RESERVOIRS and SEALS

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Chapter 10

EROMANGA BASIN

INTRODUCTION

In South Australia nearly all units from the Poolowanna facies to Murta Formation contain free-flowing oil reservoirs, with the exception of the Adori Sandstone. Multiple stacked oil pools are typical of the Cooper region (Heath *et al.*, 1989). In Queensland, the Cadna-owie Formation (Wyandra Sandstone Member) has produced oil (Newton, 1986), although no economic discoveries have been made in South Australia. The Coorikiana Sandstone also has limited reservoir potential.

The Hutton Sandstone has proved to be the most productive onshore unit within the Jurassic–Cretaceous. Nearly half the total oil produced from the Eromanga Basin in South Australia originates from the Hutton Sandstone sealed by Birkhead Formation (Fig. 10.1).

Eromanga Basin oil and gas fields in the Cooper region are generally located either along the zero edge of Triassic seal units, at the Permian zero edge, or are associated with faults (Fig. 10.2). Although the Hutton and Namur Sandstones are part of the GAB, hydrodynamic effects on oil migration are insignificant (Bowering, 1982; Muller, 1989). It is capillary pressure and buoyancy which control oil migration into these reservoirs (Boult, 1993). The thickness of Hutton and Namur oil columns is controlled by seal efficiency (Boult, 1993; Boult *et al.*, in press) and is typically <20 m (Heath *et al.*, 1989). As a result, no reservoir is filled to spill point.

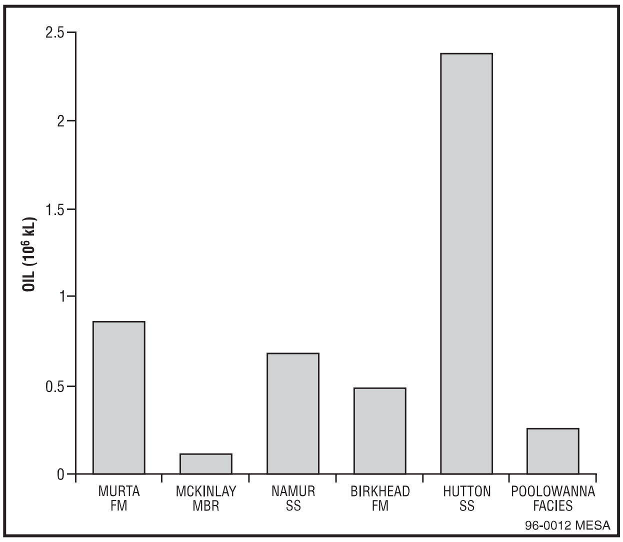

Fig. 10.1 *Oil produced from the Eromanga Basin by formation.*

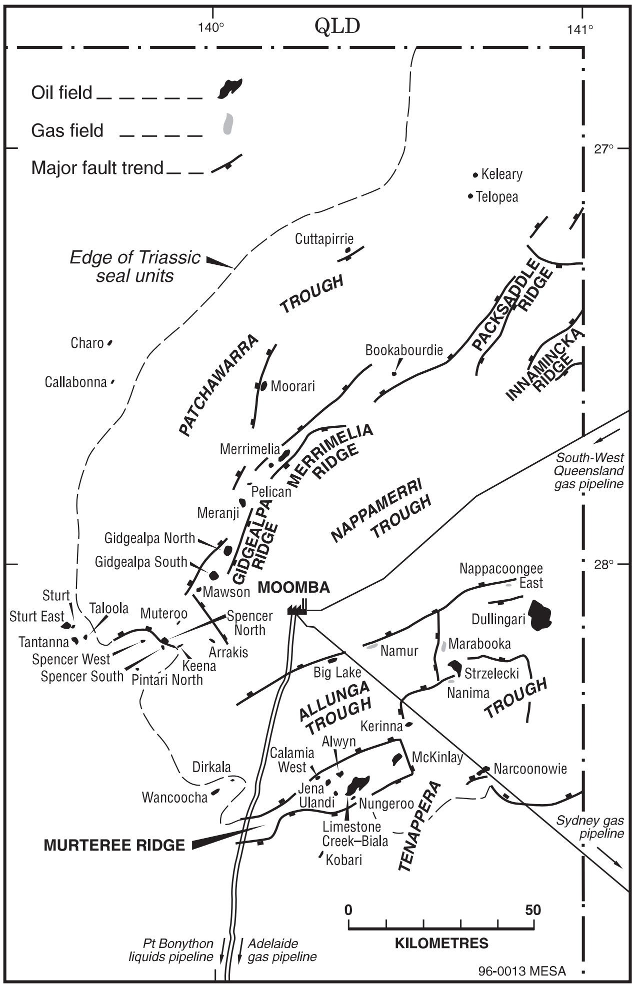

Fig. 10.2 *Eromanga Basin oil and gas fields in the Cooper region.*

PETROPHYSICAL DATA

The petrophysical properties of key Eromanga Basin reservoirs were studied in detail by Gravestock and Alexander (1986, 1988, 1989). A total of 270 m of core was logged and 638 plugs sampled over a range of grain sizes and facies. These were subjected to a variety of routine and special core analyses. Key results of the study, summarised from Gravestock and Alexander, (1988; Table 10.1) are as follows:

- Porosity–permeability trends are controlled by grain size and two trends can be readily identified — the RES trend for good to excellent quality reservoir rocks and the CAP trend for poorer quality reservoir rock and caprocks (Fig. 10.3).

