WORLD SHALE GAS RESOURCES:
AN INITIAL ASSESSMENT OF 14 REGIONS OUTSIDE THE UNITED STATES

Prepared for:
U.S. Energy Information Administration
At the U.S. Department of Energy
Washington, DC

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February 17, 2011

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XIV. AUSTRALIA

INTRODUCTION

Australia has major gas shale potential in four main assessed basins. Additional potential may exist in other basins that were not assessed due to budget and data limitations. With geologic and industry conditions resembling those of the USA and Canada, the country appears poised to commercialize its gas shale resources on a large scale. The Cooper Basin, Australia's main -onshore gas-producing basin, could be the first to develop, although its Permian-age shales have a non-marine (lacustrine) depositional origin and the gas has elevated CO_2 concentrations. Santos and Beach Energy testing the shale reservoirs in this basin, with reservoir core wells being drilled and initial frac production test wells planned for later in 2011.

Other prospective shale basins in Australia include the small, scarcely explored Maryborough Basin in coastal Queensland, which contains prospective Cretaceous-age marine shales that are over-pressured and appear gas saturated. The Perth Basin in Western Australia, undergoing initial testing by AWE and Norwest Energy, has prospective marine shale targets of Triassic and Permian age. Finally, the large Canning Basin in Western Australia has deep, Ordovician-age marine shale that is roughly correlative with the Bakken, Michigan, and Baltic basins. **Figure XIV-1** shows the main prospective gas shale basins of Australia. These basins hold an estimated total 396 Tcf of technically recoverable shale gas resources, **Table XIV-1**.

Figure XIV-1. Australia's Prospective Gas Shale Basins, Gas Pipelines, and LNG Infrastructure

