Basin (Michaelsen and McKirdy, 1996). Geochemical investigations have revealed excellent oil-prone source rocks in the Eringa Trough that have reached temperatures sufficient for petroleum generation (Alexander *et al.,* 1996; Tingate and Duddy, 1996; Ambrose *et al.,* 2002). In the Poolowanna Trough, hydrocarbon generation is proven by the existence of oil shows in five wells at the Simpson Basin level, including the DST recovery of two distinct types of oil from the Triassic Peera Peera and Jurassic Poolowanna formations in Poolowanna 1 (Wiltshire, 1978). In the northern Poolowanna Trough and Madigan Trough (Northern Territory), Early Permian source rocks are predicted to have expelled significant quantities of oil and gas during deposition of the Winton Formation (Ambrose *et al*., 2002).

Twenty-four petroleum exploration and two appraisal wells have been drilled in this region to test the Mesozoic to Ordovican sequence without a commercial discovery being made except for coal bed methane. A relative lack of maturity of hydrocarbon source material has proven to be a main reason for the disappointing absence of success. Adequate oil prone source rocks and porous and permeable reservoirs with effective overlying seals have been found in all of the 24 wells. A large number of structures and structural types remain to be tested, many of them presenting an early structural history. Mt Hammersley 1 in 1987 has demonstrated that the Eringa Trough contains a much thicker succession of sedimentary rocks than seen elsewhere in the Pedirka Basin. It is highly probable that Permian and Triassic sediments in this trough would have reached temperatures sufficient for peak generation and migration of oil, and it is postulated that source rock horizons in the Eringa and Madigan troughs will prove to be organically very rich with a larger portion of exinitic (oil prone) material (Questa, 1990). Drilling in 2008 by Central Petroleum has confirmed very thick coal measures in the depocentres.

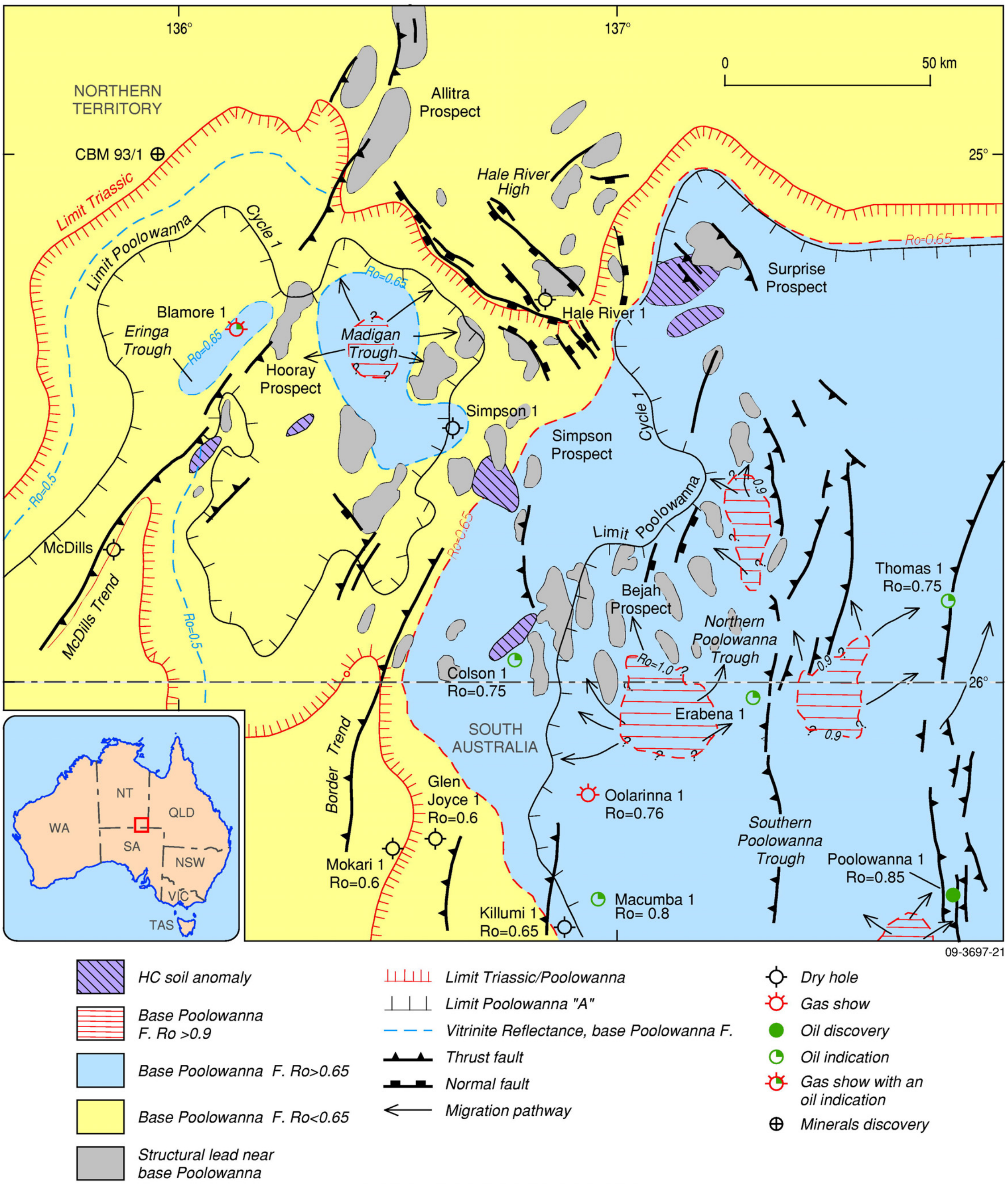


Figure 23: *Relationship of the Eringa, Madigan and Poolowanna Troughs with thermal maturity (isoreflectance contours), structure and leads (from Ambrose, 2005).*

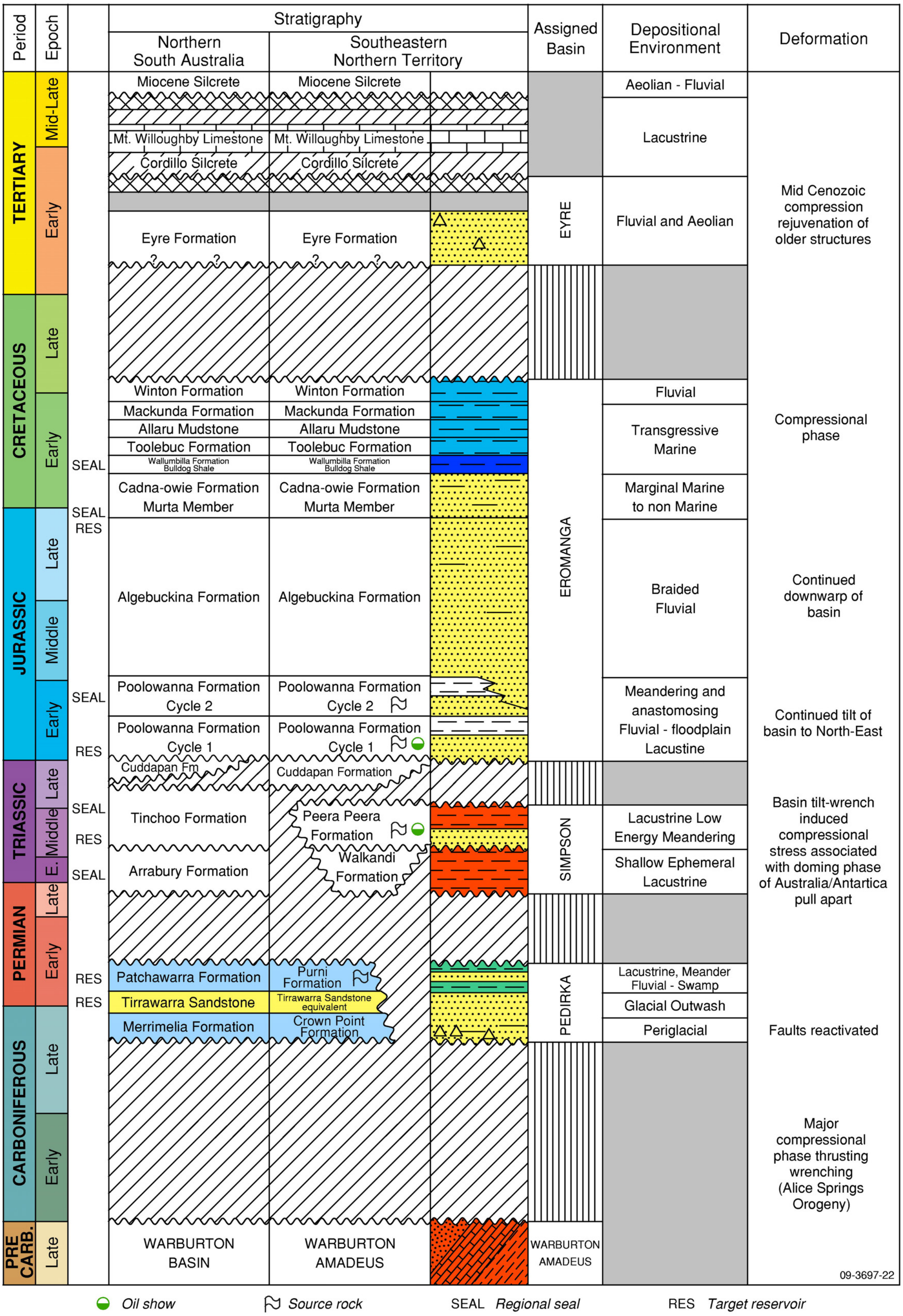


***Figure 24**: Stratigraphy of the Pedirka, Simpson and Eromanga Basins (from Ambrose et al., 2007).*

The pre- Permo-Carboniferous section along and to the west of the DMM Trend provides additional potential, the Mereenie Sandstone exhibiting particularly good reservoir properties at McDills 1. This play is complex but the missing ingredient is an effective source rock. Horn Valley Siltstone (Amadeus Basin nomenclature) equivalents have been identified at Colson 1 and Hammersley 1, and source quality of the unit could improve towards the west into the Eringa Trough where reducing depositional conditions are probable.

The Eringa Trough area appears to have been a pronounced depression of unknown alignment during Early Paleozoic time, with an anticipated different suite of basinal facies to the shelf/platform facies intercepted to date. It forms the apparent link between the Warburton, Amadeus and Officer Basins. Basin architecture is unknown due to only partial seismic coverage and where it exists, lacks adequate penetration to delineate any deep structure.

2.2.2.3 Hydrocarbon shows

Numerous hydrocarbon shows have been encountered in the region, although significant shows have been rare and commercial flows have not been obtained. Most of the explorations wells have been drilled in the shallower parts of the basin to the south (predominantly in South Australia) where a lack of organic maturity has been the issue. Poolowanna 1, drilled in a structural depression in the central Poolowanna Trough region, remains the most significant and encouraging, and was the first well to intersect oil in the Eromanga sequence. Several sandstones in the middle part of the Jurassic Poolowanna Formation yielded an initial flow of oil to surface of 4 barrels/hour but water was being recovered with the oil after a few hours of production. This waxy parrafinic crude was 37^{o}API gravity with a pour point of 41^{o}C, indicating a mature oil which was severely water-washed, having lost the lighter hydrocarbon fractions and gas. This oil was present in fractures but appeared not to have saturated intergranular voids, with the exception of thin sandstones at 2559 m. Poolowanna 2 was drilled low to prediction, and appeared to have intercepted the reservoir below the oil/water contact. Poolowanna 3 encountered an oil-saturated section at the same structural level as Poolowanna 1 but recovered oil cut water from a relatively tight sand.

Hydrocarbon shows from wells in the Northern Territory are disappointing, having been drilled into structurally shallow parts of the basin where source rocks remain immature for significant generation and migration of hydrocarbons. Shows from Colson 1, Thomas 1 and Poeppels Corner 1 are more encouraging. The hydrocarbon charge and migration history of the Poolowanna Formation is recognised in Colson 1 on the evidence of a palaeo-oil and gas accumulation over a 70 m interval (Ambrose *et al*., 2002). In 2008, Blamore 1 intersected a 15 m thick palaeo-oil accumulation within the Algebuckina Sandstone at 996-1017 m. Thomas 1 encountered residual oil shows in the lower Poolowanna Formation (2183-2278 m) and in the basal Algebuckina Sandstone, minor fluorescence and oil in coal cleats within the Peera Peera Formation. Poeppels Corner 1 had no significant hydrocarbon shows, but repeated fluorescence was evident in side wall cores from the Peera Peera Formation (2290 m), Poolowanna Formation, Algebuckina Sandstone, and Cadna-owie Formation (1403 and 1435 m) (Questa, 1990).

A complete inventory of hydrocarbon shows is tabulated by Questa (1990, Table 1), and dry hole analysis is presented in Alexander and Jensen-Schmidt (1995) and Carne and Alexander (1997).

2.2.2.4 Source rocks

With an abundance of coal and fine-grained siliciclastics, fair to excellent source potential is indicated in four formations: the Algebuckina, Poolowanna, Peera Peera, and Purni Formations. Lesser potential is seen in the Wallumbilla, Bulldog Shale, Cadna-owie and Crown Point Formations (**Figure 25**). Dispersed organic matter and coals in the sequence are in general, vitrinite and inertinite predominant, and lean in exinite.

The Wallumbilla and Cadna-owie Formations are not considered important hydrocarbon sources, however the Cadna-owie still has some potential for both oil and gas generation. Type III (vitrinite) kerogen is predominant but locally exinite can constitute as much as 35% of organics (i.e. in Colson 1). Although a sandstone interval, TOC in the Algebuckina Sandstone can be as high as 10% with exinite comprising up to 30% of macerals. Most notable is the heterogeneity of dispersed organic matter where vitrinite is the dominant maceral.

The Poolowanna Formation reaches in excess of 200 m thickness in the more prominent structural depressions and has one of the richest source rocks, containing up to 15% TOC. Coals and coal-related lithologies are volumetrically important in the sequence. Maceral composition ranges from vitrinite and vitrinite-rich clarite through a range of trimacerites to durite. Inertinite is dominant in dispersed organic matter (DOM) but vitrinite is also abundant. Eastwards to Poeppels Corner 1, woody herbaceous DOM is rich in exinite.

The Peera Peera Formation has fair to good hydrocarbon potential with TOC as high as 5%. Generally the DOM is higher towards the top of the unit and inertinite is dominant. Much of the source potential of this unit lies in its abundant coals which have comparable macerals to those in the overlying Poolowanna Formation. The formation appears to be predominantly gas prone but with potential for a modest oil yield.

The upper and lower members of the Purni Formation have alternating shale, coal and siltstones of lacustrine, swamp and floodplain deposition. These have good to excellent source rock potential. Coals are the richest source rocks, and comprise predominantly vitrinite and inertinite, with exinite generally less than 5% (but up to 20%). DOM in carbonaceous shales is generally poor. In the eastern Pedirka, Purni Formation sediments contain both H–rich exinite and vitrinite, and H-poor vitrinite rich source rocks (Questa, 1990). These rocks equate to the lower Patchawarra Formation in the Cooper Basin. Drilling in 2008 by Central Petroleum has established extremely thick coal accumulations away from structural highs, with cumulative thicknesses exceeding 100m for individual seams thicker than 2 m.

Glaciogenic shales in the Crown Point Formation are organically lean (averaging <0.5% TOC) from rare dispersed organic matter. Kerogens are H-poor.

2.2.2.5 Thermal maturity

Vitrinite reflectance and spore thermal alteration indices (TAI) indicate that the Cretaceous and Middle-Late Jurassic sequences are predominantly immature to marginally mature for effective oil generation and expulsion (R_o <0.7%). However, the Early Jurassic (Poolowanna) and Permo-Triassic sequences have reached the main oil generative window (R_o 0.7-0.9%) over large portions of the region (**Figure 25**).

Maturation modelling of Questa (1990) incorporated quantitative organic geochemistry, and indicated that conditions necessary for peak oil generation would only have been reached by the Eocene or later, after the last structural deformation (Kosciuskan Orogeny). Structures then present in the basin would have been available as effective traps for any major hydrocarbon generation (Questa, 1990). However, new burial and thermal geohistory modelling with more recent techniques suggests oil and gas generation and expulsion from Carboniferous-Permian source kitchens responded to increased temperatures of early Late Cretaceous, due in part to sediment loading by the deposition of the Winton Formation. Peak expulsion of oil and gas from the Purni Formation occurred in the Bejah Syncline over about 11-80 Ma, and 90 Ma in the Madigan and northern Poolowanna Trough (Ambrose *et al*., 2002) (**Figures 26, 27**).

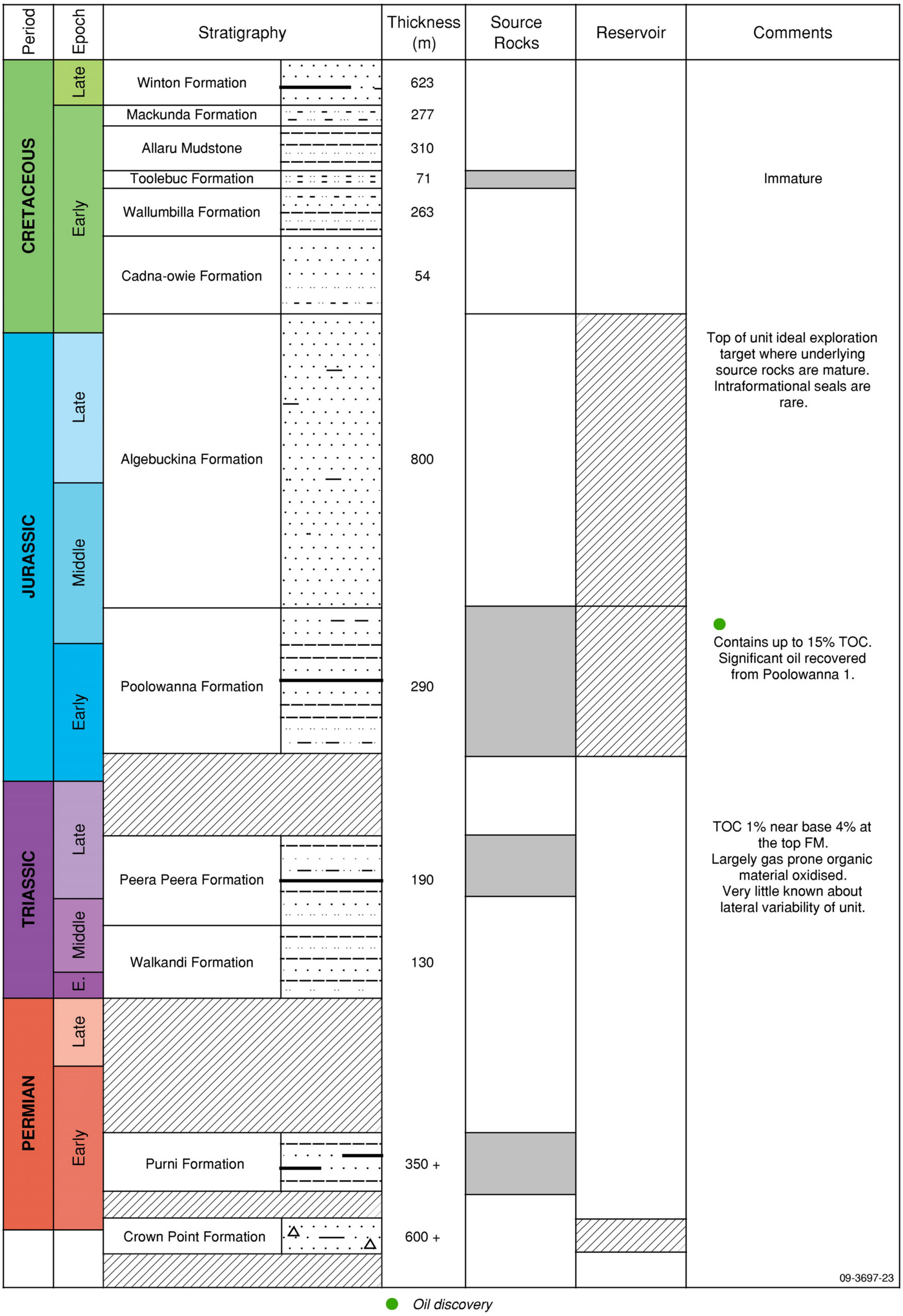


Figure 25: *Source and reservoir units in the Pedirka, Simpson and Eromanga Basins (from Questa, 1990)*

Oil has been recovered from Poolowanna 1, the second deepest well in the Poolowanna Trough, and this indicates that where sufficient maturity of source rocks exists, small but commercial oil accumulations are probable.

Organic maturation evaluation from vitrinite reflectance, spore colouration (TAI), Rock-Eval Pyrolysis and cuttings gas analysis indicates generally good correlation between methods except TAI may be locally high, probably from oxidation effects.

Onset of oil generation (R_o=0.5%) would generally be expected with burial at 1500 m, and peak oil generation (R_o=0.7%) at 2200 m, although there is considerable scatter in the oil window because of variations in both dominant maceral types in the organic matter and the local geothermal gradient. Gas generation is expected from 0.6% R_o at 1900 m. The maturity threshold for oil generation is considerably varied by the dominant maceral present in the source rocks. Resinite-rich sources can commence generation at 0.45% R_o, compared to 0.7% R_o for resinite-poor organic matter. Algal or bacterial matter has a generation threshold at 0.5% R_o (Powell and Snowdon, 1983; Monnier *et al.*, 1983). Resinite is only a minor constituent of DOM in the known richer source rocks of the region so R_o of 0.7% may be more indicative of the oil generation threshold.

The presence of exsudatinite and fluorinite in the Algebuckina and Poolowanna formations in Walkandi 1 indicates that prolific oil generation has occurred (R_o 0.69% in Poolowanna shales).

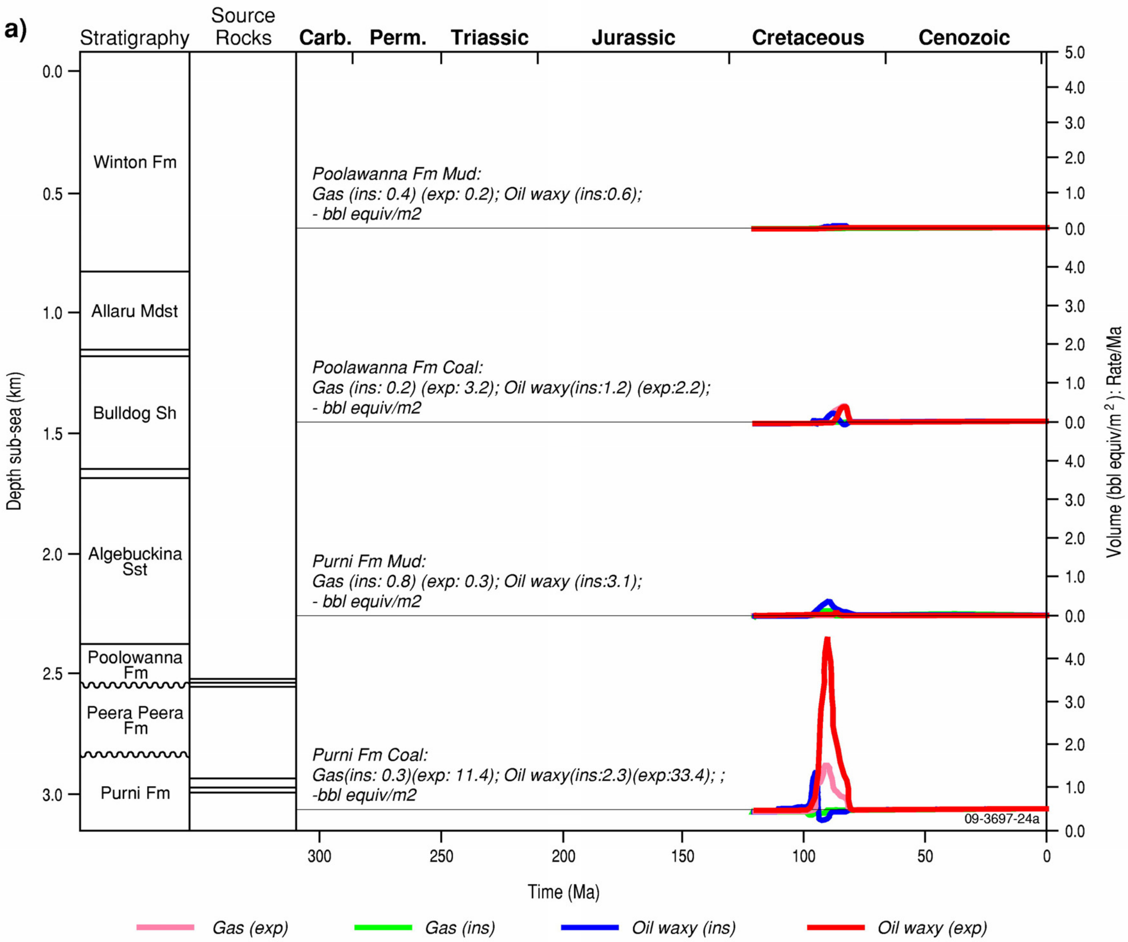


Figure 26 (a): *Maturation and expulsion modelling for the (a) North Poolowanna Trough (from Ambrose et al., 2002).*

2.2.2.6 Thermal history

Geothermal gradients in the Eringa-Poolowanna Troughs are significantly lower than in the Cooper Basin. Although variable within individual wells and lithofacies, gradients appear to regionally increase from about 3^{o}C/100 m in the west (Mokari 1, McDills 1, Hammersley 1) to almost 5^{o}C/100 m to the east in Beachcomber 1. Present day geothermal gradients are higher now than prior to about 5-10 Ma, but it is unknown whether the gradient increased steadily after a Late Cretaceous low, or was a sudden and more recent phenomenon. This is indicated by the disparity between recorded vitrinite reflectance values with calculated maturation modelling indices. The observed high gradient appears to be regional, as it is similar in timing and magnitude to that suggested by Pitt (1986) and Deighton *et al.* (2003) for the Cooper/Eromanga basins. Some evidence suggests an earlier pulse of high gradients in the Permian to Jurassic but this may actually be indicating changes in the geothermal gradient between lithofacies.

The geothermal history of the pre-Permian sequence is unknown.
High heat flow may have occurred with the Alice Springs Orogeny in Early to Late Carboniferous time. However, there is no evidence of high geothermal gradients in the Paleozoic sequence in the Amadeus Basin (Questa, 1990).

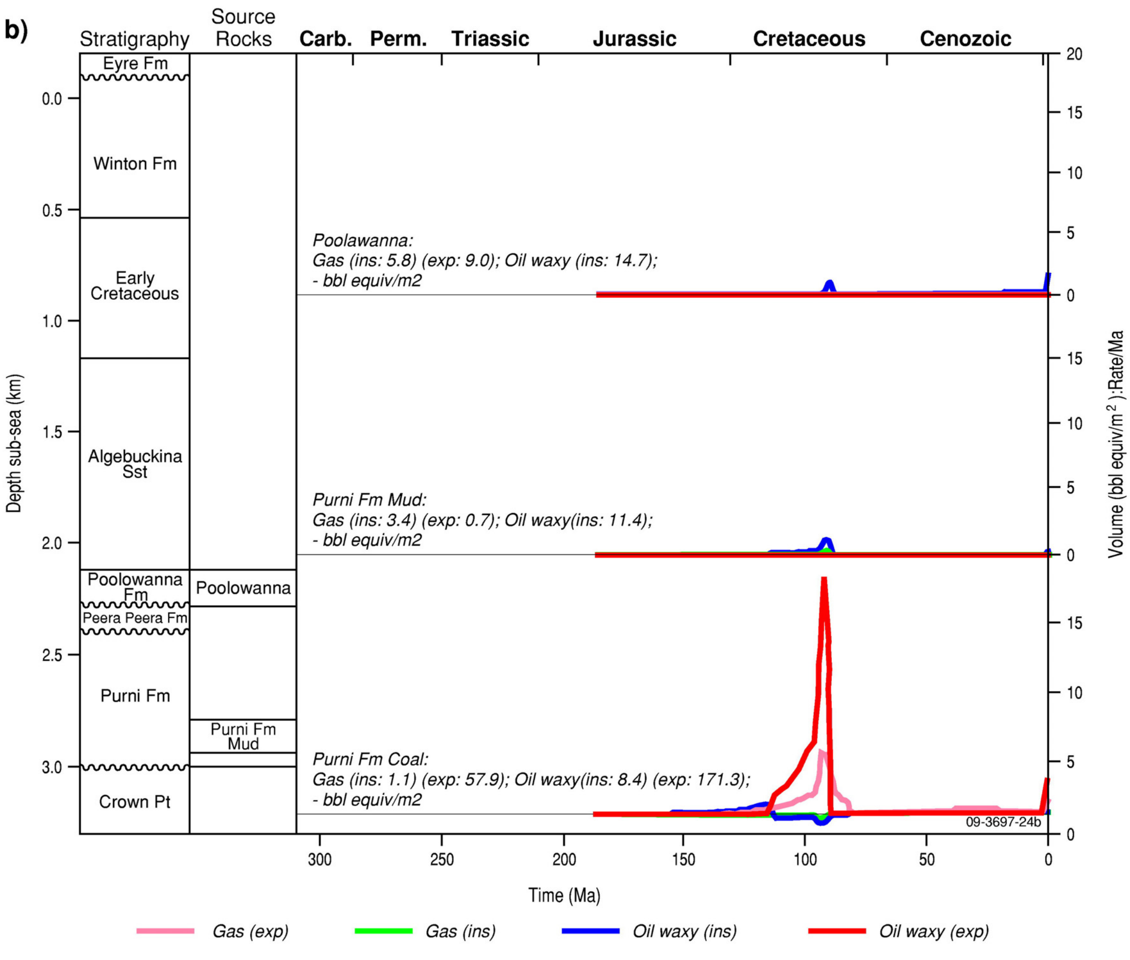


Figure 26 (b): *Maturation and expulsion modelling for (b) Madigan Trough (from Ambrose et al., 2002).*

2.2.2.7 Structural timing and hydrocarbon generation

In the Pedirka-Poolowanna region, maturation analysis suggests that Permian and post-Permian rocks would not have been capable of generating liquid hydrocarbons until after deposition of the Winton Formation in the Late Cretaceous. It seems unlikely that significant oil generation would have occurred much before Eocene time, immediately prior to the Oligo-Miocene tectonic event that created many of the structures in the basin. In most parts of the Troughs, the main phase of oil generation and migration would have occurred up to, during, or after this last phase of structuring. All structural and stratigraphic traps existed prior to any significant oil migration.

In the deeper parts of the Eringa and Madigan Troughs, the main phase of oil generation and migration from Permian source rocks may have accompanied deposition of the Winton Formation and the significant sediment loading would have facilitated hydrocarbon expulsion and migration. Modelling of early Paleozoic (Ordovician rocks) in the Eringa Trough suggests that source rocks would not have reached maturity for oil generation until the Permian. Higher geothermal gradients than modelled would have made generation earlier but it is unlikely that there was significant petroleum migration prior to the Alice Springs Orogeny in Carboniferous time (Questa, 1990)

Long distance lateral migration could be expected in the laterally extensive sandstones of the Algebuckina Sandstone, Poolowanna Formation, and to a lesser extent, the Purni and Crown Point Formations. It remains contentious what effect groundwater migration had and has on hydrocarbon migration. Vertical migration may be facilitated by faulting which commonly penetrates into the Jurassic and sometimes younger units.

At Colson 1, hydrocarbon staining in pre-Permian sediments is attributed to a Purni Formation source, based on n-alkane profiles, pristine/phytane ratios, and presence of exsudatinite and micritised exinite in the Purni Formation (McKirdy, 1981). Oil was recovered from Poolowanna 1 at several intervals. McKirdy (1981) proposed that oils were sourced from intraformational coals and shales in the Poolowanna Formation while Smyth and Saxby (1981) suggested the oil was derived from the underlying Peera Peera Formation.

2.2.2.8 Reservoirs

Sands of good to excellent reservoir quality occur in the Cadna-owie Formation, Algebuckina Sandstone, and Poolowanna Formation (**Figure 25**). Additional reservoir potential lies in the underlying Peera Peera, Walkandi, Purni and Crown Point Formations and in places within pre-Permian (Amadeus Basin equivalent) sands and carbonates.

2.2.2.8.1 Cadna-owie Formation

Excellent porosities and permeabilities are expected in the uppermost part of this formation throughout the region. However, the unit is not considered the primary reservoir objective because of its apparent isolation from the deeper organic-rich source rocks. It is insufficiently buried for adequate maturity, even in the deeper parts of the troughs (**Figure 27**). This formation is the uppermost potential reservoir that lies immediately beneath the thickest regional seal (Bulldog Shale/Wallumbilla, Allaru and Mackunda Formations) in the basin.

2.2.2.8.2 Algebuckina Sandstone

This a laterally extensive aquifer comprising fine to coarse grained, porous and permeable sandstone, that overlies the Poolowanna Formation which is a proven source of oil, and underlies siltstones and shales of the Cadna-owie Formation which form an effective seal. Stratigraphic equivalents of this unit in the central and eastern Eromanga basin include the Hutton Sandstone and Namur Formation which contain some 85% of all known Eromanga oil and gas reserves. The hydrocarbon-prone nature of these equivalents dismisses earlier views of dominant groundwater flushing.

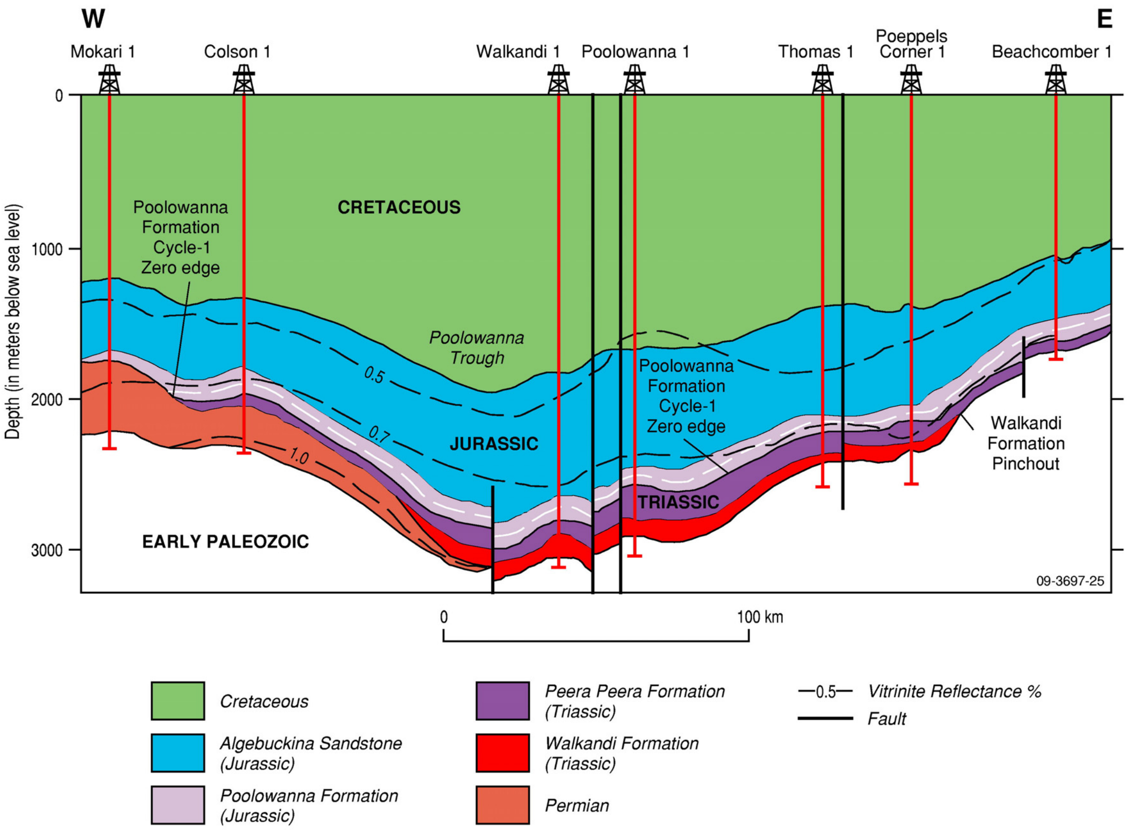


Figure 27: *Cross section of the Poolowanna Trough with isoreflectance contours, showing maturity of the sequence up to the basal Jurassic, and a progressively shallower mature sequence to the east (from Ambrose et al., 2007).*

2.2.2.8.3 Poolowanna Formation

Reservoir properties are variable. In the deeper parts of the basin, the majority of sandstones are fine to very fine grained with low porosity and permeability from extensive silica cementation. In the shallower parts of the basin, this sequence becomes sandier, coarser grained and less siliceous – an excellent reservoir objective. Intraformational shales and coals provide oil and gas prone source rocks, and shales and siltstones in the upper part of the formation offer an effective seal. Two thick sandstone bodies, each overlain by a thick silt-shale interval constitute the formation at Poeppels Corner 1 and Thomas 1. Elsewhere in the Northern Territory, the formation comprises a single sand unit capped by a shale/siltstone interval and forms a good to excellent reservoir/seal couplet. In Poolowanna 1, the reservoir characteristics were poor (Questa, 1990). Ambrose *et al.* (2007) subdivide this unit into two transgressive fluvial-lacustrine cycles and imply partitioning of the aquifer where significant hydrocarbon shows and oil recoveries are largely restricted to sandstones below the seal of Cycle 1. They see structural closure into the depositional edge of Cycle 1 as an important oil play. In the Poolowanna Trough, calcite is prevalent in Cycle 2 of the Poolowanna Formation as compared to the unaltered Cycle 1. This is because of diagenesis of the volcanic lithics introduced into Cycle 2. By analogy with a comparable feature in the Birkhead Formation of the Cooper Basin, highest prospectivity lies with Cycle 1 as a reservoir unit (P. Boult, pers.comm., 2007).

2.2.2.8.4 Peera Peera Formation

This formation is of fluvial –floodplain-lacustrine origin and includes only a few thin sands of poor reservoir characteristics, and is unlikely to be laterally extensive (Questa, 1990). In the southern region in South Australia, there are abrupt facies and porosity/permeability changes. However, the occurrence of thick well-developed channel sandstones is a possibility. With sparse well penetration, little is known of the lateral facies patterns and variability (Questa, 1990). However, Ambrose *et al*. (2007) highlight the correlation of the Peera Peera Formation with the Tinchoo Formation in the Cooper Basin where basal sheet-like fluvial-alluvial sands are prime reservoir targets that produce oil at Jame 1. Hydrocarbon shows are evident in the Simpson Basin in Poolowanna 1, Colson 1, Walkandi 1, Potiron 1, and Mackillop 1.

2.2.2.8.5 Walkandi Formation

This formation has only been penetrated by six wells and little is known of the formation. The sequence is predominantly fine-grained and of low porosity and permeability although reservoir quality sands are recognised from log analysis.

2.2.2.8.6 Purni Formation

Point bar and other channel-derived sands in the Purni Formation have excellent reservoir potential. Laterally extensive, high energy sands have excellent porosity/permeabilities in the western region. East of the McDills-Mayhew Trend, sands reach an average thickness of about 30 m. West of this high, the sandstones appear to be thinner but with improved porosity/permeability. The formation has only had two valid DST resulting in a flow of 1654 bblwpd from Mokari 1 (2010-2040 m) and a recovery of slightly gas cut water from Macumba 1 (2503-2525 m).

2.2.2.8.7 Crown Point Formation

Reservoir quality in this formation has been generally proven to be poor, with best reservoir development exhibited by coarser sands across palaeo-structural highs and within glacial outwash sands which commonly cap the formation. Excellent reservoir quality was however found in the lower Crown Point Formation in Hammersley 1. From limited data, it is probable that the formation is a well-developed reservoir west of the McDills–Mayhew Trend. The recently discovered increase in perceived Permian thickness in the Eringa Trough provides scope for the presence of thick sands associated with thick, organic-rich and mature lacustrine shales in the northern part of the Eringa Trough.

2.2.2.8.8 Pre-Carboniferous reservoirs

Little is known of the reservoir potential of the pre –Carboniferous sequence.

Amadeus Equivalents

The Langra Formation, Polly Conglomerate, and in particular the Mereenie Sandstone each contain potential reservoir beds, with the middle unit of the Langra and the Horseshoe Bend Shale that could act as seals. Ordovician clastics have proven to be good oil and gas producers in the Amadeus Basin. It has been suggested that the Carmichael Sandstone may extend into at least the northern part of the Pedirka Basin, and could provide another potential Ordovician reservoir. Low permeability units like the Stokes Siltstone could act as caprock.

Cambrian

No suitable reservoirs have been identified within Cambrian strata underlying the Pedirka Basin. Tight carbonates have been encountered. In the Amadeus Basin, sands are the predominant Cambrian facies and might therefore be expected in the western part of the study area.

2.2.2.9 Exploration Potential

The two most prospective areas of the western Eromanga Basin are in the Eringa and Poolowanna Troughs where it overlies the Pedirka and Simpson Basins (Cotton and McKirdy, 2006). Exploration in these troughs to date has demonstrated an abundance of organic-rich source rocks, porous and permeable reservoirs with effective vertical seals, and closed anticlinal structures occur throughout the region. Reservoir-source rock couplets range in age from earliest Cambrian to Early Cretaceous. However, geochemical evidence points to insufficient organic maturity as one reason for lack of exploration success. Geothermal gradients in the western region are low, compared to the Cooper /Eromanga Basin, but increase eastwards through the Poolowanna Trough.

The most encouraging well, Poolowanna 1 was drilled near the centre of the Poolowanna Trough where source rocks have reached the maturity for optimum oil generation. The most prospective areas for future exploration are considered to be in the Eringa, Madigan, and Poolowanna Troughs where burial depth ensures adequate source rock maturity. Long distance migration of hydrocarbons might only be expected in the Algebuckina Sandstone and perhaps the Poolowanna Formation.

Permo-Carboniferous organic-rich lacustrine shales and coal measures are expected in the Eringa and Madigan Troughs where well and seismic information suggests adequate source maturity for oil generation and expulsion (Middleton *et al*., 2007). The near total absence of hydrocarbon shows along the McDills-Mayhew Trend remains unexplained.

On the assumption that the northern Eringa Trough sequence has generated significant oil and gas, it follows that either the McDills-Mayhew Thrust Fault provides a barrier to the eastward migration from the trough, or that the structural configuration in the trough does the same. The throw on this thrust is significant, juxtaposing potential Permian to Early Jurassic source rocks in the Eringa Trough against poorly permeable Devonian sediments in the upthrown block. The porous Mereenie Sandstone encountered in McDills 1 is interpreted to be juxtaposed against non-source rocks of the Crown Point Formation. This suggests predominant hydrocarbon migration would be west to northwest, away from the McDills-Mayhew Trend. Structural and stratigraphic traps along these flanks of the trough are highly prospective. This part of the basin has very limited seismic coverage and has only CBM93001 drilled in 2008 **(Figure 23)**, which established a resource of coal bed methane from the thick coal seams (138 m cumulative thickness) in the Permian Purni Formation.

The Madigan Trough, with similarities to the Eringa Trough, contains a suitable source kitchen of sufficient burial for hydrocarbon generation and expulsion, and therefore requires serious evaluation.

Blamore 1, drilled in 2008, established a 132 m cumulative thickness of coal seams (>2m thick) in the Purni Formation. This hole tested a much thicker Permian sequence basinward from the palaeohighs drilled in previous decades on the DMM Trend where coal thicknesses thin southwestwards from <20m in the NT to <10m in SA. Reinterpretation of seismic in both Madison and Eringa Troughs, using well control from Blamore 1 and CBM93001, has indicated a potential sub-bituminous coal resource of 1.25 trillion tonnes $_{av.}$ (250 billion $_{min}$. – 4 trillion $_{max)}$ over an area of 9000 km^2 within one exploration tenement (EP93) held by Central Petroleum. This source kitchen varies in depth, with about half this coal resource shallower than 1000 m (Jones and Maynard, 2009).

The pre-Carboniferous sequence needs additional investigation. McDills 1 and Mt Crispe 1 have verified that a thick sequence of Devonian and older rocks are present in the western region. To date where encountered in the subsurface, the Amadeus-equivalent rocks have exhibited predominantly redbed characteristics that offer little source rock potential, and with the exception of the Mereenie Sandstone, little reservoir potential.

The underlying Cambro-Ordovician sequence of the Warburton-Amadeus Basins remains largely untested. The DMM Trend is located along a palaeo-hingeline of the proto-Eringa Trough. Wells intercepting early Paleozoic sediments have apparently penetrated platform or shelf facies. Earlier basinal features and trends are largely masked from the seismic records due to the thick coal measures that blanket the area and act as an effective absorber of seismic energy.

Trapping mechanisms are predominantly provided by anticlines with four-way dip closure over pre-existing 'basement' highs. Eromanga Basin reservoirs appear to be rarely faulted, but Permian and Triassic traps commonly rely on faults to establish full closure. Eromanga Basin structures in South

Australia and Queensland are typically not oil filled to spill – net oil columns are considered relatively thin compared to the area under closure (Carne and Alexander, 1997).