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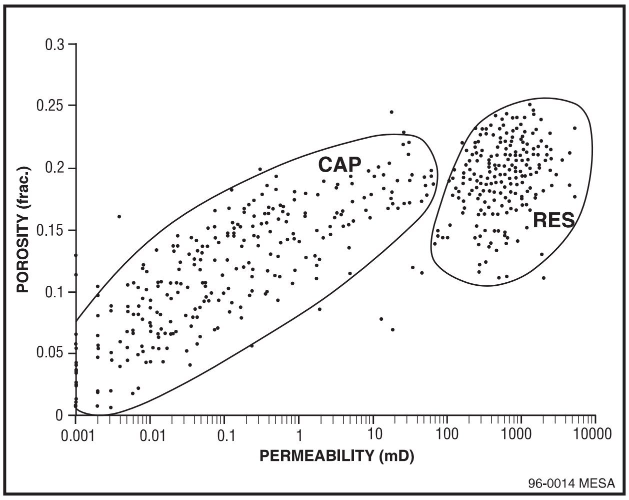

Fig. 10.3 *Eromanga Basin porosity–permeability trend.*

- Density log porosity is the most accurate for all formations where hole conditions are good. Sonic log porosity can be used effectively where hole conditions are poor or a density log is not available. The exception is the thinly bedded Murta Formation, where typical log resolutions are insufficient to distinguish centimetre-scale bed thicknesses.
- Application of a density–neutron method, calibrated with cation exchange capacity, produces accurate shale volumes in Eromanga Basin reservoirs.
- Semi-quantitative x-ray diffraction analyses indicate that kaolinite is the dominant clay mineral (Fig. 10.4) and that clay rarely exceeds 20% by weight of bulk samples — even in siltstone and mudstone (Fig. 10.5).
- Clay conductivity contributes significantly to wireline log response in the low salinity (formation water resistivity ~2–8 ohm-m @ 25°C) and high temperature conditions prevalent in these reservoirs.
- The modified Waxman-Smits equation (calibrated with Eromanga Basin laboratory data) most accurately calculates water saturation in these reservoirs. A reduction in water saturation of 5–15% results from the Waxman-Smits method compared to the commonly used ‘Indonesian equation’.

Table 10.1 *Summary of Eromanga Basin porosity and permeability data.*

	Depth (m)	**AKHC** (mD)	**APHC** (frac.)	**OKHC** (mD)	**OPHC** (frac.)
Murta Formation and McKinlay Member 214 samples					
Average	1447.5	28.20	0.22	21.03	0.13
Maximum	1804.7	999	0.251	661	0.245
Minimum	1199.4	0.007	0.045	0	0.008
Namur Sandstone 128 samples					
Average	1499.3	884	0.20	601	0.19
Maximum	1615.4	10 000	0.28	4300	0.239
Minimum	1242.2	0.011	0.1	0.003	0.085
Birkhead Formation 119 samples					
Average	1667.4	252	0.14	200	0.13
Maximum	2167.4	7620	0.258	4950	0.251
Minimum	1559.8	0.008	0.024	0.001	0.005
Hutton Sandstone 118 samples					
Average	1801.4	1308	0.21	897	0.19
Maximum	1882.3	9780	0.273	5130	0.244
Minimum	1685.4	0.321	0.083	0.02	0.066
Poolowanna facies 133* samples					
Average	2310.7	423	0.13	364*	0.08*
Maximum	2667.5	3674	0.219	1917*	0.15*
Minimum	1806.4	0.001	0	0.002*	0*

APHC: Porosity (ambient pressure).
OPHC: Porosity (reservoir or overburden pressure).
AKHC: Permeability (ambient pressure).
OKHC: Permeability (reservoir or overburden pressure).
*Indicates the 29 samples from Beanbush 1 were measured at overburden pressure.

RESERVOIRS AND SEALS

Poolowanna facies

Seal

Siltstones within the Poolowanna facies are intraformational seals, but the occurrence of stacked oil pools in fields such as Tantanna (Poolowanna, Hutton, McKinlay and Namur pools) and Taloola (Poolowanna, Hutton and Namur pools) indicates they are not wholly effective. Seal effectiveness is reduced by their limited areal extent, thickness and siltstone mineralogy.