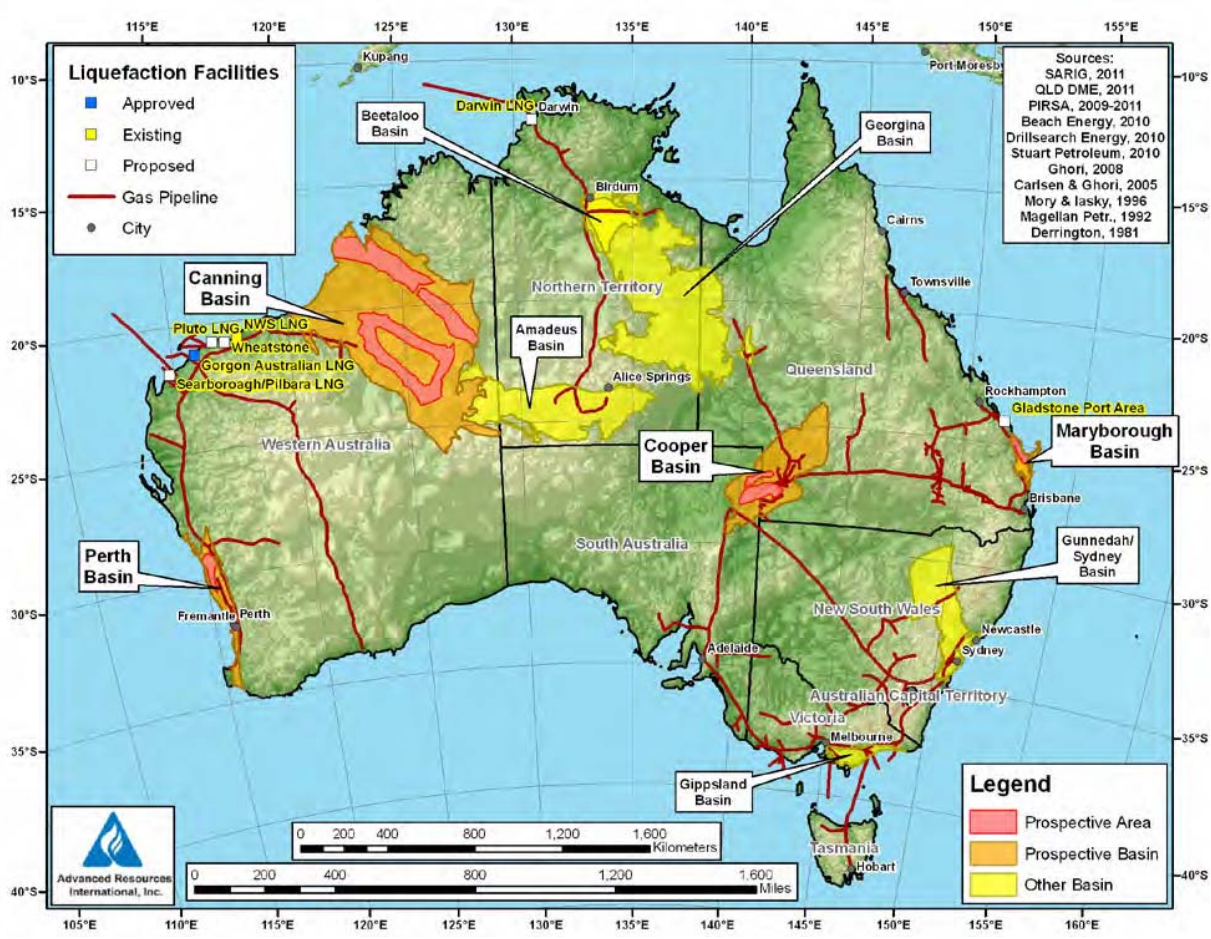


Table XIV-1. Shale Gas Reservoir Properties and Resources of Australia

	Basin/Gross Area		Cooper Basin (46,900 mi²)	Maryborough Basin (4,290 mi²)	Perth Basin (12,560 mi²)		Canning Basin (181,000 mi²)
Basic Data	Shale Formation		Roseneath-Epsilon-Murteree	Goodwood/Cherwell Mudstone	Carynginia Shale	Kockatea Fm	Goldwyer Fm
	Geologic Age		Permian	Cretaceous	Upper Permian	Lower Triassic	M. Ordovician
Physical Extent	Prospective Area (mi²)		5,810	1,555	2,180	2,180	48,100
	Thickness (ft)	Interval	0 - 1,800	300 - 3,000	300 - 1,500	300 - 3,000	300 - 2,414
		Organically Rich	500	1,250	950	2,300	1,300
		Net	300	250	250	230	250
	Depth (ft)	Interval	6,000 - 13,000	5,000 - 16,500	4,000 - 16,500	3,300 - 16,500	3,300 - 16,500
		Average	8,500	9,500	10,700	10,000	12,000
Reservoir Properties	Reservoir Pressure		Moderately Overpressured	Slightly Overpressured	Normal	Normal	Normal
	Average TOC (wt. %)		2.5%	2.0%	4.0%	5.6%	3.0%
	Thermal Maturity (%Ro)		2.00%	1.50%	1.40%	1.30%	1.40%
	Clay Content		Low	Low	Low	Low	Low
Resource	GIP Concentration (Bcf/mi²)		105	110	107	110	106
	Risked GIP (Tcf)		342	77	98	100	764
	Risked Recoverable (Tcf)		85	23	29	30	229

Given budget limitations for this study, other less promising basins in Australia were rapidly screened out as non-prospective for gas shale development. These include the Sydney Basin (where Permian coal measures are mature but appear ductile); Lorne Basin (no apparent potential source rocks); the Clarence-Moreton, Ipswich, Surat, Eromanga basins (Jurassic Walloon Coal Measures are mature but appear ductile); Gippsland Basin (coaly shale appears ductile); and Amadeus Basin (thin shale in a mostly sandstone unit). However, these and other basins warrant further evaluation at a future time.

COOPER BASIN (SOUTH AUSTRALIA AND QUEENSLAND)

Straddling the South Australia and Queensland border, the Cooper Basin has been the Australia's main onshore gas supply region for the past several decades. Current production from the basin is about 0.5 Bcfd of natural gas from conventional and low-permeability reservoirs. Within the basin, the Nappamerri Trough contains thick, overpressured and organic-rich shales at prospective depth, as well as extensive deep coal deposits. Gas pipelines connect the basin to Sydney and other urban markets in eastern Australia. With extensive tight sandstone gas production, the basin has service industry capability for advanced hydraulic fracturing that could be adapted for developing gas shale reservoirs.

