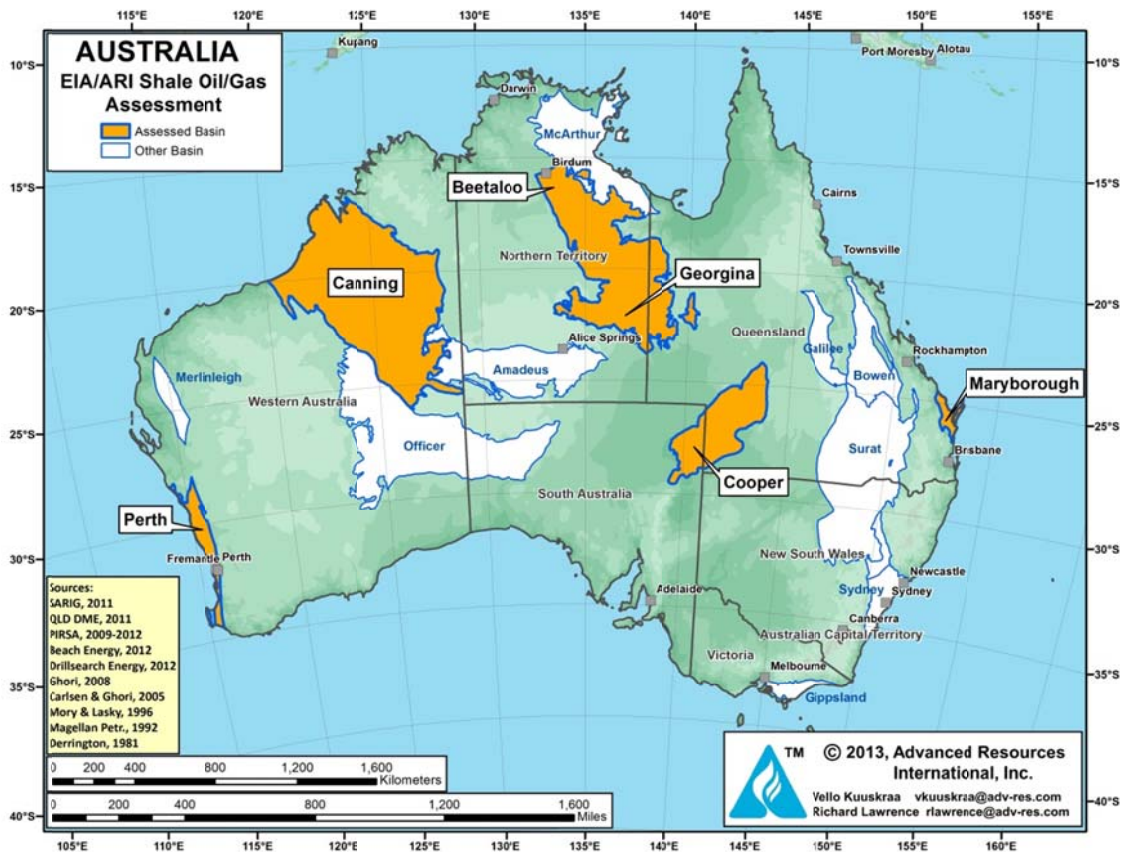


# III. AUSTRALIA

## SUMMARY

With geologic and industry conditions resembling those of the USA and Canada, Australia has the potential to be one of the next countries with commercially viable shale gas and shale oil production. As in the US, small independents have led the way, assembling the geological data and exploring the high potential shale basins of Australia, Figure III-1. International majors are now entering these plays by forming JV partnerships with these smaller independents, bring capital investment to the table. But, with the remoteness of many of Australia’s shale gas and shale oil basins, development will likely proceed at a moderate pace.

Figure III-1. Australia’s Assessed Prospective Shale Gas and Shale Oil Basins



Source: ARI, 2013

This report assesses the shale gas and shale oil potential in six major Australian sedimentary basins having sufficient geologic data for a quantitative assessment. Additional potential is likely to exist in other basins not yet assessed.

The six assessed shale gas and oil basins of Australia hold an estimated 2,046 Tcf of risked shale gas in-place, with 437 Tcf as the risked, technically recoverable shale gas resource, Tables III-1A, III-1B, and III-1C. These six basins also hold an estimated 403 billion barrels of risked shale oil in-place, with 17.5 billion barrels as risked, technically recoverable shale oil resource, Tables III-2A and III-2B.

Of the six assessed basins, the Cooper Basin, Australia's main onshore gas-producing basin, with its existing gas processing facilities and transportation infrastructure, could be the first commercial source of shale hydrocarbons. The basin's Permian-age shales have a non-marine (lacustrine) depositional and the shale gas appears to have elevated CO<sub>2</sub> content, both factors adding risk to these shale gas and shale oil plays. Santos, Beach Energy and Senex Energy are testing the shale reservoirs in the Cooper Basin, with initial results from vertical production test wells providing encouragement for further delineation.

The other prospective Australian shale basins addressed in this report include the small, scarcely explored Maryborough Basin in coastal Queensland, that contains prospective Cretaceous-age marine shales thought to be over-pressured and 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. The large Canning Basin in Western Australia has deep, Ordovician-age marine shales that are roughly correlative with the Bakken Shale in the Williston Basin. In Northern Territory, the Pre-Cambrian shales in the Beetaloo Basin and the Middle Cambrian shale in the Georgina Basin have reported oil and gas shows in shale exploration wells. If proved commercial, these two shale gas and shale oil basins would become some of the oldest producing hydrocarbon source rocks in the world.

Table III-1A. Australian Shale Gas Reservoir Properties and Resources (Page 1 of 3)

**Gas Resources**

Basic Data	Basin/Gross Area	Cooper (46,900 mi <sup>2</sup> )							
	Shale Formation	Roseneath-Epsilon-Murteree (Nappamerri)			Roseneath-Epsilon-Murteree (Patchawarra)			Roseneath-Epsilon-Murteree (Tenappera)	
	Geologic Age	Permian			Permian			Permian	
	Depositional Environment	Lacustrine			Lacustrine			Lacustrine	
Physical Extent	Prospective Area (mi <sup>2</sup> )	625	555	3,525	1,010	1,150	170	200	
	Thickness (ft)	Organically Rich	250	500	500	125	100	100	225
		Net	150	300	300	75	60	60	135
	Depth (ft)	Interval	5,000 - 7,000	6,000 - 10,000	7,000 - 13,000	7,000 - 9,200	8,000 - 10,000	8,000 - 13,000	5,000 - 6,500
Average		6,000	8,000	10,000	8,000	9,000	10,500	5,500	
Reservoir Properties	Reservoir Pressure	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Normal	Normal	Normal	Normal	
	Average TOC (wt. %)	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	
	Thermal Maturity (% Ro)	0.85%	1.15%	2.00%	0.85%	1.15%	1.30%	0.85%	
	Clay Content	Low	Low	Low	Low	Low	Low	Low	
Resource	Gas Phase	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	
	GIP Concentration (Bcf/mi <sup>2</sup> )	13.1	87.6	100.1	7.3	15.6	18.6	10.1	
	Risked GIP (Tcf)	6.1	36.5	264.7	4.4	10.8	1.9	1.2	
	Risked Recoverable (Tcf)	0.7	9.1	79.4	0.4	2.7	0.5	0.1	

Table III-1B. Australian Shale Gas Reservoir Properties and Resources (Con't) (Page 2 of 3)