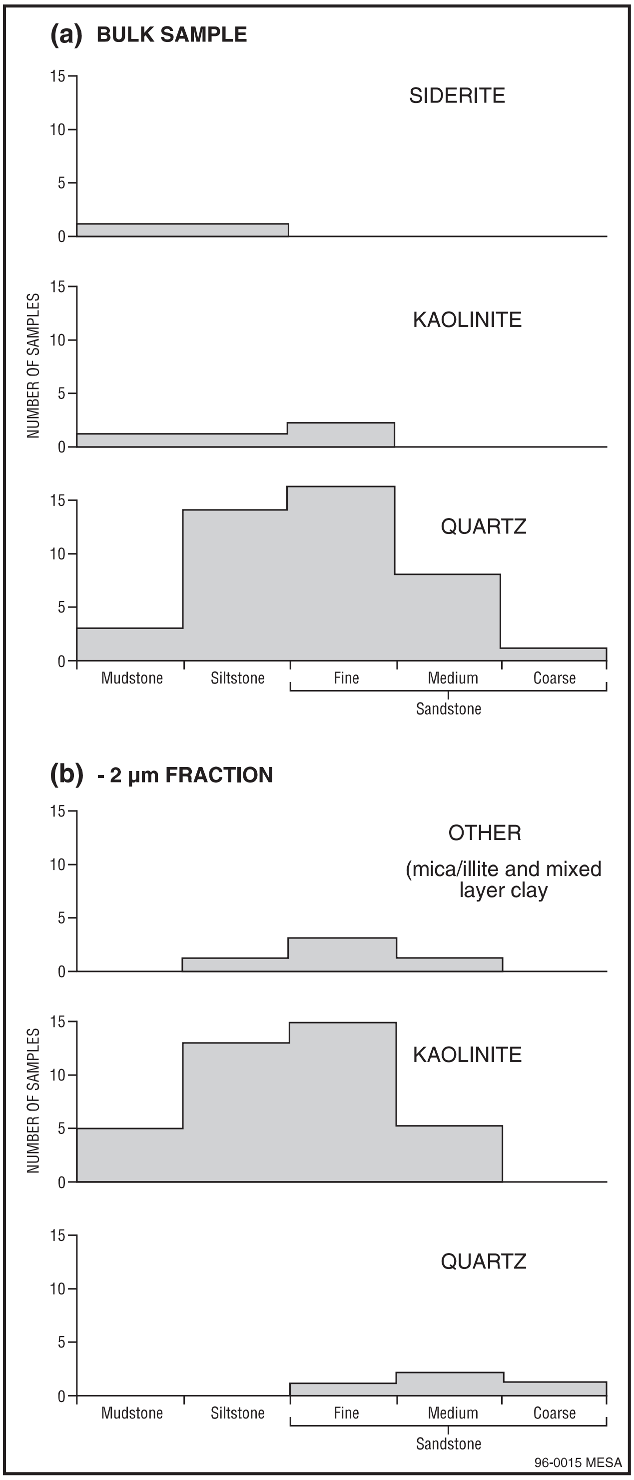

***Fig. 10.4** Distribution of bulk and clay fraction mineralogy.*

Reservoir characteristics

The Poolowanna facies contains the deepest reservoir in the Eromanga Basin, occurring at depths up to 2226 m. Deeper samples show the lowest average porosities due to the formation of quartz overgrowths. Poolowanna facies reservoir sandstones are quartzose with traces of potassium and plagioclase feldspar. Porosity distribution (Fig. 10.6) is a relatively even average of 18%. In thin section, porosity is predominantly primary with some development of secondary porosity via grain dissolution. Permeability distribution (Fig. 10.6) shows a spread of values, but high permeability samples form a separate population (RES trend). Both CAP and RES trends are clearer on the plot of permeability versus porosity.

Algebuckina Sandstone

Seal

Thick marine shales of the Wallumbilla Formation and Bulldog Shale form a regional seal to the Algebuckina Sandstone. Siltstones at the base of the Cadna-owie Formation may also act as seals.

Reservoir characteristics

The Algebuckina Sandstone has good to excellent porosity and permeability and forms a major artesian aquifer. Few laboratory measurements are available, but log-derived porosities average >20% (e.g. New, 1989). Reservoir properties can also be gauged from aquifer flow rates which are of the order of 500–1000 kL/day (Krieg, 1985).