2.2.2.10 Prospects and Leads

2.2.2.10.1 Structural traps

Numerous structural closures are identified in the Poolowanna Trough **(Figure 23)** but tend to have low relief and be crossed by meridional faults. The seismic acquired for this interpretation is across sand dune terrain. With such subtle structure, and numerous fault displacements, accurate seismic mapping requires the effective application of realistic statics corrections to seismic processing, careful correlation between seismic lines, and consideration of fault blocks. Dune sand and weathering profiles have been demonstrated to be complex, and can only be resolved with a seismically-measured geophone static, tied to suitable uphole control (Senycia,1989). Dry hole analysis of former wells indicates that few wildcat wells had effectively tested closure. The recent drilling of Blamore 1 in 2008 also revealed disparities between seismically-prognosed and drillhole formation tops for the upper Algebuckina Sandstone reservoir. It remains speculative whether this well actually tested the crest of a structure. To date, numerous structural leads and prospects have been identified from individual and composites of earlier seismic surveys but the biggest challenge remains to accurately define real and effective closures.

Indications from Poolowanna 1 suggest that robust Miocene structural reactivation had breached the trap, leaving only minor remnants of water-washed oil. Other large Miocene structures, bound by reverse faults and some reflecting major inversion, have failed to yield commercial hydrocarbons. Conventional structural targets are numerous but future exploration should target subtle Triassic to Jurassic-Early Cretaceous age structural and combination stratigraphic traps, with an older drape and compaction component that is largely free of Paleogene fault reactivation (Ambrose *et al*., 2002, 2007).

2.2.2.10.2 Stratigraphic Traps

Stratigraphic prospects have yet to be identified in this region as there are numerous structural prospects that await testing. To date, all seismic has been 2D, and much of questionable quality. Until better seismic resolution is achieved in the region, either 2D or 3D, the basis for recognition of stratigraphic plays is wanting.

Stratigraphic traps will occur as onlap and pinchout features along basin margins and on flanks of the main structural highs such as the DMM Ridge. Unconformity traps are anticipated at the base of the Eromanga, Simpson and Pedirka sequences, but seal integrity would need to be established. Because of the fluvial sedimentation, and as in the Cooper–Eromanga Basin, heterogeneous facies are anticipated.

Perhaps the best stratigraphic traps will be identified where the Peera Peera and Poolowanna Formations wedge out towards the east and north, or where the Purni and Crown Point Formations wedge out to the east. Intraformational sandstone wedge outs should offer the best potential (Questa, 1990).

2.2.3 Galilee-Eromanga Basin system (Lovelle Depression)

The basin structure and stratigraphy of the Galilee Basin is documented in Appendix 1.

2.2.3.1 Exploration Potential

The western extent of the Lovelle Depression is currently unconstrained through lack of seismic coverage. It is possible that the Lovelle Depression may have once extended southwestwards - and more speculatively, into the Pedirka - Simpson Basin, prior to Late Permian uplift and erosion. Furthermore, erosional remnants of hydrocarbon-mature Cooper-Galilee source rocks may be

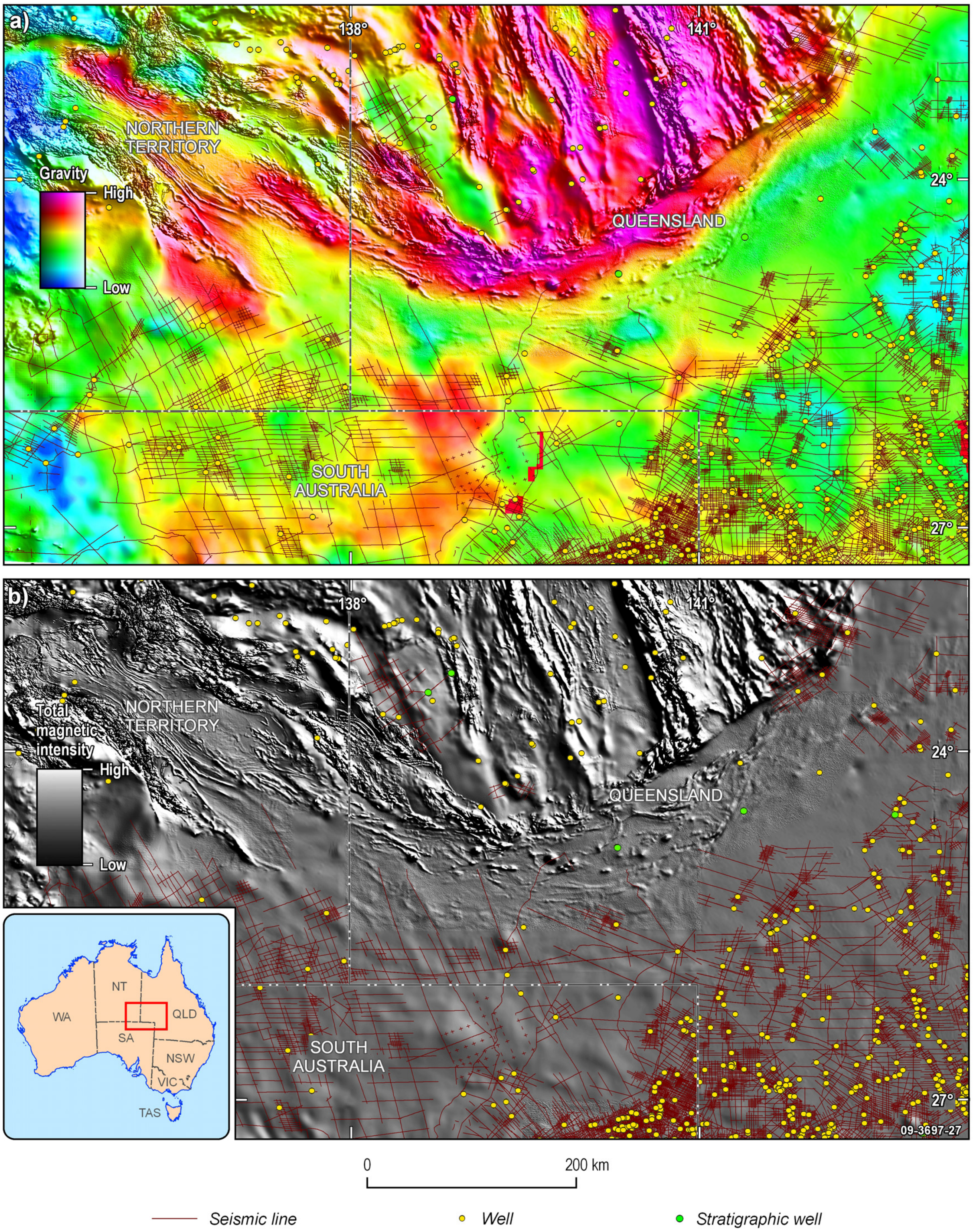


Figure 28*: Under-explored terrain along the southern margin of the Mt Isa Block: (a) Combined gravity (colour)/magnetics (shadow) image and (b) Magnetics (TMI rtp) image, both with superimposed seismic survey lines and exploration wells.*

preserved as downthrown asymmetric wedges adjoining both the north-northwest aligned faults associated with the Arunta Block (movements through the late Triassic to Recent) as well as against the southern margin of the basement Mt Isa Block. In this latter margin, extending from Brighton Downs to Machattie 1:250,000 Sheets, the combined magnetic/gravity imaging (**Figure 28**) as well as estimates of magnetic basement depth from forward modelling (Meixner, pers.comm., 2007) **(Figure 29)** suggest that the Holberton Structure and the Cork Fault diverge southwestwards to delineate a tight graben against the Mt Isa Block with >2000 m of preserved sequence. Depth estimates of 1800 m were determined on the shallower margins of this basement structure, but the central axis is devoid of any high frequency magnetic features, indicating much deeper basement. This graben could hold sediment packages with anything from Proterozoic to Carboniferous-Triassic age.

The adjoining southern margin of the Mt Isa Block appears to be locally upturned from tectonism on the margin of this block. North from this margin, magnetic basement again deepens suddenly, then shallows gradually northwards towards Canary 1 and Elisabeth Springs 1 on the Springvale 1:250,000 sheet where a probable Neoproterozoic sequence and Paleozoic Georgina sequence underlie thin cover of the Eromanga Basin. It is speculative whether a wedge of Galilee sequence could lie between the Georgina and Eromanga sequences south of Canary 1.

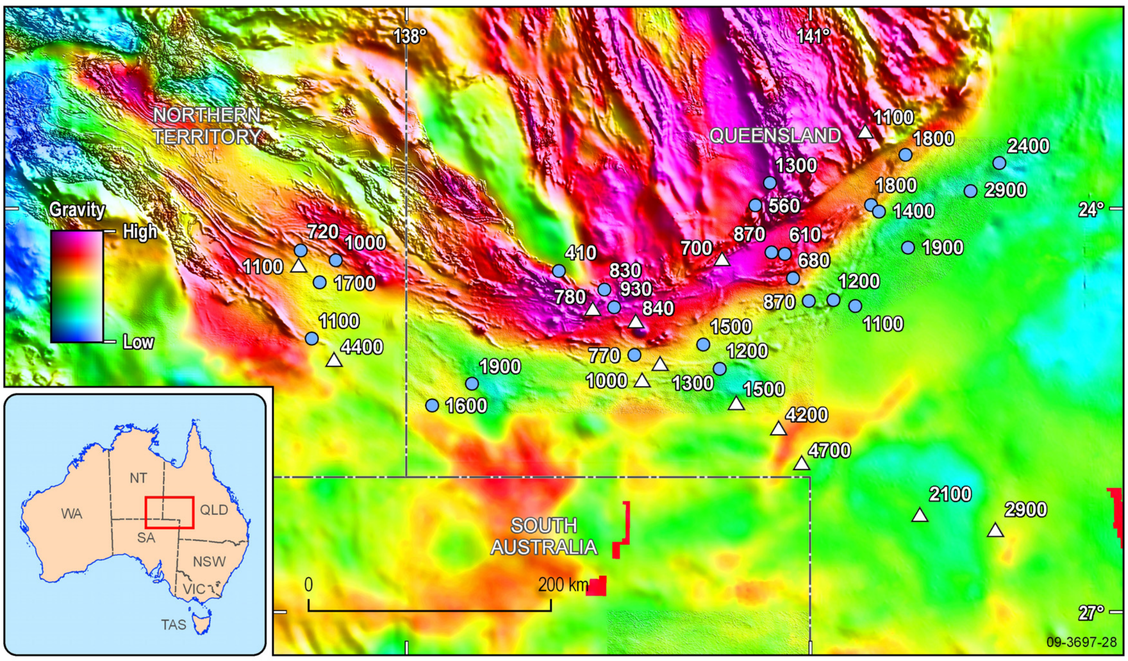


Figure 29: Depth to magnetic basement (spot determinations from forward modelling by Meixner, pers. comm., 2007). Circles are depth (m) with high confidence; triangles are depths (m) of lower confidence.

A linear narrow gravity anomaly has a parallel trend to the south of the Holberton Structure on Brighton Downs and Connemarra 1:25, 000 sheets **(Figure 28a)**. Modelled basement depths suggest a probable thicker sequence up to 2400 m. These three prospective areas, depocentres or preserved basin remnants, have no seismic coverage. Westwards towards the Arunta Block small negative gravity features coincide with thicker modelled basement depths, and may indicate preserved remnants of Paleozoic or Proterozoic basins.

Isolated randomly-distributed small magnetic bright spots **(Figure 30)** are discernible over this area, 'floating' well above magnetic basement, and apparently lying at or near surface. The presence of magnetite and anomalous levels of base metals is known in these palaeo-spring structures that contain cohesive ferricretes of oolitic and peloidal textures, within surrounding exposed Cretaceous rocks. Another subset of these circular features have lateritised Cretaceous collapse material within dolines in exposed Georgina carbonates on the Boulia 1:250,000 sheet, and some of the collapse material contains slumped stratiform layers with pseudomorphs of centimetre-sized sulphide crystals. Partly on the basis of this evidence, one phase of hydrocarbon migration within the Georgina sequence in the Burke River Structural Belt was considered to be Cretaceous-Paleogene (Radke, 1982). These clusters of circular features have the attributes of palaeo-groundwater - hydrocarbon seeps that could be on any post-Cretaceous age. If hydrocarbons were transported and flushed with artesian groundwaters, then these palaeo-spring features may be much younger, related to the initiation of the artesian system somewhere between 10-15 Ma (Senior and Habermehl, 1980) and 5 Ma (Toupin *et al.,* 1997). Artesian groundwater springs are still active along both the Burke River Structure and the Mulligan River-Toomba Thrust region further west (Radke *et al*., 2000 **(Figure 31)**.

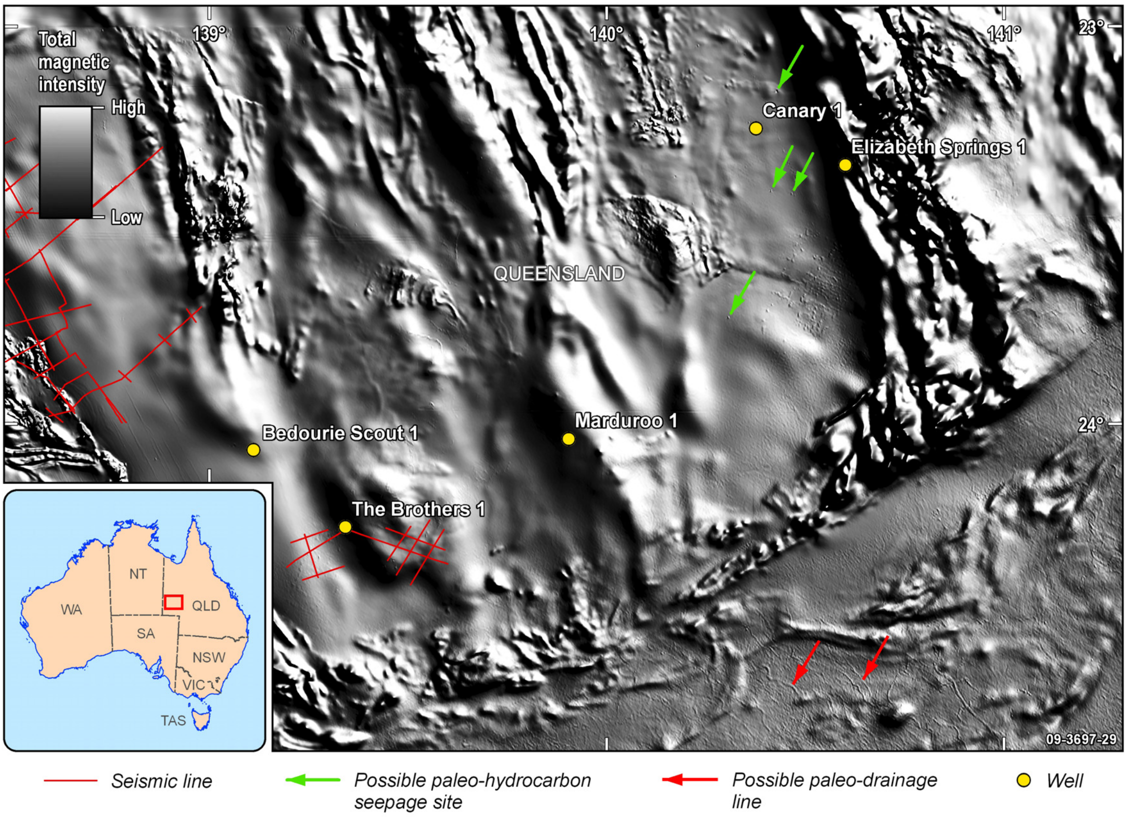


Figure 30*: Detail of TMI rtp image showing: 1) isolated bright spots (green arrows) – possible palaeo-hydrocarbon seepage sites, and 2) palaeodrainage lines (red arrows) - possibly within Cretaceous Winton Fmn or younger Paleogene fluvials – that could be foci of uranium roll-front deposits induced by hydrocarbon seepage and/or groundwater migration*

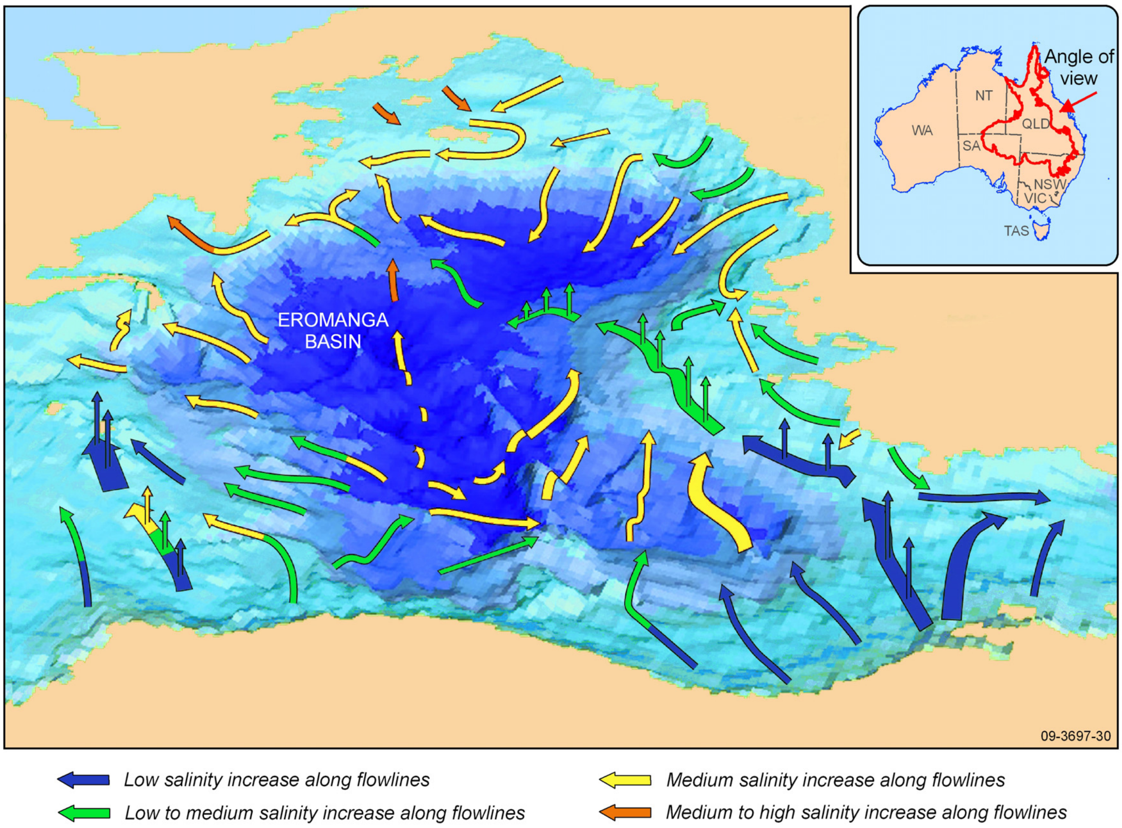


Figure 31*: Groundwater flow lines within the Eromanga Basin main aquifer, showing recharge,vertical leakage, and progressive salinisation along flowlines [colour change from blue (low salinity) to red (high salinity)] under the present hydrodynamic regime. At 10-15 Ma prior to uplift of the Great Dividing Range, dewatering of the basin was predominantly by radial expulsion of connate fluids towards basin margins (from Radke et al., 2000).*

3 Petroleum Systems

The study area within the Eromanga Basin has multi-stacked basins. Throughout the history of exploration, the understanding of petroleum origin, geothermal history and thermal maturity of sequences has and continues to evolve. Many reservoirs have been multi-charged (McKirdy *et al*., 2001; Michaelsen and McKirdy, 2001; Arouri *et al.,* 2004; Underschultz and Boult, 2004; Hallmann *et al.,* 2007) and the unfolding picture of phases of petroleum generation and migration is becoming progressively complex. In hindsight, we now know that earlier simplistic exploration tenets overlooked many potential fields in the past. On the basis of this lesson, many new fields remain to be discovered beyond the large structural plays, and the possibilities appear to be only limited by the exploration rationales.

A question of critical relevance, and one which continues to perplex explorers, is how much of the oil within the Eromanga Basin sequence is derived wholly or in part from more mature source rocks in the underlying Cooper Basin or deeper basins?

3.1 STATE OF KNOWLEDGE

Oil is reservoired mainly in the sandstone reservoirs of the Eromanga Basin. Gas and dry gas are predominantly reservoired in the Cooper Basin sequence. Source-reservoir couplets are identified, the main two are: Cooper Basin Source and reservoir or Cooper Basin source and Eromanga Basin reservoir. A subordinate is Eromanga Basin source and Eromanga Basin reservoir. Minor inputs are known from pre-Permian sources to reservoirs of the Cooper and Eromanga Basins (Boreham and Summons, 1999; Hallmann *et al*., 2006; Hallmann *et al.,* 2007).

The principal Gondwana Petroleum Supersystem originating from Permian sources of the Cooper Basin has been further subdivided into two petroleum systems associated with the Lower Permian Patchawarra Formation and the Upper Permian Toolachee Formation sources respectively. Reservoir placement of oil in either of these units is, in general, a good guide to its source and perhaps an indirect measure of seal effectiveness. The subordinate Murta Petroleum Supersystem of the Eromanga Basin is subdivided into the Birkhead Petroleum System and Murta Petroleum System to reflect individual contributions from these source units. The minor Larapintine Petroleum Supersystem is tentatively identified as involving pre-Permian source rocks in the far eastern Warburton Basin and western margin of the Warrabin Trough in Queensland (Boreham *op cit*.).

The extent to which the Early Jurassic Poolowanna Formation and pre-Permian (probably Cambrian) source rocks contributed to different oil accumulations is yet to be fully investigated. Of the known hydrocarbon sources, the Patchawarra and Birkhead Formations are the most prolific, accounting for the bulk of the cumulative petroleum resources of the Cooper and Eromanga Basins.

Long range migration (>50 km) from Permian sources has been established for oil accumulations in the Eromanga Basin. This, together with the contribution from local Eromanga sources, highlights petroleum prospectivity beyond the Permian edge of the Cooper Basin (Boreham *op.cit.).* However, the Birkhead Petroleum System has adequate and sufficient potential as a source contributor, for exploration to be warranted without reliance on a Permian contribution.

3.1.1 Differentiation of oil sources - Coevolution of geochemical techniques and the unravelling of oil migration/mixing processes

Organic geochemical research has evolved rapidly to provide major advances in the last decade towards understanding and answering this question. From the identification of several Petroleum systems in the Cooper/Eromanga Basin, the research effort has moved to differentiation of sources in mixed oils derived from various sources/systems, and more recently the history of oil generation and charging has been unravelled in specific producing fields – as a result of increasing sophistication of sampling techniques.

Previously, classic 'biomarker' or 'molecular fossil' studies often provided ambiguous results for the Cooper–Eromanga couplet but a breakthrough by Alexander *et al.* (1988) was in the identification of a number of age-specific land–plant biomarkers produced by araucariacean conifers that are unique to the Mesozoic. Other geochemical studies of the area have exploited the maturity contrast between the Permian source rock and oils, and those from the Eromanga sequence (Michaelsen and McKirdy, 1989; Tupper and Burkhardt, 1990). A subsequent geochemical means of identifying various degrees of mixing of these oils was developed by Alexander *et al.* (1996). These two sources can also be distinguished by their different n-alkane C-isotopic profiles in oil-oil and oil-source rock correlations. This approach appears to be robust provided the Eromanga source input is >25% in oils of mixed origin (Boreham and Summons, 1999). However, this approach requires expensive analysis. Pre-Permian inputs are recognized by n-alkanes more depleted in ^{13}C compared with the late Paleozoic and Mesozoic sources (Boreham *op cit.)* and low methylcarbazole/2-2-methylcarbazole ratios (Hallmann *et al.,* 2005). An alternative, faster, and less expensive method was developed by Michaelsen and McKirdy (2001), entailing a novel combination of aromatic hydrocarbon source and maturity parameters based on methylphenanthrene isomers.

A more refined understanding of complex reservoir charging has developed out of the use of sequential solvent flow-through extraction (SFTE) techniques (Schwark *et al.,* 1997; Hallmann *et al.,* 2006; Hallmann *et al.,* 2007), modeled mixing (Michaelsen and McKirdy, 2001), and artificial mixing curves of Cooper-Eromanga oils (Arouri and McKirdy, 2005).

3.1.2 Differentiation of gas sources

There are several processes that significantly affect gas composition. Reservoired gases derived predominantly from land plants are slightly wetter than those derived from marine sources. Although marine source rocks, which are more oil prone, paradoxically generate drier gas. The non-hydrocarbon gases CO_2 and N_2 were sourced from both inorganic and organic materials. A mantle and/or igneous origin is likely in the majority of cases of gases with >5% CO_2. A strong inter-dependancy between source and maturity has been recognized from the carbon isotopic composition of individual gaseous hydrocarbons. There is evidence of water-washing in the Cooper–Eromanga Basins, resulting in the increase of wet gas content. The greater mobility of gas within subsurface rocks can have a detrimental effect on oil composition whereby gas-stripping of light hydrocarbons is common amongst Australian oil accumulations (Boreham *et al*., 2001).

The Cooper/Eromanga Basin has the greatest proportion of gas samples with high CO_2 contents between 10 and 20%, and these are more regionally distributed than any other producing basin in Australia. A few gases (Coonatie 4, Cuttapirrie Field, Kanawana 1) are depleted in ^{13}C (<-10 $^{o}/_{oo}$) and also have high to extremely high CO_2 content. In gases of extremely high CO_2 content, it is probable that the isotopically light CO_2 component was derived from decarboxylation of organic matter in interbedded organic-rich fine-grained sediments within the reservoir (Boreham *et al*., 2001). Gas released from organic matter over the maturity range up to the onset of oil generation is dominated by CO_2 (Tissot & Welte, 1980). Gas from Kirby 1 has both very high CO_2 content

(31.8%) and is isotopically heavy (^{13}C 0.3$^{o}/_{oo}$) suggesting a carbonate origin, most likely sourced from overmature sediments in the underlying Ordovician to Cambrian Warburton Basin (Sun, 1997).

Very high N_2 values, between 20 and 50% occur in Jackson 1, Rheims 1, Coonatie 4. The highest N_2 contents are along the basin highs south of the Nappamerri, the western Patchawarra and in the Windorah Troughs. This contrasts with the CO_2 concentration which is highest to the west and east of the Nappamerri Trough. The known sources of nitrogen are from the deep mantle and/or igneous bodies, and from decomposition of organic matter at high temperature (Hunt, 1996). Boreham *et al.* (2001) consider the main contribution is from mantle/igneous sources. The lack of a strong correlation between the regional distribution of high levels of CO_2 and N_2 could result from a dataset of insufficient statistical validity, or more likely suggests separate timing and migration pathways for the two inorganic gases. The Cooper–Eromanga basin couplet, like the Bonaparte Basin, shows a higher hydrogen content. Wackett 2 has 1.4% and Adria Downs 1 has 1.75% H. While hydrogen is generally ubiquitous in natural gases, it usually occurs only in trace amounts. These relatively high concentrations may reflect a dual origin from a deeper inorganic source, together with a released byproduct from decomposition of kerogen at elevated maturities.

Water-washing has had a pronounced influence on gases. The major effect of water-washing is to increase the wet gas content. Gases with C3/C2 >1 represent only 3% of Australian natural gases and these are most likely the result of water-washing. Water solubility of gaseous hydrocarbons decreases with increasing carbon number (McAuliffe, 1979). Associated oils are extensively water-washed, resulting in petroleum accumulations with low gas to oil ratios (GOR).

Gas is a major factor in enabling moderate to long range migration of oil. Gas has displaced oil from the deeper Cooper Basin reservoirs, enabling migration to shallower reservoirs in the overlying Eromanga Basin (Heath *et al*., 1989; Boreham and Summons, 1999).

The complementary process of migration fractionation, where a gas and liquid phase separate during upward migration, is best evidenced in stacked oil accumulations. Its effect on gas composition is minimal, with a slight increase in wet gas content within the separated gas phase (Boreham *et al.,* 2001)

3.2 SOME CASE STUDIES

3.2.1 Birkhead-Hutton (!) petroleum system

Trap formation occurred soon after deposition, essentially reflecting drape over underlying Permian structure. Hydrocarbon charges were generated over a period of time, in contrast to two critical charge moments (Peak generation times). Seal diagenesis evolved over a period of time and is necessary for entrapment. Preservation time and critical seal moment are not well constrained but it is assumed that seal leakage must have occurred between two charge events. Through time, contact of a seal rock with oil is likely to change its wettability and the Gidgealpa seal (heavily oil-soaked) is probably now not as good as prior to leakage. The change of wettability of the Birkhead seal allowed the huge majority of generated oil to leak away. All that is left is presently migrating oil that is temporarily backed up behind a permeability seal (Boult *et al.,* 1998).

3.2.2 Strzelecki Field

The oil-bearing sandstones of the Strzelecki Field are all Mesozoic. At any given level, there is no significant difference in either maturity or source affinity between 'free' and 'adsorbed oils'. However, 'free oils' display a field-wide maturity differential: Hutton 0.87%; Birkhead, 0.86%; and Namur 0.94% R_c. All three oils comprise mixtures of intra-Jurassic (probably Birkhead) and

Permian hydrocarbons. The major contribution (65-80%) appears to have been derived from source rocks in the Toolachee Formation of the underlying Cooper Basin (Kramer *et al*., 2004) on the basis of high pressure SFTE.

3.2.3 Cooper–Eromanga hydrocarbon migration

On the basis of a recent oil discovery at Sellicks 1, there is recognition of a widespread intra-Patchawarra seal that implies that vertical migration out of the lower Patchawarra is only likely along the eroded basin margin, or through vertical breaches such as faulting. Any specific search for oil within the Jurassic sandstones should therefore be focused at or beyond the erosional margin of the lower Patchawarra Formation. Jurassic traps basinward are only likely to have a charge where faulting has allowed migration through the Patchawarra seal (Altmann and Gordon, 2004) (**Figure 17**). However, the oil in nearby Christies 1 has been shown to comprise a mixture of ~60% Permian oil (Patchawarra source) and ~40% Jurassic (inferred Birkhead source) (Errock, 2005).

3.2.4 Murteree Ridge

The Murteree Ridge is a broad flat-topped basement horst (Warburton rocks) capped by Jurassic strata of the Eromanga Basin. The Cooper Basin sequence was eroded off during the Late Triassic. This ridge separates two major source kitchens, the Nappamerri Trough to the north, and the Tenappera Trough to the south, and is a main structural focus for up-dip migration from these two troughs. The petroleum system of the Murteree Ridge area contains hydrocarbons of mixed Cooper and Eromanga origin. The filling histories of its Cretaceous reservoirs, as determined geochemically, indicate multiple-charging episodes involving oils varying in source affinity up to 80% Permian and appear to have fed the three Eromanga reservoir units: Murta Formation, McKinley Member and Namur Sandstone in a complementary manner. Consistently throughout their charging histories, the Murta/McKinley reservoirs show evidence of retaining a higher proportion of Permian-sourced hydrocarbons in their mixed oils than do those in the underlying Namur Sandstone. Although most of these charges are low maturity (0.78-0.95% R_c), early charge is evident in the Namur Sandstone at the Nungeroo, Ulandi, and Biala fields. These more mature pulses are not reflected in DST oils that instead show a limited range of maturity (0.59-0.68% R_c) representing either the compositional average of all previous charges to their respective reservoirs or a continuation of the alternating filling pattern observed for successive charges. Oils in the stratigraphically lower Hutton reservoir of the outlying Kerrina and Mudlalee Fields to the northeast appear to be mixtures of two distinct Early Permian oil families, variably commingled with locally-derived Jurassic and possibly Cambrian hydrocarbons (Arouri *et al*., 2004).

The distributions of residual oil saturations in live and palaeo-columns are consistent with the existence of two compartments – the uppermost pools (Cadna-owie, Murta) showing the highest Permian inputs. These accumulations represent the earliest escape of low-maturity Cooper-sourced oil into the Eromanga strata. This initial charge was displaced upwards into the shallower traps by subsequent hydrocarbon pulses. Three separate Permian-charge episodes can be recognized.

This multiple-filling scenario is opposite to that inferred for the Dirkala, Garanjanie, Thurakinna and Wancoocha Fields located 15-20 km to the west near the edge of the Cooper Basin where the maturity of residual and DST oils increases with reservoir age (Cretaceous, Jurassic and Permian), and both types of oil are more mature than the local putative source rocks (McKirdy *et al.,* 2001).

3.2.5 Gidgealpa

A double pulse of migration appears to have charged the Gidgealpa southern dome – indicated by biomarker analysis, seal studies and maturation modeling (Boult *et al.,* 1998). Maturation modeling within the Gidgealpa drainage area (Boult *et al.,* 1997) indicates that the Birkhead Formation of the

Nappamerri Trough expelled the majority of its oil during the first pulse between 90 and 70 Ma. Then at about 70 Ma, the Birkhead Formation in the Patchawarra Trough entered the oil window and possibly contributed hydrocarbons to the first pulse which entered the southern dome. More recently, in the last 1 million years, a significant increase in geothermal gradient for the Cooper/Eromanga region, as suggested by Pitt (1986) and Boult *et al*. (1997) provided the second pulse of oil. By this time, the Birkhead in the Nappamerri Trough was overmature for oil generation, and much of the second charge appears to have originated from the Birkhead in the Patchawarra Trough. On the basis of geochemical evidence, much of the second charge may have come from the Tindilpie area.

3.2.6 Larapintine (!) Petroleum System- Warburton Basin as source and reservoir

Although initially the main exploration target in this province, the Cambrian sediments of the underlying Warburton Basin have subsequently never been seriously considered to have participated in the petroleum systems.

The discovery of oil in the pre-Cooper Mooracoochie Volcanics in Sturt 6 and 7, as well as gas in fractured shales in Lycosa 1 and Moolallie 1, has renewed interest in the Warburton Basin. However, on the basis of biomarker and isotopic studies (Kagya, 1997), these accumulations were shown to have most likely been sourced from the overlying Gondwanan and Murta Petroleum Supersystems, and migrated downdip or laterally into porous Warburton strata. Sun (1999) demonstrated high fracture porosity in some facies of the eastern Warburton Basin that could act as conduits for migration and accumulation.

Earlier dismissal of the Warburton sequence as a source of hydrocarbons was based on its apparent low generative potential as measured by TOC and Rock-Eval analyses. Boucher (1997b, 2001c) has demonstrated that the upper part of this basin succession is largely severely weathered and oxidised, and that these data most probably do not reflect the true nature of all the Warburton lithofacies.

Additional to the general diagnostic indices cited above by Boreham and Summons (1999), C-1 carbazoles appear to be mainly governed by source facies, in contrast to the benzocarbazole ratio used as an indicator of relative migration distance. Low methylcarbazole/2-methylcarbazole ratios were only encountered in pre-Permian source rocks and in a number of residual extracts. Notably, most of these residual oils, which occur widely throughout the Cooper and Eromanga sequences, derive from the first pore-filling oil pulse and exhibit maturities of up to 2.0% R_c. On this conclusive evidence, Hallmann *et al.* (2005) confirm that the Warburton Basin has expelled hydrocarbons which may have been intermittently stored in Cambro-Ordovician reservoirs before spilling or leaking into the overlying basin sequences. Paleogene migration in this Larapintine Petroleum Supersystem must have occurred after deposition of the Jurassic reservoir sands but before the emplacement of Permian and subsequent Jurassic oils. It is unknown whether the expelled (and trapped) amounts were negligible in the first place, or were displaced by subsequent oil charges from younger petroleum systems.

4 Applicability of Regional Airborne Surveys

4.1 AIRBORNE HYDROCARBON PROSPECTING

Conventional oil exploration has worked from conceptual models to acquisition of seismically-imaged data to a decision to drill. Seismic surveys and drilling are major financial and logistical investments. Any additional approach that may contribute to an improved understanding of an area so as to reduce risk in well siting, and to improve success rates, could be a valuable exploration tool (Land, 1996). The history of exploration in the Central Basins region has repeatedly shown that evident hydrocarbon occurrences were ignored because they did not fit the exploration paradigm of the time.

The special advantage of airborne surveying is the speed of execution in regional surveys with reduced initial planning, negotiation and effort in land access issues until the followup ground survey stage.

Aeromagnetic and high-sensitivity radiometrics offer less direct detection of surface hydrocarbon-related anomalies, but high resolution aeromagnetics offer an increased resolution of structural delineation that is necessary to interpret detected anomalies by other methods. Lineament analysis from satellite or air photo data is an additional available data type for structural interpretation of near surface fracture/tectonic features.

In light of the federal government funding for Geoscience Australia to pioneer innovative and integrated geoscientific research to better understand the geological potential for onshore energy, the onshore program should seriously consider evaluation and use of prospecting technologies such as airborne sniffing as an adjunct to conventional geophysical and seismic imaging. Petroleum prospecting, in both airborne and followup ground studies, appears to be at a sufficiently advanced stage of development in each of the detection technologies, evaluation procedures and conceptual understanding, to warrant serious consideration as an additional remotely-sensed data source (Schumacher and Abrams, 1996; Abrams and Segall, 2002).

The empirical methodologies and theoretical platforms for this prospecting have been steadily evolving since the 1930s with a growing breadth of tested case histories that can be used on a comparative basis. Most compelling as an argument for use of this technology is that it directly measures hydrocarbon components. The whole approach is predicated on the understanding that many petroleum fields have upward leakage of lighter fractions of the reservoir charge. Gas migration along fractures and faults is dominant over diffusion processes (Jones and Droszd, 1983). If this leakage can be detected at or above ground surface, its surface expression delineated and related to geological features, it could be a valuable adjunct for understanding the petroleum system.

As the commercial choice of service providers of this prospecting technology grows in Australia, industry may look to a credible independent assessment of the offered technologies. An audit of the expenditure for detection surveys and follow-up evaluation could help place a perspective on investment against information gain.

4.2 AEROMAGNETICS

Recent usage and forward modelling of magnetic basement depth with high resolution aeromagnetics over the southern part of the Mt Isa Block (**Figure 29**) has provided direct insights into the advantages of such high resolution data over basinal areas. Not only were detail and features of magnetic basement clarified, but also detail of intra-basinal features and magnetic bright spots attributed to former hydrocarbon seepage (**Figure 30**). The present juxtaposition of older low resolution and current high resolution aeromagnetics surveys over basinal areas offers an opportunity for critical comparison. There is no comparison in the resolution quality and additional information offered by the recent high resolution coverage. All of the central basins should have complete high resolution aeromagnetic coverage.

Authigenic magnetic minerals are known to occur in near-surface sediments over many petroleum accumulations. The reducing regime created by the migration of hydrocarbons through the regolith apparently enables conversion of common nonmagnetic iron oxides and sesquioxides to magnetic mineral species. Aerobic hydrocarbon-oxidising bacteria consume methane and decrease oxygen. Sulphate-reducing bacteria, sulphate ion reduction and oxidation of organic carbon produce reduced-sulphur species. These highly reactive reduced-sulphur species combine available iron to form iron sulphides and oxides giving pyrite, magnetite, pyrrhotite and maghemite (Schumacher, 1996).

Such hydrocarbon-induced mineralisation is detectable in high resolution, broad bandwidth magnetic data acquired at low altitude and closely-spaced flight lines, as well as in ground surveys. Anomalous magnetic susceptibility in drill cuttings and near-surface sediments is frequently due to the presence of ferromagnetic minerals such as greigite, maghemite, magnetite, and pyrrhotite.

Over the last 20 years there has been considerable research into the use of low-level, high resolution aeromagnetic data to detect Sedimentary Residual Magnetic (SRM) anomalies and Magnetic Bright spots (MBS) that are commonly associated with oil and gas fields (Foote, 1996). This research has evaluated fields in North and South America, Africa, Australia and the Middle East. Most compelling are the statistics of US onshore drilling success rates when categorised as being within or outside MBS areas.
Within MBS areas – of 470 wells, 79% are producers and 21% dry holes.
Outside MBS Areas – of 883 wells, 10% are producers and 90% dry holes (Foote, 1996).

The first derivative of aeromagnetics imagery over the study area (**Figure 32**) indicates the presence of SRM over known hydrocarbon fields in the Cooper Basin. Adjoining SRM anomalies imply existing or former hydrocarbon accumulations that require further evaluation. High resolution aeromagnetics can also be considered a valuable adjunct to airborne sniffing, to help define related fault/fracture systems.

4.3 AIRBORNE HYDROCARBON SNIFFING

Hydrocarbon detecting systems in light aircraft are known to be offered commercially in Australia by Red Sky Energy. From their promotional prospectus, the Red Sky system implies detection of additional heavier hydrocarbon molecules that allows for differentiation of wet and dry gas sources. Approaching commercial status is Shell's 'Light Touch' which involves a detection capability of only methane and ethane.

To effectively utilise data on trace gases in the atmosphere and to be able to track their ground source, requires assumptions about atmospheric dispersion and/or diffusion. Only the Shell system uses sophisticated dispersion modelling that incorporates real-time meteorological information as a requisite input to inverse modeling of the ground position of gas emanations (Hirst *et al*., 2004).

The Red Sky Energy service apparently does not utilise or integrate any meteorological data. This would necessitate an interpretation of the location of emanations on a simplistic assumption that the gas plume emanates vertically from the source. Such an assumption could only approach being realistic over very high discharge sites.

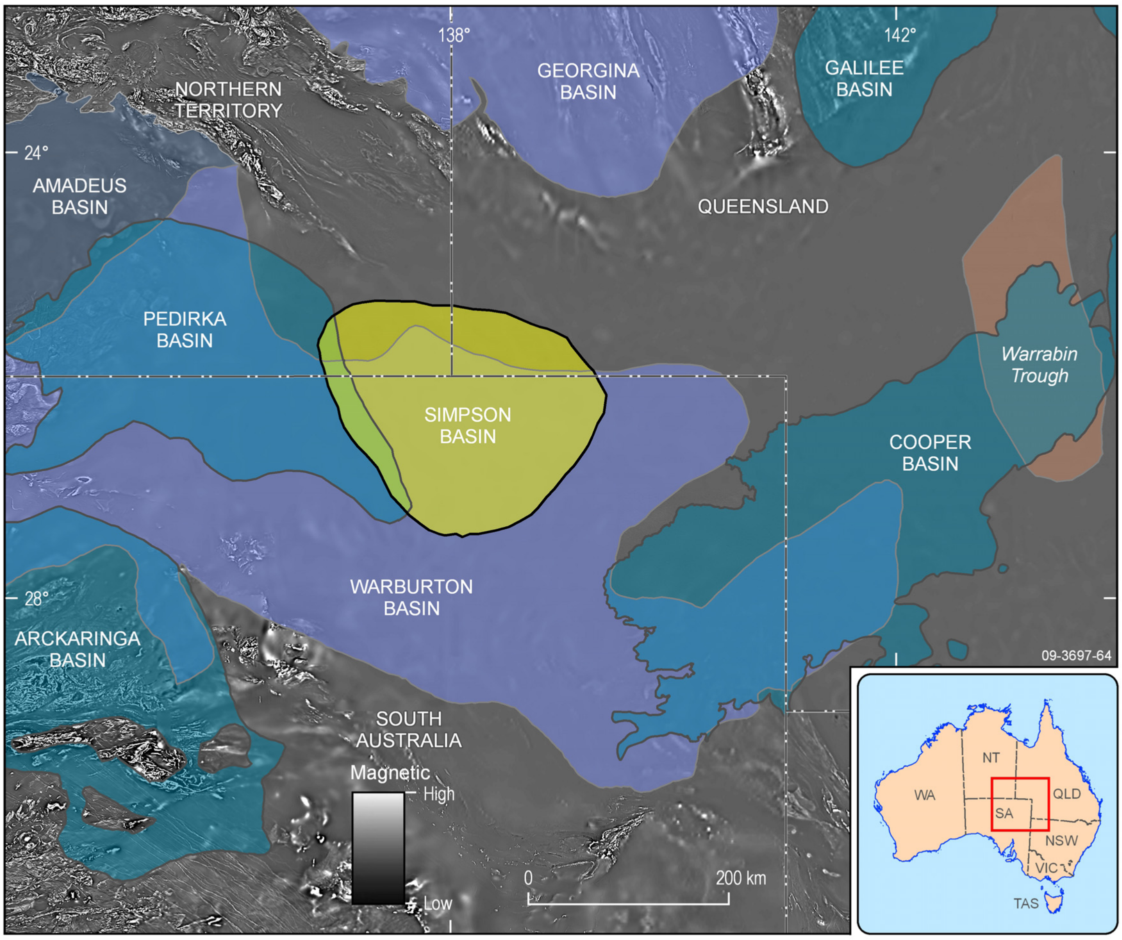


Figure 32*: First vertical derivative of aeromagnetics indicates probable sedimentary residual magnetic (SRM) anomalies over known hydrocarbon fields in the Cooper Basin. Untested SRM anomalies adjoin this region.*

In 2007, Stuart Petroleum completed Rainbird 1 on the Rainbird Structure, a four-way dip closure 8 km southwest of the Warrior oil field. Red Sky Energy, a farminee in this project, identified hydrocarbon geochemical anomalies over the Rainbird Structure. This was the first well to test Red Sky airborne sniffing technology in the Cooper–Eromanga Basin system. Primary targets were the McKinlay Member, Murta and Birkhead Formations, with secondary objectives in the Epsilon and Patchawarra formations before a planned total depth of 2010 m. No significant hydrocarbons were detected in this hole (PNN News, 21 August, 2007).