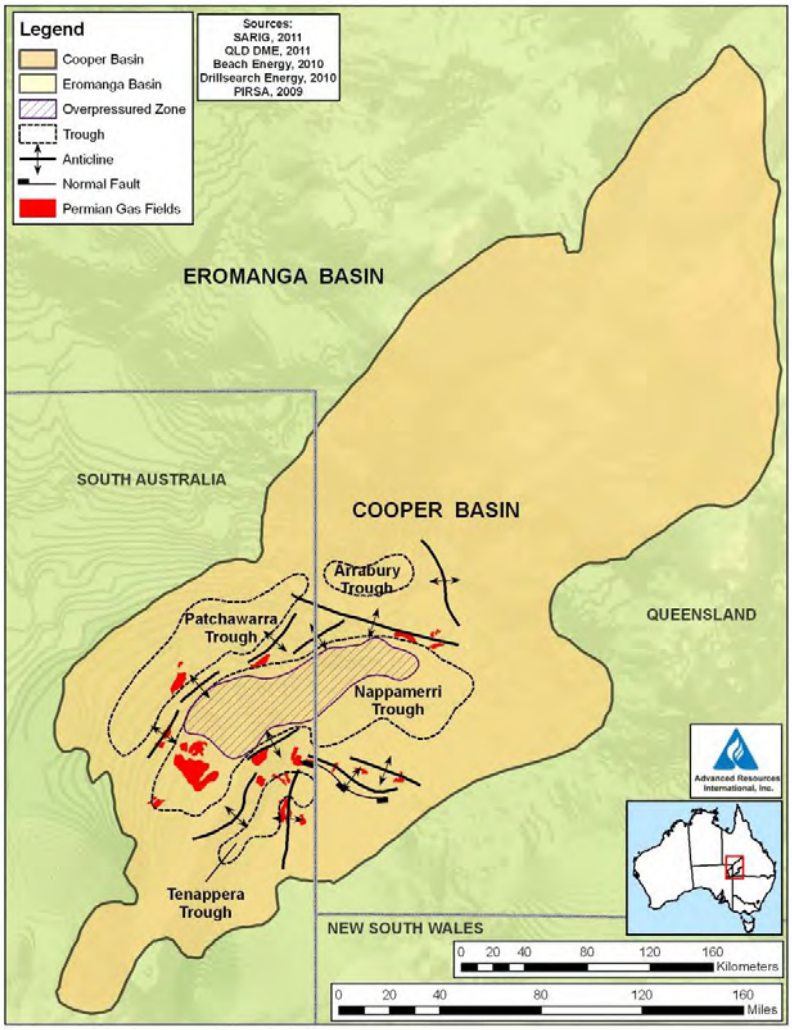
However, while overall the Cooper Basin appears favorable for shale gas development, a key risk remains that the shales were deposited in a lacustrine (not marine) environment. In addition, high CO_2 occurs in the deeper more mature troughs, though concentrations may be lower in shallower settings.

Geologic Characterization. The Cooper Basin is a Gondwana intracratonic basin containing about 2.5 km of entirely non-marine Late Carboniferous to Middle Triassic strata, which include prospective Permian-age shales. Following an episode of regional uplift and erosion during the late Triassic, the Cooper Basin continued to gently subside and the Paleozoic sequence was unconformably overlain by up to 1.3 km of Jurassic to Tertiary deltaic deposits of the Eromanga Basin, which contain the basin's conventional sandstone reservoirs.[1]

Extending over a total area of about 130,000 km^2, the Cooper Basin contains four major deep troughs with shale gas potential (Nappamerri, Patchawarra, Tenappera, and Arrabury; **Figure XIV-2**). These troughs are separated by faulted anticlinal structural highs, from which the Permian shale-bearing strata largely have been eroded.[2] Conventional oil and gas