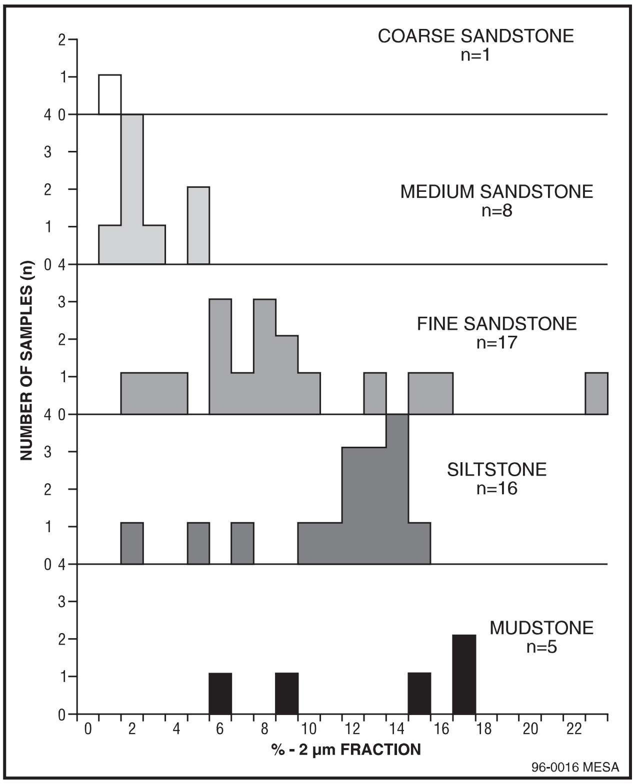

***Fig. 10.5** Distribution of bulk and clay fraction with grainsize.*

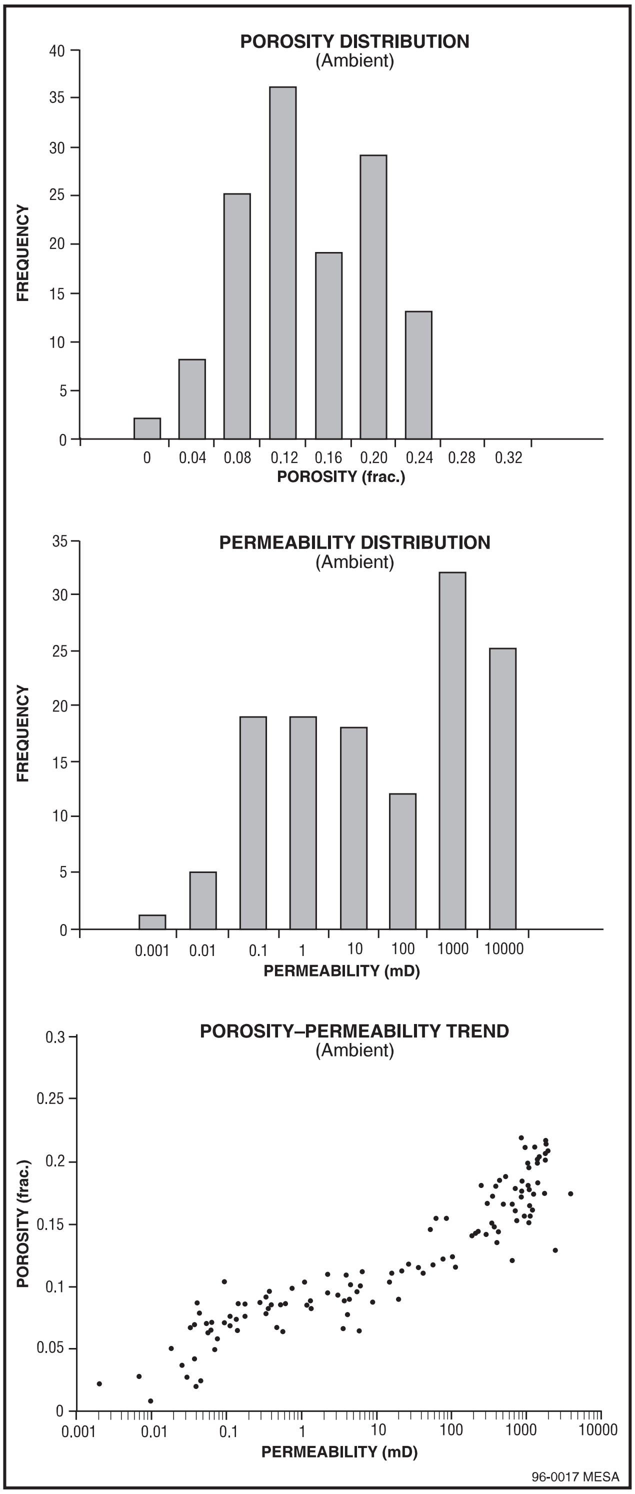

***Fig. 10.6** Poolowanna facies porosity and permeability distributions and porosity–permeability trend.*

Hutton Sandstone

Seal (P. Boult[†])

The Hutton Sandstone is sealed by a capillary type seal within the Birkhead Formation (Boult, 1993), and traps are rarely filled to structural spill point. The Birkhead Formation represents a change from the low sinuosity fluvial facies of Hutton Sandstone to lower energy, high sinuosity to lacustrine facies. Within this latter facies there is a sharp change of sediment source from cratonic to volcanic arc provenance (Boult *et al.*, in press). The contact is diachronous, with localised erosion and channelling on the edge of the basin. Diagenesis of lithic arenites within the volcanic arc derived sediment has altered feldspars and rock fragments to a framework of authigenic clays which has closed down pore throats and created a capillary seal (Boult, 1993). Another form of seal is shale interbeds in the lower Birkhead Formation, however these are not laterally extensive or thick enough to be regionally effective seals (Boult, 1993). There are indications that the wettability of the capillary seal within the Birkhead Formation may be changed with the onset of maturation and that prior to maturation, the seal is capable of retaining much larger oil columns than post maturation.