To test the effectiveness of this generic airborne sniffing approach, a requisite of any survey should be replication of the survey results temporarily under similar barometric conditions.

On the basis of system design and transparency of technical rationale, the Shell system is the only technology currently available that could be considered seriously. Background ethane concentrations in the atmosphere of the southern hemisphere are an order of magnitude less than seen in the winter atmosphere of the northern hemisphere (Hirst, unpublished), promising increased detection sensitivity under Australian conditions.

4.4 RADIOMETRICS

Commercial providers classify radiometrics as a first wave culling tool for reconnaissance geochemical surveys (GRDC Inc.). High-sensitivity (60,000 cps), quick-response full-spectrum scintillometers have been used in airborne platforms with Sodium Iodide crystals of approx 18 litre volume (McPhar Geosurveys) and 8 litres volume for ground-based studies (Gallagher, 1996). Hydrocarbon gases in soils are known to absorb low energy gamma radiation, and consequently the key characteristic of hydrocarbon gases in soils appears to be localised dark spots in background radiometric imagery. In flat terrain with minimal variation in soil moisture and vegetation, high resolution radiometrics have considerable potential for hydrocarbon prospecting. The McPhar system uses characteristic eK and eU anomalies relative to eTh. Because low energy gamma radiation is most affected by hydrocarbon gases, optimised detection aims at any energy window below 1.50 MeV and preferably 4-6 KeV (Gallagher, 1996; GRDC Inc.).

4.5 MULTISPECTRAL SCANNING

Airborne scanner techniques have potential as surrogate airborne methods if convincing correlations with hydrocarbon seeps or related phenomena can be established in any study area. Surveying with Hymap airborne hyperspectral scanner is apparently available commercially through Hyvista in Perth (G. Logan and M. Thankappan, pers.comm, 2007)

4.6 FOLLOW-UP GROUND SURVEYING

Ground confirmation of airborne anomalies is essential, to help understand the cause and type of conduit paths to the ground surface. For hydrocarbon sniffing, most research to date promotes immediate targeting of the emanation site rather than regional grid work (Abrams and Segall, 2002), Follow up ground surveying has a wide selection of established detection techniques (Abrams, unpublished) that include both direct (hydrocarbon gas sampling, absorption sample collection) and surrogate testing as with iodine (Gallagher, 1984), biochemical, microbiological and radiometric data (GRDC Inc.). The efficacy of these techniques for improved drill site success is reviewed by Land (1996).

4.7 EVALUATION OF CASE STUDIES

Given the breadth of remote sensing and ground techniques already applied and assessed over the known natural gas seepage at the Palm Valley Gas Field, from spectral mapping with Landsat TM and NASA aircraft NS001 scanner (Simpson *et al*., 1991) and multispectral airborne scanners (AGAR, 1999), to comparison of ground techniques (rock weathering, diagenetic, geobotanical and soil pH) to detect these anomalies (Huntington and Simpson, 1985, Simpson *et al.,* 1991) this case study would be the ideal onshore area for initial study to evaluate new techniques. Climatic conditions of this Amadeus Basin area have close similarity to the Central Basins project area.

Lower topographic complexity over the Central Basins region should help reduce both survey flight elevation and modelling of atmospheric plumes to offer greater sensitivity of detection. With a wide choice of types and depths of gas and oil fields in the Cooper–Eromanga Basin system, an unprecedented diversity of case studies are potentially available for calibration of airborne sniffing under Australian conditions with added control offered by high density well data. Adjunct acquisition of high resolution radiometrics has apparent relevance.

In the Cooper–Eromanga Basin system, given the large inventory of oil and gas fields from different stratigraphic reservoirs, depths, and structural settings, excellent controls are already established for research and development of procedures and criteria for verification of airborne-indicated anomalies.

5 Geothermal Resources

5.1 IDENTIFIED GEOTHERMAL RESOURCES

The immense store of heat in the earth (~1013 EJ), provided mainly by the decay of natural radioisotopes, is the ultimate source for geothermal resources. It results in a global terrestrial heat flow of 40 million MW, which alone would take over 10^9 years to exhaust the earth's heat. Thus the geothermal resource base is extremely large and ubiquitous (Rybach and Mongillo, 2006). Geothermal energy is currently used in 71 countries, of which 24 generate electricity. Current installed capacity worldwide is ~9000 MWe, equivalent to 14 million tonnes of oil, with a comparative reduction of CO_2 emissions by 50 million tonnes if equivalent production utilised fossil fuels (Hill, 2006).Australia has vast world-class enhanced geothermal resources and over the last six years, the level of interest in this resource has increased significantly. Within Australia, the Eromanga Basin holds 83% of estimated geothermal energy as evident in **Table 2** (Somerville *et al.,* 1994). Individual high heat producing (HHP) granites appear to be the dominant point sources for these thermal anomalies **(Figures 33, 34)**.

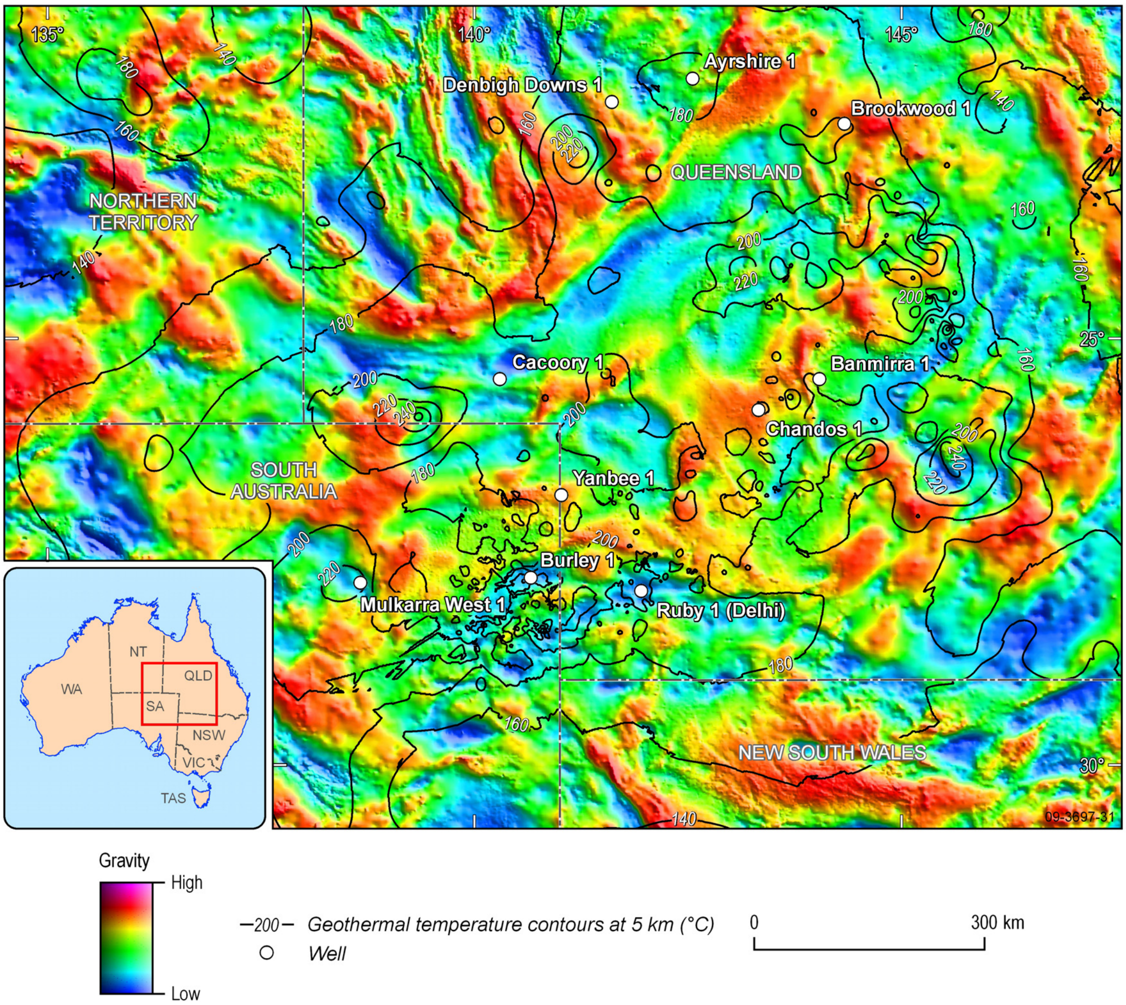


Figure 33: Geothermal highs as contours of predicted temperature at 5km depth, superimposed on gravity, with selected wells in the Eromanga Basin. The temperature contours contained in this figure have been derived from proprietary information owned by Earth Energy Pty Ltd ACN 078 964 73. (Contour interval 20^{o}C above a base contour at 200^{o}C).

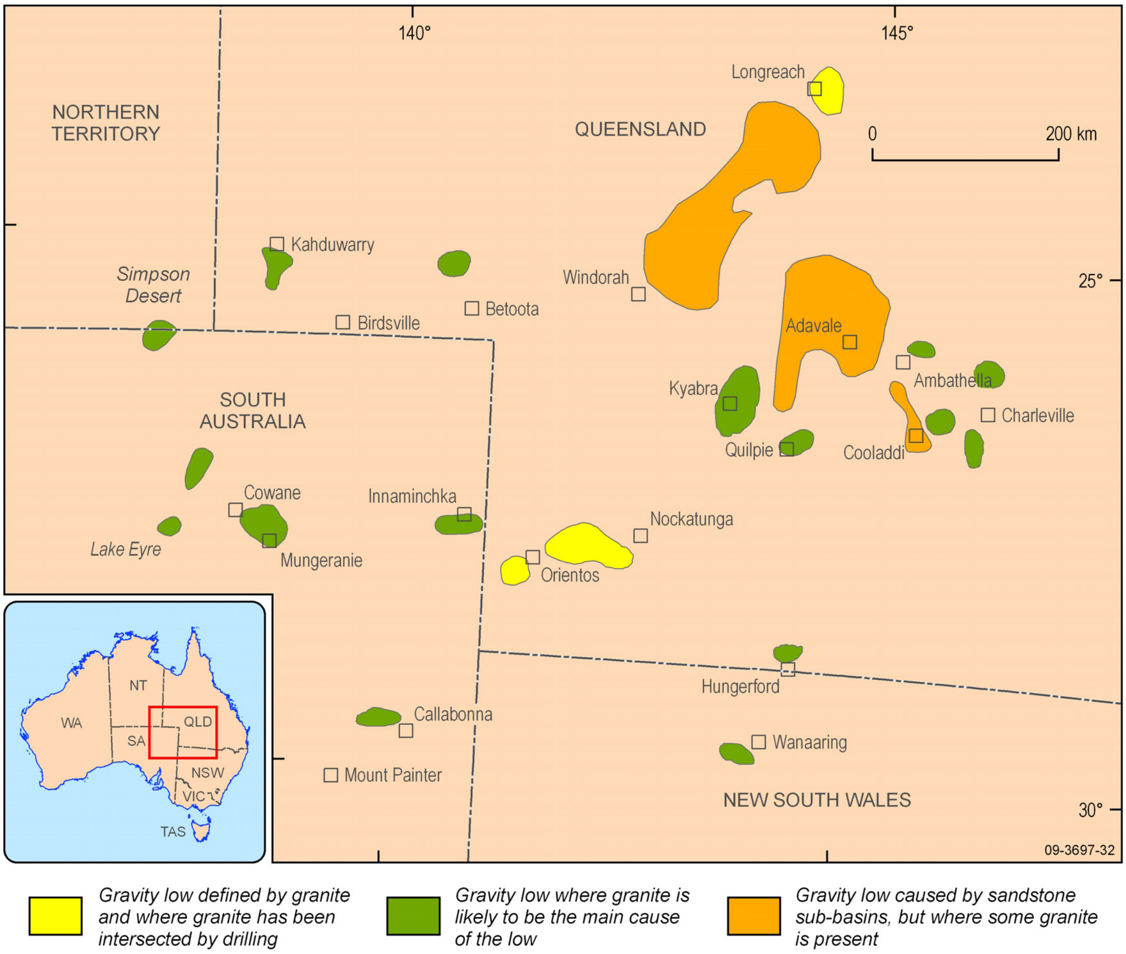


Figure 34: *Gravity lows defined beneath the Eromanga Basin, with intercepted granites, and hot siliciclastics (from Somerville et al, 1994).*

Currently, the only geothermal energy utilised commercially in the region is at Birdsville township where a 120 kW plant captures some of the energy of the hot artesian groundwater prior to it providing the town water supply. However, hot dry rocks (HDR) geothermal exploration has been active in the Cooper Basin region (Innamincka) since 2001 and has now attained ‘proof of concept’ in 2009.

Table 2: Inventory of Australian geothermal resources (from Somerville *et al*., 1994).

Locality	Sub-locality	Surface area in square kilometres where T_{5k}>225°C	Volume of rock (cubic km) above 5km temperature above 165°C (average thickness of 1.5km)	Heat energy available assuming average rock temperature of 195°C (in petajoules = 10^{15} joules)
Eromanga Basin		191400	287100	18948600
	Cooper Basin	7900	118500	7821000
	Galilee Basin	6300	94500	6237000
	Cacoory	2100	31500	2079000
	Mulkarra West	11000	16500	1089000
	Denbight Downs	10000	15000	990000
	Brookwood	3000	4500	297000
	Ayrshire	1800	2700	178200
	Banmirra	1200	1800	118800
	Yanbee	700	1050	69300
	Chandos	700	1050	69300
McArthur Basin		29000	43500	2871000
Otway Basin		5000	7500	495000
Carnarvon Basin		2000	3000	198000
Murray Basin		1200	1800	118800
Perth Basin		500	750	49500
Canning Basin		290	435	28710
East Queensland		80	120	7920
Sydney Basin		50	75	4950
TOTAL		**229520**	**344280**	**22722480**

Notes for Table 2. An average rock heat capacity of 2.2 petajoules per cubic kilometre per °C has been used.

2.Calculating assumes a temperature of 225°C at 5 km depth, but large volumes of rock in the 4-5 km depth range are up to 300°C. These volumes would give three times the more usable energy per unit volume.

3. Australia consumes approximately 3000 petajoules per annum, so the resource would last for approximately 7500 years at current consumption levels.

5.1.1 Cooper Basin

The Cooper Basin has long been thought to be suitable for HDR granites as it comprises the largest area in Australia with T_{5km}>225°C, amounting to 79,000 km^2. The prime area extends from Moomba, SA, in the southwest, into Queensland and a small part of New South Wales. With the numerous petroleum exploration and development wells drilled in the region, the area is the best defined of any area in Australia in terms of known temperature/depth profiles.

Granite bodies blanketed by over 3.5 km of insulating sediments of the Eromanga and Cooper Basin near Innamincka have the highest known temperature gradients. The granites are moderately fractionated and high in potassium, with a high but not excessive abundance of radiogenic elements. Th/U ratios are about 2 compared to the crustal average of 4, and contribute to a heat productivity of 7-10μwatts/m^3 (Wyborn *et al.,* 2004). While this granite has lower heat production when compared to Mesoproterozoic granites, the thick thermal blanket of coal, sandstone and siltstone has very effectively trapped generated heat (PIRSA, 2007).

Granites also underlie areas of slightly lower temperature gradients in the Moomba and Big Lake areas to the southwest of Innamincka, areas well known from dense petroleum drilling. Small amounts of HHP granite are present (Moomba 1 and Big Lake 1). The granite bodies in this area are not defined by significant gravity lows and several bodies appear to be present as cupolas, separated by metasediments and volcanics of the Warburton Basin beneath the Cooper Basin (Gatehouse, 1986).

Other wells in Queensland have equally high thermal gradients as those in South Australia, but they do not penetrate to such great depths. Such wells include Dingera 1 and Ruby 1 in the Nockatunga gravity low which have T_{5km} exceeding 300°C, and a number of wells that penetrated sandstones of the Devonian Barrolka Trough (Murray, 1986, 1994) which have T_{5km} of about 250°C. The Barrolka Trough is not known to contain granite like the adjacent Adavale Basin to the east, but both areas have similar gravity patterns and similarly-aged massive sandstone accumulations. Although these sandstones are not regarded as an ideal HDR source at present, they form a considerable resource for the future.

About 30 km east of the Q/SA border and to the east of Moomba is another feature, the Orientos gravity low. Granite has been intersected at depths of 2.2 to 2.3 km in this feature with Wolgolla 1, Roseneath 1, and Ashby 1 wells. The T_{5km} is about 225°C in this area, which is somewhat lower than the surrounding areas. Granites intercepted in these wells are older than the suite in the Innamincka area, and they appear not to be HHP types.

5.1.1.1 Innamincka

Wyborn *et al.* (2004) summarise the attributes of this region

- Depth to basement below the Nappamerri Trough is approximately 3.5 to 4.5 km.
- This trough has higher than normal geothermal gradients of 55-60°C/km (measured).
- The trough exhibits a gravity low that cannot be explained by the thickness of sediments alone.
- A number of drillholes bottoming in the basement of the trough have intersected granite.
- Modeling suggests that granite with a thickness of 10 km underlies the whole of the gravity low of approx. 1000 km^2 (Meixner *et al.*, 1999).
- Stress conditions in the Nappamerri Trough indicate an overthrust environment in common with many basement areas of the Australian continent (Denham and Windsor, 1991).
- Overpressures have been observed towards the base of the basin in the trough.

The hottest well drilled in Australia was Burley 2 near Innamincka, with an extrapolated bottom hole temperature of 253°C at 3.7 km, and an estimated temperature of 310°C at 5 km depth. Burley 2 and the adjacent McLeod 1 well were sited over the Innamincka gravity low. Both wells intercepted HHP granites at depths over 3.5 km. The area of this gravity low is approximately 1000 km^2 and as such, holds the greatest concentration of HDR geothermal energy in a confined region in Australia. It could constitute perhaps the most accessible large HDR resource in the world as it contains an estimated 1350 km^3 of granite at an average temperature of 260°C, enough energy to provide all of Australia's needs for 94 years.

5.1.1.2 Cacoory

This geothermal anomaly is named after Cacoory 1 well which intersected metamorphosed sedimentary rocks at 1478 m. The gradient was 68°C /km, with an extrapolated T_{5km}=325°C. Other wells further west are hot, for example Adria Downs 1. Cacoory 1 was drilled on the margin of the Betoota gravity low (approx. 750 km^2), thought to correspond to a HHP granite buried at about 1.5 km. With T_{5km}=325°C, a 2.5 km thickness of granite above 5 km would be a candidate for energy extraction and power generation. On present limited indications it contains enough energy above 5 km depth to provide all of Australia's energy needs for 89 years.

5.1.1.3 Mulkarra West
The Mulkarra West 1 well intercepted metamorphosed sedimentary basement at 1287 m depth, with a gradient of 58°C/km. The well was drilled above the large Mungeranie gravity low, an area with suspected buried granite of large dimension (Somerville *et al.,* 1994), but also interpreted as a very thick deeper sedimentary basin (FrOG Tech Ozseebase). Paleozoic sedimentary cover is about 1.5 km thick and no granite has been intercepted. Regardless, the area has good HDR potential. Two other smaller gravity lows, Cowarie and Lake Eyre are adjacent to the Mungeranie gravity low. No well information is available, but they are not considered as major HDR resources by Somerville *op.cit*. mainly because of the thin sedimentary cover in the region.

5.1.2 Galilee Basin
The Galilee Basin is considerably thinner than the Cooper Basin to the south and southwest, but it forms a geothermal area almost as large as the latter (63,000 $km^{2)}$. Wells in this crustal province have gradients well above 60°C per km and an estimated T_{5km} >300°C. Because of the thinner overlying basinal sequence, wells generally do not penetrate greater than 1 km, so the extrapolation to 5 km is more tenuous.

Table 3: Estimated temperatures and calculated gradients below the Galilee Basin (from Somerville *et al*., 1994)

WELL	DEPTH DRILLED	GRADIENT(° C/km)	ESTIMATED T_{5km} °C
Connemarra 1	1268	60	265
Corona 1	1067	67	292
Low 1	1021	67	304
Maneroo 1	1192	69	300

5.1.2.1 Denbight Downs
This geothermal anomaly is entirely due to a high gradient (60°C/km) in the Denbight Downs 1 well, which intersected granite basement, presumably on the covered part of the Mt Isa block (Somerville *et al.,* 1994) at 1009 m. The estimated temperature at 5 km depth, based on the gradient, is 260°C and a relatively large area of high temperature rock is predicted. However, there is no associated gravity low, and the thin sedimentary cover precludes the presence of a significant HDR resource.

5.1.2.2 Brookwood
Brookwood 1 well forms a separate geothermal anomaly to the northeast of the main Galilee Basin geothermal high. A very high temperature gradient (78°C/km) was measured in the well which intersected granite at 1465 m. T_{5km} is estimated at 338°C but there is no associated gravity low. This location could contain a significant HDR resource if the high gradients continue to greater depths, but it is likely that the gradient within the granite is lower than in the overlying sediments. Although this Brookwood site is seen as well down the ranking in Australian sites, it is in many ways comparable to the Soultz site which is regarded as the best HDR prospect in all Europe.

5.1.2.3 Ayrshire

Another anomaly in the Galilee Basin to the north of the main Galilee Basin High is Ayrshire. No granite has been found in this area, but two wells (Ayrshire 1 – 1966 m, and Goleburra 1 – 1581 m) have gradients of above 50°C/km.

5.1.2.4 Banmirra

This anomaly in the southeast of the Galilee Basin geothermal high is based solely on the Banmirra 1 well, drilled to a depth of 2065 m. The measured gradient was 48°C/km and T_{5km} =256°C. The well is on the eastern edge of the Adavale Basin gravity low.

5.1.2.5 Yanbee

Another single well anomaly based on Yanbee 1 close to the Queensland-South Australian border. There is no associated gravity low. The well was drilled to 2592 m with a gradient of 50°C/km, and estimated T_{5km} =251°C.

5.1.2.6 Chandos

The Chandos geothermal anomaly lies between the Cooper and Galilee geothermal highs. It is based on Chandos 1, depth 2979 m, gradient 58°C/km, and Kyabra 1 (depth 2509 m, gradient 49°C/km). There is no associated gravity low.

5.2 PROOF OF CONCEPT AND COMMERCIAL DEVELOPMENT

Although the energy contained in HHP granites is at an impressive and unprecedented scale, even by world standards, what remains unknown is the amount of extractable energy production that can be sustained over the project life of decades that would be necessary to offset the investment in drilling and development to produce a viable extraction field. In this region, Geodynamics is the only company that has been consistently investing in and advancing development of this potential resource since 2002.

The first stage of 'Proof of Concept' was demonstrated in 2004 with the development of a large subhorizontal enhanced-permeability zone as heat exchanger at >4 km depth within the Innamincka Granite (**Figure 35**). The subsequent stage of testing has been delayed by several years as it has demanded pushing the envelope on existing drilling technologies, competition for drilling services with the petroleum industry in the same region, as well as overcoming simple but expensive accidents common to boreholes. As of February 2009, the final stage of 'Proof of Concept' was completed with the independent confirmation by GeothermEx – testing the circulation between the heat exchanger in the granite and the surface, energy extraction, and dynamic stability of requisite water temperatures. The drilling to date has demonstrated thermal energy in place to be 1800 petajoules of measured resource and 7600 PJ indicated resource, suggesting a world-class geothermal resource.

Out of this, the first commercial stage is to be a 1 MW pilot plant to power both the Habanero operations as well as the town of Innamincka. This is expected to be commissioned in early 2010. Stage 2 consists of a 50 MW power plant based on approximately 9 wells. The company plan to finalise its preferred design for this commercial demonstration plant in 2010.. Stage 3 involves building a 500MW plant comprising ten such 50 MW modules, each to be similar to the commercial demonstration plant.

5.2.1 Innamincka Granite – Hot Fractured Rock (HFR)

The mid-Carboniferous Big Lake Suite granite has been blanketed by over 3.5 km of insulating sedimentary cover. While this granite does not have the highest heat production when compared to

Mesoproterozoic granites, the thick thermal blanket of coal, sandstone and siltstone has very effectively trapped past generated heat. Temperatures of 250°C occur at 4.5 km depth.

The Innamincka Granite has received major investment and effort by Geodynamics Pty Ltd which since 2002 has held geothermal exploration licences (GELs) and now geothermal retention licence (GRL) applications over this entire granite body.

Prior to the initial conceptual resource survey of Somerville *et al*. (1994), it was known that Burley 2 near Innamincka had an extrapolated bottom-hole temperature of 253°C at 3.7 km. In 2003, Habanero 1 reached 4.13 km, 468 m into the granite and >245°C. From Geodynamics second well Habanero 2, and extracting from an interval below 3.9 km, flows of up to 25 L/s (13 565 bbl water per day) with output temperatures of 210°C were recorded from a shallower fracture system during production testing in 2005 without appreciable pressure depletion. Prior to the drilling of Habanero 1, this granite was considered to be a hot dry rock (HDR) resource, but the unexpected discovery of contained pressured water within the granite was a significant and unexpected bonus (35 MPa - 350 bar at wellhead). In proposed future production, this water will be cycled to the surface for energy extraction through heat exchangers, but then returned fully pressured to the subsurface heat exchanger at > 4 km depth. After the drilling of Habanero 1, where the main anticipated asset of natural horizontal fracturing was confirmed within the granite **(Figures 35 b, c)**, the subsurface heat exchanger was developed to an areal extent of over 5.5 km^2 by hydraulic fracturing from the injection of 23,000 m^3 water at about 66 MPa (9500 psi).

The preferred transmission properties in a subsurface heat exchanger are for a decentralized and uniform water flow through the network of fractures from injection to production well, the wells spaced approximately 500 m apart. The existence of, or development of major highly-permeable fracture/fault pathways between wells can reduce the effectiveness of uniform heat extraction and if not managed effectively during production, can reduce the life of that portion of the heat exchanger through cold temperature breakthrough. For sustainable geothermal energy, the extraction system needs to be able to sustain the production level over long periods of several decades. Excessive production is often pursued mainly for economic reasons, such as a quick payback and return on investments, but this may be at the expense of premature reservoir depletion and cold breakthrough (Rybach and Mongillo, 2006).

Habanero 3 was completed in early 2008 as a production well to test subsurface heat exchanger flow characteristics from Habanero 1, and thereby to complete 'Proof of Concept' before commencing full development of the field.

The effort and financial investment in drilling and pressure-casing a single well to production depth is in the order of 3 times that of a comparable oil well. A production field for producing 275 MW power would require a well field comprising some 41 wells over 28 km^2 at a capital cost in excess of $150-200 million, excluding the plant costs for a surface Kalina Cycle power station. However, projected energy costs remain favourable at A$40/MWhr **(Figure 36)**. Since initiation of this project in 2002, Geodynamics has been a recipient of Commonwealth Government START fund and REDI Grant funds to the value of $13M. Additional Federal financial support is awaiting proof of concept. Independent international reviews of this project indicate it to have the greatest chance of economic viability for any geothermal resource in the world if the remaining technological and development challenges can be met.

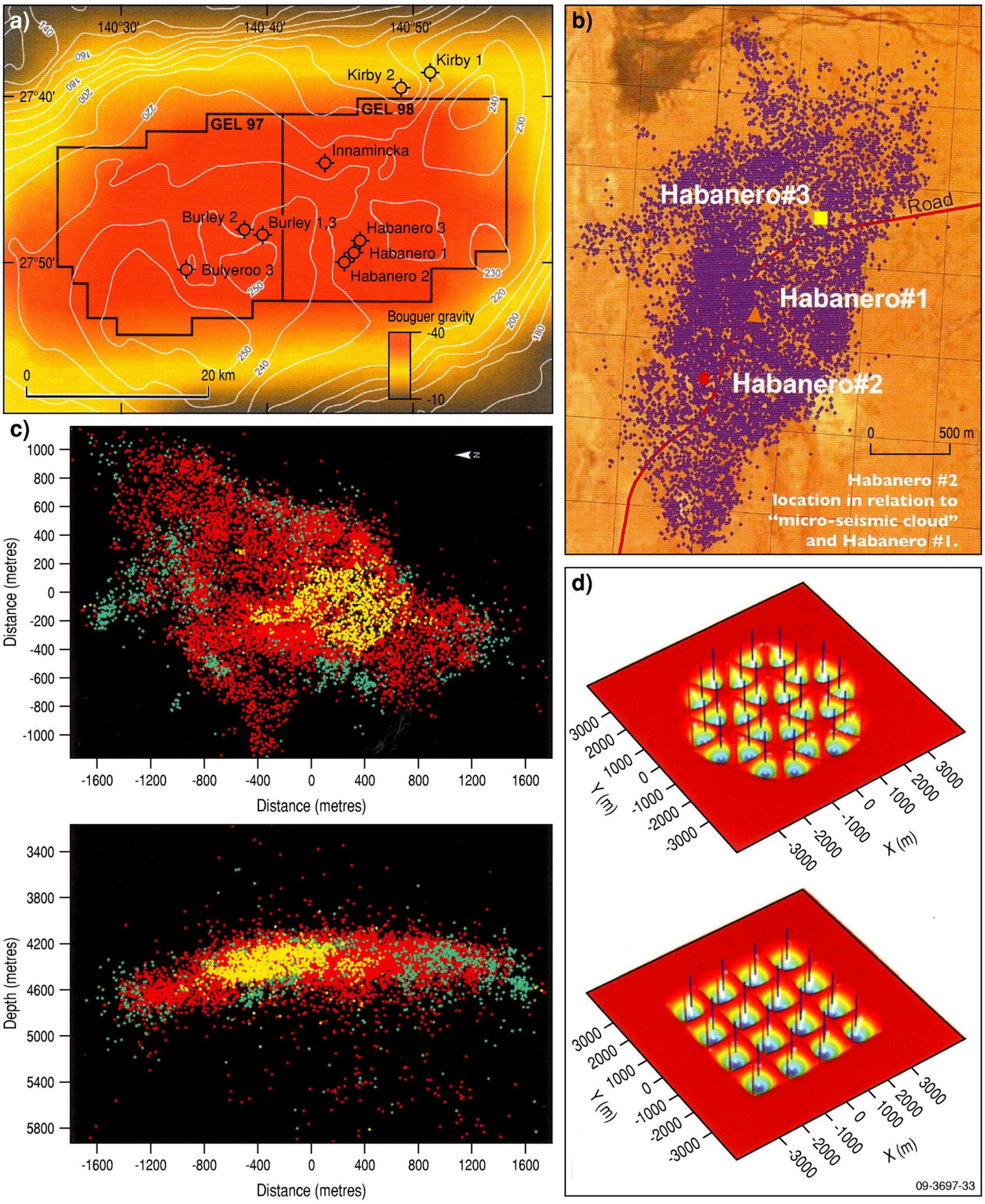


***Figure 35**: The Innamincka Hot Fractured Rock Project of Geodynamics Ltd.*

a) The Innamincka Granite with projected bore field size required to generate 275 MW.

b) Recorded microseismic events in the hot granite during hydraulic stimulation from Habanero 1 shows the lateral extent and horizontal tabular nature of the developed subsurface heat exchanger.

c) Extent of subsurface heat exchanger relative to existing wells (grid is 500m).

d) Modeled temperature drawdowns of proposed production fields in triangular and square well patterns after 20 years production for 43 and 41 wells respectively. Note temperature breakthrough between injection and production wells has not yet occurred

(From Geodynamics Annual Reports, 2004 & 2006; Wyborn et al., 2004).

5.2.2 Hazard evaluation

Potential seismicity generated by the development of hot fractured rock operations in the Cooper Basin has been evaluated by Hunt & Morelli (2006) who found that reactivation on any of the basement faults is unlikely, and therefore the region is ideally suited to HFR activities in terms of natural background seismic hazard. Only the northern end of the Big Lake Fault would require consideration as it may overlap the attenuation distance effect, and could subsequently be influenced by associated stress changes. However, the Geodynamics Innamincka site falls below the background coefficient of ground acceleration (0.05 g, this not exceeding current government building design standards for peak ground accelerations). Any static stress damage zone created would not be expected to have any impact on identified local structural features.

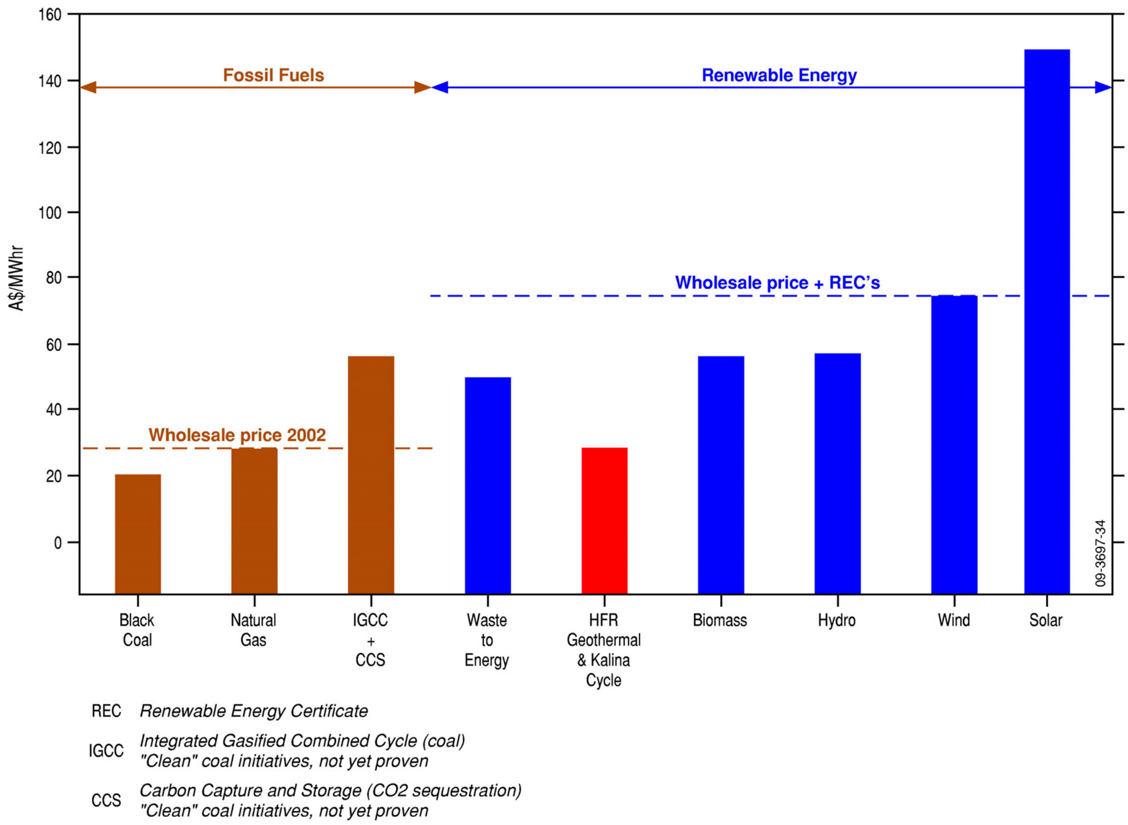


***Figure 36**: Comparison of electricity generation costs from fossil fuels and HFR sources (from Geodynamics Pty Ltd, 2004 Annual Report).*

5.3 HOT GROUNDWATER

Thermal energy within the Great Artesian Basin aquifer system is a much lower-level energy resource for electricity generation. Geothermal extraction potential of such a resource is three orders of magnitude lower than HFR as seen in the Innamincka Granite, but is more readily accessible because of shallower depths.

The Birdsville geothermal power plant is an example of the very modest energy that can be captured from this system. The 120 kW Rankine demonstration plant has been operating from the town water bore since 1999 using 99^{o}C groundwater from the main artesian aquifer. However, if such an extraction system attempted to capture the thermal energy and then reinject the cooled effluent back into the aquifer, a scenario that is desirable to conserve the groundwater resource and to maintain aquifer pressure, then the parasitic power demand for reinjection severely reduces the net extractable power from this already modest system.

Extrapolated basement temperatures below the Cooper Basin region are some of the highest in Australia yet are locally variable (**Figure 37**). Accordingly, in the main artesian aquifer of the Eromanga Basin, the groundwater is hottest over this region and approaches 100°C (**Figure 38**).

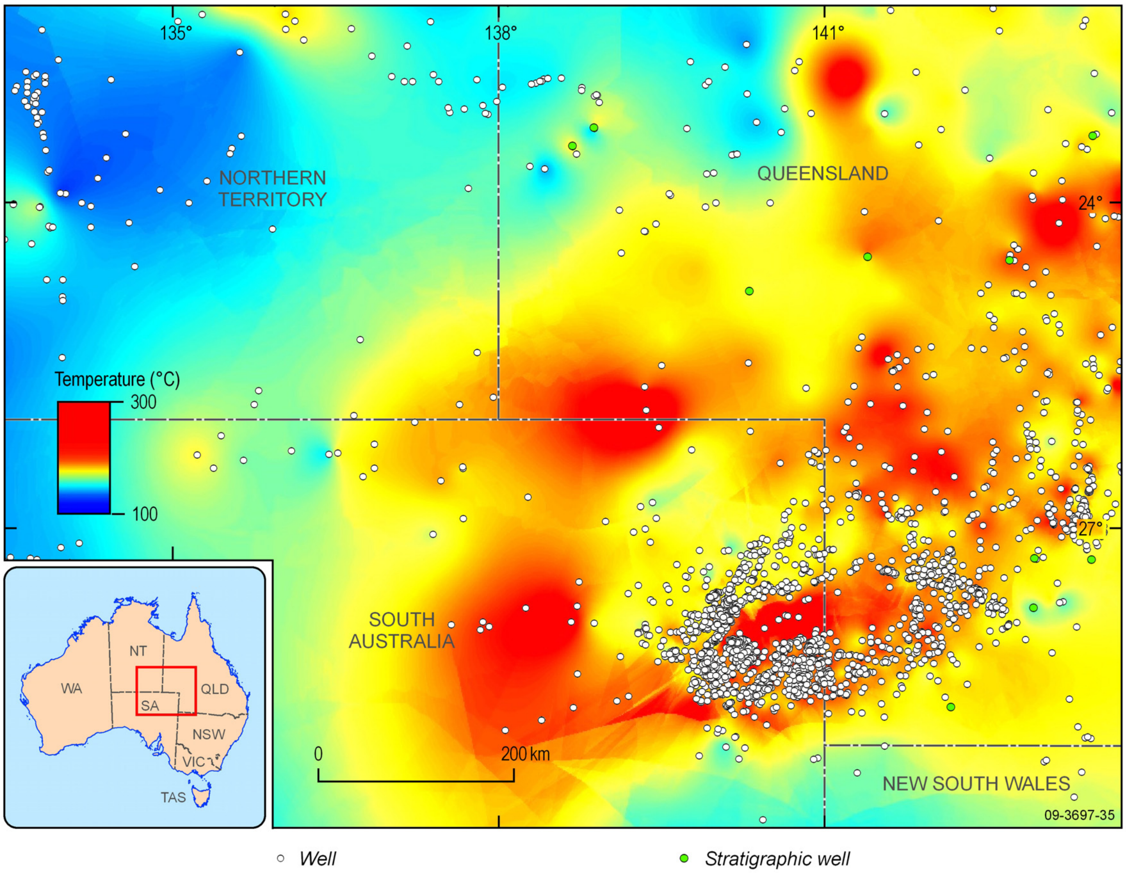


***Figure 37**: Relatively high temperatures over basement granites on the Birdsville Track Ridge and over the Big Lake Granitoids. Crustal temperatures extrapolated to 5 km depth (from Earthinsite.com, Chopra and Holgate, 2005).*

Tri-Star Energy is a recognized applicant for Geothermal Exploration Licences covering the Eromanga Basin west of the Birdsville Track Ridge. Tri-Star proposes to exploit a hot groundwater resource contained in the Algebuckina Sandstone. Here indicated aquifer temperatures of 130°C at 2 km depth are the target.

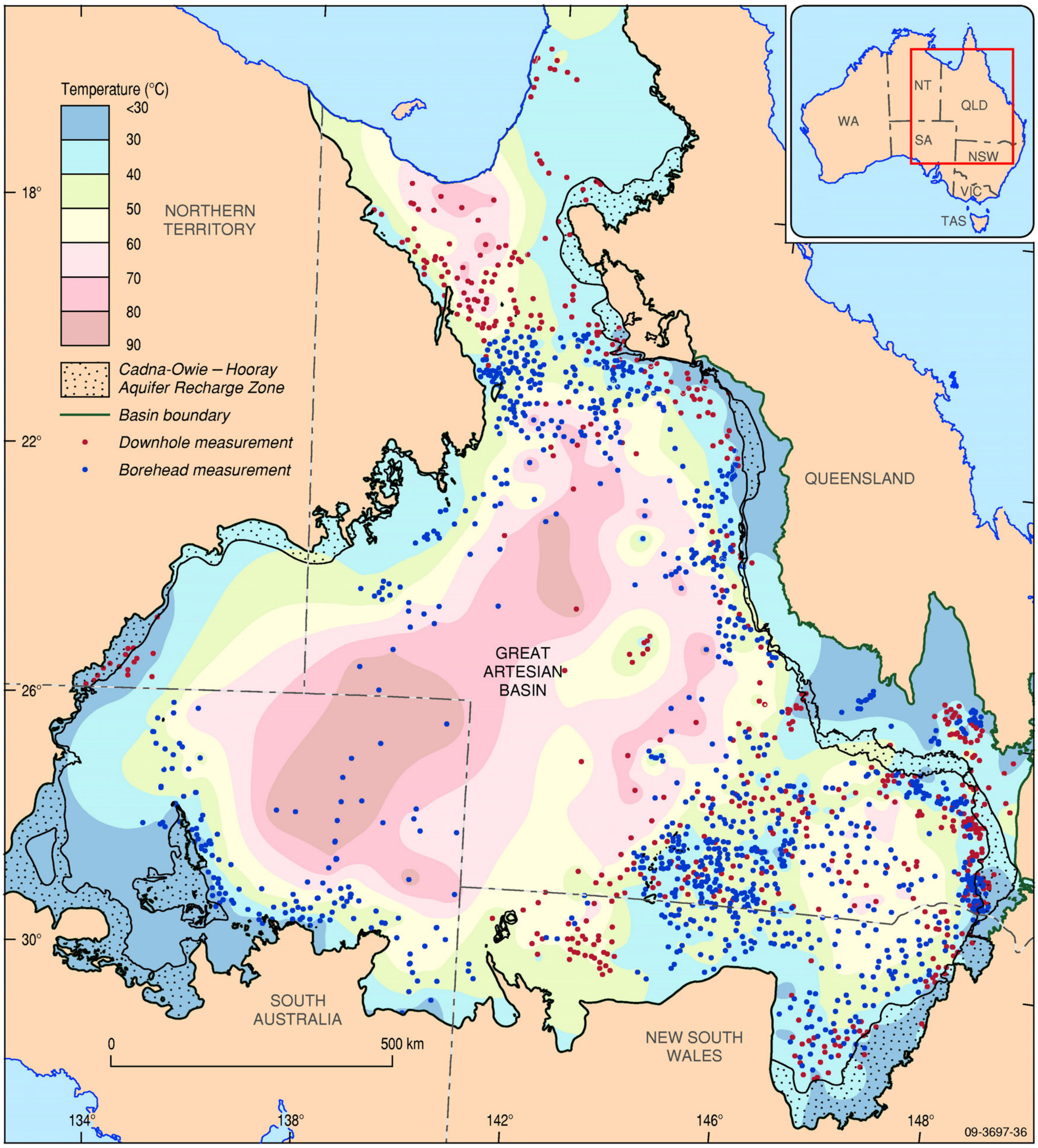


Figure 38: *Groundwater temperatures in the upper Cadna-owie - Hooray aquifer of the Great Artesian Basin (from Radke et al., 2000).*

6 RECOMMENDATIONS

The objectives of these recommendations are:

- To meet the requirements of stimulating, fast-tracking, and offering guidelines for an increased exploration success rate within industry;
- To promote new prospects and plays supported by research; and
- To encourage greater investment in exploration outside of proven and developed fields.

6.1 UNEXPLORED AND UNDER-EXPLORED REGIONS

6.1.1 Amadeus/Warburton-Pedirka-Simpson-Eromanga Basins

Source rock, facies, and thermal maturity characteristics of the deeper early Paleozoic sequences have yet to be investigated in this region. Outside of the three main troughs, much of the Upper Paleozoic and Mesozoic sequence is immature. By analogy with the Warburton Basin contribution to the Cooper Basin hydrocarbon resources, the Warburton-Amadeus sequence is a potentially mature source in this region and therefore requires serious appraisal.