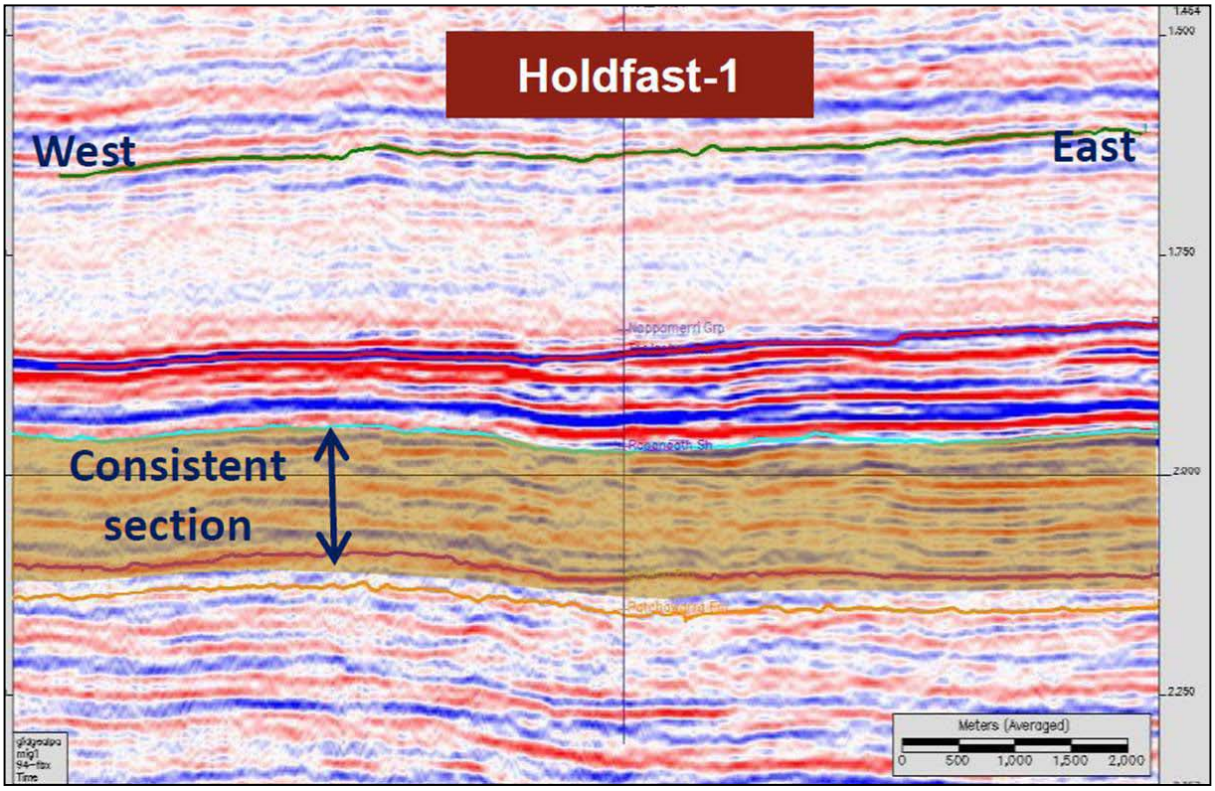
generated by the organic-rich shales and coals within the Nappamerri, Tenappera and other deep hydrocarbon kitchens accumulated along the Murteree and other uplifted ridges.

Figure XIV-2. Major Structural Elements of the Cooper Basin.



The Nappamerri Trough is particularly large (15,000 km^2), deep (>10,000 feet), thermally mature, and overpressured, and thus appears to be the most prospective portion of the Cooper basin for gas shale development. The top Permian horizon reaches maximum depths of over 9,000 feet in the center of the Nappamerri Trough and over 10,000 feet in the Patchawarra Trough. Prospective Permian shales, approximately 2,000 feet below the top Permian, occur at depths of 10,000 to 14,000 feet. Nearly the entire extent of the two troughs appears to be depth-prospective for shale development. Furthermore, relatively little faulting occurs within these troughs, **Figure XIV-3,** as structural deformation is confined largely to the uplifted ridges.

Figure XIV-3. Seismic Reflection Line Showing Permian REM Sequence In The Cooper Basin And Location Of Beach Energy's Planned Holdfast-1 Test Well, Scheduled For January 2011.