**Gas Resources**

Basic Data	Basin/Gross Area		Maryborough (4,290 mi <sup>2</sup> )	Perth (20,000 mi <sup>2</sup> )		Canning (181,000 mi <sup>2</sup> )			
	Shale Formation		Goodwood/Cherwell Mudstone	Carynginia	Kockatea		Goldwyer		
	Geologic Age		Cretaceous	U. Permian	L. Triassic		M. Ordovician		
	Depositional Environment		Marine	Marine	Marine		Marine		
Physical Extent	Prospective Area (mi <sup>2</sup> )		1,540	2,200	860	1,030	14,900	19,620	22,860
	Thickness (ft)	Organically Rich	1,250	950	300	300	1,000	1,300	1,300
		Net	250	250	160	160	250	250	250
	Depth (ft)	Interval	5,000 - 16,500	3,300 - 16,500	3,300 - 15,100	9,200 - 16,500	3,300 - 7,200	7,200 - 10,500	10,500 - 16,500
Average		9,500	10,000	9,200	11,000	5,200	8,800	13,500	
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	4.0%	5.6%	5.6%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		1.50%	1.40%	0.85%	1.15%	0.85%	1.15%	1.40%
	Clay Content		Low	Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Assoc. Gas	Wet Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi <sup>2</sup> )		110.7	94.0	14.0	58.9	18.7	67.1	109.2
	Risky GIP (Tcf)		63.9	124.1	7.2	36.4	83.5	395.0	748.7
	Risky Recoverable (Tcf)		19.2	24.8	0.6	7.3	6.7	79.0	149.7

Table III-1C. Australian Shale Gas Reservoir Properties and Resources (Con't) (Page 3 of 3)

**Gas Resources**

Basic Data	Basin/Gross Area		Georgina (125,000 mi <sup>2</sup> )					Beetaloo (14,000 mi <sup>2</sup> )					
	Shale Formation		L. Arthur Shale (Dulcie Trough)		L. Arthur Shale (Toko Trough)			M. Velkerri Shale			L. Kyalla Shale		
	Geologic Age		M. Cambrian		M. Cambrian			Precambrian			Precambrian		
	Depositional Environment		Marine		Marine			Marine			Marine		
Physical Extent	Prospective Area (mi <sup>2</sup> )		2,260	1,950	3,220	2,010	790	2,650	2,130	2,480	4,010	2,400	1,310
	Thickness (ft)	Organically Rich	115	115	65	65	65	450	450	450	520	520	520
		Net	85	85	50	50	50	100	100	100	130	130	130
	Depth (ft)	Interval	7,200 - 10,500	2,300 - 3,300	3,300 - 4,000	4,000 - 5,000	5,000 - 6,500	3,300 - 5,000	5,000 - 7,000	7,000 - 8,700	3,300 - 5,000	5,000 - 6,000	6,000 - 8,000
Average		8,800	3,000	3,600	4,500	5,700	4,200	6,000	7,500	4,200	5,500	6,500	
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.0%	5.5%	5.5%	5.5%	5.5%	4.0%	4.0%	4.0%	2.5%	2.5%	2.5%
	Thermal Maturity (% Ro)		1.15%	1.50%	0.85%	1.15%	1.50%	0.85%	1.15%	1.60%	0.85%	1.15%	1.60%
	Clay Content		Low	Low	Low	Low	Low	Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi <sup>2</sup> )		22.8	29.1	4.5	17.5	26.7	7.2	30.7	42.0	11.7	37.1	49.6
	Risked GIP (Tcf)		19.3	21.3	5.5	13.2	7.9	9.6	32.7	52.0	23.5	44.5	32.5
	Risked Recoverable (Tcf)		3.9	4.3	0.4	2.6	1.6	1.0	8.2	13.0	2.3	11.1	8.1

Table III-2A. Australian Shale Oil Reservoir Properties and Resources (Con't) (Page 1 of 2)

## Oil Resources

Basic Data	Basin/Gross Area		Cooper (46,900 mi <sup>2</sup> )				Perth (20,000 mi <sup>2</sup> )		Canning (181,000 mi <sup>2</sup> )			
	Shale Formation		Roseneath-Epsilon-Murteree (Nappamerri)		Roseneath-Epsilon-Murteree (Patchawarra)		Roseneath-Epsilon-Murteree (Tenappera)		Kockatea		Goldwyer	
	Geologic Age		Permian		Permian		Permian		L. Triassic		M. Ordovician	
	Depositional Environment		Lacustrine		Lacustrine		Lacustrine		Marine		Marine	
Physical Extent	Prospective Area (mi <sup>2</sup> )		625	555	1,010	1,150	200	860	1,030	14,900	19,620	
	Thickness (ft)	Organically Rich	250	500	125	100	225	300	300	1,000	1,300	
		Net	150	300	75	60	135	160	160	250	250	
	Depth (ft)	Interval	5,000 - 7,000	6,000 - 10,000	7,000 - 9,200	8,000 - 10,000	5,000 - 6,500	3,300 - 15,100	9,200 - 16,500	3,300 - 7,200	7,200 - 10,500	
Average		6,000	8,000	8,000	9,000	5,500	9,200	11,000	5,200	8,800		
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Normal	Normal	Normal	Normal	Normal	Normal	Normal	
	Average TOC (wt. %)		2.6%	2.6%	2.6%	2.6%	2.6%	5.6%	5.6%	3.0%	3.0%	
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	0.85%	0.85%	1.15%	0.85%	1.15%	
	Clay Content		Low	Low	Low	Low	Low	Low	Low	Low	Low	
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Oil	Oil	Condensate	Oil	Condensate	
	OIP Concentration (MMbbl/mi <sup>2</sup> )		22.5	14.5	11.1	3.0	21.9	18.9	6.1	41.1	10.2	
	Risked OIP (B bbl)		10.5	6.0	6.7	2.1	2.6	9.8	3.8	183.7	60.0	
	Risked Recoverable (B bbl)		0.63	0.36	0.34	0.10	0.13	0.39	0.15	7.35	2.40	

Table III-2B. Australian Shale Oil Reservoir Properties and Resources (Con't) (Page 2 of 2)

**Oil Resources**

Basin/Gross Area		Georgina (125,000 mi <sup>2</sup> )			Beetaloo (14,000 mi <sup>2</sup> )			
Shale Formation		L. Arthur Shale (Dulcie Trough)	L. Arthur Shale (Toko Trough)		M. Velkerri Shale	L. Kyalla Shale		
Geologic Age		M. Cambrian	M. Cambrian		Precambrian		Precambrian	
Depositional Environment		Marine	Marine		Marine		Marine	
Prospective Area (mi <sup>2</sup> )		2,260	3,220	2,010	2,650	2,130	4,010	2,400
Thickness (ft)	Organically Rich	115	65	65	450	450	520	520
	Net	85	50	50	100	100	130	130
Depth (ft)	Interval	7,200 - 10,500	3,300 - 4,000	4,000 - 5,000	3,300 - 5,000	5,000 - 7,000	3,300 - 5,000	5,000 - 6,000
	Average	8,800	3,600	4,500	4,200	6,000	4,200	5,500
Reservoir Pressure		Normal	Normal	Normal	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
Average TOC (wt. %)		3.0%	5.5%	5.5%	4.0%	4.0%	2.5%	2.5%
Thermal Maturity (% Ro)		1.15%	0.85%	1.15%	0.85%	1.15%	0.85%	1.15%
Clay Content		Low	Low	Low	Low	Low	Low	Low
Oil Phase		Condensate	Oil	Condensate	Oil	Condensate	Oil	Condensate
OIP Concentration (MMbbl/mi <sup>2</sup> )		3.5	14.7	5.2	16.7	5.3	27.1	8.9
Risky OIP (B bbl)		2.9	17.7	3.9	22.1	5.7	54.4	10.7
Risky Recoverable (B bbl)		0.12	0.71	0.16	1.11	0.28	2.72	0.54

## 1. COOPER BASIN

### 1.1 Introduction

Straddling the South Australia and Queensland border, the Cooper Basin has been Australia's main onshore oil and gas supply region for the past several decades.<sup>1</sup> Within the basin, the Nappamerri Trough contains thick, overpressured and organic-rich shales at prospective depth. The Cooper Basin already has service industry capacity for well drilling and hydraulic fracturing that could be used to develop the prospective shale reservoirs in this basin.