Reservoir characteristics

Hutton Sandstone reservoirs consist of mineralogically mature quartz arenites with minor amounts of feldspar (Gravestock *et al.*, 1983). Kaolinite booklets, quartz overgrowths and sericite form the matrix. Excellent reservoir properties are indicated by porosity and permeability distributions (Fig. 10.7).

Birkhead Formation

Seal

Birkhead Formation sandstone reservoirs are sealed by intraformational shales and diagenetic seals as described above.

Reservoir characteristics

In contrast to the Hutton Sandstone, porosity and permeability distributions show considerable spread and a bimodal pattern (Fig. 10.8) encompassing both CAP and RES trends. Birkhead Formation sandstones are lithic arenites with a significant proportion of labile volcanogenic grains (chloritised) and feldspar (kaolinitised). Calcite, siderite and dolomite cements occur, and quartz overgrowths, sericite and kaolinite fill pores.

Namur Sandstone

Seal

The Namur Sandstone is either sealed by siltstones of the McKinlay Member or by interbedded low permeability sandstones and siltstones of the lower Murta Formation. In the Murteree Ridge oilfields, seals are not effective and oil trapped in the Namur has migrated upwards along vertically connected sandstone beds into the Murta Formation (Williams *et al.*, 1994).

Reservoir characteristics

The Namur Sandstone has similar porosity and permeability distribution to the Hutton Sandstone and plots on the RES trend (Fig. 10.9).

Murta Formation and McKinlay Member

Seal

Interbedded low permeability sandstones and siltstones of the lower Murta Formation form capillary seals to the Namur Sandstone and McKinlay Member (Boult *et al.*, in

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press). However these seals are not effective, as oil and water from the Namur Sandstone – McKinlay Member pool is produced from the Murta Formation in fields on the Murteree Ridge (Williams *et al.*, 1994). The shaly M1 unit at the top of the Murta Formation forms a regional seal for thin sandstones within the Murta Formation (Williams, 1994) and hence the entire lower non-marine succession of the Eromanga Basin. In South Australia this upper seal is effective — economic accumulations of oil have not been discovered above the Murta Formation.

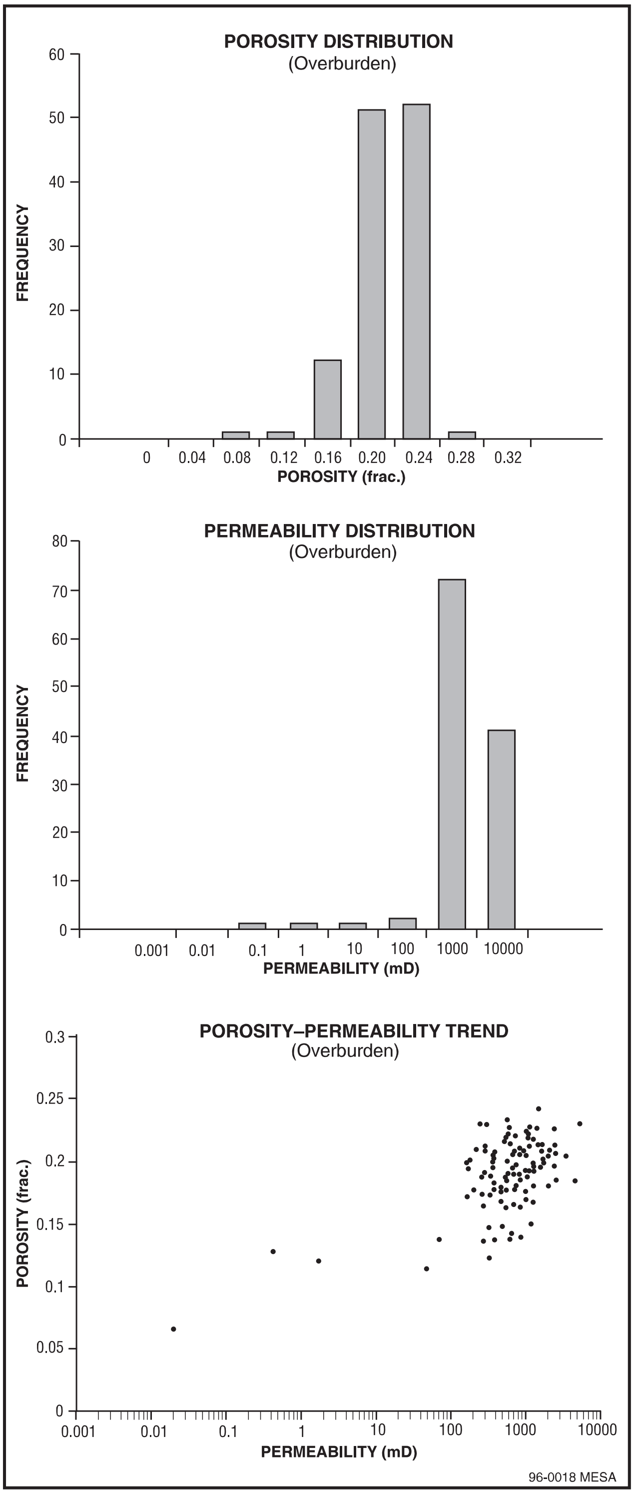

Fig. 10.7 *Hutton Sandstone porosity and permeability distributions and porosity–permeability trend.*