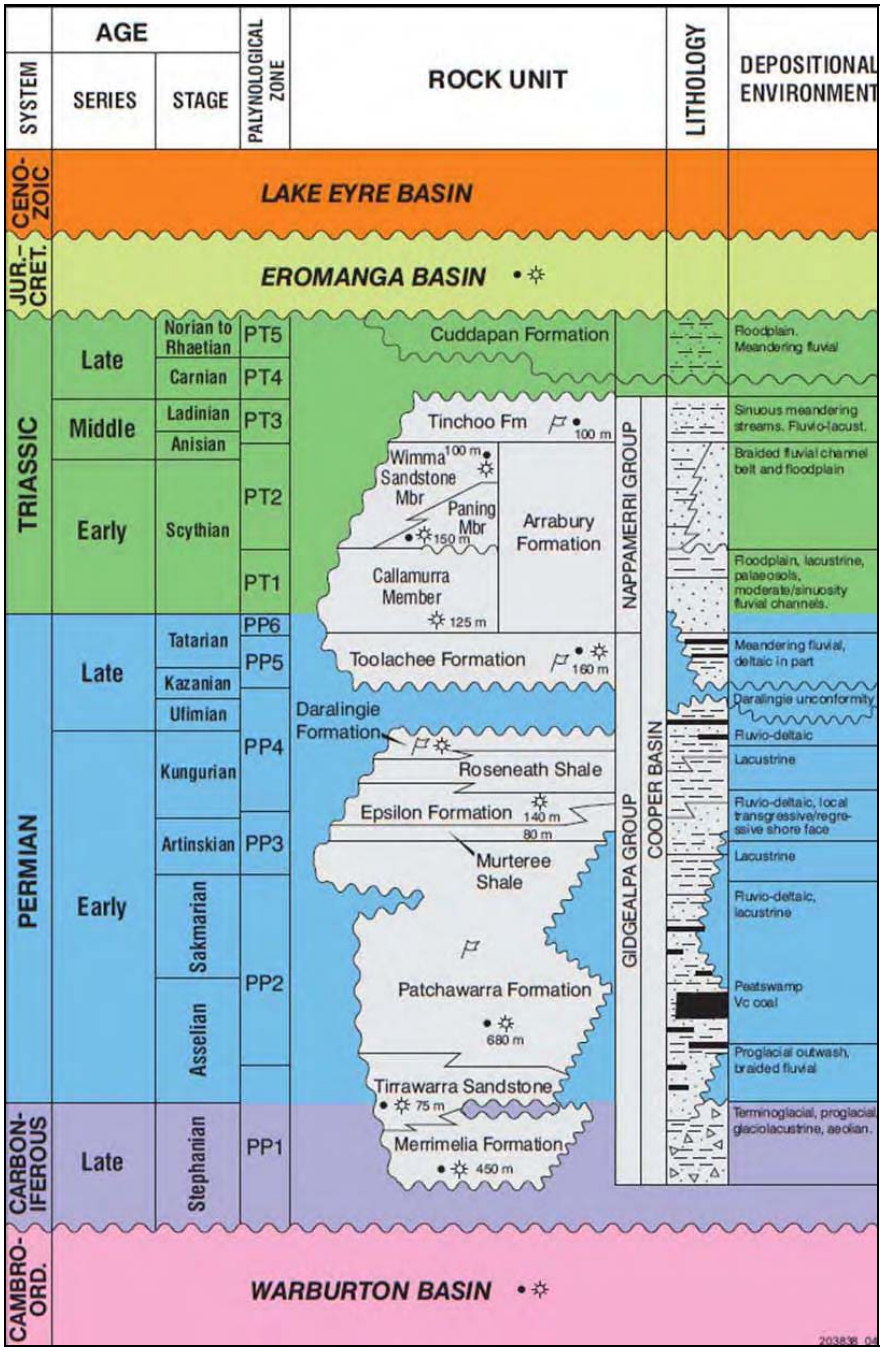


Source: Beach Energy, 2010

The stratigraphy of the Cooper Basin is shown in **Figure XIV-4**. Conventional and tight sandstone oil & gas reservoirs are found in the Patchawarra and T oolachee formations, interbedded with coal deposits. These were sourced by two organic-rich complexes: the Late Carboniferous to Late Permian Gidgealpa Group and t he Late Permian to Middle Triassic Nappamerri Group, both of which were deposited in non-marine settings. Of the two source rock groups, the Gidgealpa Group appears the more prospective. Most of the gas generated by the Nappamerri Group likely came from its multiple, thin, discontinuous coal seams; shales in this unit are low in TOC, humic, and often oxidized.