However, while overall the Cooper Basin appears favorable for shale development, a key risk remains in that the shales were deposited in a lacustrine (not marine) environment. Lacustrine shales often have higher clay contents with uncertainty on how the shales will respond to hydraulic stimulation treatments, in comparison with lower clay content marine shales. In addition, high CO<sub>2</sub> volumes have been noted in the deeper troughs in this basin.

### 1.2 Geologic Setting

The Cooper Basin is a Gondwana intracratonic basin containing 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. 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.<sup>2</sup>

Extending over a total area of about 130,000 km<sup>2</sup>, the Cooper Basin contains three major deep troughs with shale gas and shale oil potential - - Nappamerri, Patchawarra (including the Arrabury Trough) and Tenappera, Figure III-2. These troughs are separated by faulted structural highs from which Permian shale-bearing strata have largely been eroded, Figure III-3.<sup>3,4</sup>

The prospective areas within the Cooper Basin's troughs are large, thermally mature and overpressured. Depth to the Permian horizon ranges from 5,000 feet at the southern end of the basin to 13,000 feet in the center. Nearly the entire areal extent of the Nappamerri and Patchawarra troughs, as well as the Tenappera Trough in the south, appear depth-prospective for shale development. Furthermore, relatively little faulting occurs within these troughs as structural deformation is confined largely to uplifted ridges, Figure III-3.



Figure III-2: Major Structural Elements of the Southern Cooper Basin.

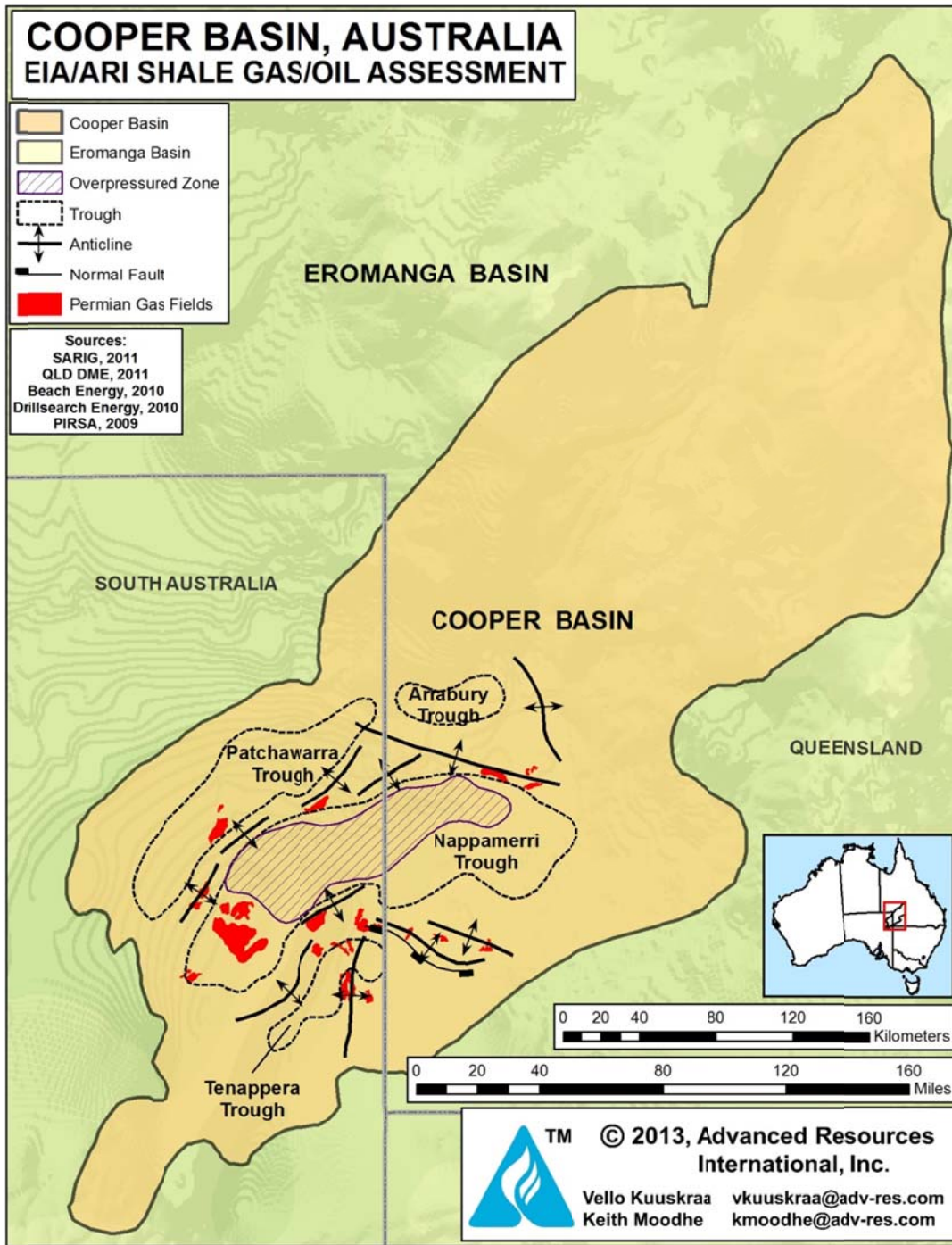
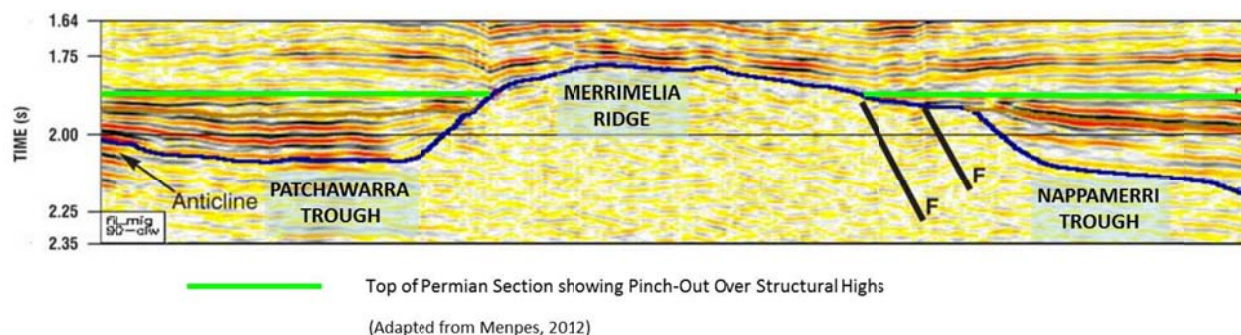


Figure III-3. Seismic Section Across the Merrimelia Ridge



The stratigraphy of the Cooper Basin is shown in Figure III-4. Conventional and tight sandstone oil and gas reservoirs are found in the Patchawarra and Toolachee formations, interbedded with coal deposits. These formations were sourced by two complexes - - the Late Carboniferous to Late Permian Gidgealpa Group and the Late Permian to Middle Triassic Nappamerri Group, both of which were deposited in non-marine settings. Of the two source rocks, the Gidgealpa Group is more prospective. Most of the gas generated by the Nappamerri Group likely came from its multiple, thin and discontinuous coal seams, since the shales in the Nappamerri Group are low in TOC.