Considerable hydrocarbon potential remains untested in the Northern Territory sector of the Pedirka Basin region because of insufficient or ineffective seismic coverage and drilling penetration. Exploration drilling to date has proven that good source rocks, reservoirs and seals are present throughout most of this area. Numerous apparent structures and potential stratigraphic traps remain to be confirmed and tested.

The critical uncertainties in this region are those of thermal organic maturity and the ability to map effective structural closure.

6.1.1.1 Thermal organic maturity

Organic maturity can be expected in the Eringa, Madigan, and central Poolowanna Troughs, and is sufficient for dry gas. As in the Cooper–Eromanga Basin, shallower reservoirs in the overlying sequence, although below thermal maturity, may still be charged with hydrocarbons. Generally lower thermal maturity is evident in the west than further east. However, there remain many untested deeper structures and sequences in the Eringa and Madison Troughs. Adequate organic maturity for hydrocarbon generation, although preferable, is not an essential as CSG/CBM is also a target option. Being a lower-value product, methane is disadvantaged by the distance to existing infrastructure. However, CSG is one of the current commercial targets in the eastern part of the Poolowanna Trough in Northern Territory and Queensland.

6.1.1.2 Mapping structural closure

Structural plays in this region are numerous but many are of subtle relief in faulted terrain. Effective seismic delineation of these demands a higher density of accurate high resolution seismic imaging and good structural interpretation and correlation. Realistic and reliable seismic statics have apparently been elusive for most past surveys, which has led to unacceptably large mis-tie corrections between survey lines of different vintage. This, and the inability to accurately correlate faults to identify fault blocks, has led to questionable structural interpretations and isopach mapping. Much of the earlier structural contouring has been shown to be across unrecognized fault displacements and has thus introduced artefacts into the interpretation of structures and their closure (P. Boult, pers. comm., 2007). Accurate mapping of faults between lines, and the determination of their penetration limits up into the sediment pile are critical for evaluating potential trap integrity. High resolution magnetics is an important adjunct to assist good structural interpretation.

On the basis of existing 2D seismic, the Basement reflector (top-Warburton), top of Poolowanna, and Cadna-owie seismic reflectors are all that can confidently be mapped throughout the region (Boult, pers.comm., 2007). The effective exploration of low-relief structural closure requires seismic with good resolution and this necessitates good statics control.

6.1.2 Petroleum potential of Warburton and pre-Permian sequences

Additional to the proposed investigation into the Warburton and Amadeus sequences in the Eringa Trough region, this basin is largely unknown outside of the eastern Warburton region. Premature terminations of drilling in pre-Permian 'basement' has meant little to no penetration of the sequence to provide data for a comprehensive appraisal of this sequence.

Critical uncertainties for this sequence are identified as:

- Organic maturity of different lithofacies in various regions
- Variations in grade of metamorphism in the Warburton sequence.

Necessary research for an adequate Warburton Basin overview includes:

- Definition of regional structure and integrity of the sequence,
- Mapping the regional metamorphic grade,
- Determining source rock potential,
- Determine the maturation, and hydrocarbon migration history

As a consequence, this research would determine favourable regions of overlying sequences that may have trapped and retained hydrocarbons.

6.2 SEISMIC

6.2.1 Reprocessing of existing seismic surveys in key areas

Thick coal sequences, especially in both the Eromanga Poolowanna Formation and the Cooper Patchawarra Formation, have presented a challenge to seismic penetration where underlying strata is frequently at significant dips, and little effective signal of these deeper strata is recorded. In the Pedirka-Simpson-Eromanga Basins system, early seismic surveys predating 1985 had considerable difficulty in acquiring adequate seismic resolution of the sequence. Recent exploration drilling has established very thick coal measures (up to 198 metres thick in the Purni Formation) off structural highs. Even above the coal sequences, subtle structures have remained elusive to validation by drilling. Reviews of exploration drilling in the region (Alexander and Jensen-Schmidt, 1995; Carne and Alexander, 1997) assign the cause of many dry holes to not drilling on closure.

With smaller or lower-relief structural traps in the Eromanga sequence, accurate structure and fault delineation is essential. Adequate statics control is necessary for quality processing. Mis-ties and contour artefacts that have previously led to spurious interpretation of closure can be minimised with better statics and addressing phase differences between overlapping surveys (Senycia, 1989; Greaves and Surka, 1989). Static corrections in earlier times were largely refraction-based, if any. The known worst regions for statics were in the tablelands area of Haddon Downs, and across the dune fields of the Simpson Desert. Acquisition of new uphole data would facilitate a much better static control and hence improve reprocessing results. However, this would be a very costly program if at all feasible, as accurate relocation of old lines and stations may no longer be possible. It may be instructive to run some reprocessing trials first, using approximated statics to simulate the benefit or otherwise of acquiring new statics for the old data. At least 1985/1987 and 1988 seismic surveys had upholes recorded and there appears to be no more signal around basement than on lines without upholes. This suggests the need for a full analysis of spread, sweep frequencies, and vibrator size that may reveal as much about this problem as the issue of statics. Perhaps new recording with a greater number of channels and with careful consideration of input sweep frequencies and geophone arrays are necessary. An experimental program, in conjunction with an appraisal of some key lines on the eastern side of the Birdsville Track Ridge may offer the best contribution to this problem (P. Hough, PIRSA, pers. comm., 2007).

Many explorers are now using 3D seismic in critical areas\where the extra cost can be justified. In producing fields, resurveying with 3D seismic has increased field size by up to 50%, increased reserves, and raised drilling success rates.

In the Cooper Basin, top of basement is difficult to discern on seismic, largely because of insufficient velocity/density contrast near the basement boundary. Here, substantial weathering of the upper Warburton Basin sequence is widespread, and sometimes this transgresses the basal unconformity as an alteration zone up into the Cooper Basin sequence (Boucher, 2001c, 1997a). On some lines it may be that the acoustic penetration of signal is insufficient to reach basement and /or provide a clear signal of Warburton basement. Acquisition of new seismic data with current equipment and processing algorithms may help improve this definition.

6.2.2 Linking Galilee-Cooper-Pedirka, Georgina-Warburton-Amadeus Basins, and Field River Beds-Amadeus Basin

Previously rated as of low priority, the under-explored region to the north of, and surrounded by the Cooper Basin, Lovelle Depression of the Galilee Basin, Pedirka Basin and Toko Syncline of the Georgina Basin, has indications of very high recent geothermal gradients related to scattered radiogenic granites in this area. The Eromanga sequence in this region has source maturity below, but approaching the oil maturity window. OzSeebase coverages (FrOG Tech, 2005), indicate this region to contain a remnant depocentre between the Galilee Basin and the Poolowanna Trough. An underlying deep basin of probable Neo to Mesoproterozoic age was identified below the Georgina sequence in the southern part of the Toko Syncline (Lodwick and Lindsay, 1990). The western extent of the Permo-Carboniferous Galilee Basin within the Lovelle Depression has not been defined and there remains the distinct possibility of scattered preserved remnants westwards, perhaps as far across as the Pedirka depocentre. The thickness of sediment cover over the Proterozoic Arunta Block between its outcrop and the Haddon Downs 1 intercept at 1966 m is unknown. Preliminary forward modeling of aeromagnetic and gravity data on transects over this region also indicate the probability of pre-Eromanga basinal sequences **(Figures 28, 29).**

6.2.3 Seismic delineation of new basins

Regional seismic is proposed to address the regions identified above. In combination with high resolution aeromagnetics, deep penetration seismic is needed to penetrate thick coal measures to confirm and delineate new basins and/or preserved depocentres as indicated by gravity/magnetic modelled sedimentary thickness from OzSeebase **(Figure 3)** (FrOG Tech, 2005). There are many areas of implied sedimentary sequences of unknown age. A prioritised program is presented **(Figure 39),** comprising 1865 km of higher priority (lines 1 to 7), and 640 km of lower priority (lines 8-11) for consideration. Lines would be most effective if linked in with existing wells for stratigraphic and seismic velocity control.

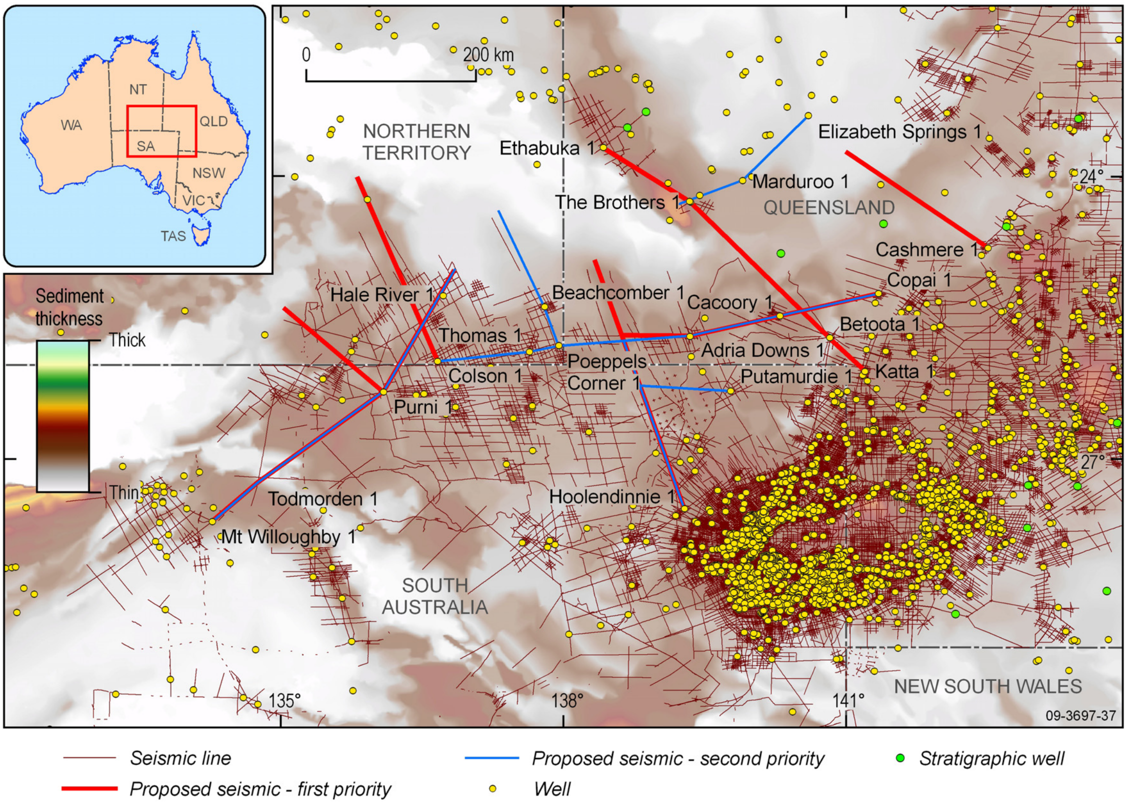


Figure 39*: Proposed and prioritised seismic surveys to assist delineation of basement granites and/or inferred new basins.*

Proposed deep penetration seismic lines are ranked in priority, and the main objective of each line is outlined briefly.

1 From Katta 1 to Ethabuka 1.

Test the gravity low north of Betoota 1, test the implied basin of FrOG Tech, define the margin of the Mt Isa Block, and delineate the sequences in the southern Toko Syncline. This proposed line crosses lakes and drainage channels, and dune country. The southern tie end of the line would be close to tying in the proposed GSQ seismic line along the border, across the Cooper Basin.

2 From Copai 1 to Cacoory 1, Adria Downs 1, and almost to Poeppels Corner 1.

Test gravity lows within the implied basin identified on OzSeebase (FrOG Tech, 2005).

3 From Cashmere 1 northwest towards Canary 1.

Test for an extension of the Lovelle Depression across the margin of the Mt Isa Block. No seismic data exists in this area which includes channels of several river systems.

4 From Mt Willoughby 1, northeast to Todmorden 1, Purni 1, Hale River 1 and beyond.

Define the relationship of the Officer Basin -Boolthanna Trough to the Muloorinna Ridge, the very thick sequence beneath the Eringa Trough, define the Madigan Trough, and the southwestern block-faulted margin of the Arunta Block.

5 From Colson 1 to the north-northwest.

Define the very thick deep sequence adjoining the southwestern margin of the Arunta Block. This should also clarify relationships between Amadeus and Warburton sequences.

6 Northwest from Purni 1.
Define the western margin of the Eringa Trough and the Andado Shelf, as well as the deeper structure of the DMM Ridge.

7 North-northwest from Hoolendinnie 1.
Define the deep and very thick sequence adjoining the known Warburton detached rift structure, and test the thick sequence adjoining the Arunta Block. This line, as well as proposed line 4 runs across the structural trend of the lower Paleozoic Basin underlying the Pedirka Basin (Questa, 1990).

8 From the western end of line 2, westwards through Thomas 1 to Colson 1.
Define the deeper structure of the Poolowanna Trough and provide a tie for many of the existing seismic lines.

9 From Marduroo 1 west-southwest through The Brothers 1 to the Toomba Thrust Fault. Define the eastern margin and depocentre of the Toko Syncline. This line may be extended northeast to Elisabeth Springs 1 if a westward extension of the Galilee Basin is confirmed in the Lovelle Depression (proposed line 3).

10 From Poeppels Corner 1, north-northwest through Beachcomber 1.
Test the sequence on the southwestern margin of the Arunta Block.

11 West from Putamurdie 1.
Test another gravity low, an inferred component of the unnamed basin (FrOG Tech, 2005).

6.2.4 Promotion of the Cooper/Eromanga Basin system

This region is far from being a brownfield as it is endowed with numerous hydrocarbon-charged structures. New discoveries of oil are common with drilling success rates exceeding 50%.
Improved seismic and geochemical techniques enable subtler relief and smaller fields to be effectively delineated. Geoscience Australia PTAG well summaries, an unpublished component of a future APA, offer an immediate first-stop reference for the region. Although other under-explored regions are prioritised, general research into airborne prospecting and the understanding of petroleum generation, migration and trapping mechanisms should be maintained.

6.3 Application of airborne surveys

The Shell 'Light Touch' technology needs to be appraised for applicability to the Central Basins region:

Calibrate against previous satellite and ground surveys of the Palm Valley gas field;

Select discrete under-produced oil and gas fields in the Cooper Basin for testing the technology, using available well logs, seismic and high resolution magnetics for establishing fault and fracture analysis including asymmetric stress fields;

In peripheral basin areas that are not under commercial licence for production or exploration, execute airborne sniffing surveys over regions of identified potential based on greater sediment thickness, sequence organic maturity, and superimposed structure.

Following confirmation of detected anomalies through temporal survey duplication, design follow-up ground surveys.

Such technology has high potential application over many frontier Proterozoic Basins beyond the current study area. Given the huge demand for surveying coverage that may evolve if the approach is successful in the immediate study area, there is a compelling argument for Geoscience Australia to commission development of it own airborne hydrocarbon detection technology.

Complete coverage of the region with high resolution aeromagnetics is required for the combined benefits of assisting structural interpretation, and for identification of both SRM and MBS anomalies.

Airborne radiometry of high sensitivity/quick response needs appraisal for its potential and effectiveness in detection of both hydrocarbon seeps and potential near-surface uranium anomalies.

6.4 National Petroleum & Geothermal Exploration Accord

Following the positive contributions of NGMA, it is suggested that a comparable National Petroleum Exploration Accord be created, with its prime purpose to provide a forum between federal and state government petroleum authorities, to facilitate research and exploration management for:

- basic standardisation of state products;
- nationwide interactive online database, standardised;
- standardisation through a national register of well names to avoid duplicated names;
- monitoring effective Exploration Licence management;
- identifying national strategic goals within the energy sector and developing strategies to promote research and exploration of these;
- identification of legislative changes that could facilitate effective petroleum exploration in strategic areas i.e. native title issues;
- providing background papers for legislative change; and
- providing background papers for lobbying Federal and State policy instruments to invest in infrastructure elements that will stimulate exploration to very remote regions i.e. pipeline links, roads, power grids.

6.5 Geoscience Australia PTAG database

Geoscience Australia currently has as a comprehensive database with a user-friendly front-end configuration. The database is Microsoft Access-based with a front end to acrobat pdf files that can be indexed to allow both retained integrity of document, yet be accessed by various sectors of the public domain to different degrees of confidentiality etc. IT database group is currently investigating an interactive link where this database can be accessed either from Oracle or Microsoft. It is essential that custodianship of data and continual quality control remain within the sphere of responsibility of geoscience professionals, as assessment of new incoming company information and its entry into the database with adequate source context is not a task within the capacity of non-geoscience staff. All cited data is linked back to its source for evaluation by the user. Context of any information is retained through this structure, and is therefore a key attribute of this database configuration. The database covers all Australia, onshore and offshore. Currently over 4000 exploration and production titles and over 12,000 wells are all referenced back to individual graticules. With this basic structural architecture, the complete licensing and data acquisition history of each graticule can be readily reconstructed.

Current custodians of this database actively use it for monthly reporting of APA and national production statistics. Herein lies the direct incentive for continual update improvement of the system. Data storage requirements of this database currently exceed the total corporate capacity of the rest of Geoscience Australia and therefore a prioritised urgent upgrade is required for realistic and dedicated data storage capacity if this database is to be integrated with the online system of Geoscience Australia.

If a front-end configuration was available to outside users, the condensed summaries from APA data **(Figure 40)** would be an example of first pass summaries available for company interrogation – information convenient to assess planning for uptake of licences, and for exploration work plans.

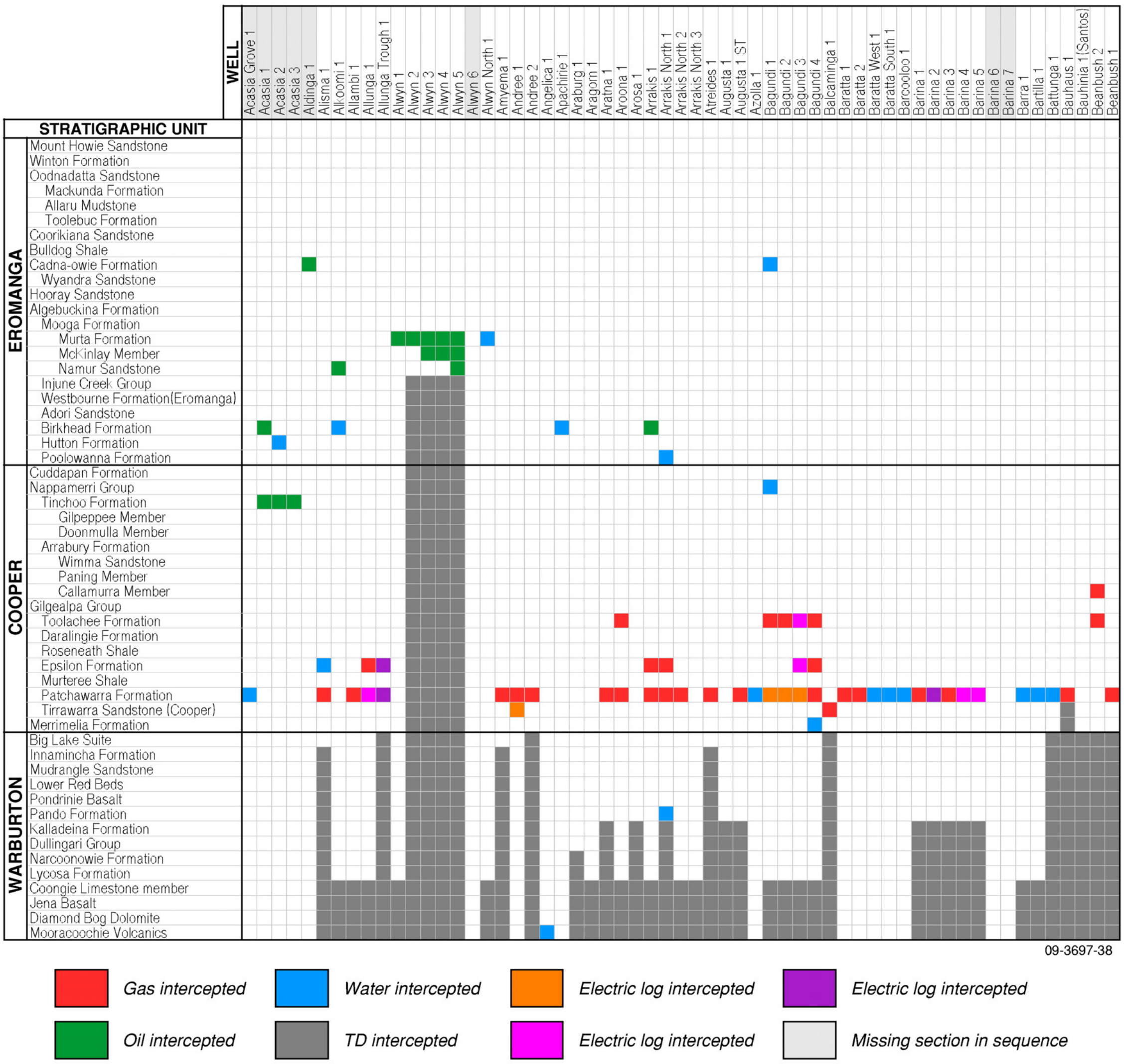


***Figure 40**: Example of graphic well summaries available from the Geoscience Australia PTAG database for Cooper Basin wells. gas (red), oil (green), water (blue). Solid colours- intercepted. orange, pink and purple –electric log interpreted. Dark grey is TD, light grey is missing section in the sequence. (S. Le Poidevin, pers. comm., 2007).*

In summary, it is recommended that there be:

- development of the national PTAG database to complement this current study area and therefore provide a stimulus for strategic planning of company exploration;
- completion and release of the APA for Cooper/Eromanga Basin;
- increasing data storage capacity within the mainframe system of Geoscience Australia for this database to be accommodated.

6.6 INFRASTRUCTURE AS AN EXPLORATION STIMULANT

The ever-increasing growth of infrastructure within and around the Cooper/Eromanga Basin petroleum fields understandably has irresistible appeal for many exploration companies to consolidate their activity within this area where there exists the insurance of available services with predictable costs. The relative over-imbalance of enticement to this province, compared to surrounding lesser-explored regions, raises the issue for federal and state governments- if they are indeed aware of the problem - to commit to investment in infrastructure to encourage decentralized exploration. An all weather road, pipeline and power grid between Moomba and Alice Springs would do much to increase attractiveness to the exploration of the Eringa-Madison-Poolowanna Troughs region.

7 ACKNOWLEDGEMENTS

The content and recommendations developed in this study have evolved through stimulating discussions with Elinor Alexander, Peter Boult, Dave Cockshell, Barry Goldstein, Tony Hill, Dragan Ivic, and Don Vinall of PIRSA, Adelaide; John Draper, Kinta Hoffmann and Cec Murray of GSQ, Brisbane; Julie Adams, John Dunster, and Ian Scrimgeour of the NTGS, Darwin; Tim Barton, Tom Bernecker, Chris Boreham, Anthony Budd, John Creasey, Fiona Holgate, John Kennard, Steve Le Poidevin, Graham Logan, Tony Meixner, Peter Milligan, Michael Morse, Peter Southgate, Russ Temple and Medhavy Thankappan of Geoscience Australia.

Tony Meixner assembled the latest high resolution aeromagnetic datasets available for the region, and conducted preliminary forward modelling to estimate basement depths for some unexplored regions of Queensland and Northern Territory.
Kristy Van Putten and Murray Woods compiled ARC project 7092 and Bianca Rees prepared related figures for this report.

The data and geotherm image of Figure 37 is attributed to Prame Chopra, Earthinsite.com Pty Ltd.
Appendix figures are based on data provided by the State of Queensland, DME, 2007; State of South Australia, PIRSA, 2007; and Northern Territory, NTGS, 2007.

I have unashamedly condensed and paraphrased much from many of the excellent reviews offered by Alexander *et al*. (1996), Cotton *et al.* (2006), Gravestock *et al*. (1998), PIRSA, Questa (1990), and Somerville *et al.* (2004).

8 GLOSSARY Abbreviations and Acronyms

AFTA	Apatite fission track annealing dating technique
bbl	Barrel, oil industry volume equivalent to 159litres
Bcm	Billion cubic metres
BTR	Birdsville Track Ridge
CAI	Conodont alteration index
CBM	Coal bed methane
CSG	Coal Seam Gas
DTM	Digital terrain model
DEM	Department Energy and Mines, Qld
DOM	Dispersed organic matter
DMM	Dalhousie – McDills – Mayhew (Ridge or Trend)
DST	Drill Stem Test
EMADP	Equivalent Mercury/air displacement Pressure
FCI	Foraminiferal colouration index
FWL	Free water level
GA	Geoscience Australia
GEL	Geothermal exploration licence (SA)
GHG	Greenhouse gases
GL	Gigalitres
GMI	Gidgealpa – Merrimelia – Innamincka (Ridge)
GOI	Grains with oil inclusions method
GOR	Gas to oil ratio
GRL	Geothermal retention licence (SA)
GSQ	Geological Survey of Queensland
HDR	Hot dry rock
HFR	Hot fractured rock
HHP	High heat producing granite
JNP	Jackson-Naccowlah-Pepita Trend
kl	Kilolitres
MBS	Magnetic bright spot anomaly
mD	Millidarcy
MESA	Department of Mines and Energy South Australia
ML	Megalitres
MMbbl	Million barrels
MPa	Megapascals
MPI	Methylphenanthrene Index
NGMA	National Geoscience Mapping Accord
NTGS	Northern Territory Geological Survey
oe	Oil equivalent. An approximation of the energy in gas equivalent to that of oil
OEL	Oil Exploration Licence
OMI	Oil migration intervals
OWC	Oil-water contact
PEDIN	Petroleum exploration database managed by Geoscience Australia
PIRSA	Primary Industries & Resources, SA
PMA	Petroleum Minerals Authority

P-OWC	Palaeo oil-water contact
PTAG	Petroleum accumulations database, Geoscience Australia
PY	Potential yield of hydrocarbons
QGF	Quantitative grain fluorescence method
R_c	Reflectance, calculated (see Radke & Welte, 1983)
R_o, R_v	Reflectance, vitrinite
SFTE	Solvent flow-through extraction
SRM	Sedimentary Residual Magnetic anomaly
T	Temperature
TAI	Thermal alteration Index (for spores)
Tcf	Trillion cubic feet
TD	Total depth of well
TOC	Total organic carbon
TVDSS	Total vertical depth of sandstone
VAD	Volcanic-arc derived sediment
ZFTA	Zircon fission track annealing dating technique

9 REFERENCES

Abrams, M. and Segall, M.P., 2002 – Surface Geochemistry Calibration Study Vol.1. Energy and Geoscience Institute at the University of Utah. *EGI Research report* **2002-SDS00725**.

AGAR, 1999 – http://www.agarss.com.au/Papers/PalmValley/PalmValley.htm

Alexander, R., Bastow, T.P., and Kagi, R.I., 1996 – Novel approaches to the determination of the origins of petroleum hydrocarbons in the Cooper–Eromanga Basin system. *Report for the Department of Mines and Energy South Australia (unpublished).*

Alexander, E.M., Hibburt, J.E. (Eds.), 1996 - The Petroleum Geology of South Australia. Eromanga Basin, vol.2. *Department of Mines and Energy, South Australia, Report Book* **96/20**

Alexander, E. and Hough, L.P., 1990 – Exploration opportunity: Lake Eyre-Birdsville Track Ridge. *South Australia, Department of Mines and Energy, Report Book* **90/35**.

Alexander, EM. and Jensen-Schmidt, B., 1995 – Eringa Trough exploration opportunity. *South Australia, Department of Mines and Energy. Report Book,* **95/36**.

Alexander, R., Larcher, A.V., Kagi, R.I., and Price, P.L., 1988 – The use of plant-derived biomarkers for correlation of oils with source rocks in the Cooper/Eromanga Basin system. *The APEA Journal,* **28 (1),** 310-324.

Alexander, E.M., Pegum, D., Tingate, P., Staples, C.J., Michaelsen, B.H. and McKirdy, D.M., 1996 - Petroleum potential of the Eringa Trough in South Australia and the Northern Territory. *APEA Journal,* **36(1),** 322-349.

Altmann, M.J., and Gordon, H.M., 2004 – Oil on the Patchawarra Flank – some implications from the Sellicks and Christies oil discoveries. In Boult, P.J., Johns, D.R., and Lang, S.C., 2004*, Eastern Australian Basins Symposium II, PESA Special Publication, 2*. 29-34.

Ambrose, G.J., 2006 – NT Onshore Oil. *NTGS DVD*.

Ambrose, G.J., 2005 – The Pedirka/Eromanga Basins. In Ambrose, G.J. and Marshall, M.R., 2005 – Northern Territory of Australia – Onshore hydrocarbon potential 2005. *Northern Territory Geological Survey, Record* **2005-002**, 78-95.

Ambrose, G.J., Liu, K., Deighton, I., Eadington, P.J. and Boreham, C.J., 2002 – New petroleum models in the Pedirka Basin, Northern Territory, Australia. *APPEA Journal,* **42 (1):** 259-286.

Ambrose, C.J. and Putnam, P.E., 2007 – Carbonate ramp facies and oil plays in the Middle/Late Cambrian, southern Georgina Basin, Australia. In Munson, T.J. and Ambrose, G.J., (Eds), Proceedings of the Central Australian Basins Symposium, Alice Springs, 16-18th August, 2005. *Northern Territory Geological Survey, Special Publication* **2,** 236-253.

Ambrose, G., Scardigno, M. and Hill, A.J., 2007 – Petroleum geology of Middle-Late Triassic and Early Jurassic sequences in the Simpson Basin and northern Eromanga Basin of Central Australia. *APPEA Journal* **47 (1):** 127-143.

Apak, S.N., Stuart, W.J., Lemon, N.M., & Wood, G., 1997- Structural evolution of the Permian-Triassic Cooper Basin, Australia: relation to hydrocarbon trap styles. *AAPG Bulletin* **81 (4)**: 533-555.

Apak, S.N, Stuart, W.J.; Lemon, N.M. 1993, Structural-stratigraphic development of the Gidgealpa-Merrimelia-Innamincka trend with implications for petroleum trap styles, Cooper Basin, Australia, *The APEA Journal,* **33(1)** p.94-104

Arouri, K.R. and McKirdy, D.M., 2005 – The behaviour of aromatic hydrocarbons in artificial mixtures of Permian and Jurassic end-member oils: Applications to in-reservoir mixing in the Eromanga Basin, Australia. *Organic Geochemistry* **36 (1): 105-115**

Arouri, K.R., McKirdy, D.M., Schwark, L., Leythaeuser, D. and Boult, P.J., 2004 – Accumulation and mixing of hydrocarbons in oil fields along the Murteree Ridge, Eromanga Basin, South Australia. *Organic Geochemistry,* **35**: 1597-1618.

Baillie, P.W, Powell, C.M, Li, Z, Ryall, A.M, 1994, The tectonic framework of Western Australia's Neoproterozoic to Recent sedimentary basins in P.G. Purcell and R.R. Purcell, 1994, The Sedimentary Basins of Western Australia: *Proceedings of Petroleum Exploration Society of Australia Symposium* **1**, p.45-62;

Battersby, D.G., 1976 – Cooper Basin oil and gas fields. In Leslie, R.B. *et al*., (Eds), *Economic Geology of Australia and Papua New Guinea,* **Volume 3**: Petroleum. Australasian Institute of Mining and Metallurgy, Melbourne, 321-368.

Boreham, C.J. and Ambrose, G.J., 2007 – Cambrian petroleum systems in the southern Georgina Basin, Northern Territory, Australia. In Munson, T.J. and Ambrose, G.J., (Eds), Proceedings of the Central Australian Basins Symposium, Alice Springs, 16-18th August, 2005. *Northern Territory Geological Survey, Special Publication* **2,** 254-281.

Boreham, C.J., Hope, J.M. and Hartung-Kagi, B., 2001 – Understanding source, distribution and preservation of Australian natural gas: a geochemical perspective. *APPEA Journal* **41 (1)**, 523 – 547.

Boreham, C.J. and Summons, R.E., 1999 **-** New insights into the active petroleum systems in the Cooper and Eromanga Basins, Australia. *APPEA Journal,* **39 (1),** 263-296.

Boucher, R.K, 2001 a – Warburton Basin GIS data atlas. *South Australia, Department of Primary Industries and Resources, Report Book* **2001/019**.

Boucher, R.K., 2001b – Analysis of seals and of the Roseneath and Murteree Shales, Cooper Basin, South Australia. *South Australia, Department of Primary Industries and Resources, Report Book* **2001/015**.

Boucher, R.K., 2001c – Nature and origin of the altered zone at the base Cooper Basin unconformity, South Australia. *South Australia. Department of Primary Industries and Resources, Report Book* **2001/012**.

Boucher, R.K., 1998 – Lineament associations in the Cooper Basin region, South Australia – basement controls on hydrocarbon distribution. *South Australia, PIRSA Report Book* **1998/30**, 38p.

Boucher, R.K., 1997a – Lineament tectonic data, South Australia, with a focus on the Cooper Basin. *South Australia, PIRSA Report Book* **1997/39**, 76p.

Boucher, R.K., 1997b – A beginner's guide to picking 'basement' from wireline logs, Cooper Basin area. South Australia. *South Australia. Department of Primary Industries and Resources, Report Book* **97/37**.

Boult, P.J., Lanzilli, E., Michaelsen, B.H., McKirdy, D.M., & Ryan, M.J., 1998 – A new model for the Hutton/Birkhead reservoir/seal couplet and the associated Birkhead-Hutton (!) petroleum system. *APPEA Journal* **38:**724-744.

Boult, P.J., Ryan, M.J., Michaelsen, B.H., McKirdy, D.M., Tingate, P.R., Lanzilli, E. and Kagya, M.L.N., 1997 – The Birkhead-Hutton (!) petroleum system of the Gidgealpa area, Eromanga Basin, Australia. *Proceedings of the Petroleum Systems of SE Asia and Australasia Conference, Indonesian Petroleum Association,* 213-235.

Campbell, I., and O'Driscoll, 1989 – Lineament-hydrocarbon associations in the Cooper and Eromanga Basins. In O'Neil, B.J. (Ed), *The Cooper and Eromanga Basins, Australia.* Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. Petroleum Exploration Society of Australia, Society of Petroleum Engineers, Australian Society of Exploration Geophysicists (SA Branches), 295-313.

Carroll, P.G, 1990, - Pre-Permian structure and prospectivity at Gidgealpa, South Australia. MSc Thesis, University of Adelaide (unpublished).

Carne, G.E., and Alexander, E.M., 1997 – Eromanga Basin prospects inventory, Blocks ER97-A to C. Exploration opportunity. South Australia. *Department of Mines and Energy Resources, Report Book* **97/21**.

Chopra and Holgate, www.earthinsite.com

Compston, W. and Arriens, P.A., 1968 – The Precambrian geochronology of Australia. *Canadian Journal of Earth Sciences* **5**, 561-583.

Cook, A. C., 1986 – The nature and significance of organic facies in the Eromanga Basin. In Gravestock, D.I., Moore, P.S., and Pitt, G.M. (Eds), 1986 – Contributions to the geology and hydrocarbon potential of the Eromanga Basin. *Geological Society of Australia. Special Publication* **12**, p. 203-219

Cook, A.C., and Stuckmeyer, H., 1986 – The role of coals as a source rock for oil. In Glennie, R.C., (Ed). *Second South-Eastern Australia Oil Exploration Symposium, Petroleum Exploration Society of Australia,* Melbourne. 419-432.

Cotton, T.B. and McKirdy, D.M., 2006 – Hydrocarbon generation and migration. In Cotton, T.B., Scardigno, M.F. and Hibburt, J.E. (Eds) *The petroleum geology of South Australia. Vol 2: Eromanga Basin*. 2nd edition. South Australia, Department of Primary Industries and Resources. Petroleum Geology of South Australia Series, Chapter 10, 22p.

Cotton, T.B., Scardigno, M.F. and Boult, P.J., 2006 – Sequence Stratigraphy. In Cotton, T.B., Scardigno, M.F. and Hibburt, J.E. (Eds), *The petroleum geology of South Australia. Vol 2: Eromanga Basin.* 2nd edition. South Australia, Department of Primary Industries and Resources. Petroleum Geology of South Australia Series, Chapter 7.

Cotton, T.B., Scardigno, M.F. and Hibburt, J.E. (Eds), 2006 – *The petroleum geology of South Australia. Vol 2: Eromanga Basin.* 2nd edition. South Australia, Department of Primary Industries and Resources. Petroleum Geology of South Australia Series.

Deighton, I., Draper, J.J., Hill, A.J. and Boreham, C.J., 2003 – A hydrocarbon generation model for the Cooper and Eromanga Basins. *APPEA Journal,* **43 (1),** 433-451.

Deighton, I., Hill, A.J., 1998 – Thermal and burial history. In Gravestock, D.I., Hibburt, J.E., Drexel, J.F., (Eds), Petroleum Geology of South Australia. Cooper Basin, v. 4, *Department of Primary Industry and Resources, South Australia, Report Book* **98/9**, p. 143-155.

Denham, D. and Windsor, C.R., 1991 – The crustal stress pattern of the Australian continent. *Exploration Geophysics* **22 (1)**, 101-105.

Draper, J., 2007 – Georgina Basin – an Early Paleozoic carbonate petroleum system in Queensland. *APPEA Journal* **47 (1),** 107-126.

Draper, J.J., 2005 – The Thompson Fold Belt in Queensland revisited. Unpublished PowerPoint, Queensland Government.

Draper, J.J., (Ed.), 2002 – Geology of the Cooper and Eromanga Basins, Queensland. *Queensland Government, Natural Resources and Mines, Queensland Mineral and Energy Review Series, DVD.*

Draper, J.J., Shergold, J.H., and Heighway, K.A., 1978 – A review of petroleum exploration and prospects in the Georgina Basin. *Bureau of Mineral Resources, Australia. Record* **1978/10** (unpublished).

Duddy, I.R., 2002 – Provenance and Thermal History studies in Cooper–Eromanga Basin wells: Burley-2, Daralingie-1, Gidgealpa-1,-5 and -7, Merrimelia-2 and -4, Pando-2, Sturt-7 and -8 and Tinga Tingana-1 using Apatite and Zircon Fission Track Analysis & VR Data. *Geotrack Report* **744**, 253p.

Elliot, L.G., 1993. Post-Carboniferous tectonic evolution of eastern Australia. *APEA Journal,* **33(1):**215-236.

Epstein, A.G., Epstein, J.B. and Harris, L.B., 1977 – Conodont colour alteration- an index to organic metamorphism. *US Geological Survey, Professional Paper* **995**, 1-27.

Errock, C.H., 2005 – Hydrocarbon migration and mixing in four recently discovered oil fields of the southwestern Eromanga Basin. University of Adelaide B. Sc. Honours Thesis (unpublished).

Evans, P.R., 1980 – Geology of the Galilee Basin. In Henderson, R.A. and Stephenson, P.J., (Eds), The Geology and Geophysics of Northeastern Australia. *Geological Society of Australia, Queensland Division,* Brisbane, 299-305.

Evans, P.R., Hoffman, K.L., Remus, D.A., & Passmore, V.L., 1990 – Geology of the Eromanga sector of the Eromanga-Brisbane Geoscience Transect. In Finlayson, D.M. (Editor and Compiler): The Eromanga-Brisbane Geoscience Transect: a guide to basin development across Phanerozoic Australia in southern Queensland. *Bureau of Mineral resources, Australia, Bulletin* **232**: 83-104.

Faridi, I., 1986 – Block Review, Basin Analysis and Hydrocarbon prospectivity of the Pedirka Block in the Pedirka Sector. Delhi Petroleum. *South Australia Department of Mines and Energy, Envelope* **4891** v. 5,8,10 (unpublished).

Finlayson, D.M., Leven, J.H., Wake-Dyster, K.D. & Johnstone, D.W., 1990 - A crustal image under the basins of southern Queensland along the Eromanga-Brisbane Geoscience transect. In Finlayson, D.M. (Editor and Compiler): The Eromanga-Brisbane Geoscience Transect: a guide to basin development across Phanerozoic Australia in southern Queensland. *Bureau of Mineral Resources, Australia, Bulletin* **232**:153-176.

Flottmann, T., Campagna, D.J., Hillis, R. and Warmer, D., 2004 – Horizontal microfractures and core discing in sandstone reservoirs, Cooper Basin, Australia. In Boult, P.J., Johns, D.R., and Lang, S.C., (Eds), Conference proceedings. *Eastern Australian Basins Symposium II, PESA Special Publication* **2**, 689-694.

Foote, R.S., 1996 – Relationship of near surface magnetic anomalies to oil and gas producing areas. In Schumacher, D. and Abrams, M.A., (Eds), Hydrocarbon Migration and its near-surface expression. *AAPG Memoir* **66**: 111-126.

Foster, D.A., Murphy, J.M., and Gleadow, A.W., 1994 – Middle Paleogene hydrothermal activity and uplift of the northern Flinders Ranges, South Australia: insights from apatite fission-track thermochronology. *Australian Journal of Earth Sciences* **41 (1)**: 11-17.

FrOG Tech, 2005 – Oz Seebase™. *FrOG Tech DVD.*

Gallagher, A.V., 1996- Radiometric surveying applied to an evaluation of Sorrento Field, Cheyanne County, Colorado. *AAPG Bulletin* **80 (6)**: p.970.

Gallagher, A.V., 1984 – Iodine: A pathfinder for petroleum deposits. In Davidson, M.J. and Gottlieb, B.M., (Eds). *Unconventional methods in exploration for petroleum and natural gas – III.* Southern Methodist University Press, Dallas, Texas, 148-159.

Gatehouse, C.G., 1983, Stratigraphic units in the Warburton Basin in South Australia, Geological Survey of South Australia, *Quarterly Geological Notes*, **86**, p.5-8

Gatehouse, C.G., 1986 – The geology of the Warburton Basin in South Australia. *Australian Journal of Earth Sciences* **33 (2)**: 161-180.

Gatehouse, C.G., Fanning, C.M. and Flint, R.B., 1995 – Geochronology of the Big Lake Suite, Warburton Basin, northeastern South Australia. *South Australia, Geological Survey, Quarterly Geological Notes,* **128**: 8-16.

Geodynamics anuual reports, 2004 and 2006, from: http://www.geodynamics.com.au/IRM/content/report_annualreport.html

Gravestock, D.I, 1990 – Warburton Basin. In Alexander, E.M. (compiler), Petroleum exploration and development in South Australia. *SADME, Report Book*, **90/34**, 47-49 (unpublished).

Gravestock, D.I.; Callen, R.A.; Alexander, E.M.; Hill, A.J., 1995, Strzelecki, South Australia, sheet SH/54-2, International Index, *Explanatory Notes. 1:250 000 Geological Series*, Geological Survey of South Australia.

Gravestock, D.I., Alexander, E.M., Morton, J.G.G., Sun, X., 1998 – Reservoirs and seals. In Gravestock, D.I., Hibburt, J.E., Drexel, J.F., (Eds), Petroleum Geology of South Australia. Cooper Basin, v. 4, *Department of Primary Industry and Resources, South Australia, Report Book* **98/9**, 159-181.

Gravestock, D.I., Hibburt, J.E., and Drexel, J.F., (Eds), 1998 - Petroleum Geology of South Australia. Volume 4: Cooper Basin. *South Australia, PIRSA, Report Book* 98/**9**, 253p. 1st edition.

Gravestock, D.I., and Jensen-Schmidt, B., 1998 – Structural setting. In Gravestock, D.I., Hibburt, J.E., Drexel, J.F., (Eds), Petroleum Geology of South Australia. Cooper Basin, v. 4, *Department of Primary Industry and Resources, South Australia, Report Book* **98/9**, 49-69.

Gray, A.R.G. and Swarbrick, C.F.J., 1975 – Nomenclature of Late Paleozoic strata in the northeastern Galilee Basin*.* *Queensland Mining Journal* **76**: 344-352.

Greaves, S. and Surka, E., 1989 – Aspects of recent discoveries in ATP 299P (2), south-west Queensland. In O'Neil, B.J. (Ed), *The Cooper and Eromanga Basins, Australia*. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. Petroleum Exploration Society of Australia, Society of Petroleum Engineers, Australian Society of Exploration Geophysicists (SA Branches), 227-235.

Giuliano, M.F., 1988 – The geology and hydrocarbon potential of the Pedirka Basin. University of Adelaide, National Centre for Petroleum Geology and Geophysics. BSc (Hons) thesis, unpublished.

GRDC Inc. – http://www.grdc.co/radiometrics.html

Greene, D.C., 2006 – Neoproterozoic rifting in Central Australia and the breakup of Rodinia. *Geological Society of America Abstracts with Programs*, **38** (7), p. 450.

Hallmann, C., Arouri, K., McKirdy, D., and Schwark, L., 2005 – The petroleum generating potential of Warburton Basin source rocks, recognized by carbazole signatures in Cooper Basin residual oils. Conference Abstract – *ARC SPIRT Project C39943025*.

Hallmann, C.O.E., Arouri, K.R., McKirdy, D.M. and Schwark, L., 2006 – A new perspective on exploring the Cooper/Eromanga petroleum province – evidence of oil charging from the Warburton Basin. *APPEA Journal* **46** (1), p. 261-280.