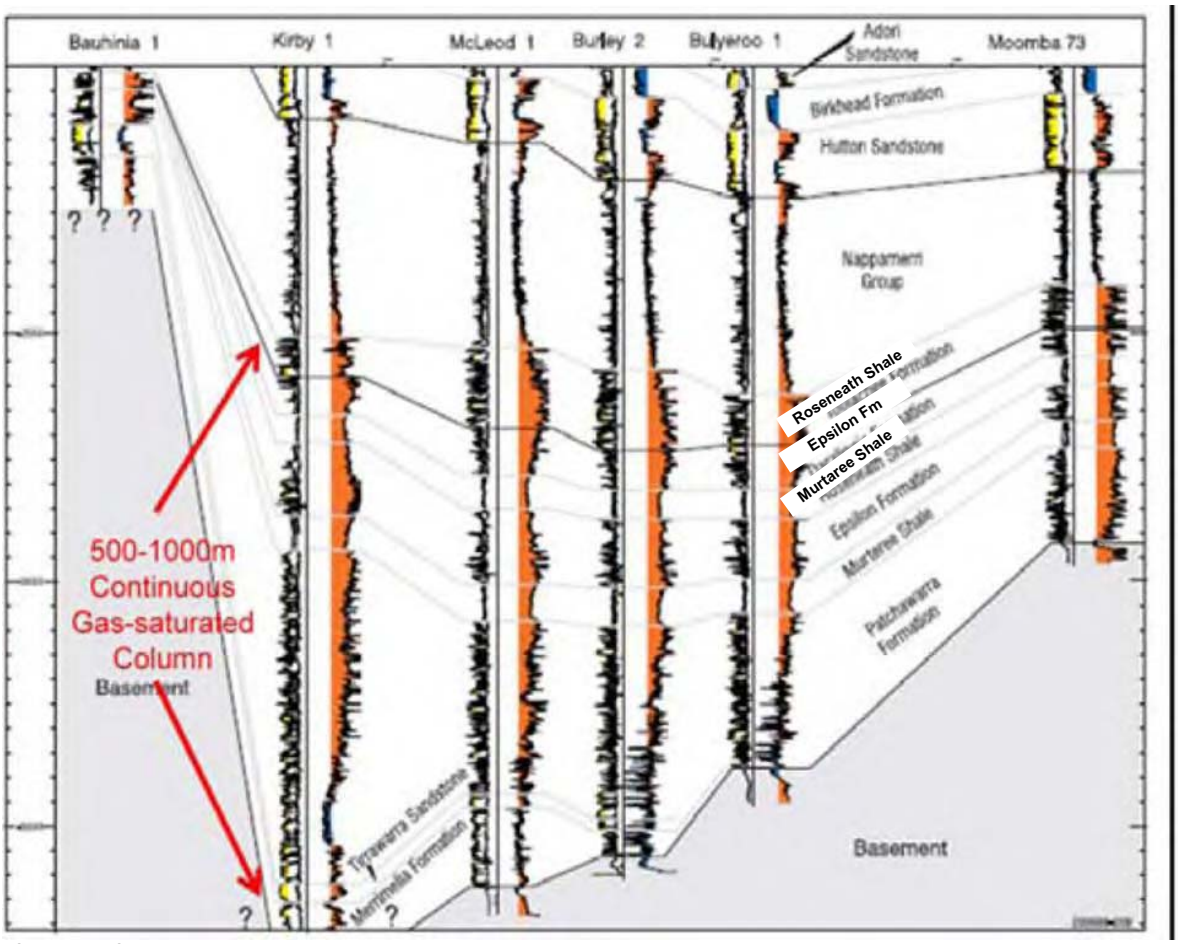
Although deposited in lacustrine environments, the best shale exploration targets within the Gidgealpa Group appear to be the Early Permian Roseneath and Murteree shales.[3] **Figure XIV-5** shows a stratigraphic cross-section of the Roseneath, Epsilon, and Murteree (collectively termed REM) sequence in the Nappamerri Trough.

Figure XIV-4. Stratigraphy of the Cooper Basin, Showing Permian-Age Shale Targets (Roseneath, Epsilon, Murteree)



Source: South Australia DMER, 2010

Figure XIV-5. Stratigraphic Cross-Section In The Cooper Basin Showing The Laterally Continuous REM Section.



Source: DrillSearch Energy, 2010

The Murteree Shale (Artinskian) is a widespread, primarily shaley formation typically 50 m thick across the Cooper Basin, becoming as thick as 80 m in the Nappamerri Trough. The Murteree consists of dark organic-rich shale, siltstone and fine-grained sandstone, becoming sandier to the south. TOC of the Murteree Shale averages approximately 2.5%, about 84% of which is inertinite, based on analyses from seven wells. The Roseneath Shale, less widespread than the Murteree due to erosion on uplifts, averages 37 m thick, reaching up to 100 m thick in the Nappamerri Trough. T he Roseneath is somewhat leaner than the Murteree, with TOC averaging just over 1.0%. The intervening Epsilon Fm consists primarily of low-permeability (0.1 to 10 mD) quartzose sandstone with carbonaceous shale and coal. The Epsilon, averaging about 53 m thick in drill cores, was deposited in a fluvial-deltaic environment.[4]

The total thickness of the REM sequence in the western Nappamerri Trough averages about 1,000 feet.[5] The unit becomes generally thicker to the east and north, where it reaches a maximum of about 1,800 feet. The REM sequence appears to have prospective shale thickness across the entire western Nappamerri Trough.