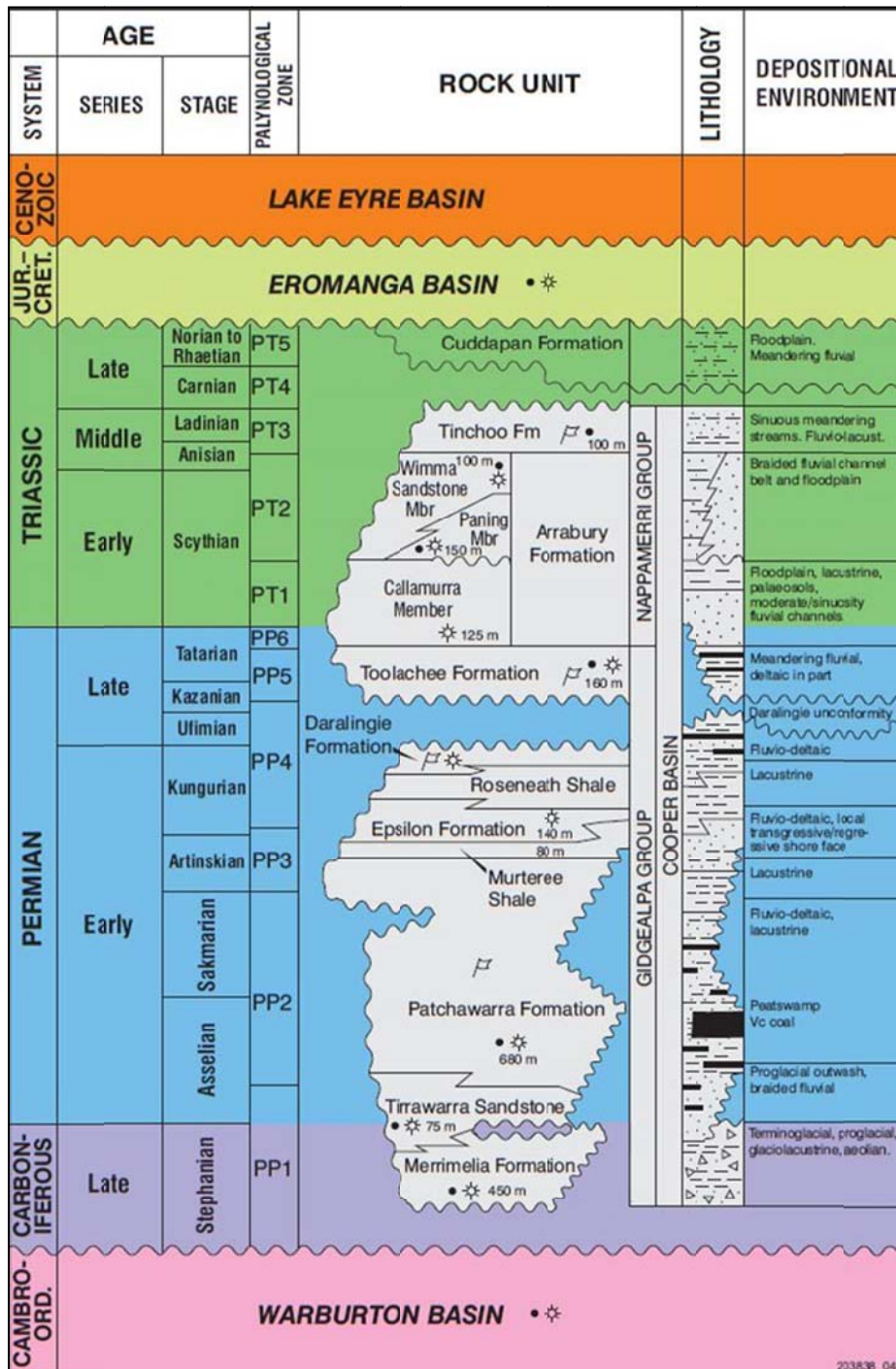
The most prospective shales in the Gidgealpa Group, with oil and gas shows during drilling and higher TOCs, are the Early Permian Roseneath and Murteree shales.<sup>5</sup> Figure III-5 shows a stratigraphic cross-section of the Roseneath, Epsilon, and Murteree (collectively termed REM) sequence in the Nappamerri Trough.

### 1.3 Reservoir Properties (Prospective Area)

The Murteree Shale is a widespread, shaley formation typically 150 feet thick across the Cooper Basin, becoming as thick as 250 feet 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 2.5% based on data from seven wells.

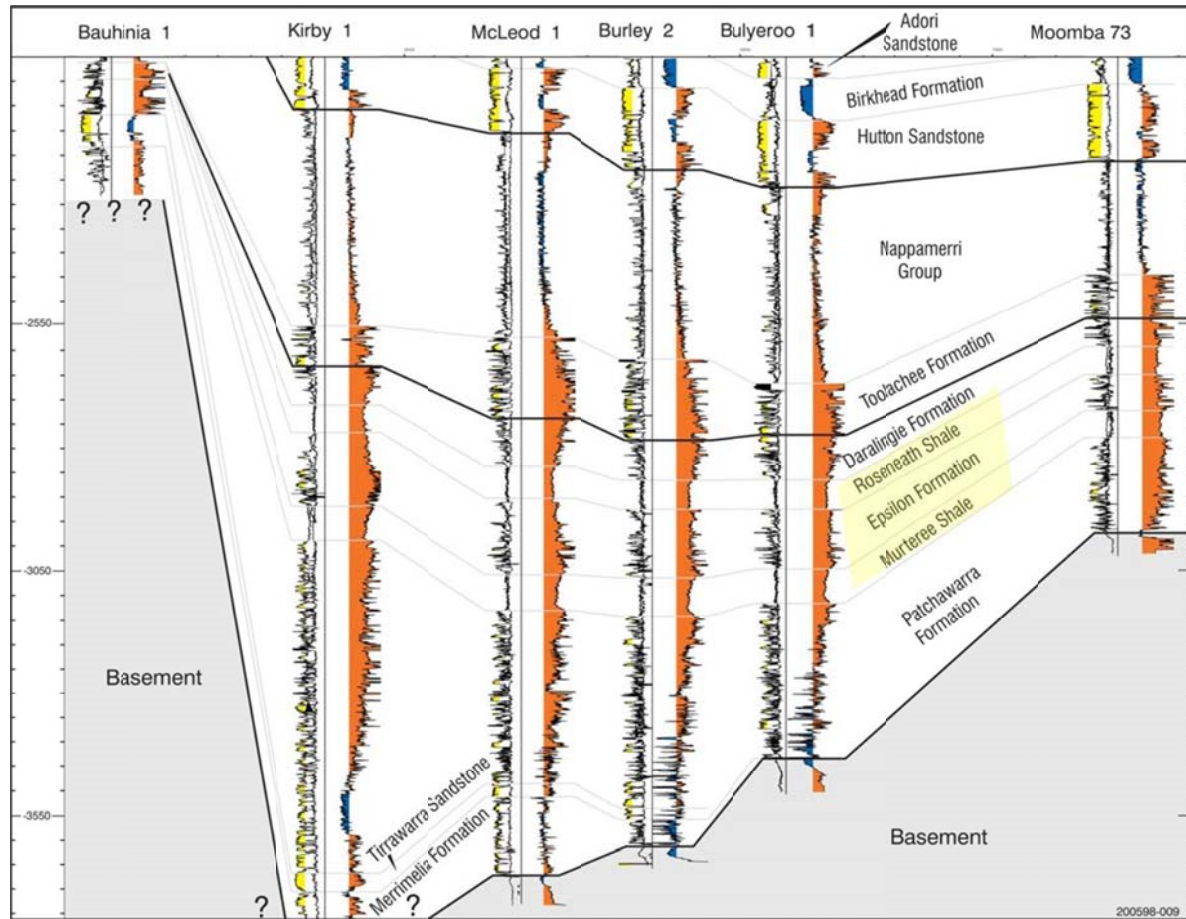
The Roseneath Shale, less widespread than the Murteree due to erosion on uplifts, averages 120 feet thick, reaching 330 feet thick in the Nappamerri Trough. The intervening Epsilon Fm consists primarily of low-permeability (0.1 to 10 mD) quartzose sandstone with carbonaceous shale and coal. The Epsilon, averaging about 175 feet thick in drill cores, was deposited in a fluvial-deltaic environment.<sup>6</sup>

Figure III-4. Stratigraphy of the Cooper Basin Permian-Age Shales



Source: South Australia DMER, 2010

Figure III-5. Stratigraphic Cross-Section in the Cooper Basin



Source: Menpes, 2012

The organic-rich gross thickness of the REM sequence in the Nappamerri Trough averages about 500 feet, with a net pay of 300 feet in the gas prospective area and a net pay of 150 feet in the oil prospective area.<sup>7</sup> The gross organic-rich REM sequence is much thinner in the Patchawarra Trough, averaging 100 feet in the gas prospective area and 125 feet in the oil prospective area, with a moderate net to gross ratio. The gross organic-rich REM sequence in the Tenappera Trough averages 225 feet.