Reservoir characteristics

Murta Formation sandstones are quartz arenites and form two types of reservoirs (Williams, 1994): a high permeability sandstone (up to 0.3 m thick), and thin low permeability very fine to fine-grained sandstone interbedded with siltstone (<50 mm thick). Boult *et al.* (1995) compared core plug and probe permeametry data and concluded that detailed permeametry measurements provided a more accurate reservoir model of a thin-bedded unit like the Murta Formation.

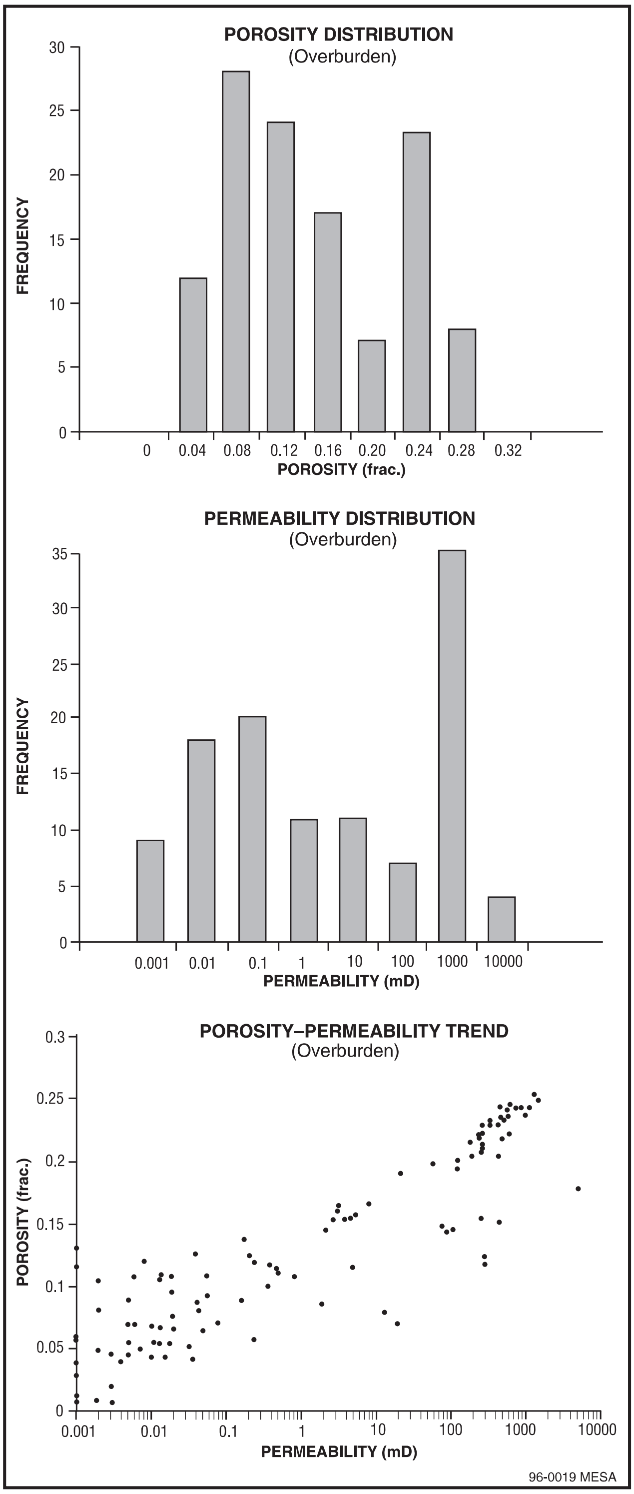

Fig. 10.8 *Birkhead Formation porosity and permeability distributions and porosity–permeability trend.*

Porosity distribution shows a spread up to a peak of 20% and then an abrupt cut off at higher porosities. Permeability distribution also shows a spread with a peak at 1 millidarcy (mD) and a tail off at higher values (Fig. 10.10); most Murta Formation samples fall on the CAP trend. The transitional nature of the McKinlay Member is reflected by the porosity–permeability continuum from the CAP trend to the RES trend (Fig. 10.10).

Wyandra Sandstone Member of the Cadna-owie Formation

Seal

Thick marine shales of the Wallumbilla Formation and Bulldog Shale form a regional seal to the Wyandra Sandstone Member and Cadna-owie Formation.