Hallmann, C.O.E., Arouri, K.R., McKirdy, D.M. and Schwark, L., 2007 – Temporal resolution of an oil charging history – a case study of residual oil benzocarbazoles from the Gidgealpa Field. *Organic Geochemistry* **38**, p 1516-1536.

Harrison, P.L., 1980 – The Toomba Fault and the western margin of the Toko Syncline, Georgina Basin, Queensland and Northern Territory. *Bureau of Mineral Resources Journal of Australian Geology and Geophysics*, **5**, 201-214.

Hawkins, P.J., and Green, P.M., 1993 – Exploration results, hydrocarbon potential and future strategies for the Galilee Basin. *APEA Journal* **33 (1)** : 280-296.

Heath, R., McIntyre, S. and Gibbins, N., 1989 – A Permian origin for Jurassic reservoired oil in the Eromanga Basin. In O'Neil, B.J. (Ed), *The Cooper and Eromanga Basins, Australia, Proceedings of the Petroleum Exploration Society of Australia.* Society of Petroleum Engineers, Australian Society of Exploration Geophysicists (SA Branches), Adelaide, 405-416.

Hibburt, J.E. and Gravestock, D.I, 1995 – Pedirka Basin. In Drexel, J.F. and Preiss, W.V. (Eds). The geology of South Australia. Volume 2, The Phanerozoic. *South Australia Geological Survey Bulletin,* **55**, 88-90.

Hill, A.J., 2006 – Geothermal energy prospectivity of South Australia. AAPG international conference presentation. PIRSA PowerPoint

Hirst, B., unpublished – Introduction to Light Touch. Confidential Shell PowerPoint presentation.

Hirst, B., Gillespie, S., Archibald, I., Podlaha, O., Gibson, G., Skeldon, K., Courtial, J., Monk, S. and Padgett, M., 2004 – Oil and gas prospecting by ultra-sensitive optical gas detection with inverse gas dispersion modelling. *Geophysical Research Letters* **31**: L2115

Hoffmann, K.L., 1989 – The influence of pre-Jurassic tectonic regimes on the structural development of the southern Eromanga Basin, Queensland. In O'Neil, B.J. (Ed), *The Cooper and Eromanga Basins, Australia.* Proceedings of the Petroleum Exploration Society of Australia. Society of Petroleum Engineers, Australian Society of Exploration Geophysicists (SA Branches), Adelaide, 315-328.

Hunt, S.P. and Morelli, C., 2006 – Cooper Basin HDR hazard evaluation: Predictive modeling of local stress changes due to HFR geothermal energy operations in South Australia. The University of Adelaide, *PIRSA Report Book* **2006/16**.

Hunt, M., 1996, Principles of a common mining code**,** *Australian Mining and Petroleum Law Association Yearbook*, 1996 p.196-233. Australian Mining and Petroleum Law Association (AMPLA)
`

Huntington, J. and Simpson, C.J., 1985 – Major new Australian/US remote sensing initiative. *The Australian Geologist* **57**: 34-35.

Jackson, K.S., 1982 – Geochemical evaluation of the petroleum potential of the Toko Syncline, Georgina Basin, Queensland. *BMR Journal of Australian Geology and Geophysics* **7 (1)**: 1-10.

Jackson, K.S., Horvath, Z. and Hawkins, P.J., 1981 – An assessment of the petroleum prospects for the Galilee Basin, Queensland. *APEA Journal*, **21**: 172-186.

Jones, P.A and Maynard, A.J., 2009 – Summary independent appraisal report of the coal potential held by Central Petroleum in the Purni Formation, Pedirka Basin, Central Australia. Unpublished consultants report of Al Maynard and Associates P/L, 27p.

Jones, V.T. and Drozd, R.J., 1983 – Predictions of oil and gas potential by near-surface geochemistry. *AAPG Bulletin* **67 (6):** 932-952.

Kagya, M.L.N., 1997 – The source rock and petroleum geochemistry of the early Jurassic Poolowanna Formation, Eromanga Basin. PhD Thesis, University of Adelaide (unpublished).

Kantsler, A. J., Prudence, T.J.C., Cook, A.J. and Zwigulis, M., 1983 – Hydrocarbon habitat of the Cooper/Eromanga Basin, Australia. *The APEA Journal* **23 (1)**: 75-92.

Kapel, A., 1966 – The Cooper's Creek Basin. *The APEA Journal* **6 (2):** 71-75.

Karajas, J., 1994 – Hydrocarbon prospectivity of the southern Georgina Basin, Northern Territory. Abstract, *PESA Journal* **22***,* p.87.

Kramer, L., McKirdy, D.M., Arouri, K.R., Schwark, L., & Leythaeuser, D., 2004 – Constraints on the hydrocarbon charge history of sandstone reservoirs in the Strzelecki Field, Eromanga Basin, South Australia. In Boult, P.J., Johns, D.R., and Lang, S.C., 2004*, Eastern Australian Basins Symposium II, PESA Special Publication* **2**, 589-602.

Krieg, G.W., 1985 – Dalhousie, South Australia, Sheet SG53-11. *South Australia Geological Survey, 1:250 000 Series – Explanatory Notes*.

Kuang, K.S., 1985 – History and style of Cooper–Eromanga Basin structures. *Exploration Geophysics*, **16 (2):** 245-248.

Land, J.P. Associates, Inc., 1996 – Nonseismic methods can provide many views of a drillsite. *Oil and Gas Journal*, February 26.

Lechler, A.R., and Greene, D.C., 2006 – Fault reactivation during intracontinental deformation: the Toko Syncline and Toomba Fault, Georgina Basin, Central Australia. *Geological Society of America Abstracts with Programs*, **38** (5), p.11.

Lindsay, J., 2000 – Source rock potential and algal-matter abundance, Cooper Basin, South Australia. *South Australia, Department of Primary Industries and Resources, Report Book* **2000/32**, 172p.

Lindsay, J.F., Korsch, R.J. and Wilford, J.R., 1987 – Timing the breakup of a Proterozoic supercontinent: Evidence from Australian intracratonic basins. *Geology* **15 (11)**: 1601-1604.

Lodwick, W.R., and Lindsay, J.F., 1990 – Southern Georgina Basin: a new perspective. *The APEA Journal* **30 (1):**137-148.

Magnier, P.H., 1965 – Well completion report of Marduroo 1, Queensland, RG 506. French Petroleum Company (unpublished. GSQ CR 1553).

McAuliffe, C.D., 1979 – Oil and gas migration: chemical and physical constraints. *AAPG Bulletin* **63**: 761-781.

McKirdy, D.M., 1981 – Petroleum geochemistry and source rock potential of the Arrowie, Pedirka, Cooper and Eromanga Basins, Central Australia. Delhi Petroleum Pty Ltd. (unpublished).

McKirdy, D.M., Arouri, K.R. and Kramer, L., 2005 – Conditions and effects of hydrocarbon fluid flow in the subsurface of the Cooper and Eromanga Basins. University of Adelaide report on ARC SPIRT Project C39943025 for PIRSA and Santos Ltd. *South Australia, Department of Primary Industries and Resources, Report Book* **2005/2**.

McKirdy, D.M., Cox, R.E., O'Leary, T. and Watson, B. 1987 – Aromatic maturity of Jurassic, Permian and Cambrian sediments in Gidgealpa No.1, Eromanga/Cooper/Warburton Basins. *South Australia. Department of Mines and Energy Report* **F6636/87**, Parts 1 and 2, (unpublished).

McKirdy, D.M. and Willinck, R.J., 1988 – Migration of hydrocarbons and groundwater towards PEL 31 southwestern Eromanga Basin, South Australia. Adelaide Petroleum NL. *South Australia. Department of Mines and Energy Open file Envelope* **6116** (unpublished).

McKirdy, D.M., Yu, X., Leythaeuser, D., Schwark, L., and Arouri, K.R., 2001 – A pilot study of secondary migration and reservoir filling in the Cooper/Eromanga Basin, South Australia. *20th International Meeting on Organic Geochemistry,* Nancy, France, Abstracts p. 425-426.

McPhar Geosurveys Ltd – http://www.mgssurveys.com/oilgas.asp

Meixner, A.J., Boucher, R.K., Yeates, A.N., Gunn, P.J., Richardson, L.M. and Frears, R.A., 1999 - Interpretation of geophysical and geological datasets, Cooper Basin region, South Australia. *Australian Geological Survey Organisation, Record* **1999/22**.

Meixner, A.J., Gunn, P.J., Boucher, R.K., Yeates, A.N., Richardson, L.M. and Frears, R.A., 2000 – The nature of the basement to the Cooper Basin region, South Australia. Exploration Geophysics **31 (1-2)**: 24-32.

Menpes, R., 2001 – New oil from a mature gas field - the history of Moomba oil discoveries. In Hill, K.C. and Bernecker, T. (Eds), Eastern Australian Basins Symposium, A refocused energy perspective for the future. *PESA Special Publication* **1**, 281-288.

Michaelsen, B.H., and McKirdy, D.M., 2001 – Migration and mixing of oils in the Cooper and Eromanga Basins, Central Australia. In Hill, K.C., and Bernecker, T. (Eds), Eastern Australian Basins Symposium, A refocused energy perspective for the future. *PESA Special Publication* **1**, 289-300.

Michaelsen, B.H., and McKirdy, D.M., 1996 – Source rock distribution and hydrocarbon geochemistry. In Alexander, E.M., Hibburt, J.E. (Eds.). The Petroleum Geology of South Australia. Eromanga Basin, vol.2. *Department of Mines and Energy, South Australia, Report Book* **96/20**, 101-110.

Michaelsen, B.H., and McKirdy, D.M., 1989 – Organic facies and petroleum geochemistry of the lacustrine Murta Member (Mooga Formation) in the Eromanga Basin, Australia. In O'Neil, B.J. (Ed*), The Cooper and Eromanga Basins, Australia.* Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. Petroleum Exploration Society of Australia, Society of Petroleum Engineers, Australian Society of Exploration Geophysicists (SA Branches), 541-558.

Middleton, M.F., Barker, C.E. and Heugh, J., 2007 – The geology of the western part of the Pedirka Basin, Australia. In Munson, T. J. and Ambrose, G.J., (editors), 2007 – Proceedings of the Central Australian Basins Symposium, Alice Springs, 16-18 August 2005. *Northern Territory Geological Survey, Special Publication* **2**, 409-426.

Middleton, M.F. and Hunt, J.W., 1989 – Influence of tectonics on Permian coal-rank patterns in Australia. *International Journal of Coal Geology* **13**, 391-411.

Miller, J.F., Evans, K.R., Loch, J.D., Ethington, R.L., Stitt, J.H., Holmer, L. and Popov, L.E., 2003 – Stratigraphy of the Sauk III interval (Cambro-Ordovician) in the Ibex Area, Western Millard County, Utah and Central Texas. *Brigham Young University Geology Studies,* **47**, 23-118.

Monnier, F., Powell. T.G. and Snowdon, L.R., 1983 – Qualitative and quantitative aspects of gas generation during maturation of sedimentary organic matter. Examples from Canadian frontier basins. In Bjoroy, M., et al. (Eds), *Advances in Organic Chemistry 1981?* Wiley, Chichester, 487-495.

Moore P.S., 1986 – Jurassic and Triassic stratigraphy and hydrocarbon potential of the Poolowanna Trough (Simpson Desert Region), northern South Australia. In Gravestock, D.I., Moore, P.S. and Pitt, G.M. (Eds), Contributions to the geology and hydrocarbon potential of the Eromanga Basin. *Geological Society of Australia, Special Publication* **12**, 39-51.

Moore, P.S. and Pitt, G.M., 1984 - Cretaceous of the Eromanga Basin – implications for hydrocarbon exploration. *The APEA Journal,* **24 (1)**: 358-376.

Morton, J.G.G. , 1996 – Undiscovered petroleum resources. In Alexander, E.M. and Hibburt, J.H. (Eds). The Petroleum Geology of South Australia. Volume 2, Eromanga Basin. *South Australia. Department of Mines and Energy, Report Book* **96/20**:181-185.

Mousavi-Harami, R., 1996 – Burial history. In Alexander, E.M., Hibburt, J.E. (Eds.). The Petroleum Geology of South Australia. Eromanga Basin, vol.2. *Department of Mines and Energy, South Australia, Report Book* **96/20**, 125-140.

Murray, C.G. 1986, Metallogeny and tectonic development of the Tasman fold belt system in Queensland**, IN:** E. Scheibner, 1986, Metallogeny and tectonic development of Eastern Australia, y *Ore Geology Reviews* **1(2-4)**315-400

Murray, C.G., 1994 – Basement cores from the Tasman Fold Belt System beneath the Great Artesian Basin in Queensland. *Queensland Geological Survey Record,* **1994/10**.

Murray, C.G and Kirkegaard, A.G., 1978 – The Thomson Orogen of the Tasman Orogenic Zone. *Tectonophysics* **48 (3-4)**: 299-325.

Nakanishi, T., and Lang, S.C., 2002 – Towards an efficient exploration frontier: Constructing a portfolio of stratigraphic traps in fluvial-lacustrine successions, Cooper–Eromanga Basin. *APPEA Journal* **42(1),** 131-150.

National Geoscience Mapping Accord, http://www.pir.sa.gov.au/petroleum/access_to_data/seismic_data/seismic_mapping_products/cooper_basin_mapping_products/ngma_cooper-eromanga_products

O'Neil, B, 1995, Above and below: the South Australian Department of Mines and Energy 1944 to 1994, South Australia, Department of Mines and Energy, Special Publication.**10**, 655p.

O'Neil, B.J. (Ed), 1989 - The Cooper and Eromanga Basins, Australia. *Proceedings of the Cooper and Eromanga Basins Conference, Adelaide.* Petroleum Exploration Society of Australia, Society of Petroleum Engineers, Australian Society of Exploration Geophysicists (SA Branches)

Parker, A.J., 1993, Gawler Craton - geological overview, In W.V. Preiss.1993, *South Australian resources*, Mines and Energy, South Australia, p.3-5;

Passmore, V.L. 1994, Impact of the Petroleum Search Subsidy Acts on the exploration for petroleum in Australia, *PESA Journal*, **22**, p.77-83.

Pitt, G.M., 1986 – Geothermal gradients, geothermal histories and the timing of thermal maturation in the Eromanga-Cooper Basins. In Gravestock, D.I., Moore, P.S., and Pitt, G.M. (Eds) Contributions to the Geology and Hydrocarbon Potential of the Eromanga Basin. *Geological Society of Australia Special Publ.* **12**, 323-351.

Pointon, D. and Simon, G., 2001 – CBM – A new play for the Cooper Basin? In Hill, K.C., and Bernecker, T. (Eds), Eastern Australian Basins Symposium, A refocused energy perspective for the future. *PESA Special Publication* **1**, 341-349.

Powell, T.G., and Snowdon, L.R., 1983 – A composite hydrogen generation model – implications for evaluation of basins for oil and gas. *Erdol und Kohle*, **36 (4),** 163-170.

Powis, G.D., 1989 – Revision of Triassic stratigraphy at the Cooper Basin to Eromanga Basin transition. In O'Neil, B.J. (Ed), *The Cooper and Eromanga Basins, Australia*. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. Petroleum Exploration Society of Australia, Society of Petroleum Engineers, Australian Society of Exploration Geophysicists (SA Branches), 265-277.s

Questa Australia Pty Ltd, 1990 – Petroleum basin study. Eromanga Basin. Prepared by Questa Australia Pty Ltd for the Northern territory Geological Survey. Northern Territory, Government Printer.

PIRSA, 2007 – Petroleum and Geothermal in South Australia. DVD

Radke, B.M., 1982 – Late diagenetic history of the Ninmaroo Formation (Upper Cambrian – Lower Ordovician), Georgina Basin, Queensland and Northern Territory. *BMR Journal of Australian Geology and Geophysics* **7 (4)**: 231-254.

Radke, B.M. and Duff, P., 1980 – A potential dolostone reservoir in the Georgina Basin: the Lower Ordovician Kelly Creek Formation. *BMR Journal of Australian Geology and Geophysics,* **5 (2),** 160-163.

Radke, B.M., Ferguson, J., Cresswell, R.G., Ransley, T.R. and Habermehl, M.A., 2000 – Hydrochemistry and implied hydrodynamics of the Cadna-owie – Hooray Aquifer, Great Artesian Basin, Australia. *Bureau of Rural Sciences*, Canberra, 229p.

Radke, M. and Welte, D.H., 1983 – The methylphenanthrene index (MPI): a maturity parameter based on aromatic hydrocarbons. In Bjoroy, M. et al. (Eds), *Advances in organic geochemistry 1981*. John Wiley and Sons, Ltd., Chichester, p.504-512.

Roberts, D.C., Carroll, P.G. and Sayers, J., 1990 – The Kalladeina Formation – a Warburton Basin Cambrian carbonate play. *The APEA Journal,* **30 (1)**: 166-183.

Rybach, L., and Mongillo, M., 2006 – Geothermal sustainability – a review with identified research needs. *GRC Transactions* **30**, 1083-1090.

Santos Ltd., 1988 a – Mulka Block acreage assessment. South Australia. *Department of Mines and Energy, Envelope***, 5036** (unpublished).

Santos Ltd., 1988 b - Lake Eyre Block acreage assessment report. South Australia. *Department of Mines and Energy, Envelope,* **4882** (unpublished).

Scheibner, 1996 – Geology of New South Wales- Synthesis. Volume 1. Structural Framework. *Memoirs of the Geological Survey of New South Wales, Geology* **13 (1).**

Scheibner, E. 1974, Fossil fracture zones (transform faults), segmentation, and correlation problems in the Tasman Fold Belt system, in: Denmead A.K, Tweedale G.W. and Wilson A.F, 1974, The Tasman Geosyncline; a symposium in honour of Professor Dorothy Hill, Brisbane, Queensl., Australia, May 31-June: *Geological Society of Australia, Queensland Division, Brisbane*,. p.66-98;

Schumacher, D., 1996 – Hydrocarbon-induced alteration of soils and sediments. In Schumacher, D. and Abrams, M.A., (Eds), Hydrocarbon migration and its near-surface expression. *AAPG Memoir* **66**, 71-89.

Schumacher, D. and Abrams, M.A., (Eds), 1996 - Hydrocarbon migration and its near-surface expression. *AAPG Memoir* **66**.

Schwark, L., Stoddart, D., Keuser, C., Leythaeuser, D., 1997 - A novel sequential extraction system for whole core plug extraction in a solvent flow through cell- application to extraction of residual petroleum from an intact pore system in secondary migration studies. *Organic Geochemistry* **26**, 19-32.

Scrimgeour, I. and Raith, J., 2001- Tectonic and thermal events in the northeaster Arunta Province. *NTGS Department of Mines and Energy Report* **12**, 45p.

Senior, B.R., and Habermehl, M.A., 1980 - Structure, hydrodynamics and hydrocarbon potential of the Central Eromanga Basin, Queensland, Australia. *BMR Journal of Australian Geology and Geophysics* **5 (1)**, 47-55.

Senycia, P.G., 1989 – Sand dune development within the Simpson Desert and its effect on statics calculation. In O'Neil, B.J. (Ed), *The Cooper and Eromanga Basins, Australia*. Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. Petroleum Exploration Society of Australia, Society of Petroleum Engineers, Australian Society of Exploration Geophysicists (SA Branches), 205-214.

Shaw, R.D. & Palfreyman, W.D. (Compilers), 1995 - Australian Crustal Elements (1:5 000 000) based on the distribution of geophysical domains. *Australian Geological Survey Organisation, Canberra.*

Shaw, RD., Wellman, P., Gunn, P., Whitaker, A.J., Tarlowski, C. & Morse, M.P., 1995 – Australian crustal elements map. *AGSO Research Newsletter* **23**:1-3.

Shergold, J.H., and Southgate, P.N., 1986 – Middle Cambrian phosphatic and calcareous lithofacies along the eastern margin of the Georgina Basin. *Australasian Sedimentologists Group Field Guide* Series 2.

Simpson, C.J., Wilford, J.R., Macias, L.F. and Korsch, R.J., 1991 – Remote sensing of natural hydrocarbon seepage at the Palm Valley gas field, Amadeus Basin, central Australia. In Korsch, R.J. and Kennard, J.M., Geological and Geophysical studies in the Amadeus Basin central Australia. *BMR Bulletin* **236**: 541-561.

Simpson, C.J., Wilford, J.R., Macias, L.F. and Korsch, R.J., 1989 – Satellite detection of natural Hydrocarbon seepage: Palm Valley Gas Field, Amadeus Basin, Central Australia. *APEA Journal* **29 (1)**: 196-211.

Smith, K.G., 1972 – Stratigraphy of the Georgina Basin. *Bureau of Mineral Resources Australia, Bulletin* **111,** 146p.

Smith, R.I., 1990 – Tertiary plate tectonic setting and evolution of Papua New Guinea. In Carman, G.J. and Z. (Eds), Petroleum exploration in Papua New Guinea. *Proceedings of the 1st PNG Petroleum Convention, Port Moresby*, pp.229-243

Smyth, M., Cook, A.C. and Philp, R.P., 1984 – Birkhead revisited: petrology and geochemical studies of the Birkhead Formation. *APEA Journal* **24 (1);** 230-242.

Smyth and Saxby, 1981 – Organic petrology and geochemistry of source rocks in the Pedirka-Simpson Basins, Central Australia. *The APEA Journal* **21 (1),** 187-199.

Somerville, M., Wyborn, D., Chopra, P., Rahman, S., Estrella, D., and Van der Meulen, T., 1994 – Hot dry rocks feasibility study. *Energy Research and Development Corporation Report* **94/243**, 133p.

Southgate, P.N., Kennard, J.M., Jackson, M.J., O'Brien, P.E. and Sexton, M.J., 1993 – Reciprocal lowstand clastic and highstand carbonate sedimentation, subsurface Devonian reef complex, Canning Basin, Western Australia. In Loucks, R.G. and Sarg, J.F. (Eds), Carbonate sequence stratigraphy: recent developments and applications. *AAPG Memoir* **57** 157-179.

Southgate, P.N. and Shergold, J.H., 1991 – Application of sequence stratigraphic concepts to Middle Cambrian phosphogenesis, Georgina Basin, Australia. *BMR Journal of Australian Geology and Geophysics* **12 (2)**: 119-144.

Sprigg, R.C, 1986, The Eromanga Basin in the search for commercial hydrocarbons, in Gravestock D.I, Moore P.S. and Pitt G.M., Contributions to the geology and hydrocarbon potential of the Eromanga Basin, *Geological Society of Australia Special Publication* **12**, p.9-24.

Sprigg, R.C , 1983, The search for commercial oil and gas in South Australia, From the Coorong to Port Bonython; the history of the oil industry in South Australia; 1983 conference of the Australian Institute of Petroleum, South Australian Branch, Adelaide, South Aust., Australia, Oct. 27, 1983-- p.C1-C119

Stuart, W.J., Jr., 1976, The genesis of Permian and lower Triassic reservoir sandstones during phases of southern Cooper Basin development, *The APEA Journal*,**16(1)**, p.37-47.

Sun, X., 1999 – Fracture analysis of the eastern Warburton Basin, South Australia. *PIRSA Report Book.* **99/00014**.

Sun, X., 1998 – Prediction of carbonate reservoirs and traps by applying sequence stratigraphy in the Eastern Warburton Basin, South Australia. *APPEA Journal*, **38(1),** 380-398.

Sun, X., 1997 – Structural style of the Warburton Basin and control in the Cooper and Eromanga Basins, South Australia. *Exploration Geophysics*, **28 (3)**, 333-339.

Sun, 1996 – Sequence stratigraphy, sedimentology, biostratigraphy and palaeontology of the eastern Warburton Basin (Paleozoic), South Australia. PhD thesis, University of Adelaide, 2 volumes (unpublished).

Sun, X. and Gravestock, D.I., 2001 – Potential hydrocarbon reservoirs in upper levels of the eastern Warburton Basin, South Australia. *PIRSA Report Book* **2001/016**.

Sun, X. and Nicoll, R.S., 2004 – Cambro-Ordovician conodont biostratigraphy and thermal maturation of the eastern Warburton Basin. In Boult, P.J., Johns, D.R., and Lang, S.C., 2004*, Eastern Australian Basins Symposium II, PESA Special Publication* **2***,* 724-734.

Sun, W., Stuart, W.J. and Warren, J.K., 1994 – Stratigraphy and sedimentology of the Cambro-Ordovician successions, eastern Warburton Basin, South Australia. *PESA Journal* **22**: 107-111.

Taylor, S., Solomon, G., Tupper, N., Evanochko, J., Horton, G., Waldeck, R., and Phillips, S., 1991 – Flank plays and faulted basement: new directions for the Cooper Basin. *APEA Journal* **31(1)**: 56-73.

Tingate, P. and Duddy, I. 1996 – The thermal history of the Eringa Trough and western Eromanga Basin. In Alexander, E.M. and Hibburt, J.H. (Eds). *The Petroleum Geology of South Australia. Volume 2, Eromanga Basin*, South Australia. Department of Mines and Energy.

Tissot, B. and Welte, D.H., 1980 – *Petroleum formation and occurrence.* Springer Verlag, Berlin, 699p.

Toupin, D., Eadington, P.J., Person, M., Morin, P., Wieck, J. and Warner, D., 1997 – Petroleum hydrogeology of the Cooper and Eromanga Basins, Australia: some insights from mathematical modelling and fluid inclusion data. *AAPG Bulletin* **81 (4):** 577-603.

Tucker, D.H., Wyatt, B.W., Druce, E.C., Mathur, S.P. and Harrison, P.L., 1979 – The upper crustal geology of the Georgina Basin region. *BMR Journal of Australian Geology and Geophysics* **4 (3)**: 209-226.

Tupper, N.P., and Burckhardt, D.M., 1990 – Use of the methylphenanthrene index to characterize expulsion of Cooper and Eromanga Basin oils. *The APEA Journal* **30 (1),** 373-385.

Underschultz, J. and Boult, P., 2004 - Top seal and reservoir continuity: hydrodynamic evaluation of the Hutton-Birkhead Reservoir, Gidgealpa Oilfield. In Boult, P.J., Johns, D.R., and Lang, S.C., 2004, *Eastern Australian Basins Symposium II, PESA Special Publication* **2**, 473-482.

Veevers, J.J. 1991, Mid-Cretaceous tectonic climax, Late Cretaceous recovery, and Cainozoic relaxation in the Australian region, in: Williams M.A.J, de Deckker P. and Kershaw A.P., The Cainozoic in Australia; a re-appraisal of the evidence, *Geological Society of Australia Special Publication* **18**, p.1-14.

Veevers, J.J. (editor) ,1984, *Phanerozoic Earth history of Australia* -- Oxford Geological Sciences Series,**2**, 418p, Clarendon Press, Oxford, United Kingdom.

Volk, H., George, S.C., Kempton, R.H., Liu, K., Ahmed, M. and Ambrose, G.J., 2007 – Petroleum migration in the Georgina Basin: Evidence from the geochemistry of oil inclusions and bitumens. In Munson, T.J. and Ambrose, G.J. (Eds), Proceedings of the Central Australian Basins Symposium, Alice Springs, 16-18th August, 2005. *Northern Territory Geological Survey, Special Publication* **2**, 282-303.

Walter, M.R., Veevers, J.J., Calver, C.R. and Grey, K., 1995 – Neoproterozoic stratigraphy of the Centralian Superbasin, Australia. *Precambrian Research* **73**, 173-195.

Wecker, H.R.B, Ziolkowski, V. and Powis, G.D., 1996 – New gas discoveries in the northern Cooper Basin. *The APPEA Journal* **36 (1):** 104-116.

Wiltshire, M.J., 1989 – Mesozoic stratigraphy and palaeontology, eastern Australia. In O'Neil, B.J. (Ed), *The Cooper and Eromanga Basins, Australia.* Proceedings of the Cooper and Eromanga Basins Conference, Adelaide, 1989. Petroleum Exploration Society of Australia, Society of Petroleum Engineers, Australian Society of Exploration Geophysicists (SA Branches), 279-291.

Wiltshire, M.J., 1978 – Poolowanna No.1 well completion report. Delhi-Santos-Vamgas-Western Mining-Total exploartion Corporation. Unpublished. *PIRSA Open File Envelope* **03170**

Wopfner, H. 1985, Some thoughts on the post-orogenic development of northeastern South Australia and adjoining regions, in: Lindsay J.M, 1985, Stratigraphy, palaeontology, malacology; papers in honour of Dr. Nell Ludbrook, *Department of Mines and Energy South Australia Special Publication* **5** p.365-372.

Wopfner, H., 1974 – Post-Eocene history and stratigraphy of northeastern South Australia. *Transactions of the Royal Society of South Australia*, **89 (1):** 1-12..

Wopfner, H., Callen, R. and Harris, W.K., 1974 - The Lower Paleogene Eyre Formation of the southwestern Great Artesian Basin. *Journal of the Geological Society of Australia,* **21**: 17-51.

Wyborn, D., de Graaf, L., Davidson, S. and Hann, S., 2004 - Development of Australia's first hot fractured rock (HFR) underground heat exchanger, Cooper Basin, South Australia. In Boult, P.J., Johns, D.R., and Lang, S.C., 2004, *Eastern Australian Basins Symposium II, PESA Special Publication*, 423-430.

Young, J, Petroleumnews.net, 2007

Youngs, B.C., 1976 – The geology and hydrocarbon potential of the Pedirka Basin. *South Australia, Geological Survey, Report of Investigations* **44**.

10 APPENDIX Basin Overviews

10.1 WARBURTON BASIN

Summary

Age	Cambro-Ordovician to Devonian
Area	~45,000km^2 east of Birdsville Track Ridge in SA
Depth to target zones	1400-3600+ m in SA
Thickness	1800+ m
Hydrocarbon shows	about 30 oil and 60 gas shows recorded beneath SW Cooper Basin
First Commercial discovery	1990 oil in Sturt 6, 1990 gas in Moolalla 1
Identified reserves	?
Undiscovered resources (50% prob.)	?
Production	
Basin type	polyphase foreland, rift/sag
Depositional setting	carbonate/siliciclastic shelf, slope and basin above volcanics
Reservoirs	fractured dolomite, volcanics, sandstone
Regional structure	flat to steeply dipping: folds, thrust faults
Seals	local intraformational seals but predominant altered zone at upper boundary with Cooper Basin
Source rocks	No identified source; gas and oil from downdip Cooper Basin source rocks (SA)
Depth to oil/gas window	Warburton plays trap Permian oil and gas (SA)
Number of wells	~420 in SA
Seismic line km	81,150 km of 2D; 6,772 km of 3D (SA)

Structural setting and sedimentation

This basin is a vast subsurface region north and northeast of the Gawler Craton that accommodated sediments during the Cambrian to Devonian (**Figure 41**). Devonian strata are preserved only below the Pedirka Basin, and are inferred in the Boorthanna Trough (seismic data). Late Carboniferous and younger strata completely cover the Warburton Basin (SA).

This basin is nominally divided into the western and eastern portions, separated by the Birdsville Track Ridge. The formation is largely seen as economic basement in the Cooper Basin where numerous well intersections have made the upper part of the eastern Warburton Basin available for intense study. In contrast, the western Warburton Basin is poorly studied.

The eastern Warburton Basin is essentially a fold belt that was deformed and uplifted during the Carboniferous Alice Springs Orogeny and subsequently buried beneath the Cooper Basin. Structural dip varies from sub-horizontal beneath the Patchawarra Trough and GMI Ridge to vertical and locally overturned. Such variation is often evident beneath a single Permian Structure (eg. Moomba and Daralingie). Early to Middle Carboniferous granitic intrusives of the Big Lake Suite beneath the Nappamerri Trough were responsible for local contact metamorphism of Cambrian country rock. A weathered zone of up to 150 m thick has altered Warburton Basin strata and the granites in particular, immediately beneath the basal unconformity of the Cooper Basin. In the early Paleozoic sequence, disconformities at three stratigraphic levels relate to tectonic events. Other time breaks, especially on the carbonate shelf, are sequence boundaries marked by sea-level fall and karst development. During the Early Ordovician, a major delta formed on the northern margin of a deep marine trough and prograded southward.

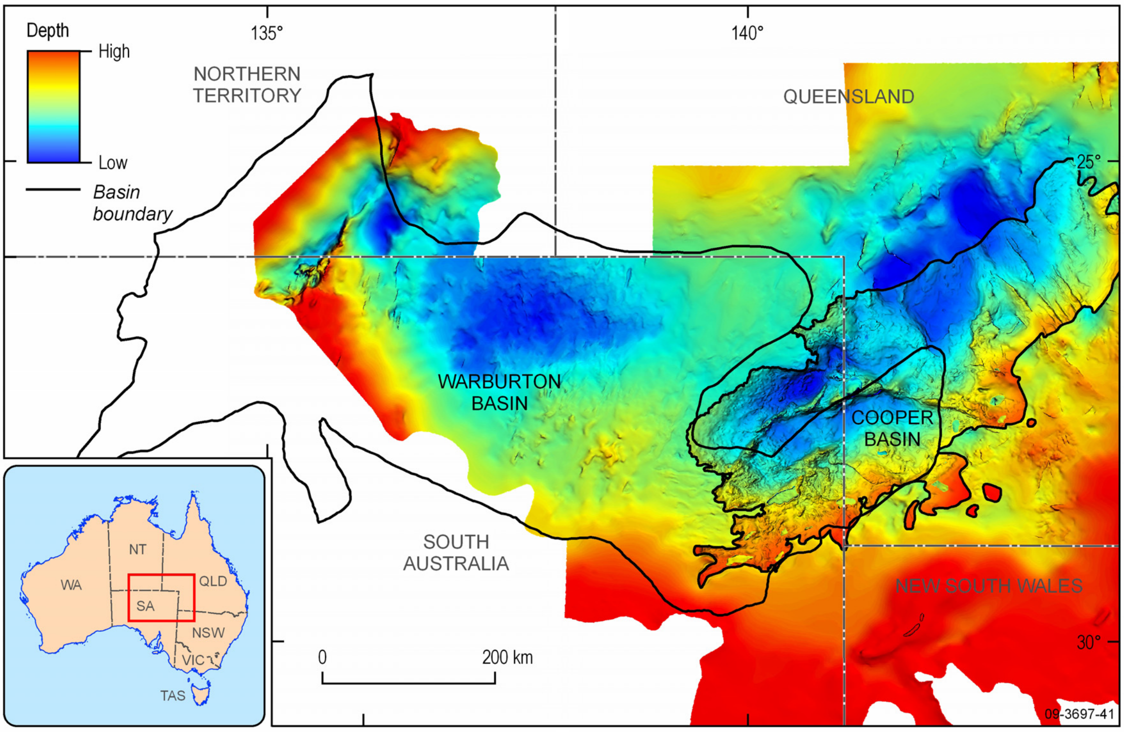


Figure 41: *Extent and depth structure of the upper erosional surface on the Warburton Basin in South Australia (from PIRSA, 2007).*

Early to Late Cambrian intraplate rifting is considered to have propagated NNW, possibly connected with the Koonenberry Fault Zone, from an origin in western New South Wales. A structural fabric was superimposed by deformation during the Alice Springs Orogeny, and follows arcuate NE trends imposed by NW-directed thrust faulting. Repetition of Cambrian strata by thrusting is evident at Gidgealpa and Daer to the north. Wrench faults have been mapped from seismic data in the Titan-Charo-Yanta area on the NW flank of the Patchawarra Trough. Complex faulting and folding is evident in the Mulga-Baratta and Toolachee-Kidman areas. These appear to consist of linear and en echelon, short meridional fault blocks beneath Permian anticlines.

Exploration history

Seismic surveys led to the drilling of Innamincka 1 in 1959, the discovery of Permian non-marine sediments, as well as a thick succession of redbeds (Innamincka Formation) now known to be Early Ordovician. Seven dry holes were drilled, including Gidgealpa 1 which tested gas-cut salt water from Cambrian dolostone and recorded fluorescence at several levels. An updip test of the dolostone led to the discovery in 1963 of commercial Permian gas in Gidgealpa 2 (the dolostone was faulted out). Consequently, subsequent exploration focused on the Permian Cooper Basin in preference to the deeper structurally complex early Paleozoic sequence.

Despite extensive seismic surveys (**Figure 42**), the structural definition of the Warburton Basin in key regions is hampered by high structural dip and the masking effects of Permian coals. Exploration drilling through the 1970s and 1980s was met with no commercial success. However, the discovery of commercial gas in Moolalla 1 and Lycosa 1, and oil in Sturt 6, all drilled in 1990, has led to renewed interest in the early Paleozoic 'economic basement' – not for indigenous petroleum but for oil and gas trapped updip from Permian source rocks. Early in 2001, Challum 19 in southwest Queensland flowed gas at 211,000 m^3/d (7.5 MMcfd) from the carbonate Kalladeina Formation.

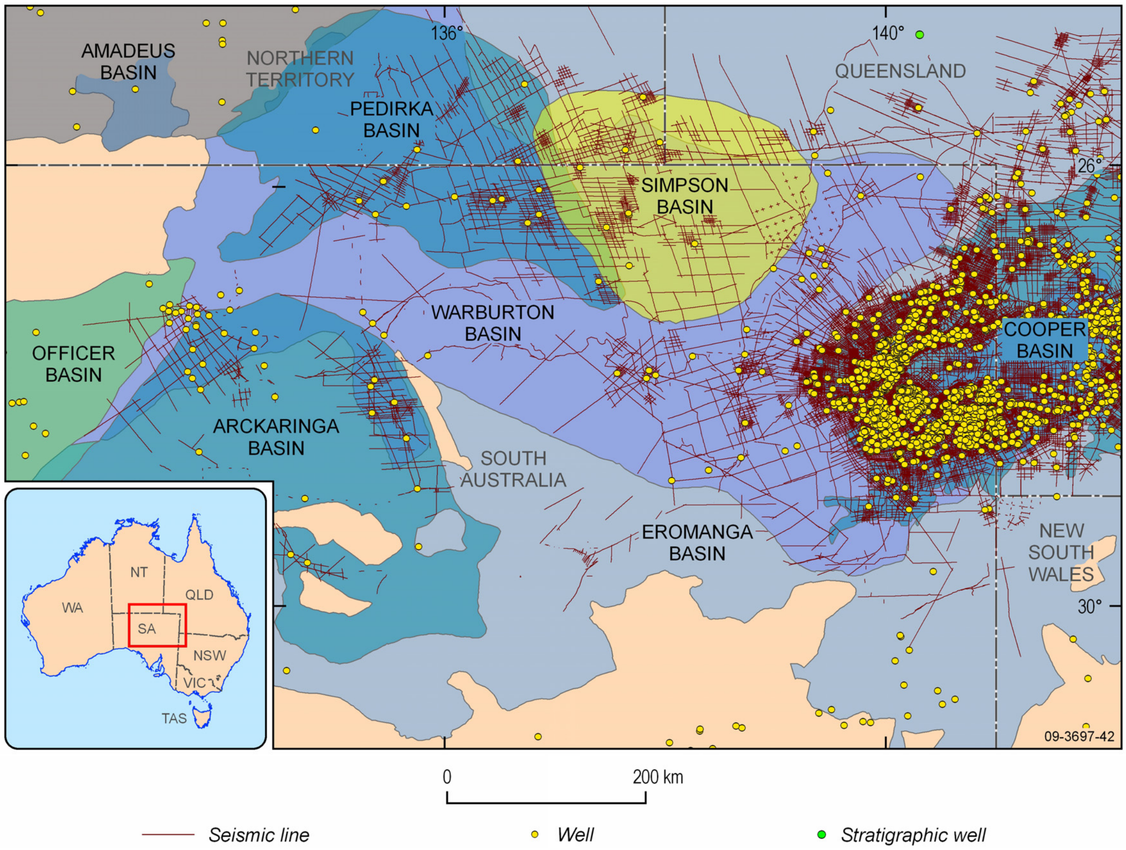


***Figure 42**: Seismic coverage across the Warburton and Cooper Basins, South Australia (from PIRSA, 2007).*

Stratigraphy

A stratigraphic summary of the eastern Warburton Basin of SA is shown in **Figure 43**. The oldest rocks comprise Early Cambrian acid-intermediate volcanics, tuff, and agglomerate of the Mooracoochie Volcanics (sequence 1) which correlates with the Truro Volcanics in the Stansbury Basin and Mt Wright Volcanics-Cymbric Vale Formation in western New South Wales.

Four seismic sequences can be differentiated above the Early Cambrian volcanics, on the basis of regional reflection seismic records. Biostratigraphy has greatly assisted the correlation of wide-spaced wells. Sequence €2 is characterized by dolostone with vuggy and moldic porosity (Diamond Bog Dolomite), indicating a highstand deposit altered by subaerial exposure. Sequence €3 is characterized by a back-stepping style in several stacked cycles of catch-up and keep-up carbonate systems (lower Kalladeina Formation/Dullingari Group). Sequence €4 was deposited after a major transgression following low relative sea level (Upper Kalladeina Formation/Dullingari Group). A succeeding highstand systems tract can be subdivided into three major parasequence sets: early highstand aggradation, middle highstand progradation and late highstand regression. A relative sea-level fall due to either tectonic uplift or a lack of accommodation space probably ended Sequence €4. The uppermost sequence (Innamincka Formation) is characterised by numerous stacked shoaling-upward parasequences, which may indicate a shallow stable shelf under influence of frequent sea-level fluctuations. An increase in siliciclastic content suggests an approaching shoreline. Shoaling is recorded on the Coongie-Cuttapirrie shelf, and the Innamincka Formation continues this trend to shallow subtidal water depths as part of a deltaic complex with siliciclastics – probably derived from the Proterozoic Arunta Block to the north. The Pando Formation is an extensive marine shelf sand equivalent to the lower Innamincka Formation. The Narcoonowie Formation is a lowstand fan, and considered a lateral-equivalent of the Innamincka Formation.

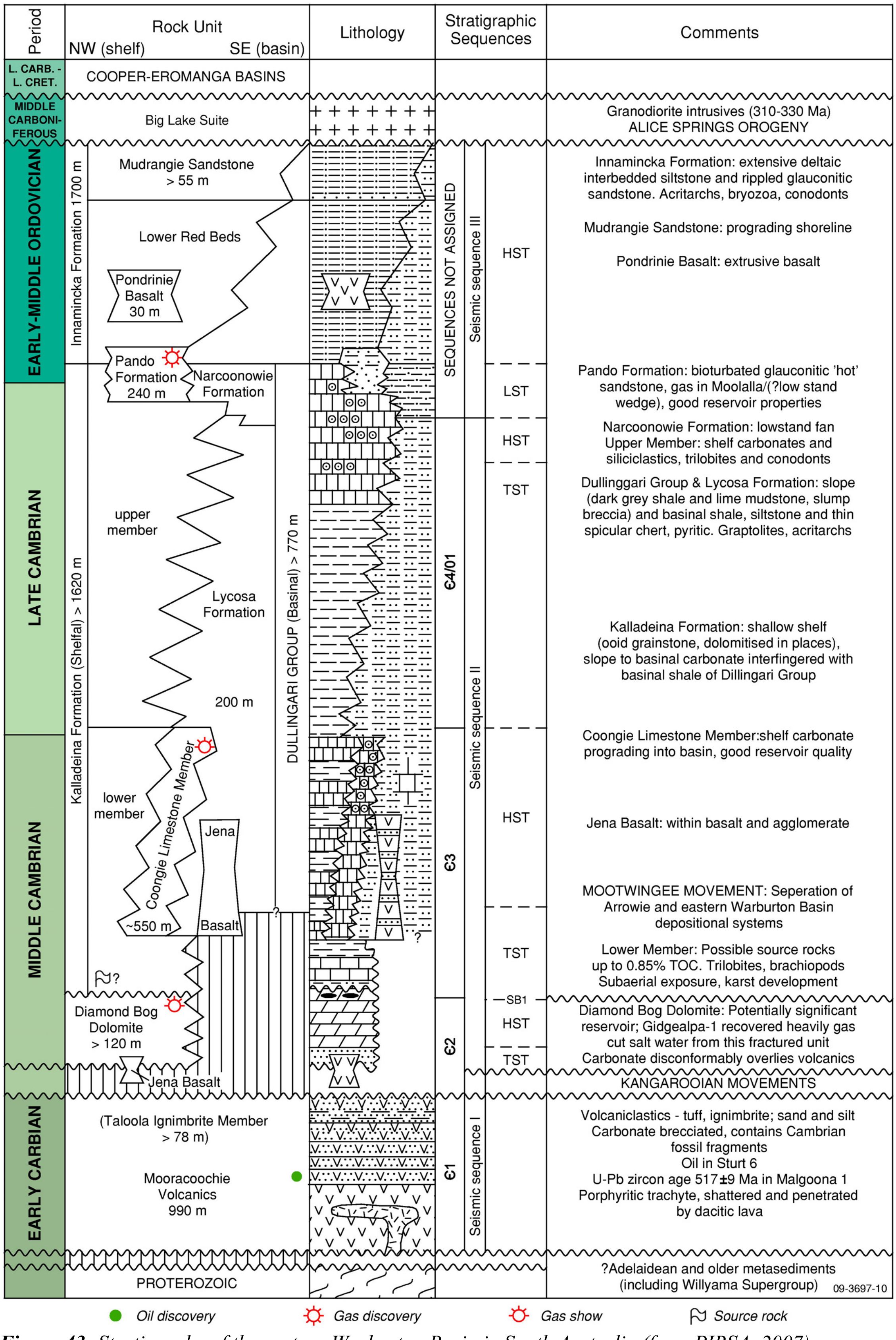


***Figure 43**: Stratigraphy of the eastern Warburton Basin in South Australia (from PIRSA, 2007).*

Graptolitic black shale of the Dullingari Group was deposited in deep water within the Tilparee Trough to the south during the Early Ordovician. This trough was flanked to the north by the Innamincka Shelf and to the south by the Gnalta Shelf, and formed part of the Larapintine Sea which extended through the Warburton and Amadeus Basins to the Canning Basin.