The REM source rocks are dominated by Type III kerogens derived from plant assemblages. They have generated medium to light (30-60º API gravity) oil rich in paraffin. Initial mineralogical data indicate that these shales consist mainly of quartz and feldspar (50%) and carbonate (30%; mainly iron-rich siderite). C lay content is relatively low (20%; predominately illite).[6] In spite of the lacustrine depositional origin, this lithology appears brittle and could respond well to hydraulic fracturing.

Temperature gradients in the Cooper Basin are high, averaging 2.55ºF/100 ft. Bottomhole temperature at depths of 9,000 feet average about 300ºF. The Nappamerri Trough is even hotter, with a gradient of up to 3.42ºF/100 ft, due to its radioactive granite basement. The Patchawarra Trough, which has a sedimentary-metamorphic basement, has a lower but still elevated 2.02ºF/100 ft temperature gradient.

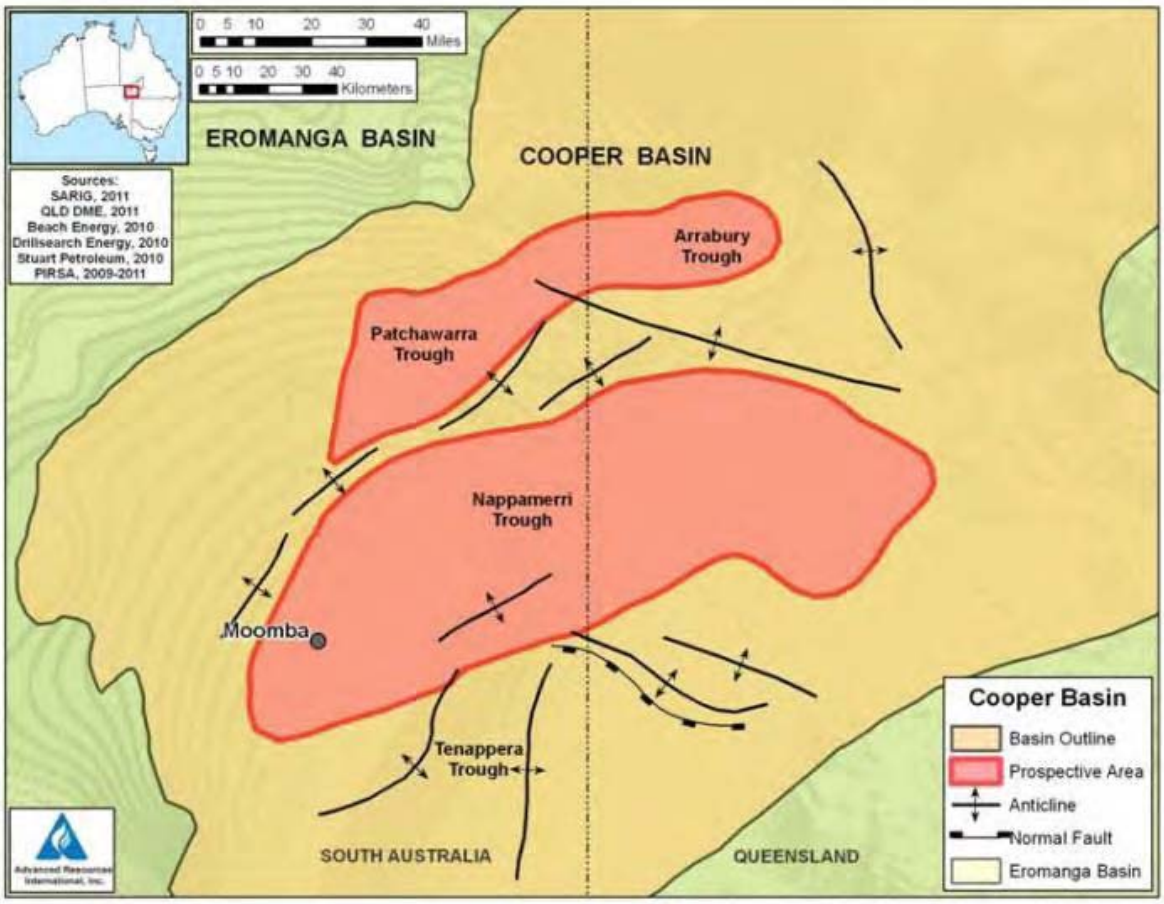
The thermal maturity of the Permian REM section in the Nappamerri Trough is gas prone (R_o = 3% to 4%), whereas the Patchawarra Trough has lower thermal maturity (Ro = 1%). Hydrostatic regional pressure gradients occur in most of the Cooper Basin, but locally in the Nappamerri Trough can become overpressured at depths of 2,800 to 3,700 m.[7] Pressure gradients of up to 0.7 psi/ft have been recorded in the deepest portions of the Nappamerri Trough.