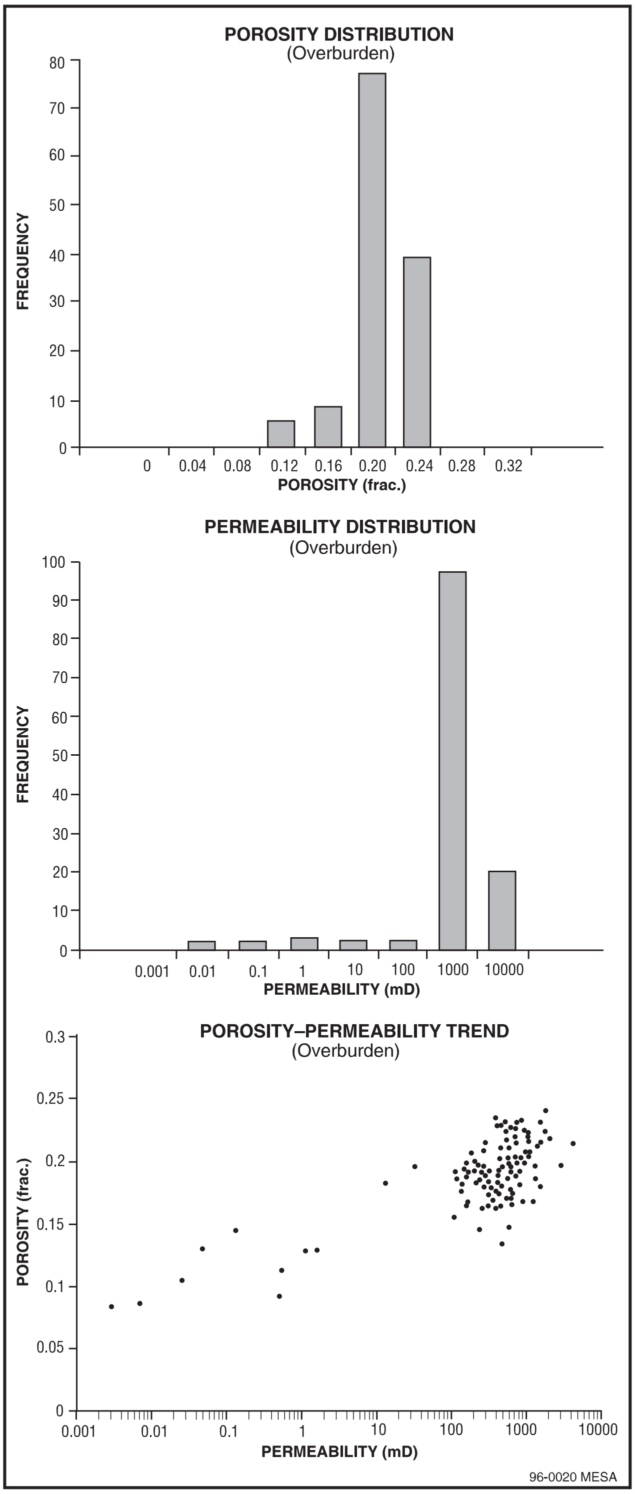

Fig. 10.9 *Namur Sandstone porosity and permeability distributions and porosity–permeability trend.*