Rare intervals of conglomerate within the Dullingari Group may signify renewed tectonism at the end of the Early Ordovician, possibly associated with sealevel fall and the exposure of the Innamincka Delta. Lithic sandstone in the Toolachee area contains volcanic detritus, suggestive of erosion of the Mooracoochie Volcanics and/or younger basalts. Middle to Late Ordovician shale and siltstone constitute the last preserved record of the eastern Warburton Basin.

Source rocks
Source rock quality of material from the Kalladeina Formation is poor to fair. Organic matter is mainly Type II kerogen derived from marine algal-bacterial precursors.

Maturity
With the exception of anomalously low maturity indices from Kalladeina 1, the succession below 3000 m is late-mature to post-mature for oil.

Heat flow associated with the Alice Springs Orogeny is likely to have reduced any remaining hydrocarbon potential east of the Birdsville Track Ridge. However, the high present-day geothermal gradients in the region ($\leq 40^{o}$ C/km) result from a Plio-Pleistocene (1-2 Ma) increase in heat flow of unknown origin.

The ARC-SPIRT project on oil migration in the Cooper and Eromanga Basins has recognized pre-Permian inputs to oil pools on or adjacent to the Gidgealpa and Warra ridges, notably at Gidgealpa, Meranji, Muteroo, Malgoona and Sturt, but also at Cowan and Mudlalee. The most likely source rocks are Cambrian carbonates in the underlying Warburton Basin.

Reservoirs and seals
Fractures in brittle siltstone, such as those in the Dullingari Group in Lycosa 1, are capable of producing commercial oil and gas.

Sandstone of the Pando Formation ranges from 5-20% porosity, but relies on fractures for permeability. The unit is glauconitic and zircon-rich with a consequent high gamma ray response. Moolalla 1 gas is reservoired in this formation which extends from Pando wells in the west to Moomba wells in the northeast.

Basal and middle Kalladeina Formation dolostones represent shelf limestones exposed to meteoric diagenesis during marine lowstands. Although minor gas shows have been recorded, porosity prediction has proved elusive- the dolostones and karst breccias proving tight when drilled.

Sturt 6 oil was produced from fractured and weathered tuff and ignimbrite which forms the Mooracoochie Volcanics. Porosity reaches 17% due to dissolution of feldspar and glass shards, but fractures create the necessary permeability for flow.

A thick impermeable altered profile forms a semi-regional seal and is distinguished on logs by its low but uniform resistivity.

Traps
There is potential for structural traps updip from Permian source rocks.

Undiscovered resources
There are no estimates available.

Current Projects

Recognition of a unique alteration profile at the basal Cooper Basin unconformity -'basement' (Warburton Basin) reservoirs sealed by an altered zone- has generated a new play concept and could have significant implications for drilling depths and costs. A study by Boucher (2001a) attempted to identify the origin of the seal from systematic mapping of wireline log signatures from every well in the Cooper Basin area, in addition to petrological and chemical analyses. The origin of the alteration remains equivocal as it has variable characteristics from those of a palaeosol to hydrothermal alteration. Boucher (2001 a) is an atlas of Warburton Basin reservoirs and seals and includes:

GIS data
The nature and origin of the altered zone at the base of the Cooper Basin
QemSCAN results for Cooper and Warburton Basin units
Petrology
Fracture analysis
Potential hydrocarbon reservoirs in the upper Warburton Basin.

Exploration access

Exploration is permitted in both the Strzelecki and Innamincka Regional reserves which overlie the eastern Warburton Basin (Sun and Gravestock, 2001).

Key References

Boucher (2001a)
Roberts *et al.* (1990)
Sun (1998)
Sun and Gravestock (2001)

10.2 GEORGINA BASIN

Summary

Age	Neoproterozoic to Devonian
Area	325,000 km^2 - 100 000 km^2 southern area
Depth to target zones	300-1000 m
Thickness	Thin (<500 m) except for preserved Paleozoic depocentres on the southern margin: Burk River Structural Belt 1525 m; Toko Syncline 2750 m; Dulcie Syncline 1200 m (Smith, 1972). Basal Neoproterozoic sequence in Toko depocentre up to 5 -8 km thick.
Hydrocarbon shows	Middle Cambrian to Upper Ordovician shows. Gas (7,000 m^3/d) in the Coolibah Fmn in the Toko Syncline. Traces of bitumen in the Basal Nora Fmn, Ninmaroo Fmn
Production	none
Known Recoverable Reserves	unknown
Basin type	intracratonic, epeirogenic marine
Depositional setting	shallow marine
Reservoirs	porous dolostones, carbonates
Regional structure	Overthrusted synclines, monoclines
Seals	marine shales
Source rocks	anoxic marine organic-rich black shales
Depth to oil/gas window	
Number of wells	~30
Seismic line km	approx. 1300 km 2D seismic

Structural setting and sedimentation

During the Neoproterozoic breakup of supercontinent Rodinia, Australia was rifted away from other elements of Rodinia along a boundary, the Tasman Line. NW and NE –trending segments of the Tasman Line form a re-entrant in the Neoproterozoic continental. NW-trending Neoproterozoic rift basins were formed (Greene, 2006). Thick sequences of Neoproterozoic rocks are preserved in apparently fault-bounded extensional sub-basins that formed around 900 Ma. These form part of the Centralian Superbasin which includes the Amadeus, southern Georgina, Ngalia, Officer and Savory basins (Walter *et al*., 1995) and sedimentation spanned from about 800 Ma to Early Cambrian. A second extensional event at about 600 Ma (Lindsay *et al*., 1987) revitalised Paleozoic deposition which was initially mixed carbonate-clastic deposition that gave way to clastics. This deposition was contemporaneous with intracratonic sedimentation within the Amadeus (**Figure 44**) and Wiso Basins, and the Warburton Basin. Unlike the Amadeus Basin where thick evaporite accumulations were later affected by salt tectonics and the formation of important structural traps, structure in the Georgina depocentres is extremely subdued.

Normal faults bounding these depocentres were selectively reactivated by transpressional deformation during the mid-Paleozoic Alice Springs Orogeny (Lechler and Greene, 2006), and are now expressed as high-angle reverse faults that invert the pre-existing rift basins. Harrison (1980) estimated an offset of 6.5 km on the Toomba Fault. These NW-trending extensional basins were truncated by NE-trending transform faults (Greene, 2006).

Moderate folding and faulting, especially with overthrusting along the southern margin was probably initiated in the Early Cambrian. This area is dominated by syndepositional horst and graben architecture with deformation later culminating during the Late Devonian-Early Carboniferous Alice Springs Orogeny (Ambrose and Putnam, 2007). Anticlinal structures in some southern areas appear to have been breached from this event, with subsequent loss of hydrocarbons. Further north, these orogenic effects were apparently less, and there is potential for post-Devonian plays (Karajas, 1994).

The southern Georgina Basin contains a simple stratigraphic succession. The earliest Cambrian was generally restricted to the southern margin with deposition of siliciclastics, shale and dolostone to a thickness of about 250m. Sedimentation resumed in the early Cambrian with a major transgression and deposition of platform carbonates (Thorntonia Limestone). The basal sediments of this unit have higher siliciclastic content. Following regional erosion, deepening marine conditions enabled accumulation of anoxic, pyritic and carbonaceous, partly dolomitic shale of the basal Arthur Creek Formation over an area of some 80,000 km^2. This unit is rich in algal/bacterial organic matter (outer ramp facies) and provides the principal source/seal rocks of the Georgina Basin (Ambrose and Putnam, 2007).

The Toko Syncline is constrained between an eastern thrust fault (French Fault) and the western Toomba Fault which created 6.5 km uplift to the west.

Neoproterozoic

Four supersequences accumulated in the southern Georgina Basin region, the thickest succession of about 8,000 m accumulating in Bedourie Block within the Toko Syncline (Tucker *et al*., 1979; Lodwick and Lindsay, 1990). Marduroo-1 penetrated the upper 800 m of this accumulation. This section may simply be a very thick, early Upper Proterozoic section, perhaps associated with the first rifting event at about 900 Ma (Lindsay *et al*., 1987). The well-stratified nature of the section with its indications of seismic sequences suggest that the section is marine, perhaps deposited at rates similar to the known lower Paleozoic section in the Georgina and Amadeus Basins. Lodwick and Lindsay, *op cit.* therefore speculate that the sequence could be Middle Proterozoic (1400-1800 Ma) and perhaps as an equivalent or lateral extension of the McArthur Basin, hold considerable potential for a deep petroleum source.

Exploration wells in the Burke River Structural Belt to the east also bottomed within this sequence, only penetrating a maximum of 618m in Canary 1. Dating of these fine-grained rocks provided ages between 790 and 600 Ma (Compston and Ariens, 1968). Sub-basins that formed along the southern margin are almost a mirror image of the configuration in the Amadeus Basin where the main petroleum prospects lie within or adjacent to the major sub-basins that formed along that basin's northern margin (Lodwick and Lindsay, *op cit.).* Metamorphosed Neoproterozoic rocks are present in the Thomson Fold Belt (Draper, 2005) and eastwards, indicating that Neoproterozoic deposition was even more widespread than realised with the original concept of the Centralian Superbasin. Metamorphism of these rocks coincided with the Delamerian Orogeny at about 500 Ma (Draper, 2007).

Cambrian

Early Cambrian rocks, mixtures of siliciclastics and carbonates, are a thin predominantly siliciclastic sequence restricted to the southern margin.

Middle Cambrian sedimentation was the most extensive phase of deposition in the basin (Southgate and Shergold, 1991) preserving a thin sequence of carbonates, black shale and minor sandstone and shale in the Thorntonia Limestone and Hay River Formation.

Middle to Late Cambrian units are again restricted to the southern region and include the Arrinthrunga and Arthur Creek Formations and the overlying Georgina Limestone. In the eastern Toko Syncline, the relationship between these units in unclear, but the Georgina Limestone is probably the deepwater facies equivalent or at least more open marine than the other units. The Arrinthrunga Formation accumulated in shallower restricted marine conditions.

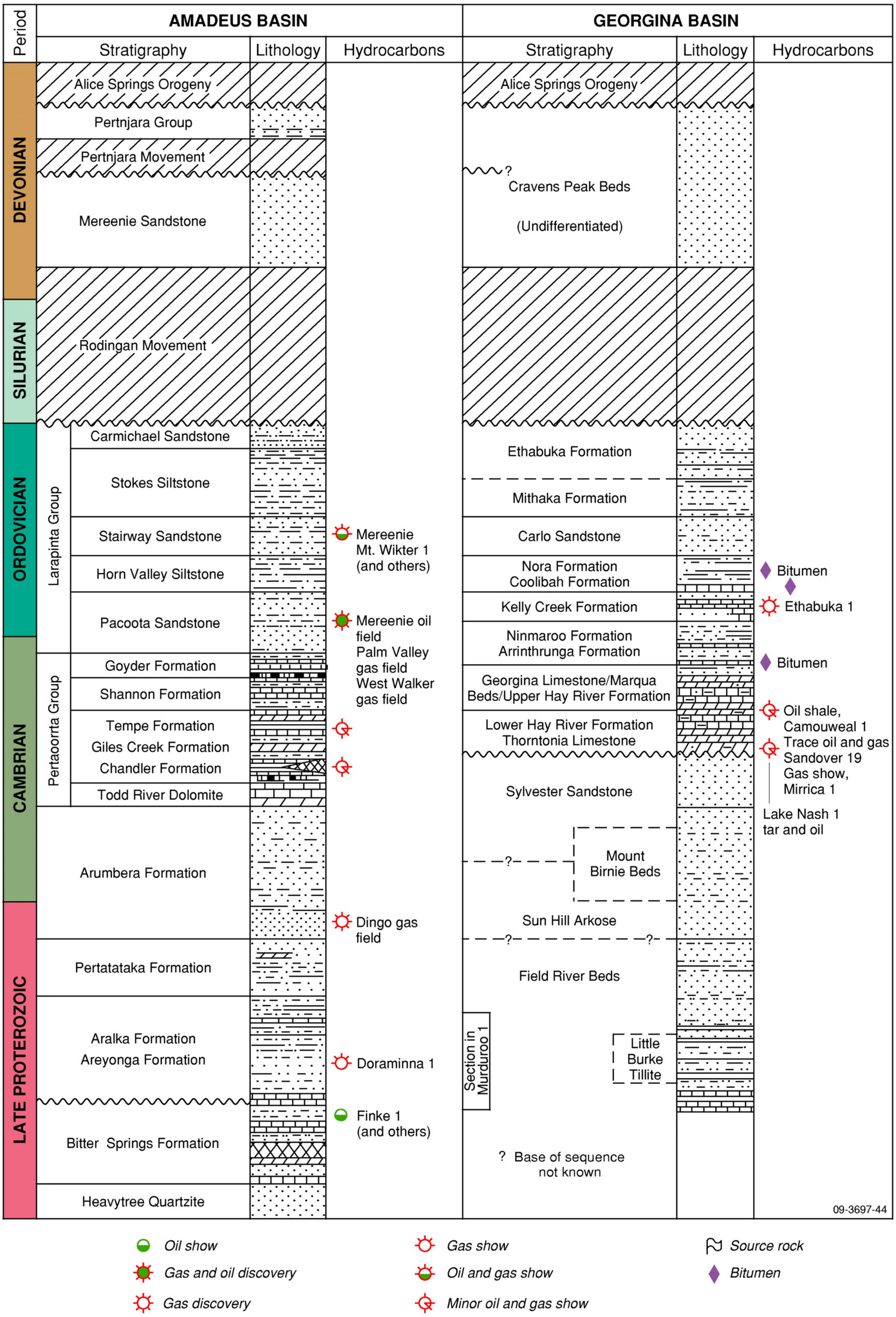


***Figure 44**: Comparison of the stratigraphy of the Georgina Basin with the Amadeus Basin (from Lodwick & Lindsay, 1990).*

The succession to the east in the Burke River Structural Belt differs in both rock types and timing of major unconformities (Shergold and Southgate, 1986). The basal Middle Cambrian Thorntonia Limestone is overlain by the marine Monastery Creek Member of the Beetle Creek Formation, the main phosphate-bearing unit. A sequence of thin shales and limestones overlie up into the Latest Cambrian shallow marine Chatsworth Limestone.

Ordovician

Ordovician rocks are restricted to the southern part of the basin due to both restricted extent and erosion. The Ninmaroo Formation conformably overlies the Chatsworth limestone, and youngs as its facies extended westward into the Toko Syncline where it unconformably overlies the Arrinthrunga Formation to the west and Georgina Limestone to the east. Emergence followed with karst development over this unit. The Kelly Creek Formation overlies this unconformity and a marine sequence of limestones and nearshore marine siliciclastics became predominant. By early Ordovician, deposition was restricted to the Toko Syncline and westwards into the Northern Territory, continuing to the mid-Ordovician.

Devonian

As a response to the Pertnjara-Brewer Movement, fluvial and marginal marine siliciclastics of the Cravens Peak beds were deposited in the Toko Syncline to Dulcie Syncline areas in Early to Middle Devonian, to be later thrusted and folded during the Alice Springs Orogeny.

Hydrocarbon Potential

The most recent phase of exploration lies west of the Toko Syncline in the Northern Territory (Boreham and Ambrose, 2007), but from present data, this region has a thin sequence. The thick sequence in the Toko Syncline, especially the Cambro-Ordovician remains the most prospective as it has known dry gas. The full Paleozoic sequence has yet to be tested, and the underlying Proterozoic sequence remains an unknown.

Hydrocarbon shows

Hydrocarbon indications have been known for over a century in the southern Georgina Basin.

Significant oil stains occur throughout the early Middle-Late Cambrian succession in the southwestern part of the Georgina Basin. No hydrocarbons were detected in drilling in the Burke River Structural Belt.

The lower Paleozoic section of the Toko Syncline has hydrocarbon shows in Middle Cambrian to Middle Ordovician rocks. Bitumen indications are present in the lower Ordovician Ninmaroo, basal Nora and Coolibah Formations in the Toko Syncline region, observed in Ethabuka 1 and Netting Fence 1. Weak indications of solid and gaseous hydrocarbons were noted in GSQ Stratigraphic holes Mt Whelan 1 and 2. The most promising gas occurrence is from the Toko Syncline where gas flowed from the Coolibah Formation in Ethabuka 1 at 7,000 m^3/d. This hole was abandoned due to drilling problems and never tested its reservoir target in the Ninmaroo Formation. The gas comprised 71% methane, 5.3% ethane, 17.5% nitrogen and 1.2% oxygen. The high N-content is comparable to the deep mature gas in the Devonian Adavale Basin (Boreham and de Boer, 1998).

Slight overpressuring was associated with gas detected over thick intervals of the Marqua Formation in Mirrica 1. Netting Fence 1 also had slight overpressuring at the same stratigraphic interval. The deeper part of the Toko Syncline may have potential for deep basin gas.

Residual oil and bitumen linings in vug porosity evident in the Arthur Creek Formation (Ambrose and Putnam, 2007).

Source rocks

In the Middle Cambrian reservoir-source couplet in the Northern Territory western area, the Thorntonia/basal Arthur Creek Formation has unique lateral extent and source richness. This areally extensive, oil-prone alginitic black shale unit is between 20 and 100 m thick, with TOC commonly 3-4% and ranging up to 9.6%. These share a similarity in geochemical and isotopic characteristics with other Cambrian-sourced oil from the Amadeus (Alice 1) and Arafura (Arafura 1) Basins and this suggests the existence of a common, expansive, early Middle Cambrian source organic facies across northern and central Australia (Boreham and Ambrose, 2007).

In the Burke River Structural Belt, TOC levels in the Chatsworth Limestone (0.12%) and Pomegranate Limestone (0.16%) indicate little potential, but the Inca Shale (2.8%) and 0.19-1.51% in the Beetle Creek Formation is more promising.

Maturity

Rich marine source rocks of Middle Cambrian age in the Toko Syncline are mature for oil in the Mid-Ordovician and the Middle Cambrian is still in the gas-generation zone - except in the deepest part of the syncline where they are mature for dry gas (Jackson, 1982). The deeper part of this syncline may be gas-saturated. In the Elkedra region, residual oil extracts from dolostones indicate maturity in the middle of the oil window (Rc 0.7-0.8%) on the basis of aromatic hydrocarbon maturity ratios (Volk *et al*., 2007).

CAI of 1-1.5 in the Ninmaroo Formation suggest that not all the sequence is overmature in the Burke River Structural Belt (Radke, 1982) but it is unclear when maturation did take place. Expulsion of hydrocarbons was possibly in the Cretaceous or Paleogene.

Structural Timing and hydrocarbon generation and migration

Burial history modelling indicates multiple phases of oil generation and expulsion with the earliest phase beginning during the Ordovician. An early phase has been degraded to bitumen, but a later phase currently exists as a relatively non-degraded crude of aromatic-intermediate composition (Karajas, 1994). Three oil types are identified in the southwestern region and are called the Thorntonia (!), Arthur Creek (!), and Hagen (!) Petroleum Systems (Boreham and Ambrose, 2007).
Subsequent erosion of much of the southern Georgina Basin, initiated during the Alice Springs Orogeny, has resulted in reservoirs now occurring at shallow depths (300-1000 m) but with an increased risk of oil alteration during this protracted time period. The identification of multiple petroleum systems in the southern region of the basin, together with relatively short migration distances from source to trap, improve prospectivity of this region (Boreham and Ambrose, 2007).

Reservoirs and seals

In the western region of the southern Georgina Basin, reservoir potential, with adequate sealing capacity occurs in two separate Middle Cambrian carbonate sequences: the basal dolomite reservoir unit (Thorntonia Limestone) and the basal Hagen Member of the Chabalowe Formation the basal dolostone unit underlies the source rock unit and is best developed over palaeohighs and in shoreward settings. Better reservoir developments contain dolomitised grainstones with intercrystalline, vuggy, and locally extensive fracture porosity. Effective permeabilities range up to 1055 mD in gross potential pay of 17 m. The basal Hagen Member is an extensive nearshore regressive blanket in the western part of the depocentre. Net reservoir thickness ranges between 3 and 18 m, porosities between 6.9 and 14.6%, with permeabilities between 2 and 3400 mD. Overlying this reservoir are tight anhydritic argillaceous carbonates (Karajas, 1994).

In the Toko Syncline, a thick and relatively homogeneous potential dolostone reservoir exists within the Early Ordovician Kelly Creek Formation in the Toko Syncline, and is characterised by high intercrystalline porosity and permeability (Radke and Duff, 1980). Fracture porosity and that associated with hydrothermal dolomite are additional secondary/diagenetic plays in an otherwise tight carbonate sequence. Fracture plays are more promising in the brittle well-indurated rocks where they are structured.

Traps

Anticlinal and fault-bounded structures below thrust faults offer best potential in the Toko Syncline.

Key References

Ambrose and Putnam (2007)
Boreham and Ambrose (2007)
Draper (2007)
Jackson (1982)
Lodwick and Lindsay (1990)
Southgate and Shergold (1991)

10.3 COOPER BASIN

Summary

Age	Late Carboniferous-Middle Triassic
Area	130,000 km^2 of which almost two-thirds of the basin is in Queensland.
Depth to target zones	1250-3670 m
Thickness	2500 m
Hydrocarbon shows	Widespread over 8 formations
First Commercial discovery	1963 gas in Gidgealpa 2
Production	5.52 million kl oil (14% of total production) and 153.9 billion m^3 gas (96.7% of total production to 2005 (GA, 2007)
Production 12 months to June 2004	3.283 G m^3 sales gas, 227.8.kt LPG, 332.06 ML condensate, 384.21 ML crude oil, 20.42 kt ethane (Cooper and Eromanga Basins)
Known Recoverable Reserves	7.6 million kl oil (14% of total reserves) and 192.5 billion m^3 gas (98.6% total reserves) to 2005 (GA, 2007)
Basin type	Intracratonic
Depositional setting	Non-marine
Reservoirs	Sandstones: fluvial, deltaic, shoreface
Regional structure	Faulted anticlines
Seals	Lacustrine shale, coal
Source rocks	carbonaceous shale, thick coal (up to 30 m)
Depth to oil/gas window	1250 m
Number of wells	~1400
Seismic line km	74,865 km 2D seismic, 7,117 km 3D seismic

Structural setting

The intracratonic Cooper Basin represents a Late Carboniferous to Triassic depositional episode terminated at the end of the Middle Triassic with widespread compressional folding, regional uplift and erosion. It lies unconformably over early Paleozoic sediments in the Warburton Basin and is overlain disconformably by the central Eromanga Basin. In the northern Patchawarra Trough, the Cooper Basin is overlain by the Late Triassic Cuddapan Formation. Total area of the Cooper Basin exceeds 130,000 km^2, of which about 35,000 km^2 lies within northeastern South Australia, the predominant balance in Queensland where northeastern limit is the Canaway Ridge and Fault which separates it from the coeval southern Galilee Basin. Three major troughs, the Patchawarra, Nappamerri and Tenappera, are separated by narrow sinuous structural ridges – Gidgealpa-Merrimelia-Innamincka (GMI) and Murteree – associated with the reactivation of NW-directed thrust faults in the underlying Warburton Basin (**Figs 45**). In Queensland, the most important structural element is the cross-axial fault-bounded Jackson-Naccowlah Trend which informally separates the northern and southern Cooper Basin. The major tectonic episode separating the Cooper and Warburton Basins is interpreted to be the Devonian-Carboniferous Alice Springs Orogeny. The three asymmetric troughs contain up to 2500 m of Permo-Carboniferous to Triassic sedimentary fill, and are overlain by as much as 1300 m of Jurassic to Paleogene cover.

There are two distinct structural trends; northeast-southwest and northwest-southeast.
The northeast-southwest orientation defines the main trend in the northern region and in accord with the majority of trends in the southern part of the basin, especially in South Australia. This is seen in the Tanbar, Gilpeppee, Morney, Curalle and Betoota Anticlinal trends. The northwest-southeast trend is evident in the Galway-Ingella, Hammond and Steward Anticlines. These features were influenced by earlier faults which were reactivated repeatedly between Permian and Paleogene times

(Hoffmann, 1989).

The basin contains a number of non-marine depositional sequences within the Late Carboniferous to Late Permian Gidgealpa Group and Late Permian to Middle Triassic Nappamerri Group. In the northern Cooper Basin, the succession reaches a maximum of 600 m where it contains an incomplete Permian section, generally less than 200 m, but a thick Triassic sequence which overlaps the Permian on the northern margins of the basin, indicating regional subsidence and tilting to the north in post-Permian times.

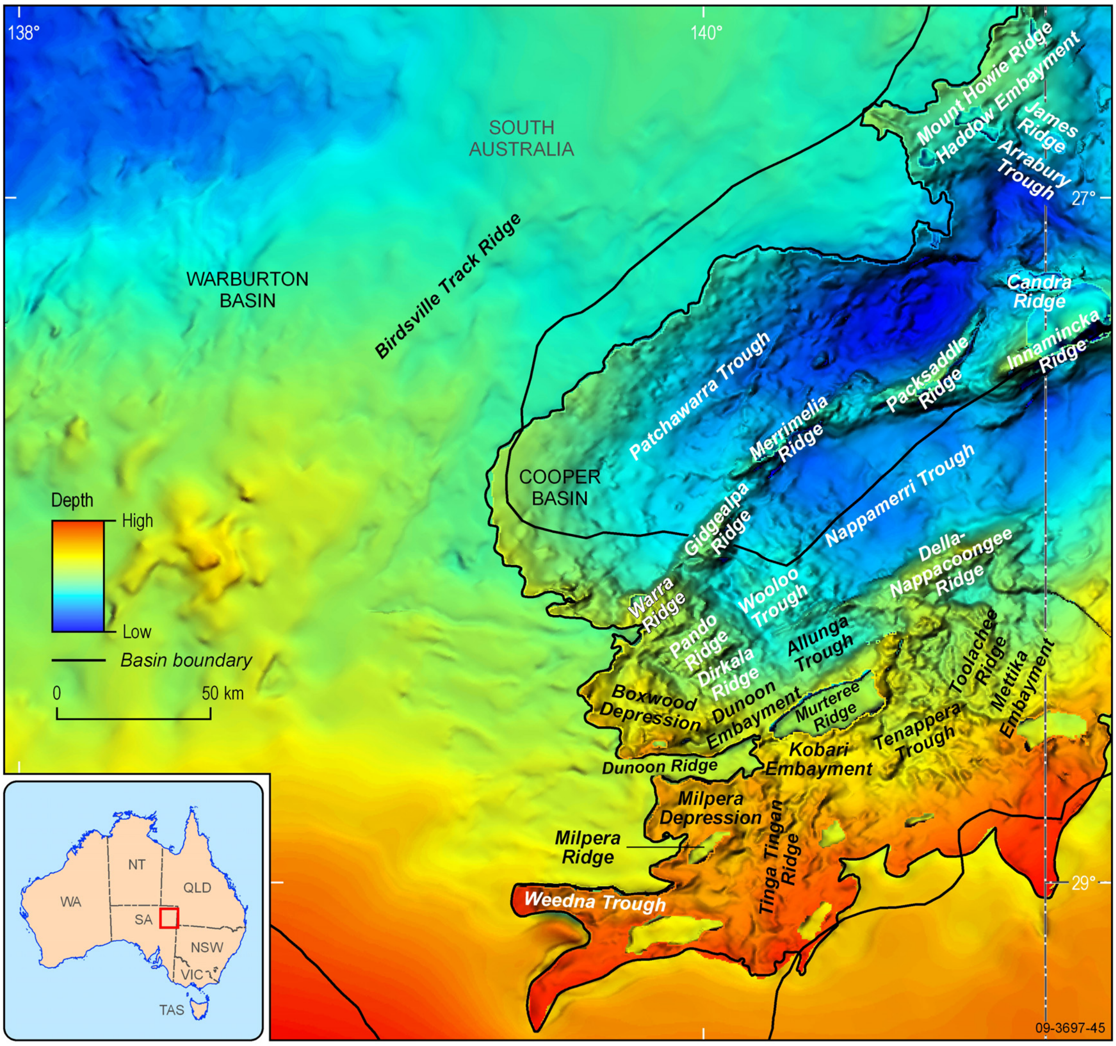


***Figure 45**: Structural elements on the 'Z' seismic horizon – top of Warburton Basin (from PIRSA, 2007, NGMA).*

Exploration history

Petroleum exploration commenced in 1954 with the granting of an exploration to Santos. Exploration commenced in 1959 with the drilling of Innamincka 1 following a reflection-refraction seismic survey carried out over the Innamincka Dome with Delhi Petroleum as operator. Additional reflection surveys over the ensuing years led to the discovery of gas in Gidgealpa 2 in 1963. Since then, over 1400 wells have been drilled and more than 80,000 km of seismic have been recorded.

Exploration was stimulated in the basin at the turn of the century in South Australia, with a licensing restructure. Between 1998 and 2000, the formerly-existing PELs 5 and 6 were split into 27 new petroleum exploration licences, and placed on offer by PIRSA. The total expenditure proposed for the first five years of exploration in the winning bids amounted to $201 million, with a minimum of 103 exploration wells committed to be drilled. In November 2001, the first of these new licences were granted to the successful bidders in CO1998 acreage release following the signing of an historic native title agreement. The subsequent agreements were completed in 2002-03 for the CO1999 and CO2000 acreage release areas.

A new phase of exploration commenced in 2002, and since then, new entrants have participated in drilling 41 exploration, 2 appraisal, and 4 development wells. Economic oil and gas pools were discovered in 20 of the 37 new entrant exploration wells, and five out of six appraisal-development wells were successful. In addition to this activity, the Santos Joint Venture continues to successfully explore and develop fields in their Cooper production licences.

Stratigraphy

The Cooper Basin unconformably overlies flat lying to compressively-deformed Cambro-Ordovician Warburton Basin strata and Carboniferous granitic intrusives. The unconformity is mapped as the Z seismic horizon **(Figure 45).** In the lower Gidgealpa Group, the oldest units are the Late Carboniferous to early Permian Merrimelia Formation and Tirrawarra Sandstone which comprise terminoglacial and glaciofluvial systems deposited unconformably on a glacially-scoured landscape. The Tirrawarra Sandstone represents braided fluvial to fan-delta deposits overlain by the dominant peat swamp and floodplain facies of the Patchawarra Formation. Locally (eg Ponfrinie Field), Merrimelia aeolianite forms a major gas reservoir.

Two lacustrine shale units (Murteree and Roseneath Shales) with intervening fluviodeltaic sediments (Epsilon and Daralingie Formations) were deposited during a phase of continued subsidence. Early Permian uplift led to erosion of the Daralingie Formation and underlying units from across basement highs.

The Late Permian Toolachee Formation **(Figure 18)** was deposited on the Daralingie unconformity surface and is overlain conformably by Late Permian to Middle Triassic Nappamerri Group. Predominant is the Arrabury Formation (comprising the Callamurra, Paning and Wimma Sandstone members) overlain by the Middle to early Late Triassic Tinchoo Formation.

Source rocks

Permian coal measures and shales are the principal hydrocarbon source rocks in the region and are dominated by Type III kerogens derived from higher plant assemblages. Oils and condensates are typically medium to light (30-60^{o} API) and parrafinic, with low to high wax contents. Most Permian oils in Permian reservoirs contain significant dissolved gas and show no evidence of water washing. Gas composition is closely related to maturity/depth with drier gas occurring towards basin depocentres although there is strong geological control on the hydrocarbon composition.

Permian source rocks have average TOC and S2 pyrolysis yields of 3.9% and 6.9 kg/t, respectively (excluding coals). Locally, the Toolachee Formation is the richest source unit averaging 7.2% TOC but up to 25%. The Patchawarra Formation is considered the other major source unit, especially the lower shales and coals. The lacustrine Murteree and Roseneath Shales have little source potential.

Thin, laterally discontinuous coals represent the best source rocks in the upper Nappamerri Group, whilst shales tend to be organically lean. The lower Nappamerri Group is coal-poor, contains kerogen that tends to be oxidized, and any source rocks are humic-rich and gas-prone.

Little is known of the source potential of the Triassic succession in the northern Cooper Basin, but the Gilpeppee Member of the Tinchoo Formation could be a potential source rock (Powis, 1989).

Maturity

The Patchawarra Trough contains the bulk of the oil and wet gas reserves consistent with local source rocks being in the 'oil window', while the hot Nappamerri Trough (40-50^{o} C/km), underlain in part by radiogenic granite, is over-mature and contains mainly dry gas.

Together, the petrographic and geochemical evidence support coals and associated dispersed organic matter as the effective source rocks capable of generating gas and minor oil, albeit in low yields. At maturity levels between 0.7-0.95% R_o, initial generation from the richer facies has led to partial filling of reservoirs with wet gas and oil. There is a sharp onset of significant hydrocarbon accumulation when the source reaches a maturity of 0.95%.

Reservoirs and seals

Multi-zone high-sinuosity fluvial sandstones form poor to good quality reservoirs. The main gas reservoirs occur primarily within the Patchawarra Formation (porosities up to 23.8%, average 10.5 %; permeability up to 2500 mD) and Toolachee Formation (porosities up to 25.3%, average 12.4%; permeability up to 199 mD). Shoreface and delta distributary sands of the Epsilon and Daralingie Formations are also important reservoirs. Oil is produced principally from low-sinuosity fluvial sands within the Tirrawarra Sandstone (porosities up to 18.8%, average 11.1%; permeability up to 329 mD). Towards the margin of the Cooper Basin, oil is also produced from the Patchawarra Formation and from fluvial channel sands in the Merrimelia Formation in Malgoona Field.

The Callamurra Member of the Arrabury Formation is conventionally regarded as a regional seal, but nevertheless contains economic oil and gas reservoirs in some areas and is a leaky seal in others. Low-sinuosity fluvial sandstones of the Paning and Wimma Sandstone members form economic oil and gas reservoirs, and high-sinuosity fluvial sandstone of the Tinchoo Formation reservoirs oil. As yet, there have been no economic oil or gas fields discovered in the Cuddapan Formation in South Australia.

Intraformational shale and coal form local seals in the major reservoir units. Beneath the Daralingie unconformity are two important early Permian regional seals – the Roseneath and Murteree Shales. The Roseneath Shale is the top seal of the Epsilon Formation, and the Murteree Shale seals the Patchawarra Formation. A younger regional seal is provided by the Triassic Arrabury Formation.

Traps

Where the regional seal is thin or absent, multiple oil and gas pools are stacked in coaxial Permian-Mesozoic structures and may occur from as low as the Patchawarra Formation to as high as the Murta Formation (**Figure 46**). Most anticlinal structures are fault-controlled zones which were rejuvenated in part by subsequent fault movements in the Triassic and Paleogene. Locally, Permian oil has migrated into Warburton Basin reservoirs on the basin margin, and gas has migrated into fractured Ordovician reservoirs fringing the Allunga Trough.

Anticlinal and faulted anticlinal traps have been relied on as proven exploration targets but potential remains high for discoveries in stratigraphic and sub-unconformity traps, especially where the Permian sediments are truncated by the overlying basal Eromanga unconformity. Economic oil and gas are reservoired in the Nappamerri Group, paradoxically regarded as a regional seal to the Cooper Basin.

In the northern Cooper Basin, the relative magnitude of post-depositional structural displacements in the Late Triassic and Paleogene are used to identify two orders of structure. Favoured as traps are the second-order class that have a dominant Triassic and subordinate Paleogene component. These are less likely to have suffered hydrocarbon leakage than those with dominant Paleogene movement (Wecker *et al*., 1996).

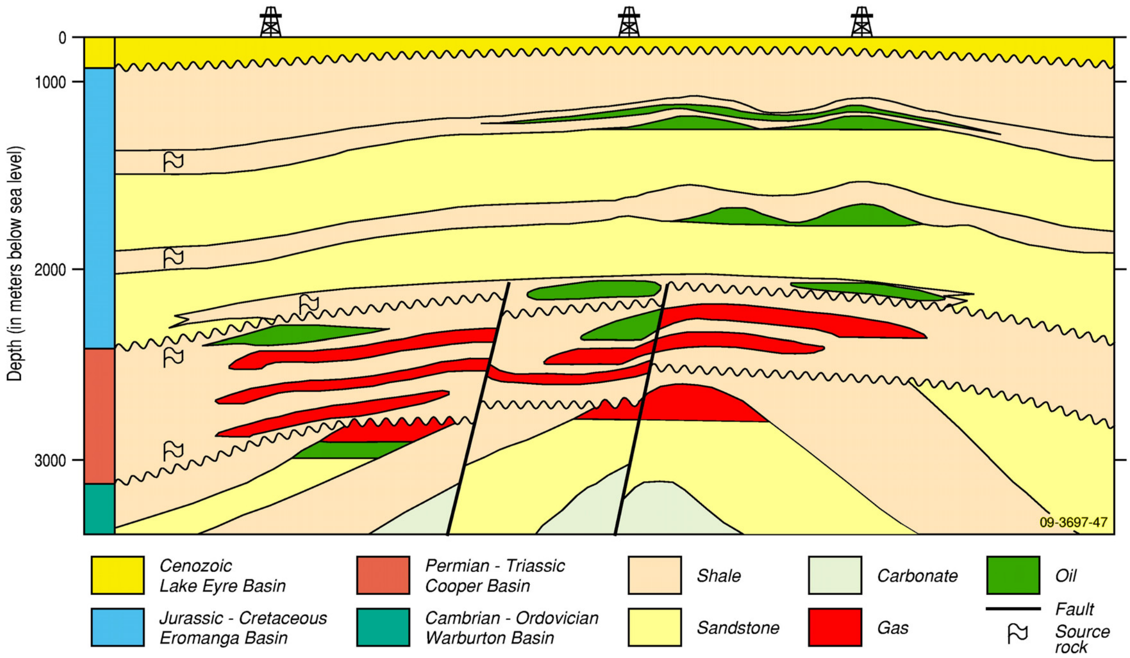


Figure 46: *Schematic section showing typical petroleum traps in the Warburton, Cooper and Eromanga Basins (from PIRSA, 2007).*

Prospectivity and undiscovered resources

The Cooper Basin is a mature petroleum province. However, potential remains high for discoveries in stratigraphic and sub-unconformity traps- these have received increasing exploration interest in the past five years. Pinchout plays along the margins of the Cooper Basin have been tested with commercial success. 3D seismic will be critically important in helping delineate more subtle traps in the future.

Current Projects

SPIRT project – Oil migration in the Cooper and Eromanga basins

Research into the conditions and effects of hydrocarbon fluid flow in the subsurface of the Cooper and Eromanga Basins has been funded through TEISA-SPIRT and results lodged with PIRSA. This joint study by the University of Adelaide and Cologne, together with PIRSA Petroleum group and Geoscience Australia, aimed to quantitatively reconstruct secondary oil migration pathways and reservoir filling histories in the Cooper and Eromanga Basins.

Electrofacies mapping

Electrofacies analysis of the Cooper Basin project complements a pilot study conducted in 1998. Routine electrofacies analysis was carried out on about 1000 wells and results have been compiled into maps. Verification was completed in 2004, and a folio of maps and gridded and contoured data sets was released at PESA's Eastern Australasian Basin Symposium II.

Exploration access

The Innamincka and Strzelecki Regional Reserves occur over the Cooper Basin, but exploration and production are permitted. Within the Innamincka Regional reserve, a special management zone exists that excludes access for petroleum activities. At the core of this zone is the Coongie Lakes National Park. Other conditional access zones exist around the Coongie Lakes area limiting access for petroleum or mineral exploration or production. Much of the current petroleum produced from the Cooper Basin originates from within the Innamincka Regional Reserve.

An historic native title agreement, involving unprecedented cooperation between native title claimants and petroleum explorers, was signed in Adelaide in October 2001, allowing $90 million worth of investment in petroleum exploration over 11 new exploration licences in the Cooper Basin (the CO1998 blocks). This agreement is to form a precedent for future native title negotiations, not only in the Cooper Basin, but throughout the country. The native title negotiation process was initiated in June 1999.

These agreements establish processes to protect Aboriginal heritage before and during field operations, and to provide payments for the interference with the enjoyment of the native title rights of the claimants. All of these agreements are conjunctive, and cover all petroleum licence activities from exploration through to development and production.

Production, Infrastructure and markets

The distribution of oil and gas fields and pipelines across the basin are shown in **Figure 47**. As at 30 June 2004, there were 112 gas fields online (with 472 gas wells online) and 39 oil fields online (with 171 oil wells online) in the South Australian portion of the Cooper Basin region.

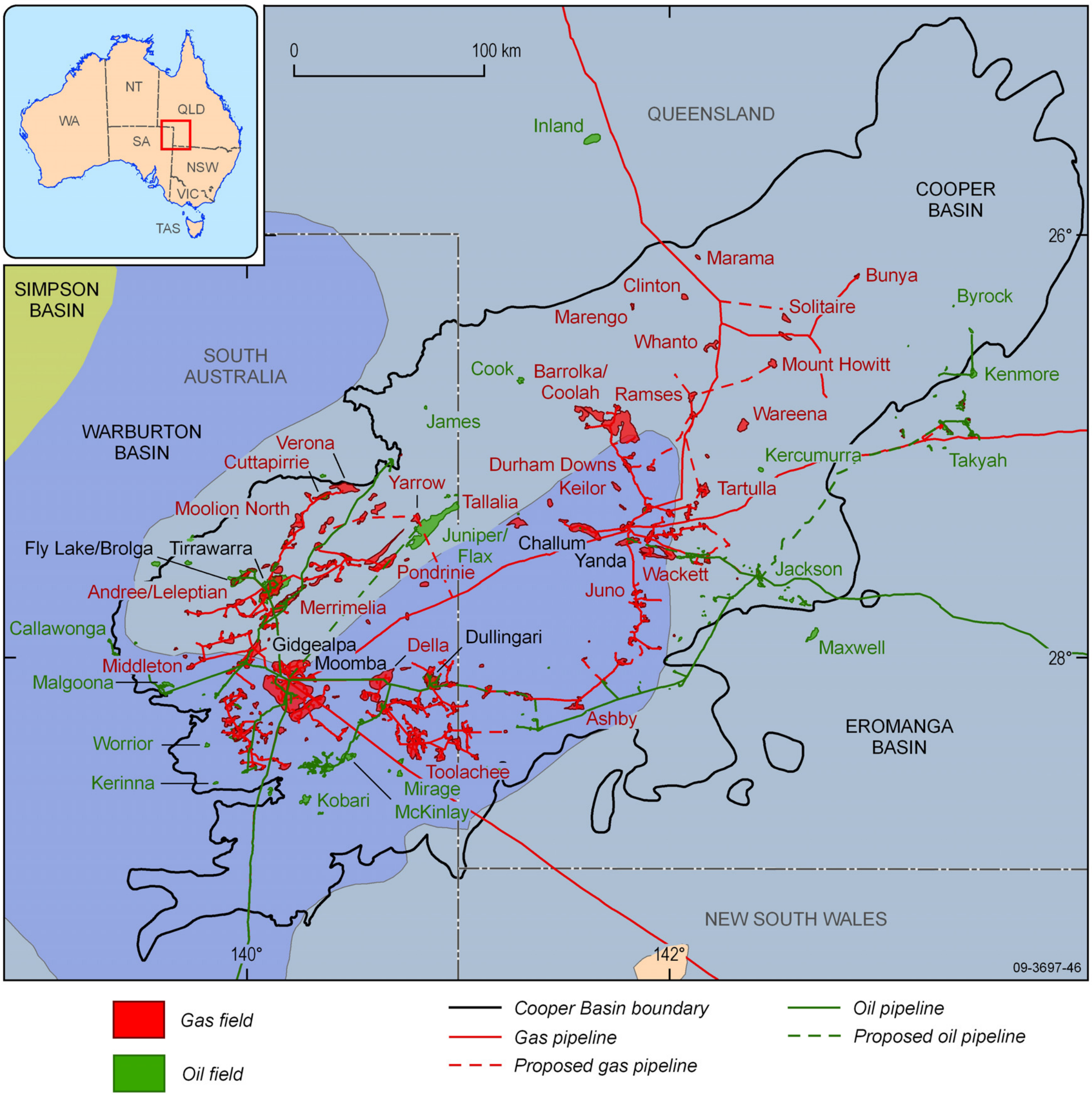


***Figure 47**: Oil and Gassfields of the Cooper Basin (from PIRSA, 2007; QNRM. 2001) Black field name denotes both oil and gas production.*

Key References

Altmann and Gordon (2004)
Boucher (2001a)
Boucher (2001b)
Deighton *et al.* (2003)
Flottmann *et al*. (2004)
Gravestock *et al*. (1998)

10.4 PEDIRKA BASIN

Summary

Age	Permo-Carboniferous
Area	27,000 km^2 in SA
Depth to target zones	600 to >2000 m
Thickness	up to 1500m
Hydrocarbon shows	minor fluorescence, trace gas
First Commercial discovery	none
Identified reserves	nil
Undiscovered resources (50% prob.)	undetermined
Production	nil
Basin type	intracratonic
Depositional setting	non-marine
Reservoirs	non-marine sandstone
Regional structure	faulted anticlines
Seals	non-marine shale, siltstone
Source rocks	non-marine shale, coal
Depth to oil/gas window	1250 m (oil) in SA
Number of wells	10
Seismic	line km 5909 km of 2D. Statics are considered a major problem in early surveys.