High levels of carbon dioxide are common in the Cooper Basin. Gas produced from tight sandstones in the Epsilon Formation (central portion of the REM sequence) contains elevated CO_2, typically ranging from 8% to 24% (average 15%). Gas produced from the Patchawarra sandstone, which underlies the REM shale sequence, contains even higher levels of CO_2 (8-40%).[8]

Resources (REM Sequence). ARI evaluated the area that could be prospective for shale gas development in the Cooper Basin, using standard minimum depth (6,000 feet) and vitrinite reflectance (R_o > 1.0%) cutoffs, **Figure XIV-6**. Completable shale intervals in the Rosemead, Epsilon, and Murteree (REM) formations have an estimated resource concentration of 105 Bcf/mi^2, benefitting from favorable thickness, moderate TOC, high thermal maturity, and

overpressuring, but reduced for 15% average CO_2 content. The prospective area for this Permian shale-bearing sequence is estimated to be approximately 5,500 mi^2, covering portions of the Nappamerri, Arrabury, and Tenappera troughs. Net of 15% CO_2 content, the estimated risked completable shale gas-in-place for the REM sequence is approximately 342 Tcf, while risked recoverable resources are approximately 85 Tcf, **Table XIV-1**.

Figure XIV-6. Western Portion Of The Cooper Basin Showing Approximate Prospective Shale Gas Area.



Activity. The Cooper Basin is Australia's largest onshore oil and gas production region. Oil and gas development began in the basin during the 1960's, while hydraulic fracturing of low-permeability formations began in 1968 and has been extensively used since. More than 400 wells have been hydraulically stimulated in the Cooper basin to date, though the jobs were much smaller (typically 50,000 lbs sand with 50,000 gal fluid) than used in modern horizontal shale wells. Nevertheless, the Cooper basin has Australia's best capabilities for fracking shale reservoirs. Current production from conventional and tight formations in the basin totals nearly 600 Mcfd from 700 gas wells and 2,500 bopd from 50 oil wells.

The Cooper Basin also has been Australia's most active area for gas shale leasing and testing. Santos, Beach Energy, and DrillSearch Energy have active shale evaluation programs, though only Beach is known to have drilled a test well. Starting in October 2010 Beach drilled and completed a vertical shale test well in the eastern Nappamerri Trough, thought to be Australia's first dedicated shale test well. Drilled to a total depth of 3,612 m, the well penetrated 393 m of REM shale formation with continuous gas shows. The company is analyzing five REM cores for gas content and mechanical properties. Beach plans to conduct an 8-stage frac of the Encounter-1 test well during 2Q-2011.

MARYBOROUGH BASIN (QUEENSLAND)

This small basin in coastal southern Queensland, located about 250 km north of Brisbane, has two potential gas shale targets within the Cretaceous Maryborough Formation. Only five conventional oil & gas exploration wells have been drilled in the Maryborough Basin. No shale activity has been reported.

Geologic Characterization. The Maryborough Basin is a half-graben bounded on the west by the major Electra Fault, **Figure XIV-7**. Extending over an area of 4,300-mi^2 in the onshore northern portion of the basin, where geologic data exist, it is filled with up to about 5 km of Late Triassic to Recent sedimentary rocks that were deposited in a trans-tensional back-arc rift basin. Major folding and faulting, along with significant erosion, occurred during the Cretaceous-Palaeogene. Three main anticlines occur onshore within the basin, all of which have been drilled but without conventional discoveries.[9]

Two main depositional sequences are present, **Figure XIV-8**.[10] The Duckinwilla Group comprises Late Triassic to mid-Jurassic non-marine sediments and is not considered a prospective shale gas target. Overlying the Duckinwilla is the Grahams Creek Formation, which contains Late Jurassic to Cretaceous (Neocomian) strata, including the marine-deposited Maryborough Formation and the fluvial-lacustrine Burrum Coal Measures.