The REM source rocks are primarily Type III kerogens. They have generated medium to light 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). Clay content is relatively low (20%; predominately illite).<sup>8</sup> 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 quite high, averaging 2.55°F/100ft. Bottomhole temperature at depths of 9,000 feet average about 300° F. The Nappamerri Trough is even hotter, with a temperature gradient of up to 3.42°F/100 ft, due to its radioactive granite basement. The Patchawarra Trough, which has a sedimentary-metamorphic basement, has a lower but still elevated 2.02° F/100 ft temperature gradient.

The thermal maturity of the Permian REM section in the deeper portions of the Nappamerri and Patchawarra troughs is gas prone ( $R_o > 1.3\%$ ).  $R_o$  values between 0.7% and 1.0% are observed at the shallower, southern ends of each trough and also in the Tenappara Trough, suggesting that the REM section is oil prone in these areas. A modest size wet gas/condensate prospective area exists between the oil prone and dry gas areas in the Nappamerri and Patchawarra troughs.

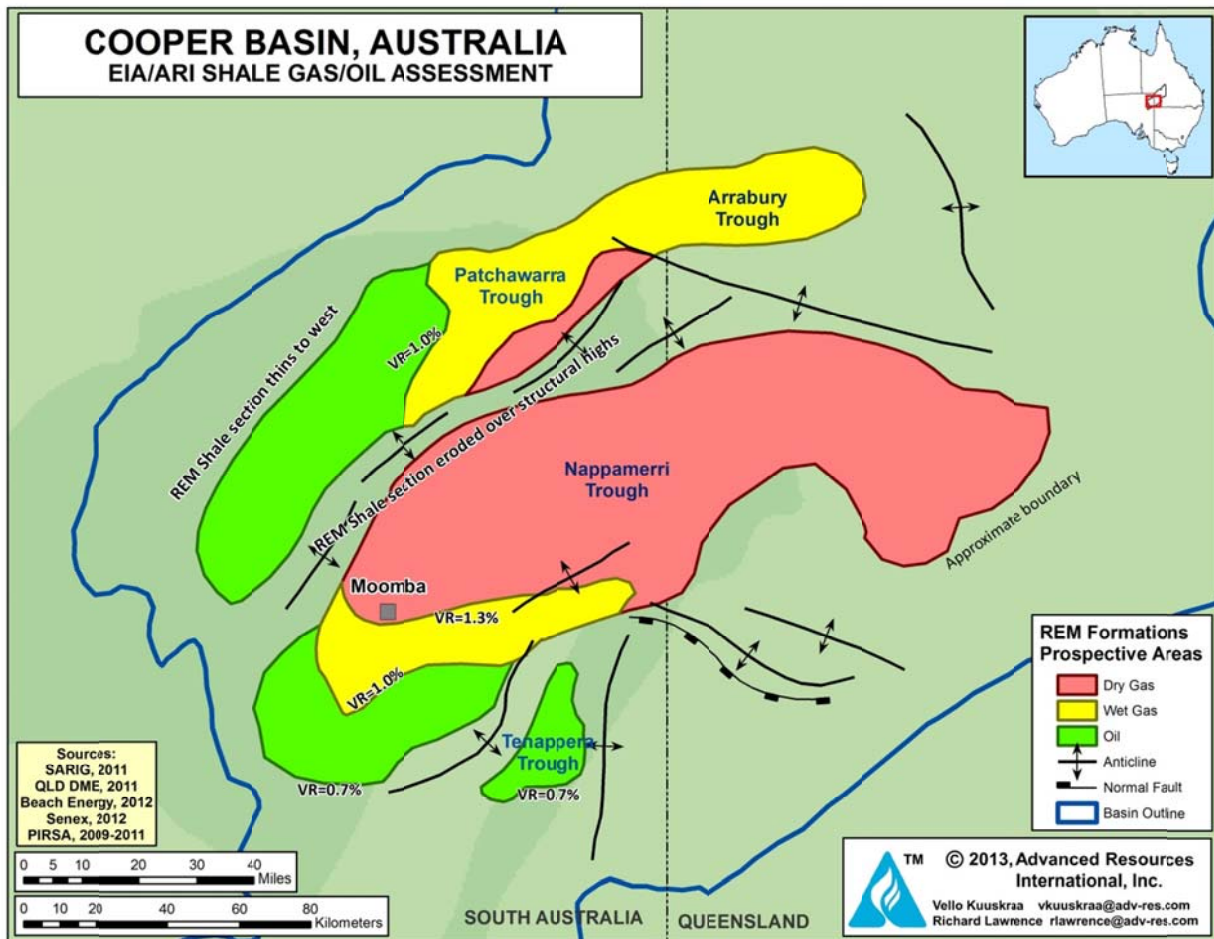
Regional hydrostatic pressure gradients are the norm in most of the Cooper Basin. However, the Nappamerri Trough becomes overpressured at depths of 9,000 to 12,000 feet, with pressure gradients of up to 0.7 psi/ft recorded in the deepest portions of the trough.<sup>9</sup> High levels of carbon dioxide are also common in the Cooper Basin. Gas produced from the Epsilon Formation (the central portion of the REM sequence) contains elevated  $CO_2$ , typically ranging from 8% to 24% (average 15%).<sup>10</sup>

#### 1.4 Resource Assessment

The prospective areas for shale gas development in the Cooper Basin area are defined by the intersection of a minimum depth of 6,500 feet (top of the gas window, as defined by thermal maturity modeling), vitrinite reflectance greater than 1.0%, and a minimum thickness of the REM section of 50 feet. The prospective areas for shale oil are defined by  $R_o$  values between 0.7% and 1.0% and a minimum thickness of the REM section of 50 feet, Figure III-6.

Completable shale intervals in the dry and wet gas prospective areas containing the Roseneath, Epsilon, and Murteree (REM) formations have estimated shale gas resource concentrations of 88 to 100 Bcf/mi<sup>2</sup> in the Nappamerri Trough, benefitting from favorable thickness, moderate TOC and overpressuring, but reduced by 15% for  $CO_2$  content. In contrast, the shale gas resource concentrations in the dry and wet gas prospective areas of the Patchawarra Trough are much less, from 16 to 19 Bcf/mi<sup>2</sup>. The resource concentration in the oil prospective area of the Tenappara Trough is 22 million barrels/mi<sup>2</sup>.

Figure III-6. Southern Cooper Basin Prospective Shale Gas and Shale Oil Areas



The total shale gas and shale oil prospective area for the Permian REM section is estimated at 7,235 mi<sup>2</sup>, covering major portions of the Nappamerri, Patchawarra and Tenapperra troughs in the Cooper Basin. Net of 15% CO<sub>2</sub> content, the estimated risked shale gas in-place is 325 Tcf, with a risked, technically recoverable shale gas resource of 93 Tcf, including associated gas in the shale oil prospective area, Table III-A. The risked shale oil in-place in the Cooper Basin is 29 billion barrels, with a risked, technically recoverable resource of 1.6 billion bbls, Table III-2A.