Structural setting

The Pedirka Basin has an area of 150,000 km^2, approximately 80% in the Northern Territory, the remainder in South Australia, and a possible extension into Queensland (**Figure 22**). It is an intracratonic basin unconformably overlying the SE Amadeus Basin and the western Warburton Basin, both of which were deformed during the Alice Springs Orogeny (ASO) (395-325 Ma) and possibly the earlier Delamerian Orogeny (510-476 Ma). A final NW-SE compressional phase of the ASO in the mid- to Late Carboniferous initiated deposition in the Pedirka Basin and created thrust faults such as occurring at Mt Hammersley. Permo-Carboniferous sediments were subsequently deposited in a tectonically quiescent sag phase. In South Australia, the Permian is entirely overlain by up to 2500 m of Triassic to Late Cretaceous sediments of the Simpson (Desert) and Eromanga Basins (**Figure 48**). NNE-striking high-angle reverse faults separate NNW to NNE-trending anticlinal complexes (**Figure 22**). The most prominent is the Dalhousie-McDills Ridge separating the Pedirka Basin into a western and eastern portion. This originated during the Permian and was reactivated during the Paleogene (Alexander and Jensen-Schmidt, 1995). Thin Permo-Carboniferous sediments are preserved across the ridge and link the two depocentres (**Figure 49**). The thickest sediments estimated from seismic interpretation (1525 m in SA) are preserved in the Eringa Trough. Mt Hammersley 1, drilled in 1987 on the eastern flank of the trough, intersected 990m of Permo-Carboniferous strata. Maximum thickness further east on this side is about 550 m near Mokari 1.

The sediments were subsequently uplifted and eroded during two major compressional episodes during the late Early to Late Permian and during the Paleogene.

Exploration history

Petroleum exploration in the Pedirka Basin was initiated in 1959 when Delhi and Santos were granted OELs 20 and 21. The Pedirka area was farmed out to the French Petroleum Company (later Total Exploration). Exploration during the first half of the 1960s included gravity, magnetic and surveys with four wildcat wells.

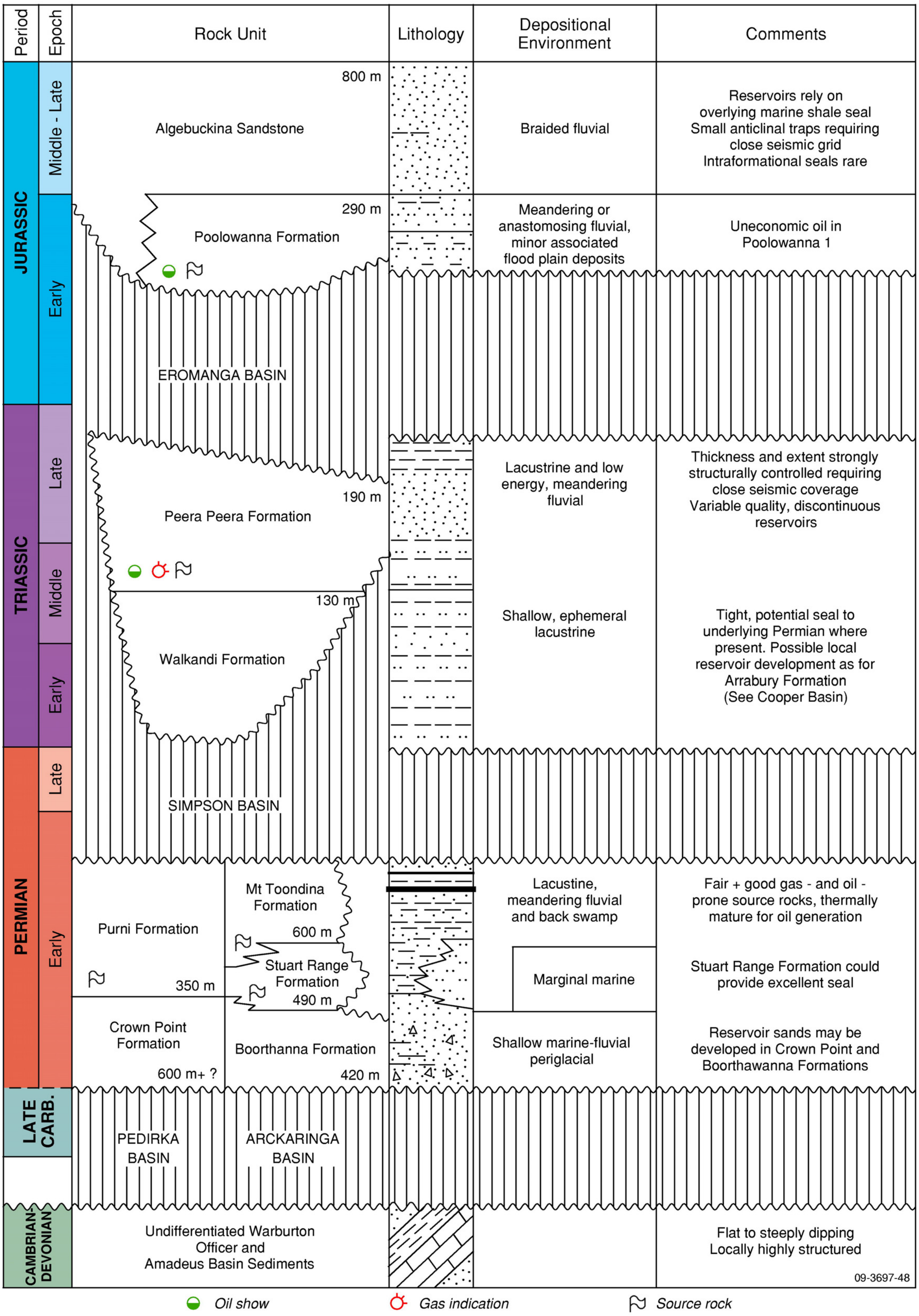


***Figure 48**: Geological summary of the Arckaringa, Pedirka and Simpson Basins (from PIRSA, 2007).*

A second phase of activity occurred from 1969-79, with five seismic surveys conducted and the drilling of one well. In 1977, there was a non-commercial flow of oil from basal Jurassic and Triassic sediments in Poolowanna 1, located in the adjacent Simpson Basin. Exploration intensifies in the 1980s in response to the Poolowanna discovery. Six additional seismic surveys were completed and five wells drilled, three in 1985 and two in 1988.

Seismic interpretation by Santos indicated that five of the previous wells were not valid structural tests as they lay outside closure at all objective horizons. Of the 1985 wells, Oolarinna 1 had no independent fault closure and Glen Joyce 1 had little closure. Dry hole analysis of previous exploration wells in this basin is offered by Carne and Alexander (1997) for the South Australian sector, and Questa (1990) for the NT

Stratigraphy

The Permo-Carboniferous formations are present in the subsurface and crop out on the basin margin in the Northern Territory. The lowermost unit (Crown Point Formation) consists of fluvioglacial and glaciolacustrine sediments. The overlying Purni Formation was deposited in a floodplain environment containing meandering river systems and extensive swamps where coal accumulated.

Three suites of facies are distinguishable on the basis of relative proportions of sandstone, shale and coal. Equivalents of the Stuart Range and Mt Toondina formations of the Arckaringa Basin are interpreted in Mt Hammersley 1.

Source rocks

The Purni Formation contains extensive coal-rich organic shale which appears to be both oil and gas-prone. It contains up to 4% dispersed organic matter, with vitrinite and exinite macerals present in moderate abundance. New data from Dalmatia 1 and Mt Hammersley 1 indicate poor to good source potential for oil in the Purni Formation, with hydrogen index values ranging from 113 to 359. Crown Point shale is lean in organic content, averaging ~0.2% TOC. However, there is potential for richer source rocks if lacustrine facies are developed in deeper parts of the thick Eringa Trough section.

Maturity

In many areas of South Australia, geothermal gradients are too low for the sediments to have generated significant quantities of hydrocarbons. On the McDills-Mayhew Ridge, maturity in Dalmatia 1 and Hammersley 1 range from 0.43 to 0.45% R_o, insufficient for oil generation (Staples *et al*, 1995). However, thermal maturity appears to increase from west to east with R_o approaching 0.9% maximum, equivalent or exceeding peak oil generation.

Oil cuts were observed on organic petrological samples of coal from Oolarinna 1, Mokari 1 and Colson 1, and consequently hydrocarbon yields from the Purni Formation are rated as excellent in Oolarinna 1, very good in Joyce 1, and fair elsewhere (Faridi, 1986).

Reservoirs and seals

Sandstones of excellent reservoir quality are locally developed in both the Crown Point and Purni formations. Channel belt and point bar sands of the middle member, Purni Formation, have porosities from 6-12% and fair to good permeability.

Reservoir quality in the Crown Point Formation is best in the west with porosities up to 20-25% and permeabilities ranging from 91-2000 mD. Seismic data indicate a deepening and thickening of this reservoir facies well into the Eringa Trough. Reservoir quality deteriorates to the east; the best sand is found on structural highs in the glacial outwash deposits which commonly occur at the top of the formation.

.

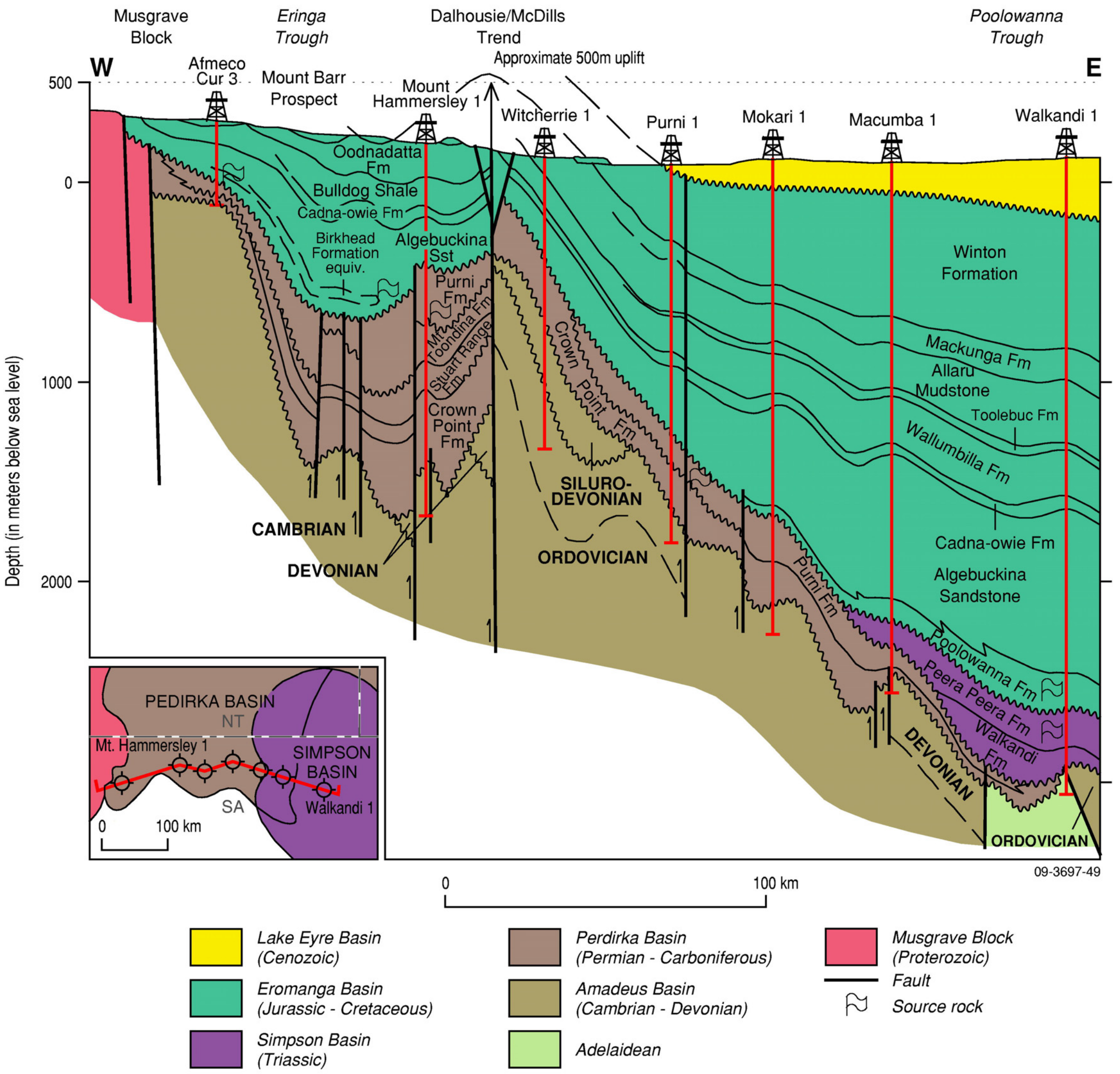


Figure 49: *Schematic section across the Eromanga, Pedirka and Simpson Basins (from PIRSA, 2007).*

Intraformational seals occur in both formations, and Triassic and Jurassic rocks provide a regional seal over the eastern part of the basin.

Traps

Early to mid Paleogene compressive deformation reactivated older structures and formed anticlines and faulted anticlinal traps. Large closures occur at the Intra-Permian and ‘C’ seismic horizons at Mayhew, Eringa and Dalton. Other potential plays are onlap, and pinchout traps within the Crown Point and Purni Formations, unconformity traps at the Early Permian-Triassic unconformity and possibly the basal Eromanga unconformity, and in facies pinchout traps within the Purni Formation or basal Algebuckina Sandstone if the Birkhead facies equivalent is developed (Alexander and Jensen-Schmidt, 1995).

Undiscovered resources

No estimates

Current Projects

The whole Pedirka Basin is either under exploration licence, or under application. Central Petroleum hold predominantly in SA and NT.

Exploration access

In South Australia, the Witjira National Park overlies the western Pedirka Basin where exploration is permitted.

Key References

Alexander and Jensen-Schmidt (1995)
Alexander *et al.* (1996)
Ambrose (2002)
Carne and Alexander (1997)
Cotton *et al.* (1996)
Guiliano (1988)
Questa (1990)
Youngs (1976)

10.5 GALILEE BASIN (LOVELLE DEPRESSION)

Summary

Age	Late Carboniferous, Permian Triassic
Area	approx. 60,000 km^2
Depth to target zones	2000m
Thickness	up to 700 m
Hydrocarbon shows	Oil show in Aramac Coal Measures, Ayrshire 1
First Commercial discovery	none
Identified reserves	nil
Undiscovered resources (50% prob.)	not determined
Production	nil
Basin type	Intracratonic
Depositional setting	Non-marine
Reservoirs	Triassic sandstones and Eromanga aquifers
Regional structure	drape structures over prominent NE and NNE faults
Seals	Intraformational shales within Triassic sandstones, otherwise, Eromanga Basin seals
Source rocks	TOC >1.5% in Aramac Coal Measures in the centre of the Depression. and Betts Creek Beds TOC 0.7-2.9%
Depth to oil/gas window	~1200 m (oil)
Number of wells	12
Seismic	20,626 km 2D seismic

Structural setting

The Galilee Basin is a large, relatively shallow intracratonic basin that commenced subsidence and deposition in the Late Carboniferous, and continued into the Permian and Triassic. In the Lovelle Depression (**Figure 51**), over 700m of Permian and Triassic sediments accumulated over Precambrian and probable early Paleozoic metamorphic and granitic rocks, over and along the junction of the Mt Isa Inlier and Maneroo Platform. It is unconformably overlain by the Jurassic-Cretaceous Eromanga Basin.

The area adjacent to the Cork fault and Wetherby Structure in the southwest-northeast trending Lovelle Depression is indicated by to be one of two most favourable areas in the Galilee Basin that are prospective for hydrocarbons on the basis of adequate source rock extent and TOC, maturation characteristics, reservoirs and trap mechanisms (Hawkins and Green,1993).

Reactivation of basement faults and downwarping led to the formation of the Lovelle Depression as well as the Koburra Trough (Jackson *et al.,* 1981). Convective down welling and regional downwarp was proposed for the formation of the entire basin by Middleton and Hunt (1989). Prominent north-northeast and northeast trending faults and related structures include the Cork Fault, Holberton Structure, Wetherby Structure, Elderslie Ridge (Jackson, *op cit*).

The western extent of the Lovelle Depression is currently unconstrained because of lack of seismic coverage. On the basis of comparable stratigraphy (**Figure 14**), it is possible in a regional context that the Lovelle Depression may have extended southwestwards into the Simpson Desert Basin under the Poolowanna Trough, prior to Triassic uplift and erosion. Furthermore, erosional remnants of hydrocarbon-mature Galilee source rocks may be preserved as downthrown asymmetric wedges adjoining both the north-northwest aligned faults associated with the Arunta Block movements through the late Triassic to Recent, as well as against the southern margin of the basement Mt Isa Block. Forward modeling of aeromagnetic data reinforces earlier evidence for thinner Paleozoic sequences on basement, but smaller locally deeper basement may indicate that remnants of a previously regional Perm Carboniferous distribution may be preserved.

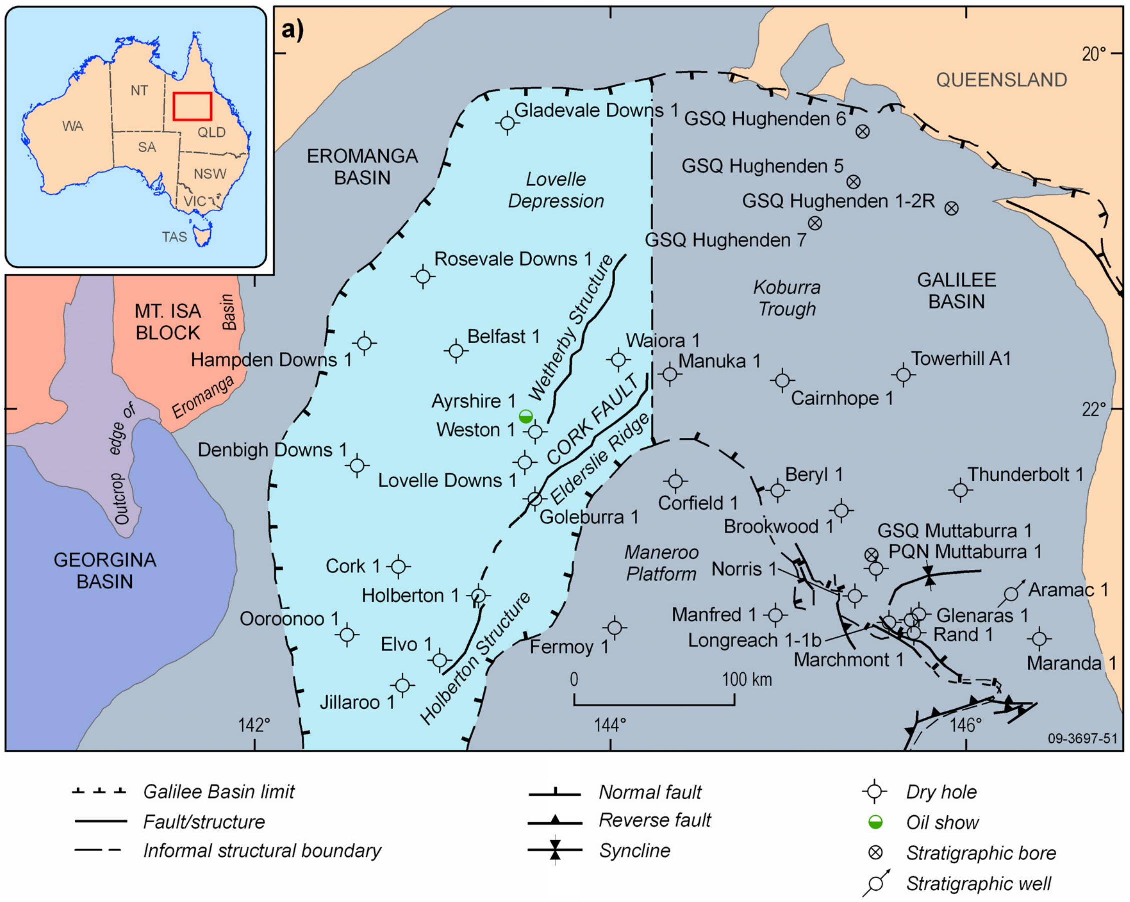


***Figure 51**: Location of the Lovelle Depression, Galilee Basin, with structure and exploration wells (after Hawkins & Green, 1993).*

Exploration history

Exploration in the northern Galilee Basin was in two phases, 1959-74 and 1980-88, with drilling peaking in 1964 (6 wells) and 1988 (6 wells). The termination of the first phase of exploration was largely due to the withdrawal of income tax concessions for explorers, and the termination of the Federal petroleum search subsidy scheme in 1974. The second phase of activity was dominated by the regional exploration program of Esso Australia Ltd in the northern Galilee Basin with a philosophy to understanding the regional tectonic and structural framework. In addition to Esso, Crusader Ltd and Minora Resources NL were also active in the Lovelle Depression. Despite all this renewed exploration activity, no economic hydrocarbons were discovered. Towards the end of each of these phases of exploration activity, the Queensland Geological Survey maintained deep stratigraphic drilling to resolve stratigraphic relationships within the basin sequence.

Tectonics, Sedimentation and Stratigraphy

Formation of the Galilee Basin commenced in the Late Carboniferous, confined to the Koburra Trough in the east. By the early Permian, sedimentation was continuous across the northern end of the Maneroo Platform and into the Lovelle Depression. Following an erosional event at the end of the Early Permian, sedimentation continued until the Middle Triassic. The stratigraphic successions in the Lovelle Depression and the Koburra Trough are summarised in **Figure 53**.

In the Early Permian, development and preservation of peat swamp deposits created the Aramac Coal Measures. During extensional tectonism, the reactivation of high angle, westerly dipping basement faults accommodated substantial thicknesses of the coal measures along the western side

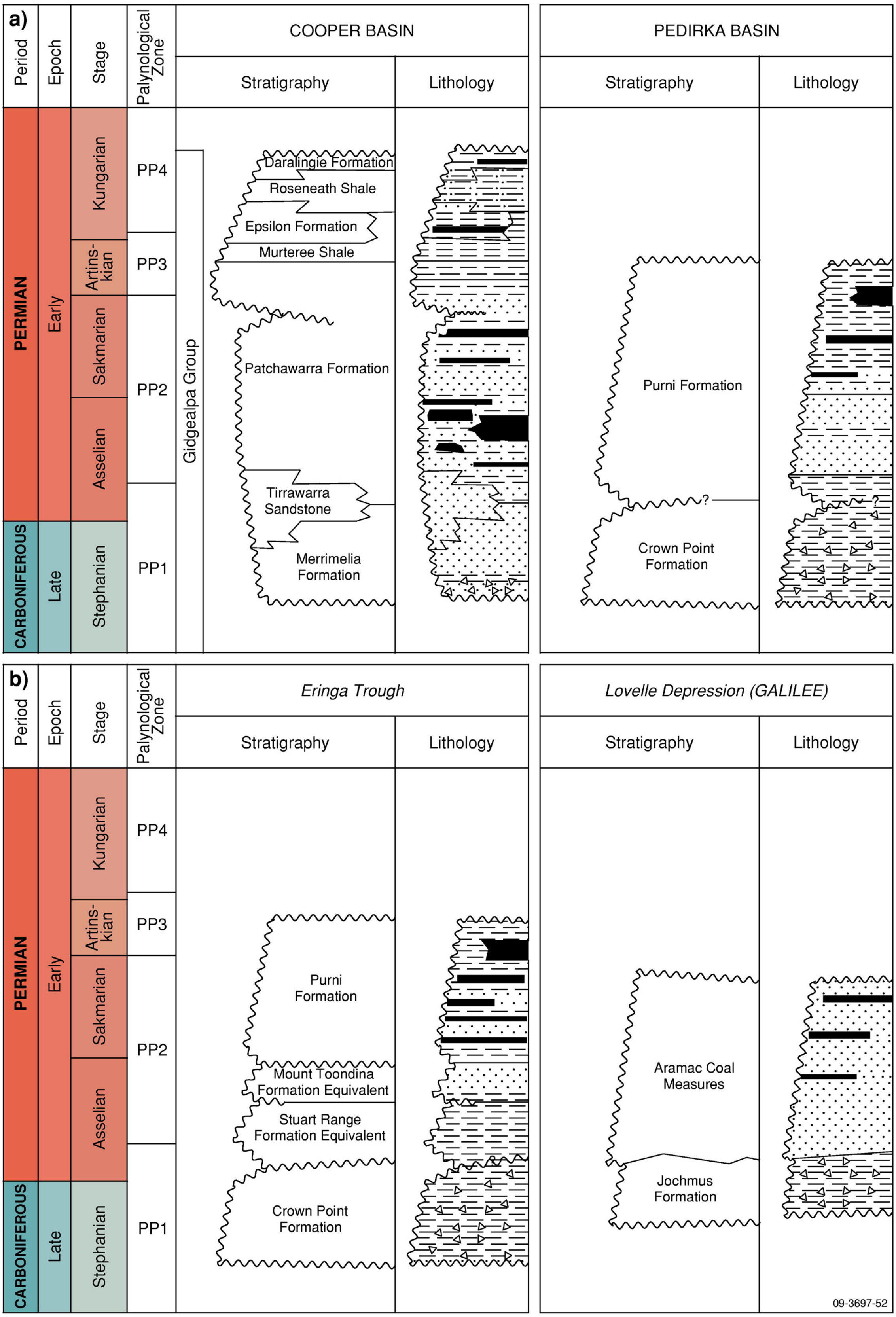


***Figure 52**: Early Permian correlations between Cooper, Pedirka and Galilee Basins (after Alexander & Jensen-Schmidt, Hawkins & Green, 1993, Evans, 1980).*

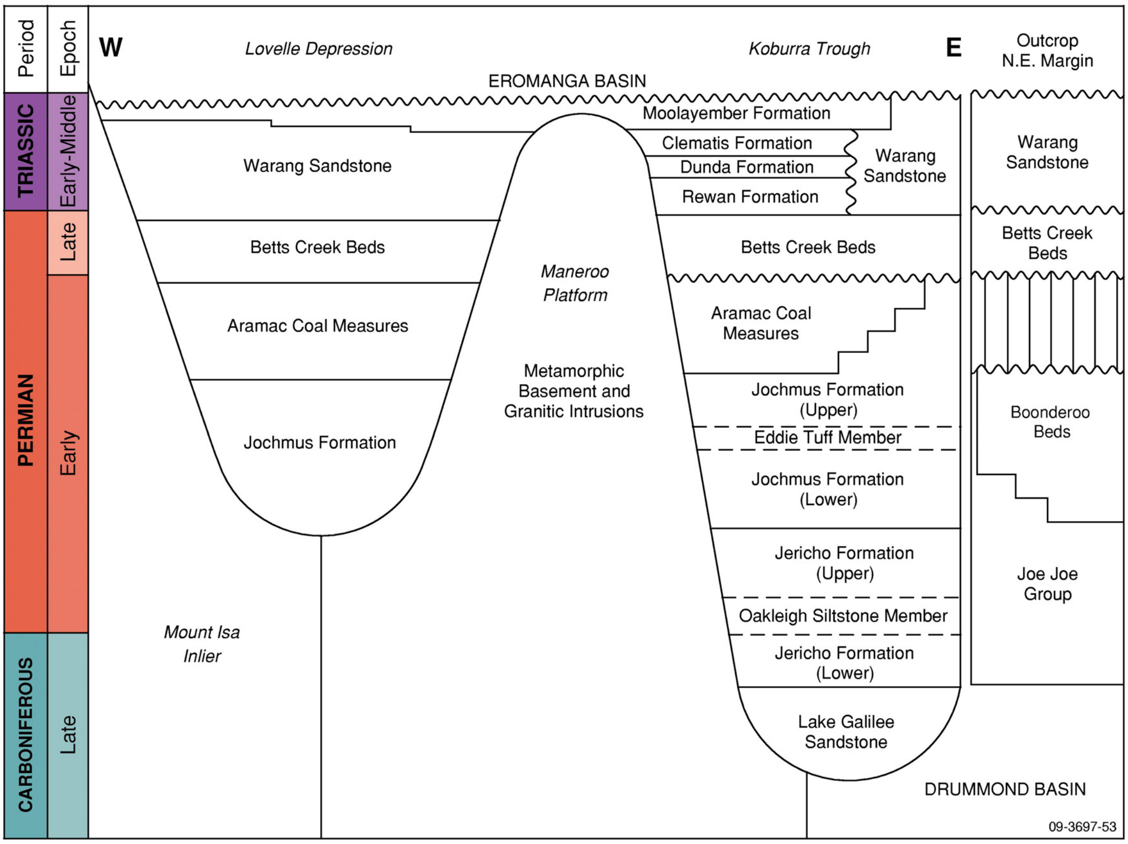


Figure 53*: Stratigraphic relationships of units in the northern Galilee Basin (from Hawkins & Green, 1993).*

of these faults. At the end of the Early Permian, east-west compression created reversal on normal faults, uplift and erosion. Tectonic stability ensued during the Late Permian and widespread coal swamps covered the basin (Betts Creek Beds) also containing fluvial sands. Coals appear to be poorly developed or absent in the southern extent of the depression. From the Early Triassic through to the Middle Triassic, southerly-flowing rivers from the northern part of the basin deposited quartz-rich sandstones of the Warang Sandstone, a basin margin facies. In the Late Triassic, east-west compression induced uplift, folding and erosion.

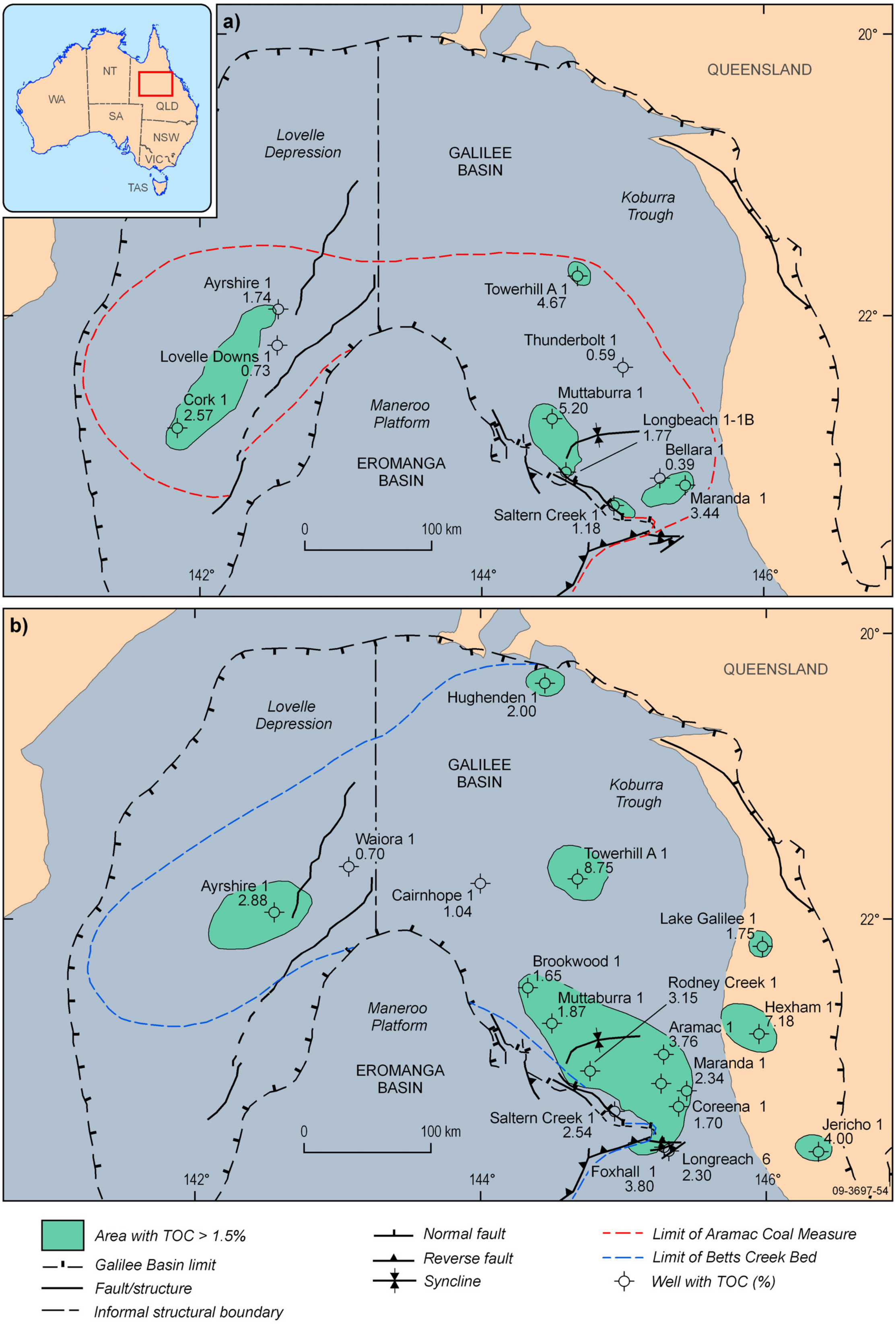
Source rocks

Two formations in the Lovelle Depression are the main identified source rock sequences – the Early Permian Aramac Coal Measures and the overlying Late Permian Betts Creek Beds **(Figure 54)**.

Aramac Coal Measures are lean to excellent, with average TOC content exceeding 1.5 mass% in the central part of the Depression. Hydrocarbon potential yield (PY) is moderate to good; however hydrogen indices are predominantly low, and indicate a gas-prone source.

The Betts Creek Beds have a source-rich area centrally in the Lovelle Depression, near the southern extension of the Wetherby Structure. Averaged TOC of the unit range from 0.7 to 2.9 mass %. PY of this sequence in the Lovelle Depression is marginal to excellent (1.6-36.3). The very high PY value (36.3) in EAL Ayrshire 1 is related to the high TOC of 11.6 mass% in a carbonaceous siltstone.

Figure 54 (next page): *Total organic carbon (TOC) of source rocks, Lovelle Depression (from Hawkins & Green, 1993).a). TOC content of fine grained rocks, Aramac Coal Measures .b). TOC content of fine grained rocks, Betts Creek beds.*



a)
WA
NT
SA
QLD
NSW
VIC
TAS
QUEENSLAND
Lovelle Depression
GALILEE BASIN
Koburra Trough
Ayrshire 1
1.74
Lovelle Downs 1
0.73
Cork 1
2.57
Towerhill A 1
4.67
Thunderbolt 1
0.59
Muttaburra 1
5.20
Longbeach 1-1B
1.77
Bellara 1
0.39
Maranda 1
3.44
Saltern Creek 1
1.18
Maneroo Platform
EROMANGA BASIN
0
100 km
142°
144°
146°
20°
22°
b)
QUEENSLAND
Hughenden 1
2.00
Lovelle Depression
GALILEE BASIN
Koburra Trough
Waiora 1
0.70
Towerhill A 1
8.75
Ayrshire 1
2.88
Cairnhope 1
1.04
Lake Galilee 1
1.75
Brookwood 1
1.65
Rodney Creek 1
3.15
Muttaburra 1
1.87
Hexham 1
7.18
Aramac 1
3.76
Maranda 1
2.34
Coreena 1
1.70
Saltern Creek 1
2.54
Jericho 1
4.00
Longreach 6
2.30
Foxhall 1
3.80
Maneroo Platform
EROMANGA BASIN
0
100 km
142°
144°
146°
20°
22°
09-3697-54
Area with TOC > 1.5%
Galilee Basin limit
Fault/structure
Informal structural boundary
Normal fault
Reverse fault
Syncline
Limit of Aramac Coal Measure
Limit of Betts Creek Bed
Well with TOC (%)

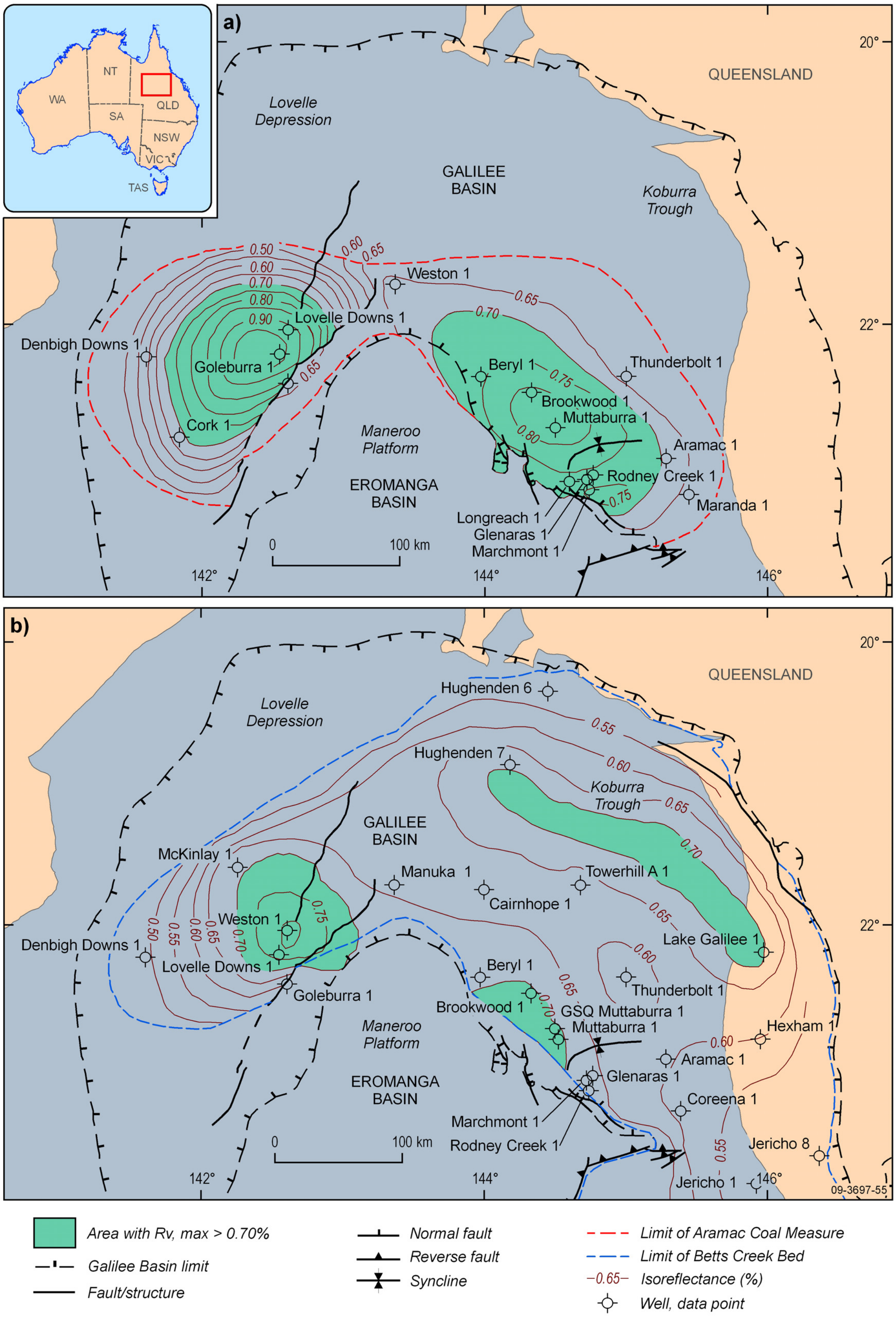
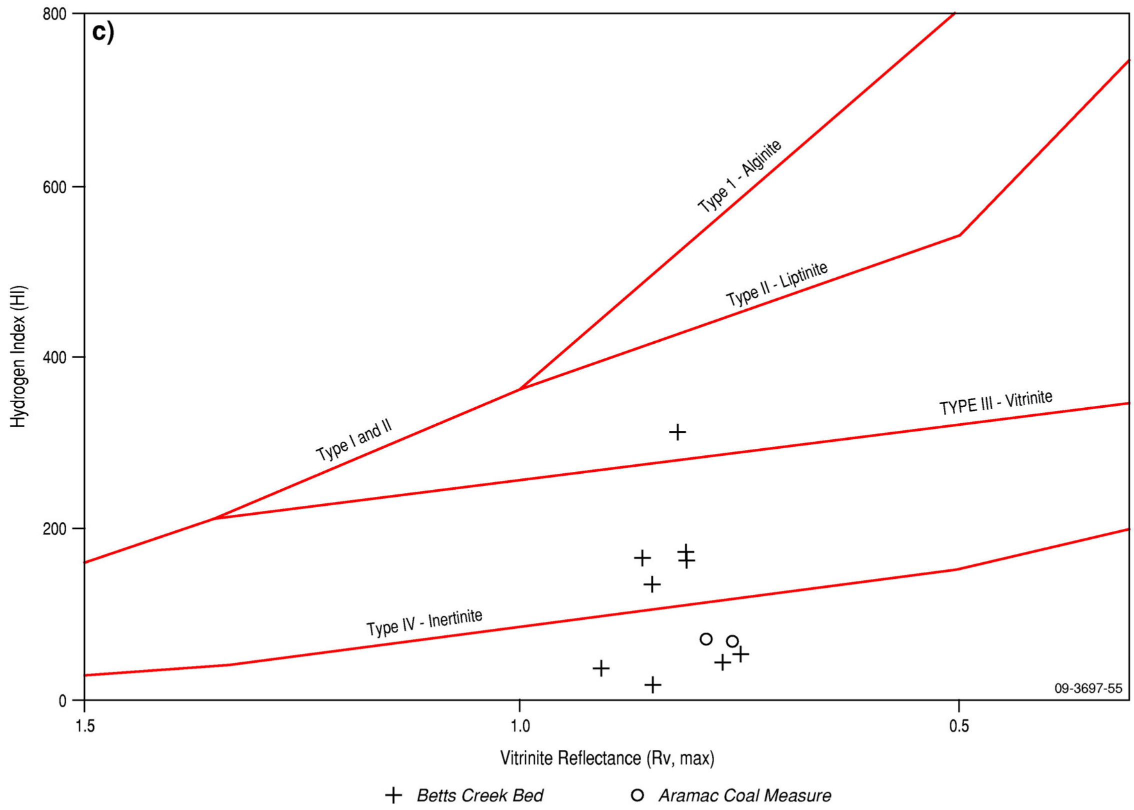


Figure 55(above) a). *Vitrinite reflectance ($R_{v\ max}$) and hydrogen index values in the Lovelle Depression (from Hawkins & Green, 1993) b).. Vitrinite reflectance ($R_{v\ max}$) contour map, top of the Aramac Coal Measures.* ***(below)*** *.c).Vitrinite reflectance ($R_{v\ max}$) contour map, top of the Betts Creek beds.*



Maturity

Early Permian Aramac Coal Measures have high thermal maturity (T_{max} 442-467^{o}C) and Late Permian Betts Creek Beds have reached early maturity for oil generation ($R_{v\ max}$ 0.5-0.7%) (**Figure 55**). The high temperatures in the Galilee Basin were locally variable but high in the Lovelle Depression, and peaked during the Late Triassic maximum burial, prior to uplift. Higher–than-present temperatures are evident in both Galilee and Eromanga sediments, probably in the Late Cretaceous and Early Paleogene but appear to have subsequently declined with uplift. Thus Paleogene formed traps are not expected to have been charged. However, a recent heating event is inferred, restricted to the western Lovelle Depression, but is unlikely to have generated significant quantities of hydrocarbons (Hawkins *op cit*.). The early Paleogene heating event is by far the most widespread and would have resulted in relative high levels of maturity where the Late Triassic thermal event was not as intense.

Unaffected by these events, the overlying Eromanga sequence has a significantly different thermal history. The Mesozoic sequence is almost entirely immature. Sediments deeper than 1050 m in Connemarra 1 had R_v >0.5%, but further west at Machattie 1, $R_{v\ max}$ of Hutton at 1074 m of 0.44% over undated but possible Georgina/Warburton sequence of steeply-dipping chloritic sediments at below 1120 m.

Hydrocarbon indications and shows

The few recorded fluorescence and oil indications in the Aramac Coal Measures occur in mudrocks of the lower part of the unit in the Lovelle Depression. The greater number of indications occurs in the Betts Creek Beds. In the Lovelle Depression, methane indications occur in coal, and rare fluorescence and oil staining were observed in the sandstones. Most hydrocarbon indications occur in sequences with well-developed coal seams and where $R_{v\ max}$ >0.7%.