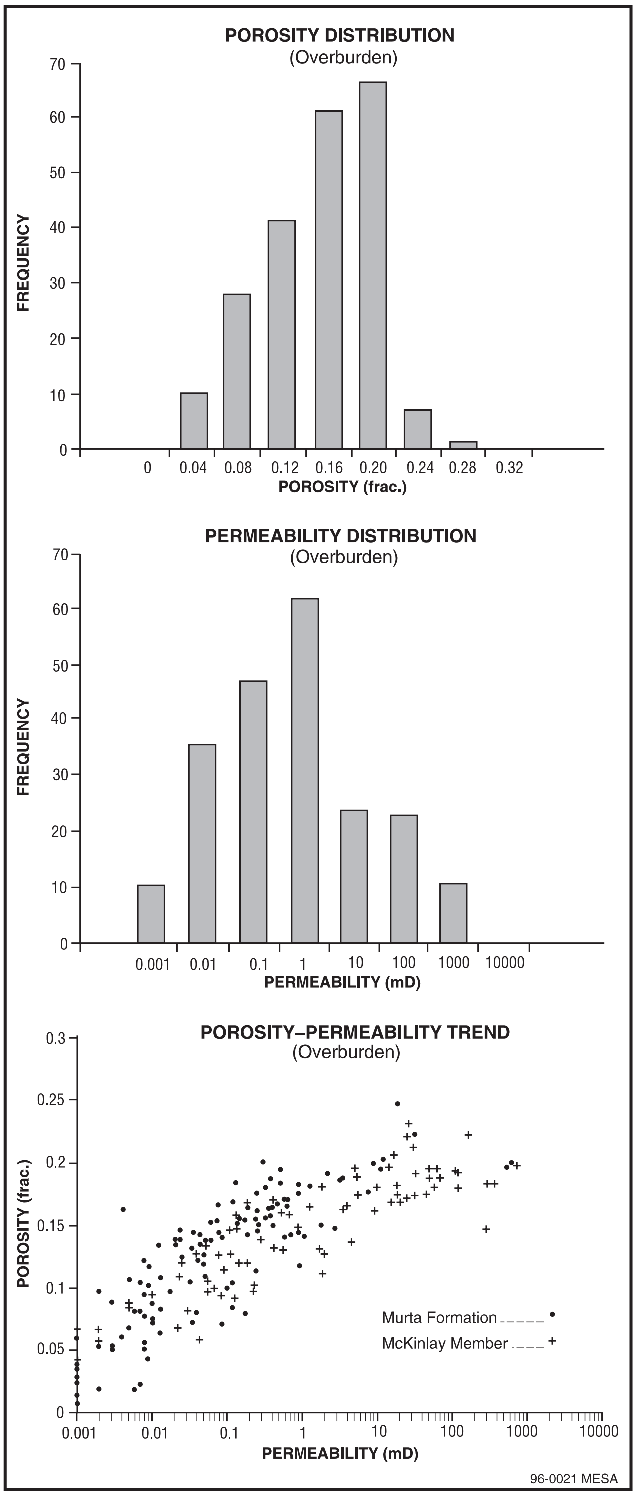

Fig. 10.10 *Murta Formation and McKinlay Member porosity and permeability distributions and porosity–permeability trend.*

Reservoir characteristics

Sandstones are quartzose, with lithics and potassium feldspar (Green, Brain *et al.*, 1989). In Tintaburra 1 (Queensland), sandstones contain up to 40% feldspar and rock fragments and authigenic clay and calcite cement occlude porosity (Newton, 1986). A drillstem test recorded flows of 534 kL oil and 2138 kL water per day through a one inch choke in Tintaburra 1 (Newton, 1986). Wyandra Sandstone Member forms a significant aquifer in Queensland. In South Australia, drillstem tests in the Cadna-owie Formation have recovered only small amounts of oil, and oil and gas-cut mud. No core analyses are available for this unit from South Australia, even though it forms an important aquifer within the GAB.

Coorikiana Sandstone

Seal

Thick marine shales of the Allaru Mudstone and Oodnadatta Formation form a regional seal to the Coorikiana Sandstone.

Reservoir characteristics

The Coorikiana Sandstone has not been cored in petroleum drillholes. The formation flowed small amounts of gas on test in Mina 1 and Strzelecki 4 and produced strong gas shows in Marabooka Field (drillstem tests were unsuccessful). The occurrence of diagenetic calcite cement, coupled with a relatively labile mineralogy (glauconite, feldspar and lithics), indicates that reservoir quality is likely to be extremely variable.

SIMPSON BASIN

Sandstone interbeds within the thick Peera Peera Formation may form reservoirs in shallower parts of the Simpson Basin. Measurements from 11 core samples in Walkandi 1 (2841.7–2850 m), located within the Poolowanna Trough, indicate poor reservoir quality in this relatively deep location. Porosity ranges from 2.8 to 8.8% and permeability from 0.005 to 0.3 mD. No data are available for the Peera Peera Formation at shallower depths or for the underlying Walkandi Formation.

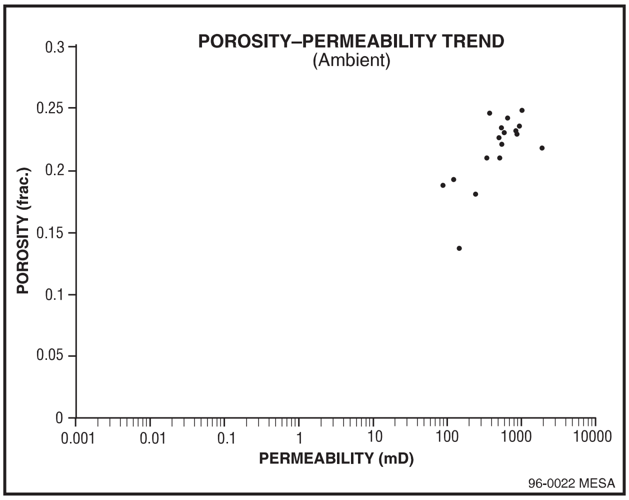

Fig. 10.11 *Porosity–permeability trend, Crown Point Formation and Mount Toondina Formation equivalent, Mount Hammersley 1.*

PEDIRKA BASIN

Permian reservoirs in the Pedirka Basin include sandstones within the Crown Point and Purni Formations and, in the Eringa Trough, Mount Toondina Formation equivalent. Laboratory measurements for the Mount Toondina Formation equivalent (893.6–903.7 m) and Crown Point Formation (1299–1317.3 m) in Mount Hammersley 1 indicate good to excellent porosities (13.5–24.5%) and permeabilities (91–1998 mD; Fig. 10.11).

ARCKARINGA BASIN

No laboratory measurements of porosity and permeability are available for Permian formations in the Arckaringa Basin. However, porosity calculated from company log analysis ranges from 10 to 20% (average ~15%) for the Mount Toondina, Stuart Range and Boorthanna Formations (Hanns Knob 1; Martin, 1988).