## 1.5 Recent Activity

The Cooper Basin is Australia's largest onshore oil and gas production region. Beach Energy, Senex, DrillSearch Energy and Santos have active shale gas and oil exploration and evaluation programs underway.

Beach has drilled two vertical test wells in the deep, central portion of the Nappamerri Trough. These wells each tested at about 2 MMcfd gas after hydraulic stimulation. The Encounter-1, thought to be Australia's first commercially viable shale well, was drilled to a total depth of 11,850 feet and penetrated 1,290 feet of the REM sequence, reporting continuous gas shows. Beach drilled an additional three vertical test wells in the first half of 2012, with three more planned for the rest of the year. The test wells will be studied to identify the best locations for placing two horizontal wells to be drilled in late 2012.

Senex has drilled five vertical test wells in the Tenappera Trough to the south and east of the Nappamerri Trough with reports of liquid hydrocarbon production. The company is planning a 12 well drilling program for 2012/13. DrillSearch Energy, in a JV with the BG Group, has undertaken detailed shale core studies along with acquiring 425 mi<sup>2</sup> of 3D seismic.

## **2. MARYBOROUGH BASIN**

### **2.1 Introduction**

This small basin in coastal Queensland, located about 250 km north of Brisbane, has two potential gas shale targets within the Cretaceous Maryborough Formation. The basin is highly unexplored with only five conventional oil and gas exploration wells drilled to date. Three large anticlines occur within the onshore portion of the basin, all of which have been drilled but without conventional discoveries.<sup>11</sup>

### **2.2 Geologic Setting**

The Maryborough Basin is a half-graben bounded on the west by the Electra Fault. It covers an onshore area of 4,300-mi<sup>2</sup>, Figure III-7. Major folding and faulting, along with significant erosion, occurred during the Cretaceous-Palaeogene establishing the structural setting of the basin. Two main depositional sequences were examined in the Maryborough Basin, Figure III-8.<sup>12</sup> The Duckinwilla Group, which contains Late Triassic to mid-Jurassic non-marine sediments, is not considered prospective for shale oil or gas. Overlying the Duckinwilla is the Grahams Creek Formation which contains Late Jurassic to Cretaceous (Neocomian) strata, including the marine-deposited Maryborough Formation.

### **2.3 Reservoir Properties (Prospective Area)**

The Maryborough Formation (Neocomian-Aptian) appears to be the primary shale gas unit in the Maryborough Basin. Up to 8,500 feet thick, it is the only definitely marine unit in the basin. The unit consists primarily of mudstones, siltstone and sandstone with minor conglomerate, limestone and coal. Within the Maryborough Formation, the most prospective sub-units are the Goodwood Mudstone, the Woodgate Siltstone, and the Cherwell Mudstone, Figure III-9. These sub-units have been described as a monotonous series of mudstones with minor shales and siltstones. The mudstones are light to dark grey, slightly calcitic, pyritic and silty. Calcite veins are common in the lower section.<sup>13</sup> The Goodwood Mudstone (Shale) interval is approximately 2,000 feet thick (gross) with a depth of 5,000 feet on anticlines to 15,000 feet in the troughs. TOC averages 2.0% and the shale is within the dry gas maturity window ( $R_o > 1.5\%$ ). The underlying Cherwell Mudstone (Shale) interval consists mainly of black shale about 500 feet thick (gross) and ranges from 8,000 feet deep on anticlines to a projected 17,000 feet deep in the troughs. TOC averages 2.0% and the shale is thermally mature ( $R_o > 1.5\%$ ). The net organic-rich pay in the two shale intervals is estimated at 250 feet.