The only hydrocarbon show in the Depression was an oil scum on water from a DST in Aramac Coal Measures in EAL Ayrshire 1.

Regionally, migration has not been modeled but is thought to have occurred from the deeper parts of both the Lovelle Depression and Koburra Trough. Vertical migration of hydrocarbons out of the Galilee Basin into the overlying Eromanga sequence is most probable where the Triassic part of the sequence is absent.

Reservoirs and seals

The Triassic sequence is sandstone-dominant, and reservoir quality good, and thus internal seals would be necessary for Triassic-hosted accumulation, otherwise upward migration into the Eromanga sequence could be expected.

Traps

In the Lovelle Depression, there was movement of basement blocks associated with the Wetherby Structure during deposition of both the Aramac Coal Measures and the Betts Creek beds. This increased deformation off the flanks of the structure. The resultant drape structures are ideally situated to accumulate hydrocarbons generated and migrated during the Late Triassic or early Paleogene thermal events.

The western downthrown side of the Cork Fault may have acquired sand fan bodies as stratigraphic plays within both the Aramac Coal Measures and the Betts Creek beds, juxtaposed at their distal ends with direct contact on source rocks. Additionally stratigraphic pinchouts could be expected on the northern depositional margins of the basin (Hawkins and Green, 1993).

Key References

Evans (1980)
Hawkins and Green (1993)
Jackson *et al.* (1981)
Middleton and Hunt (1989)

10.6 SIMPSON BASIN

Summary

Age	Triassic
Area	~100,000 km
Depth to target zones	2000-2600 m
Thickness	up to 300 m
Hydrocarbon shows	Peera Peera Formation, shows in 5 wells (SA)
First Commercial discovery	none
Identified reserves	nil
Undiscovered resources (50% prob.)	not determined
Production	nil
Basin type	Intracratonic
Depositional setting	Non-marine
Reservoirs	Sandstone, meandering fluvial
Regional structure	N-S faulted anticlines in sag basin
Seals	Lacustrine and overbank sediments
Source rocks	Underlying Pedirka Basin siltstone and shale; Peera Peera Formation siltstone and shale
Depth to oil/gas window	1250 m (oil)
Number of wells	6 in SA
Seismic line km	?11000 km, 7220 km of 2D in South Australia

Structural setting

The Simpson (Desert) Basin covers about 100,000 km, with approximately equal areas in Northern Territory and South Australia. It is a circular, poorly defined depression with one major depocentre, the Poolowanna Trough (**Figure 49**). The basin overlies Paleozoic and older basins and is overlain by the Jurassic-Cretaceous Eromanga Basin.

During the Triassic, the western Pedirka Basin remained elevated and was eroded, while the eastern portion subsided to form a depocentre, the Poolowanna Trough. Regional uplift and erosion terminated deposition in the Simpson Basin at the end of the Early to Middle Triassic. The main episode of structuring occurred in the early Paleogene, when E-W compression produced major meridional faults that truncated earlier-formed anticlines

Exploration history

A seismic survey in 1971 revealed an eastward-thickening sediment package between the eastern Pedirka Basin and the overlying Eromanga Basin. The postulated Triassic age for this package was confirmed when Poolowanna 1 recovered oil from this sequence in 1977. Six petroleum wells in SA have penetrated the basin and over 11,000 km of seismic was acquired in the 1970s and 1980s by Delhi-Santos. Licences were relinquished in 1989-1990 and renewed interest has only occurred in the last few years Exploration licences are now held by Central Petroleum, and a number of licence applications are current, covering the whole basin.

Stratigraphy

The Simpson Basin contains ?Early to Middle Triassic Walkandi Formation overlain conformably by Late Triassic Peera Peera Formation (**Figure 56**). The Walkandi Formation is restricted in extent to the Poolowanna Trough depocentre. The Peera Peera Formation has greater extent, extending westward and onlapping the Dalhousie-McDills Ridge, and also extending eastward to onlap the Birdsville Track Ridge.

The Walkandi Formation comprises interbedded shale, siltstone, and minor sandstone redbeds deposited in a shallow ephemeral lacustrine environment. This unit correlates with the Tinchoo Formation of the Cooper Basin to the east over the Birdsville Track Ridge. The Peera Peera Formation consists of grey shale and siltstone at the base with minor thin sandstone and coal, a fining upward sandy middle unit, and a black highly carbonaceous silty shale at the top – reflecting deposition on a floodplain crossed by meandering fluvial streams and lakes. It is correlated with the Cuddapan Formation of the Cooper Basin region.

Source rocks

The oxidized nature of the redbeds in the Walkandi Formation downgrades source potential. However, the overlying Peera Peera Formation is rich in organic matter (TOC up to 5%) in the Poolowanna Trough. Further west in the Eringa Trough the sequence has not been intercepted by drilling. Dispersed organic matter consists mainly of cutinite; however the unit is rich in inertinite (Alexander and Jensen-Schmidt, 1995).

Maturity

The Peera Peera should be oil mature in the Poolowanna Trough. The formation is considered to be gas-prone with potential modest oil yields (Smyth and Saxby, 1981).

Reservoirs and seals

The limited available drilling indicates that sandstone interbeds in the Walkandi Formation are fine grained with low porosity and permeability. The Peera Peera Formation has lateral variability with poor quality reservoirs (maximum measured porosity 7.8%). Reservoir quality is thought to improve updip from the Poolowanna Trough. Seals comprise intraformational siltstone and shale of the Walkandi and Peera Peera Formations.

Traps

Potential traps are dominantly structural – faulted anticlines.

Exploration access

The Simpson Basin in South Australia lies below the Simpson Desert Regional Reserve (where exploration is permitted) and the Simpson Desert Conservation Park (where exploration is currently not permitted).

Key References

Cotton *et al*. (2006)
Moore (1986)
Powis (1989)
Wiltshire (1978)

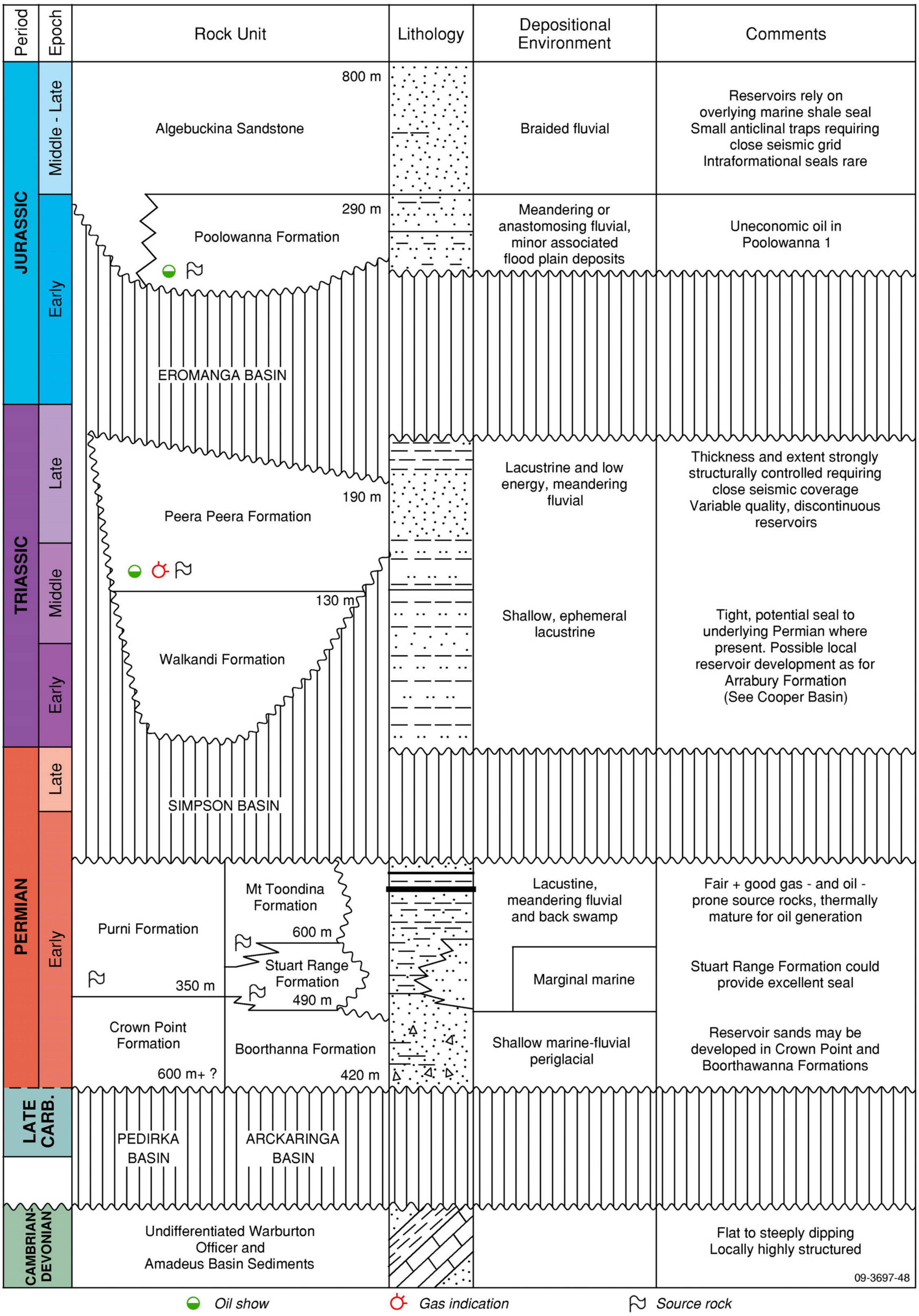


Figure 56*: Stratigraphy of the Simpson Basin, with comparisons to the Arckaringa, Pedirka and Eromanga Basins (from PIRSA, 2007).*

10.7 EROMANGA BASIN

Summary

Age	Early Jurassic – Late Cretaceous
Area	1 000 000 km^2
Depth to target zones	1200-3000 m
Thickness	up to 3000 m
Hydrocarbon shows	Commercial discoveries of oil from almost every unit from the basal Poolowanna Formation up to the base of the Cadna-owie Formation in the Cooper Basin Region; elsewhere, shows in the Poolowanna Formation.
First Commercial discovery	1976 gas in Namur 1; 1978 oil in Strzelecki 3
Identified recoverable reserves	Cooper Basin region predominantly 43.42 million kL oil (85% total reserves) and 2.9 billion m^3 gas (1.4% of total reserves) to 2005 (GA, 2007)
Production	Cooper Basin region predominantly. 35.1 million kL oil (86.5% of total production) and 2.06 billion cm gas (1.3% of total production) to 2005 (GA, 2007).
Basin type	Intracratonic
Depositional setting	Productive non-marine sequence overlain by non-productive marine, marginal marine and non-marine sediments.
Reservoirs	Sandstone: braided and meandering fluvial, shoreface and lacustrine turbidites
Regional structure	Broad and generally low amplitude, four-way dip closed anticlinal trends in the regional sag basin.
Seals	Lacustrine-floodplain shales and basin-wide volcanogenic sandstones
Source rocks	Underlying Cooper Basin coal and siltstone; siltstone and coal in Birkhead and Murta Formations
Depth to oil/gas window	1250 m (oil)
Number of wells	More than 1400 in Cooper Basin region; about 30 elsewhere in SA
Seismic line km	103,265 km 2D; 7,248 km 3D in SA

Structural setting

The Eromanga Basin covers 1,000,000 km^2 of central-eastern Australia: approx. 567,000 km^2 in Queensland, 360,000 km^2 in South Australia, and 73,000 km^2 in NT. It is one of 4 interlinked sub-basins of the Great Artesian Basin which contains a multi-aquifer system. Within the Eromanga Basin are two major depocentres, the central Eromanga Depocentre overlying the Cooper Basin and the Poolowanna Trough.

The uppermost and major aquifer of the Great Artesian Basin is equivalent stratigraphically to the Wyandra Sandstone, Cadna-owie and Murta Formations, Hooray, Namur and Algebuckina Sandstones. The predominant flow path of artesian waters in this major aquifer system is from the recharge zone along the western side of the Great Dividing Range, below the Diamantina Drainage system to, and then along the Birdsville Track Ridge (**Figure 57**). Flow along this shallower groundwater fairway is initially in the order of 1.3 to 2.5 m/year, but slows with cumulative vertical leakage, towards the southwestern efflux region. A smaller flow path is southeastwards from the Eringa Trough region towards the Birdsville Track Ridge. Within the deeper parts of the central Eromanga Depocentre overlying the Cooper Basin, groundwater is virtually static due to structural impedance and relatively low permeability, too old to be dated, and well-evolved in alkalinity signature. Elsewhere groundwater migration tends to be updip out of the depocentres (Radke *et al*., 2000).

The Eromanga Basin overlies Mid to Late Paleozoic and older basins and has two main depocentres, the Central Eromanga depocentre that is almost coincident with the Cooper Basin, and the

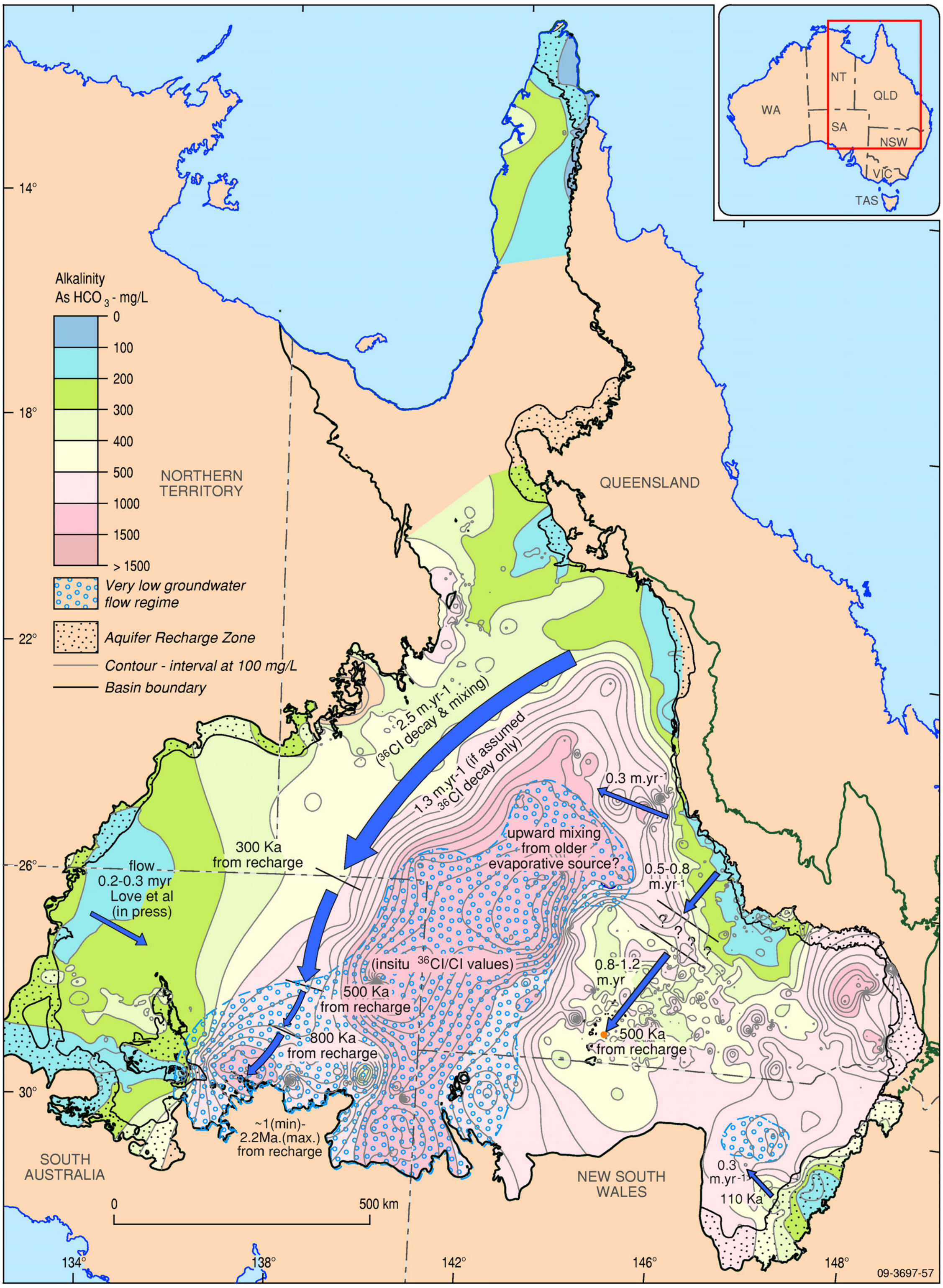


Figure 57*: Regional groundwater flow rates within the main Cadna-owie – Hooray Aquifer and the spatial correlation with alkalinity (from Radke et al., 2000).*

Poolowanna Trough – that contain up to 3000 m of sediments. These depocentres are separated by the Birdsville Track Ridge, a complex of related domes and ridges. The Central Eromanga Depocentre is overlain by the Paleogene to Recent Lake Eyre Basin.

The Poolowanna Trough in the northwest contains a thick sand-dominant sequence, the Algebuckina Sandstone, in comparison to the Central depocentre where intercalated shales and siltstones occur between the main sandstone aquifers/reservoir units. Lateritised units of the basin crop out extensively on the western, northwestern and southern margins.

At least 50% of the Eromanga Basin is underlain by older basins that include the Georgina Basin, Galilee Basin (which in turn is underlain by the Drummond and Adavale Basins), Cooper Basin (underlain in part by the Warrabin Trough), Warburton Basin, and to the western extent, the Simpson Basin, Pedirka Basin, and Amadeus Basin.

Exploration history

Petroleum exploration commenced in the 1950s when licences covering the Cooper and Eromanga basins were first acquired by Santos. Initial exploration involved surface mapping, stratigraphic drilling, aerial surveys, gravity and aeromagnetic surveys and seismic. The first exploration well was drilled in 1959 and Cooper Basin gas was discovered in 1963.

The first commercial natural gas from the Eromanga Basin was from Namur 1 in 1976 (Cooper region). Oil was discovered in 1977 with an uneconomic flow from Poolowanna 1 in the Poolowanna Trough. The first economic oil flow was recorded from Strzelecki 3 (Cooper region) in the following year.

Since 1959, over 1400 wells have penetrated the Eromanga Basin sequence and over 100,000 km of seismic has been acquired. Exploration was concentrated in the Cooper Region. A new phase of oil exploration commenced in 2002 with the release of 27 new licences after the expiry of PELs 5 and 6 in 1999. Most of the new explorers are currently focusing on oil plays. Much but not all of the oil recovered from the Eromanga Basin has a large Permian component. This fact has driven older exploration paradigms to remain centred over the Cooper Basin, or perhaps to extend beyond the Permian limits to seek plays in updip migration from a Permian source. Given the numerous previous well intercepts of oil saturation passed over to reach deeper gas, there are many prospects yet to be tested for stacked reservoirs in the Eromanga sequence overlying the Cooper Basin.

Recent advances in geochemical signatures of hydrocarbons have defined many petroleum systems within these coupled basins. It has now been established the existence of, and hence the potential for many more oil fields to be sourced solely from Eromanga source kitchens where maturation has been reached the oil window. Armed with this affirmation, it is anticipated that successful exploration will gradually extend beyond the Cooper region.

Stratigraphy

The Eromanga Basin comprises three sequences; a lower Jurassic-Cretaceous non-marine, Cretaceous marine and upper non-marine (**Figure 58**). Exploration effort is focused on the productive lower non-marine sequence. The Basin unconformably overlies Proterozoic basement, early Paleozoic Officer, Amadeus, Warburton, Georgina and Adavale basins, Thomson Fold Belt, Permo-Triassic Cooper, Pedirka, Simpson and Galilee Basins. The basal unconformity is regionally defined structurally as a combination of the 'Z' and 'P' seismic horizons. (**Figure 59**).

In the Cooper Basin region, the lower non-marine sequence comprises intertonguing braided fluvial sandstones (Hutton and Namur sandstones), lacustrine shoreface sandstone (McKinley Member) and meandering fluvial, overbank and lacustrine sandstone, siltstone, shale and minor coal (Poolowanna, Birkhead and Murta Formations).

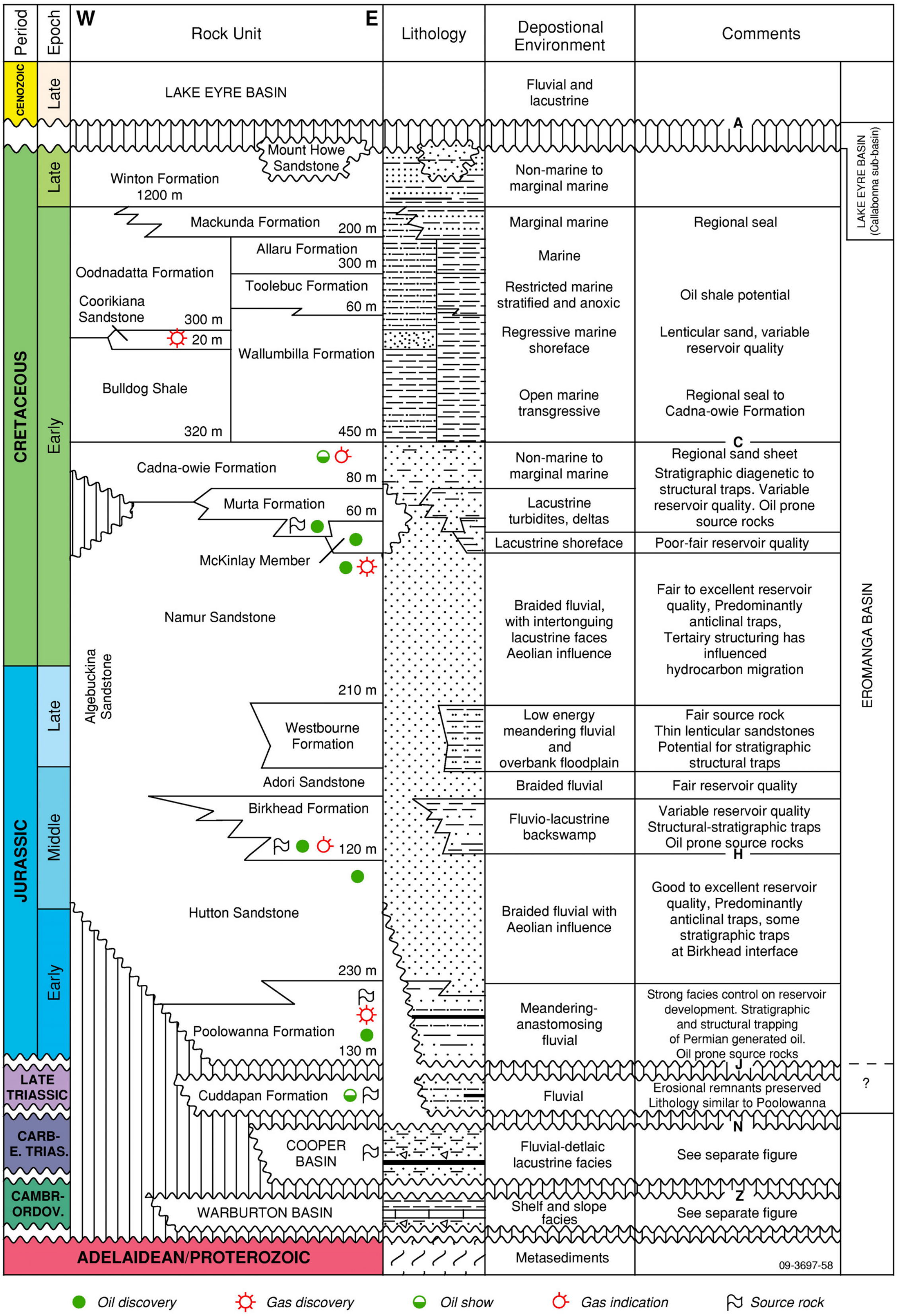


Figure 58: *Geological Summary of the Eromanga Basin (from PIRSA, 2007).*

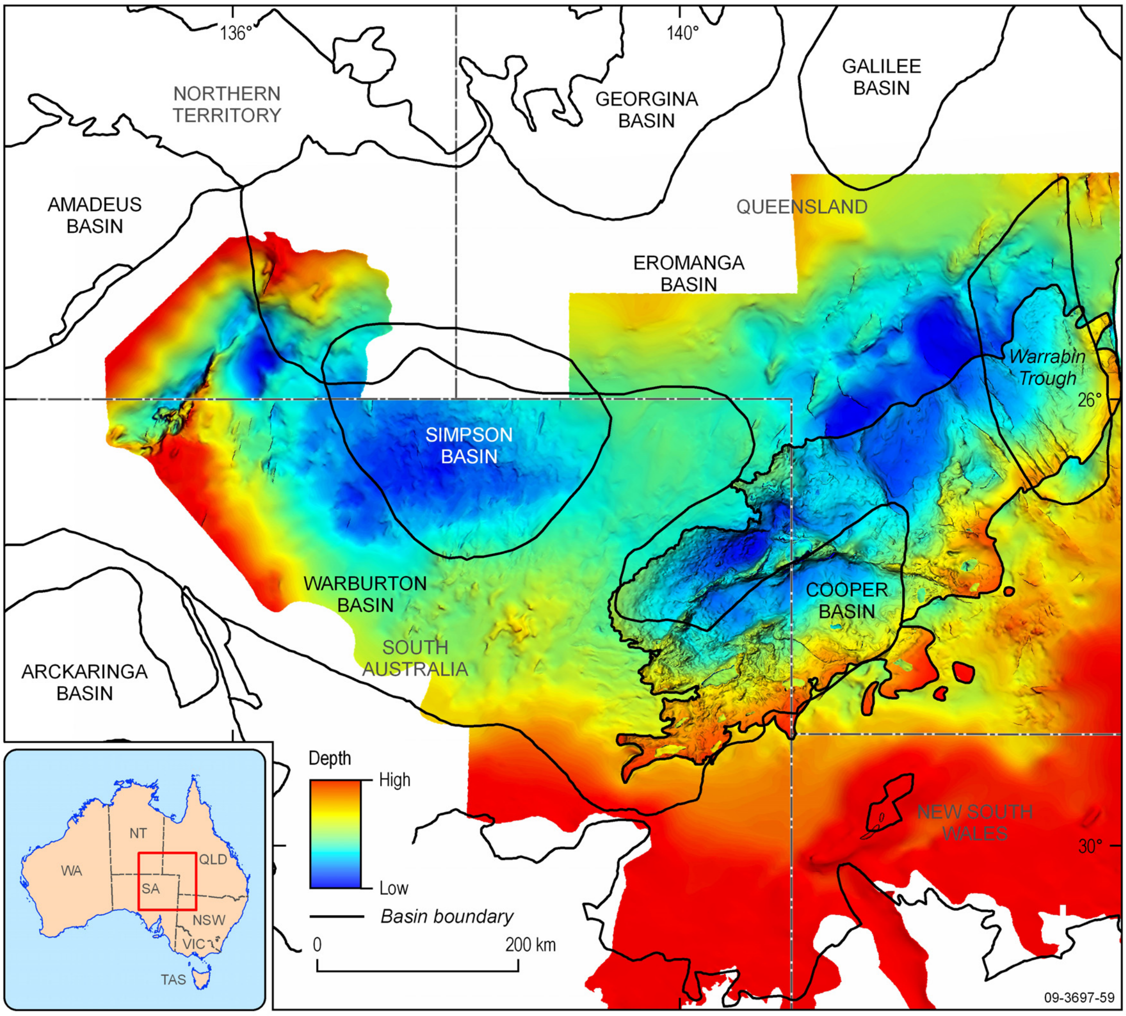


Figure 59*: Base of Eromanga Basin – Depth Structure Map (from NGMA).*

In the Poolowanna Trough, the Poolowanna Formation (up to 130 m thick) is overlain by a thick sand-dominant unit, the Algebuckina Sandstone. West of the northern Birdsville Track Ridge, Birkhead and Murta Formation shales taper out into Algebuckina Sandstone which crops out on the western and southwestern basin margin.

The non-marine sequence is succeeded conformably with a transition through marginal marine to open marine shale and sandstone. The basal unit, Cadna-owie Formation, is of significance for petroleum exploration as its upper surface approximates a distinctive seismic reflector – the 'C' seismic horizon which is mappable over the entire basin (**Figure 60**).

The upper non-marine sequence (Winton Formation) resulted from rapid deposition – up to 1100 m over about 8 million years. A period of erosion in the Late Cretaceous, caused by a switch in drainage from the Cooper region to the Ceduna Depocentre on the rifted southern margin, was followed by deposition of the non-marine Cainozoic Lake Eyre Basin.

Source rocks

Vertical migration of oil from Permian Cooper source rocks has been widely accepted as the principal source of most Eromanga-reservoired oil in the Cooper region. Both Cooper and mature Eromanga source rocks have contributed to oil accumulations in the region. Each oil accumulation, even when in stacked reservoirs within one field, may have a unique or differing charge history from

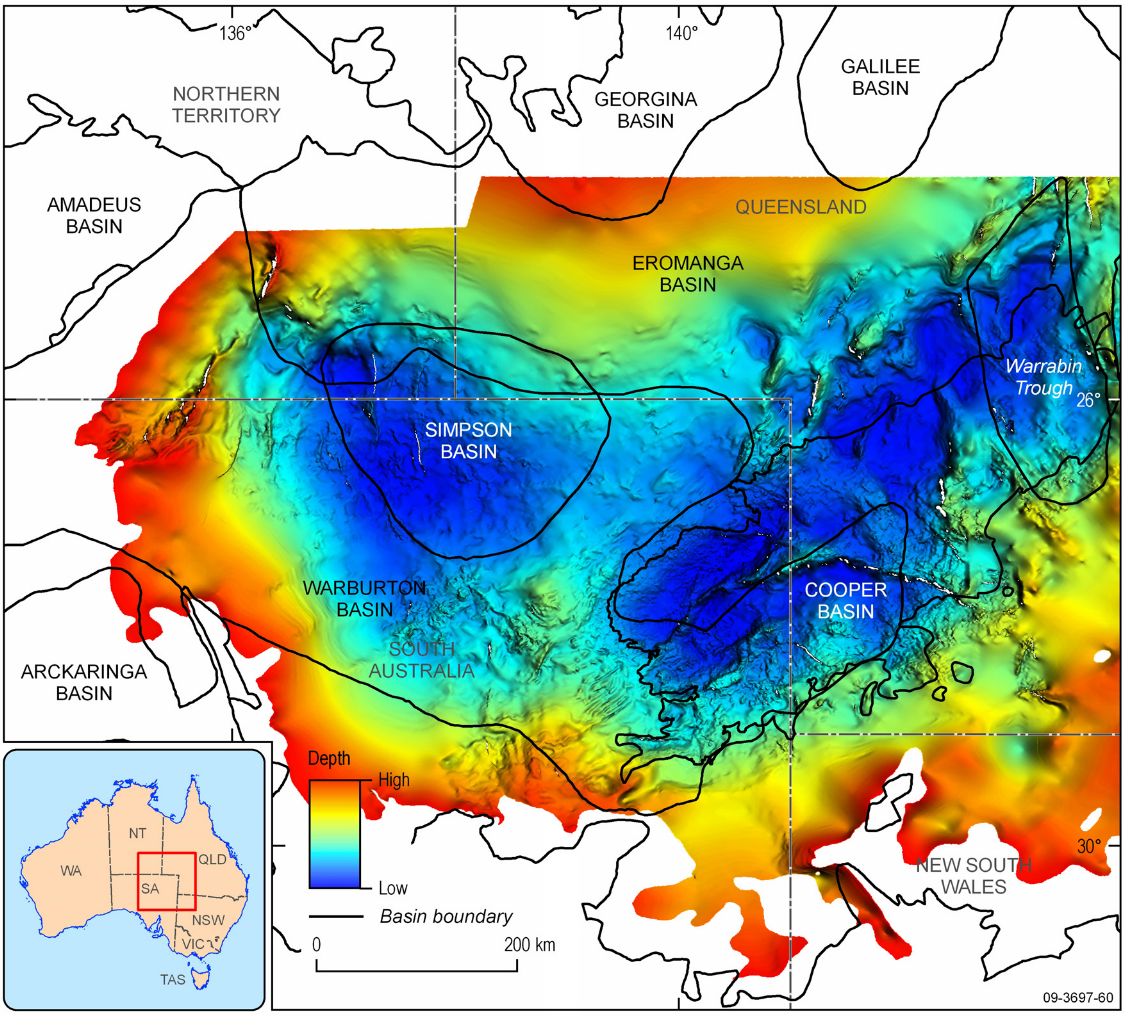


***Figure 60**: 'C' Seismic Horizon Depth Structure Map (from NGMA)*

different source kitchens. The Poolowanna and Birkhead Formations contain organic-rich shales that are oil-prone and in places at peak maturity for oil generation. Lateral migration from these source areas has also been demonstrated geochemically.

Four major coal facies are distinguished within the sequence, of which the 'Walloon Facies' includes the Birkhead and Westbourne Formations and Hutton sandstone. This coal facies is finely layered with exceptionally large amounts of exinite, and little or no inertinite (Cook, 1986) with good to excellent source potential, with hydrogen indices from 312 to 542, indicating Kerogen type II/III. Elsewhere in the basin, the presence of thick Poolowanna, Birkhead and Murta formations is critical to evaluation of source rock potential. The marine and upper non-marine sequences are immature for hydrocarbon generation over much of the basin. Underlying basins such as the Simpson, Pedirka, Adavale, Galilee, Warburton, Amadeus and Georgina Basins are well placed to have charged Eromanga Basin reservoirs.

Maturity

Maturity levels of the Eromanga sequence have been evaluated throughout most of its extent.

Comparison of vitrinite reflectance values obtained in the Pedirka area, with calculated maturation modeling indices, indicates that geothermal gradients must have been lower in the past than they are today. The observed 'high' present day geothermal gradients are a recent phenomenon representing a late thermal event, as suggested by Pitt (1986) for the Cooper region. Maturation modeling suggests the present temperatures are representative of only the past 10 million years or so (Questa, 1990). In the Poolowanna Trough, maturity estimates for the 'Walloon facies' coals suggest a rank corresponding to 0.41-0.44% R_o, in close agreement with Rock-Eval pyrolysis which fall in the range of 0.4-0.45% (Staples *et al*., 1995) **(Figure 27)**. Oil generation from resinite can commence as low as 0.4-0.45% R_o although the main phase of generation is from 0.5-0.8% (Cook, 1986). However the abundance of resinite and suberinite in the organic matter of this facies suggests an ability to generate liquid hydrocarbons at relatively low rank (Cook, 1986), and migration of oil-related compounds out of coal is an efficient process (Cook and Stuckmeyer, 1986). Resinite and fluorinate-rich coals such as the Birkhead equivalent coals can generate light napthenic oil at low maturity levels (Staples *et al*., 1995). Boult *et al.* (1998) have identified a second oil charge into the Gidgealpa South Dome which has this low-maturity source.

Historically, oil exploration has concentrated in the Eromanga Basin where it overlies the Cooper Basin, as the origin of the oil is widely regarded as the result of vertical migration from Permian source rocks (Heath *et al.,* 1989). However long-distance lateral migration towards the basin margin has also been proposed (McKirdy and Willinck, 1988) and units within the Eromanga sequence have oil source potential (Smyth *et al.,* 1984, Michaelsen and McKirdy, 1989). Oil in the Inland field (Inland 1, and 2) in Queensland is approximately 60 km from the edge of the Cooper Basin and suggests either lateral migration from the Cooper Basin, or generation from Eromanga source rocks. Recent discoveries of Growler, Wirraway, Christies oilfields outside the western limit of the Cooper Basin confirm oils sourced from both Cooper and Eromanga Basins.

Reservoirs

Principal reservoirs in the Cooper region are the braided fluvial Hutton and Namur sandstones (porosities up to 25%, permeability up to 2500 mD). Oil is also reservoired in meandering fluvial (Poolowanna and Birkhead Formations), lacustrine shoreface (McKinley Member) and lacustrine turbidite (Murta Formation) sandstones. A schematic section showing typical petroleum traps of the Eromanga Basin is shown in **Figure 46.** Reservoir properties can also be generally be gauged from groundwater flow rates in the immediate region.

In the Poolowanna Trough, principal reservoirs occur in the Poolowanna Formation (variable reservoir quality) and Algebuckina Sandstone (good-excellent reservoir quality). Elsewhere, the Algebuckina Sandstone has excellent reservoir properties (av.23% in Hammersley 1) and is a component of the main artesian aquifer. McDills 1 and Purni 1 were completed as water bores with flow rates of up to 191 kl/day (1200 bbl/day). Other bores in the Dalhousie area flow water at 500-1000kl/day (Krieg, 1985).

Structure and traps

In the Cooper region, the structural framework of the Eromanga Basin is largely inherited from mild but widespread compression, regional tilt and erosion in the Late Triassic which produced the Nappamerri unconformity surface ('N' seismic horizon). Regional downwarping commenced in the Early Jurassic. Paleogene west-east compression reactivated many Paleozoic structures.

In the Cooper region, where the Nappamerri Group regional seal is thin or absent, multiple oil and gas pools are stacked in coaxial Permian-Mesozoic structures (in some cases from the Patchawarra to Murta Formation reservoirs).

Traps sought within the Eromanga basin are dominantly structural (anticlines with four-way dip closure or drapes over pre-existing highs) with a stratigraphic component (eg Hutton-Birkhead transition, Poolowanna, McKinlay Member and Murta Formation. In the South Australian part, structures are rarely filled to spill point with oil – net oil columns are relatively thin compared to height under closure – due to poor sealing characteristics.

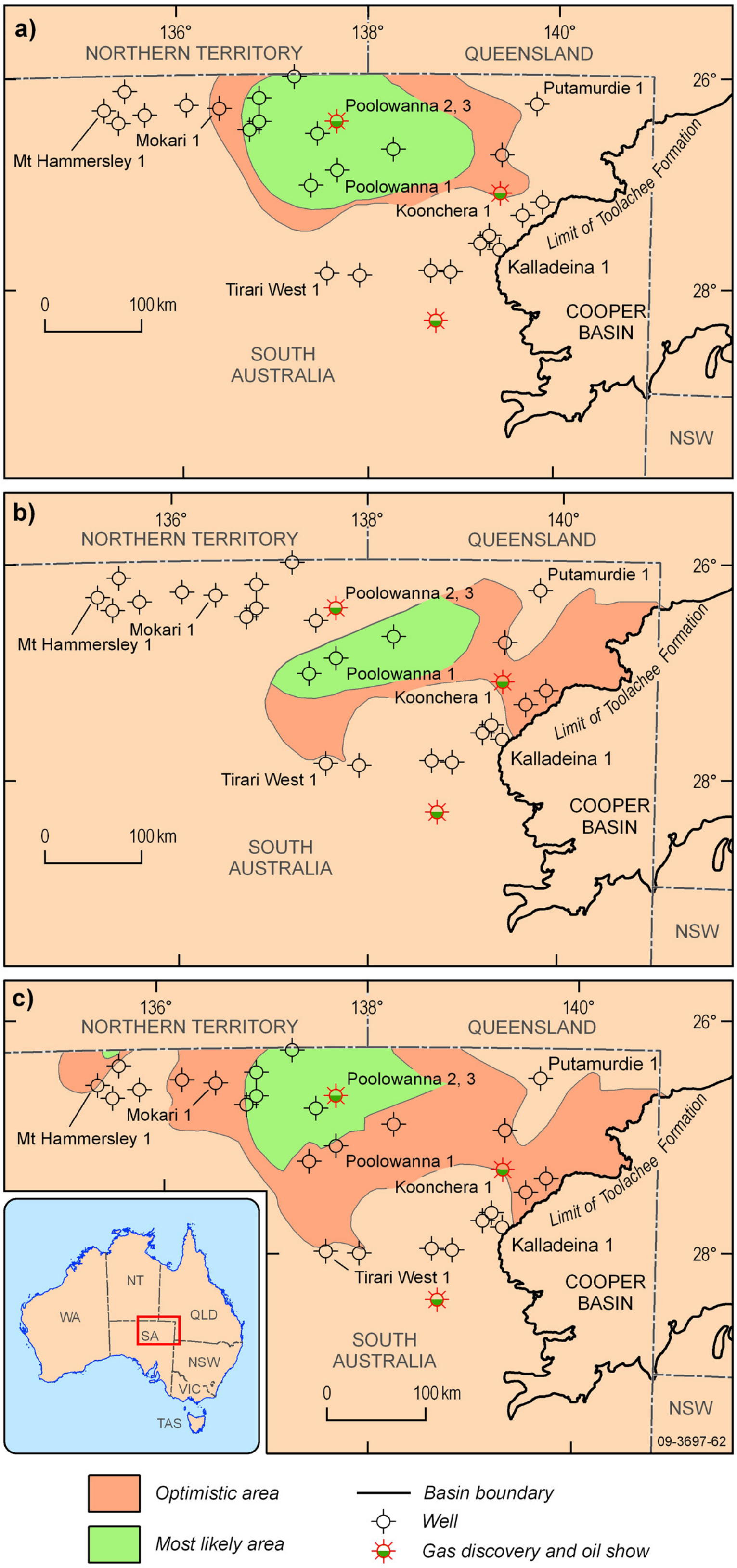


***Figure 61**: Prospectivity of the western Eromanga Basin (from PIRSA, 2007): a). Poolowanna Formation ;b). Hutton Sandstone; c). Namur-Algebuckina Sandstones.*

Seals

Seals comprise intraformational siltstones and shales in the Poolowanna, Birkhead and Murta Formations in the Cooper region. In the Poolowanna Trough seals comprise intraformational siltstone and shale in the Poolowanna Formation and siltstone of the Cadna-owie Formation. Throughout the basin, potential seals include the Cadna-owie marine sequence. Any leakage through this seal means loss of hydrocarbons to the system. Sands in the Birkhead and Poolowanna (Cycle 2) Formations have a volcanogenic component; diagenetic seals have developed through carbonate cement occlusion where earlier vertical permeability had existed.

Undiscovered resources

The Eromanga Basin is clearly oil-prone, but gas accumulations are only known from the Cooper region where they presumably accumulated from Permo-Carboniferous sources. In the western Eromanga Basin, gas discoveries are possible where older infrabasins underlie (Pedirka, Simpson, Warburton), but given the known smaller structures within this basin sequence, it is unlikely they would be economic.

Petroleum exploration has traditionally been focused on the region underlain by the Cooper Basin, a relatively mature area from both burial depth and geothermal events. Areas to the west have had minimal exploration effort, with only one sub-economic discovery to date (Poolowanna 1). Dry hole analysis of unsuccessful wells in the Poolowanna Trough are offered by Carne and Alexander (1997) for SA, and Questa (1990) for the NT. Oil found here will probably be sourced from the Poolowanna and Birkhead Formations, or the underlying Pedirka ,Simpson and/or Warburton Formation. Where the four essential components (mature source, reservoir, seal and structure) coexist, a potential prospect exists. **Figure 61** summarises these for prospects in the Poolowanna Formation, Hutton Sandstone and Namur-Algebuckina Sandstones respectively. PIRSA offers an assessment of undiscovered resources of the western Eromanga Basin in South Australia in **Table 4**.

Table 4 Undiscovered recoverable oil resources of the western Eromanga Basin (from PIRSA, 2007)

UNDISCOVERED POTENTIAL 10^6 kL (MMbbl) Probability that the ultimate potential will exceed the stated value:			
PLAY	**90%**	**50%**	**10%**
Poolowanna	0.2 (1.3)	0.6 (3.8)	1.9 (12.0)
Hutton	0.6 (3.6)	2.4 (15.1)	7.6 (47.8)
Namur-Algebuckina	1.0 (6.3)	4.1 (25.8)	13.0 (81.8)
Total	3.5 (22.0)	8.4 (52.8)	18.6 (117.0)

Note: Totals do not add arithmetically as they are Monte Carlo simulations, current 1996.

Current Projects

Results of the TEISA-SPIRT project on conditions and effects of hydrocarbon fluid flow in the subsurface of the Cooper and Eromanga Basins are available in McKirdy *et al*. (2005).

Exploration access

Several National Parks and Wildlife Reserves overlie the Eromanga Basin. Exploration is permitted in the Simpson Desert regional reserve, the Innamincka Regional reserve, the Witjira National Park, Tallaringa Conservation Park and the Lake Eyre National Park. Exploration is not permitted in the Coongie Lakes National Park, the Simpson Desert Conservation Park, or the No-Go Special Management Zone of the Innamincka Regional Reserve.

As discussed in the Cooper Basin section, an historic native title agreement signed in October 2001 has resolved cooperation between native title claimants and petroleum explorers in the Cooper Basin area of South Australia. All agreements are conjunctive, and cover all petroleum licence activities from exploration through to development and production.

Key References

Altmann and Gordon (2004)
Boult *et al*. (1998)
Cotton *et al.* (2006)
Deighton *et al.* (2003)
Gravestock *et al*. (1986)
Kramer *et al*. (2004)
McKirdy *et al*. (2005)
Nakanishi and Lang (2002)
O'Neil (1989)