Figure III-7. Maryborough Basin Prospective Shale Gas Area

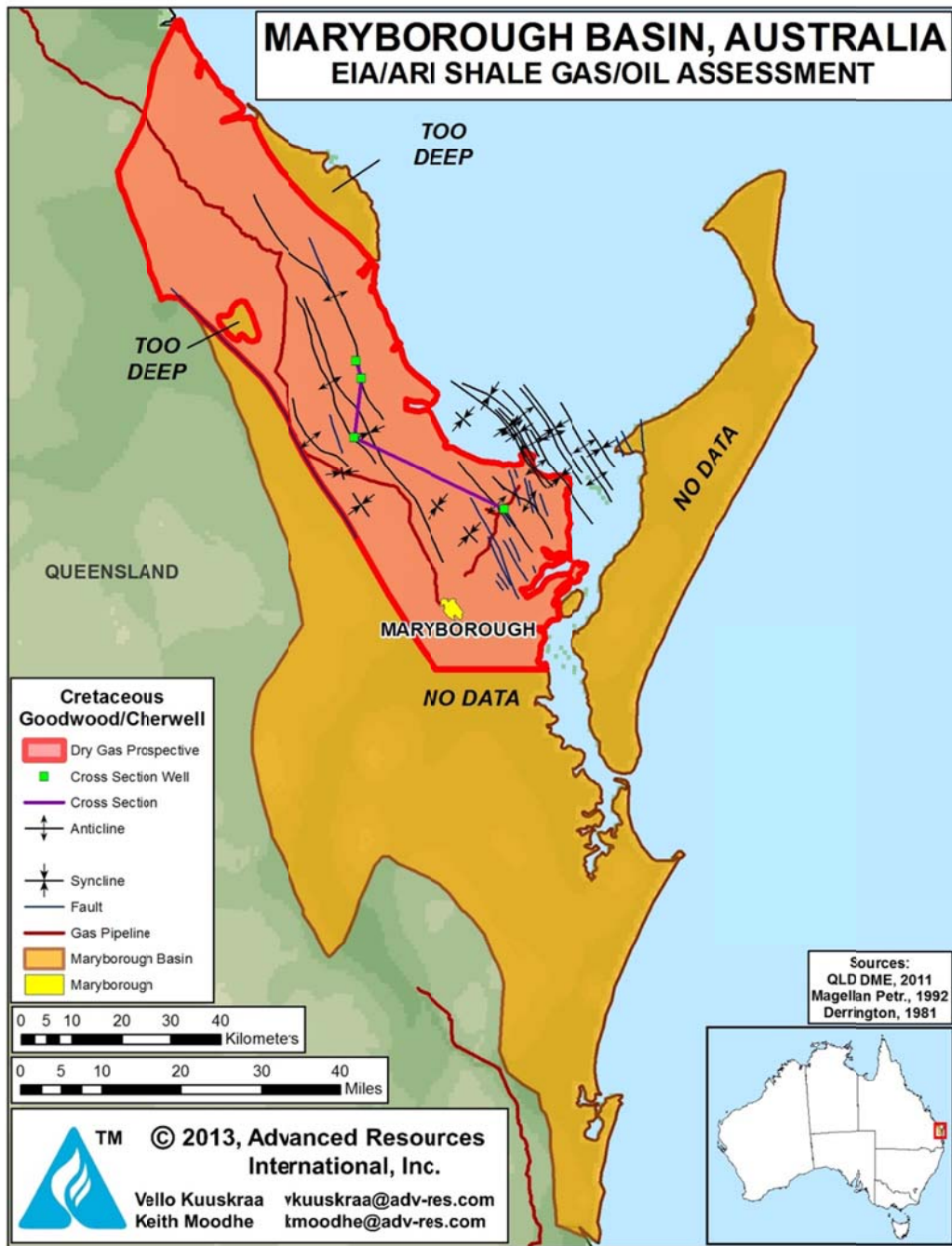


Figure III-8. Stratigraphy of the Maryborough Basin

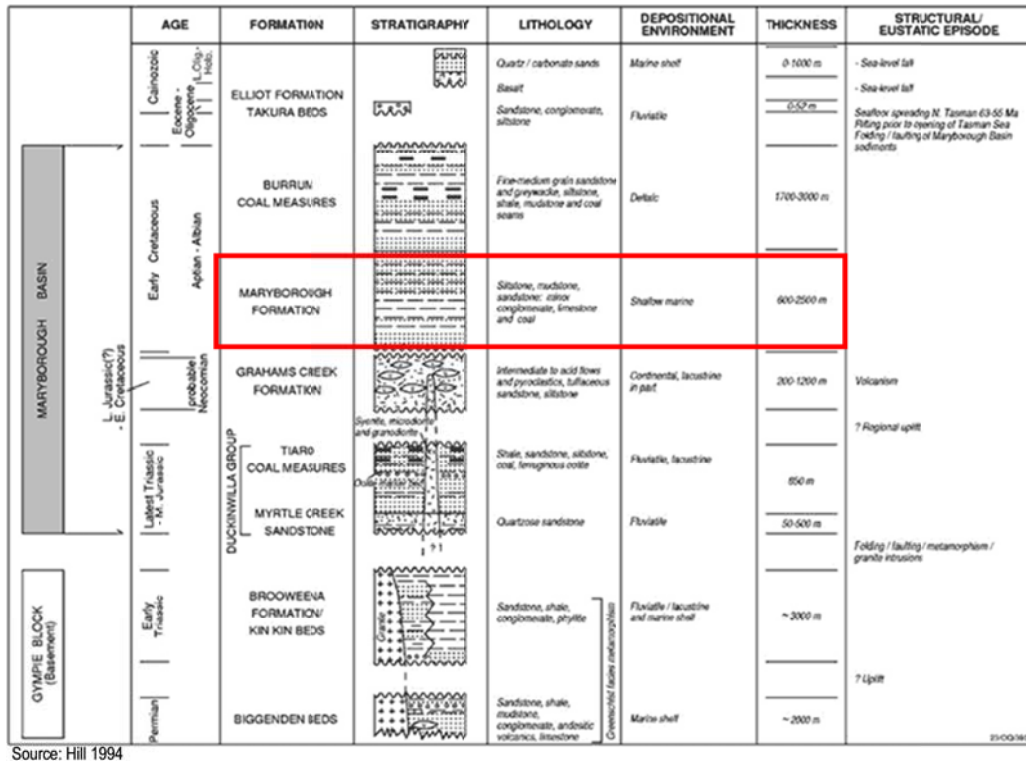
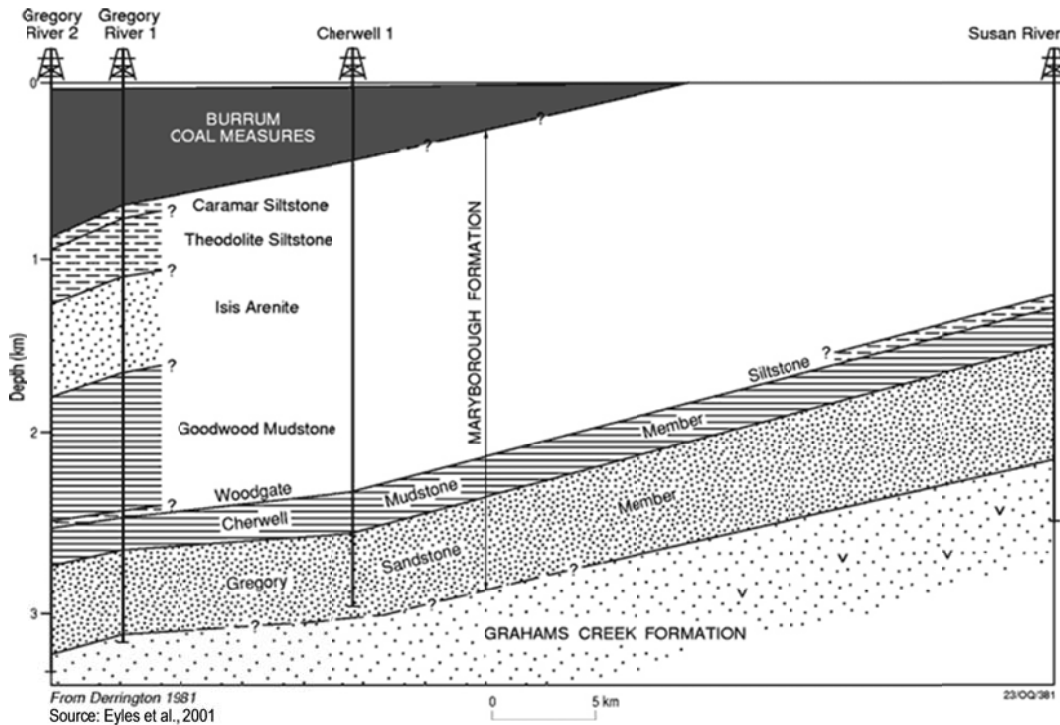


Figure III-9. Cross-Section of the Maryborough Basin and the Cretaceous Maryborough Formation.



## 2.4 Resource Assessment

ARI evaluated only the northern portion of the Maryborough Basin where geologic data exist. We estimate that a 1,540-mi<sup>2</sup> area could be prospective for shale gas development. Additional areas in the poorly constrained southern half of the basin may be prospective but lack sufficient data for a rigorous resource assessment.

The basal shales of the Maryborough Formation (Cherwell and Goodwood shales) have an estimated gas in-place concentration of 111 Bcf/mi<sup>2</sup>. The risked gas in-place for the shales in the Maryborough Basin is estimated at 64 Tcf, with a risked, technically recoverable shale gas resource of 19 Tcf, Table III-1B. With its high thermal maturity, the Maryborough Formation is dry-gas prone and thus not prospective for shale oil.

## 2.5 Recent Activity

Blue Energy Ltd., in a JV with Beach Energy, is awaiting award of three exploration permits in the northern portion of the Maryborough Basin. The companies are assessing the potential of shale gas in this basin target with a view toward determining a possible shale test well drilling location.<sup>14</sup>

### **3. PERTH BASIN (WESTERN AUSTRALIA)**

#### **3.1 Introduction**

The Perth Basin, an active petroleum producing region, extends on- and offshore in the southwest of Western Australia. The basin contains two main organic-rich shale formations, the Permian Carynginia and the Triassic Kockatea.

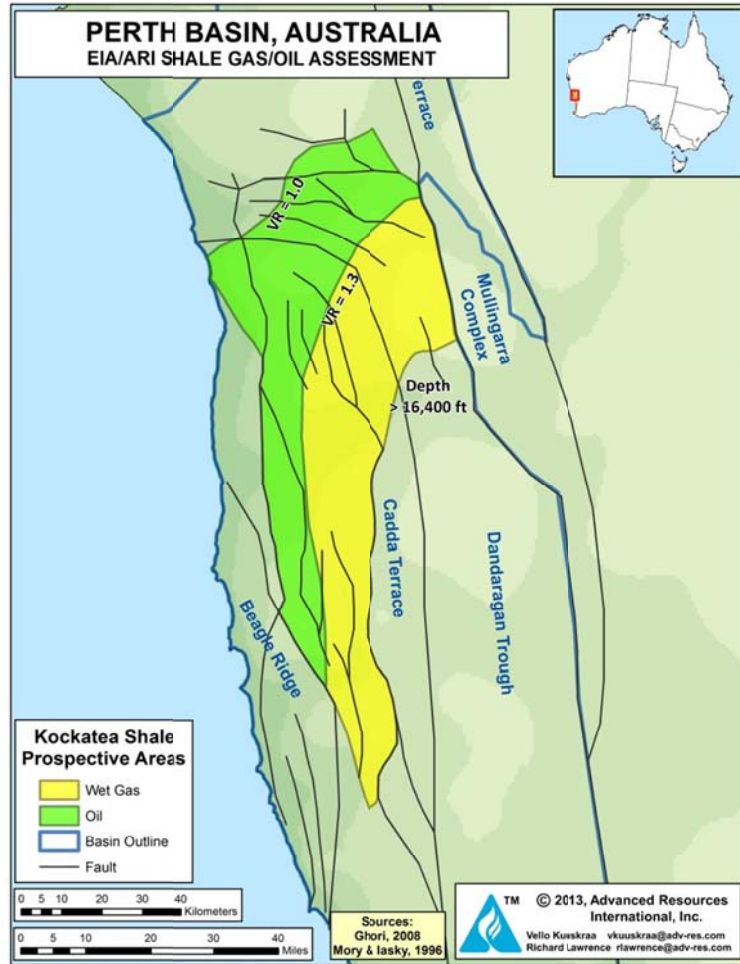
#### **3.2 Geologic Setting**

The Perth Basin is a north-northwest trending half-graben with relatively simple structure that appear favorable for shale oil and gas development. About half of the basin is onshore, covering an area of approximately 20,000 mi<sup>2</sup>. The onshore portion of the basin contains two large, deep sedimentary sub-basins, the Dandaragan and Bunbury troughs, separated by the Harvey Ridge structural high, Figure III-10.<sup>15</sup>

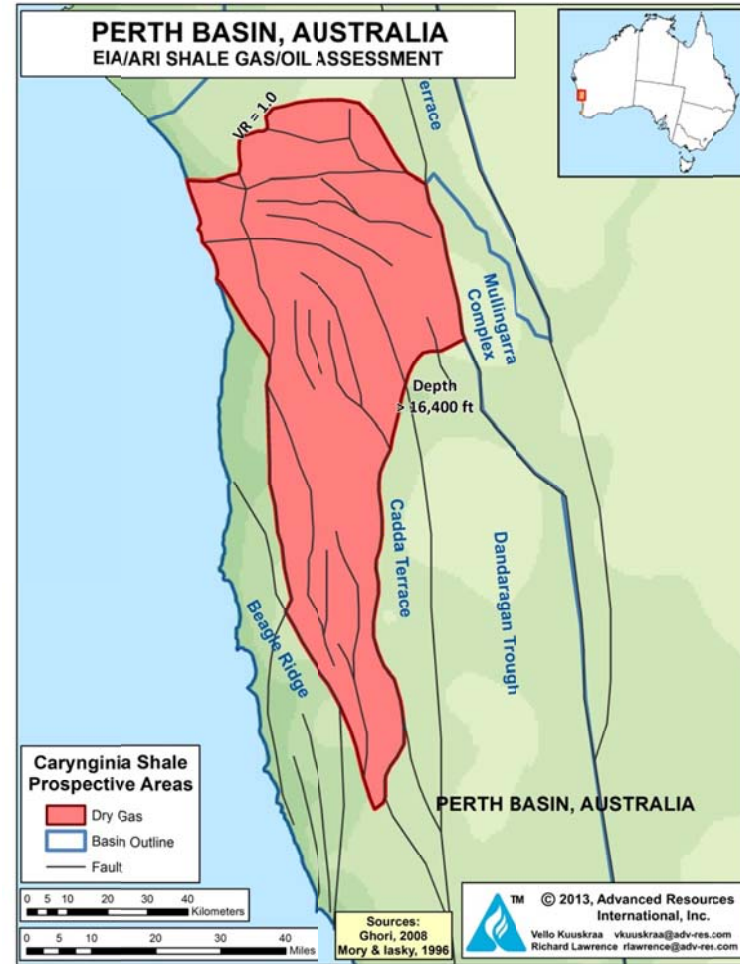
The Dandaragan Trough, a large syncline in northern Perth Basin, contains the deepest, thickest and most prospective shale gas formations. Some 300 miles long and up to 30 miles wide, the Dandaragan Trough holds as much as 9 miles of Silurian to early Cretaceous sedimentary rocks. Much of the Dandaragan Trough is too deep for shale development, but its northern area and the adjoining Beagle Ridge appear to be within the prospective shale depth window. The area is not structurally complex but does have some significant faulting, Figure III-11.<sup>16</sup>

Approximately 100 petroleum exploration wells have been drilled in the onshore portion of the Perth Basin, resulting in the discovery of six conventional natural gas fields, all located within the Dandaragan Trough. Proved reserves to date total about 600 Bcf with small amounts of associated oil in conventional reservoirs (Upper Permian Dongara Sandstone and Beekeeper Formation). Natural gas recovered from the deeper Permo-Triassic reservoirs (Dongara, Mondarra, Yardarino, Woodada and Whicher Range) tends to be dry, reflecting higher thermal maturity and higher proportions of gas-prone organic matter. CO<sub>2</sub> is generally low, apart from isolated readings of 4.1% in the Woodada-1 well and 3.9% in the Mondarra-1 well.

Figure III-10. Perth Basin Prospective Shale Gas and Shale Oil Areas

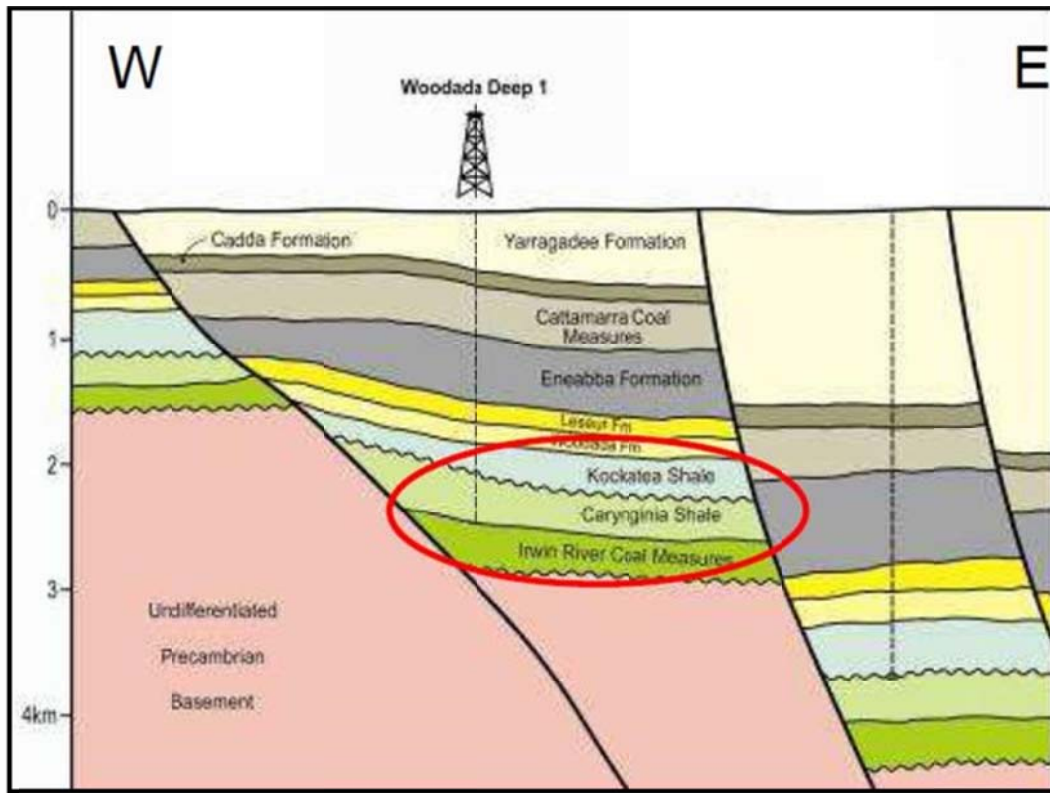


Source: ARI, 2013.



Source: ARI, 2013.

Figure III-11. The Woodada-1 Deep Well Tested the Carynginia Shale



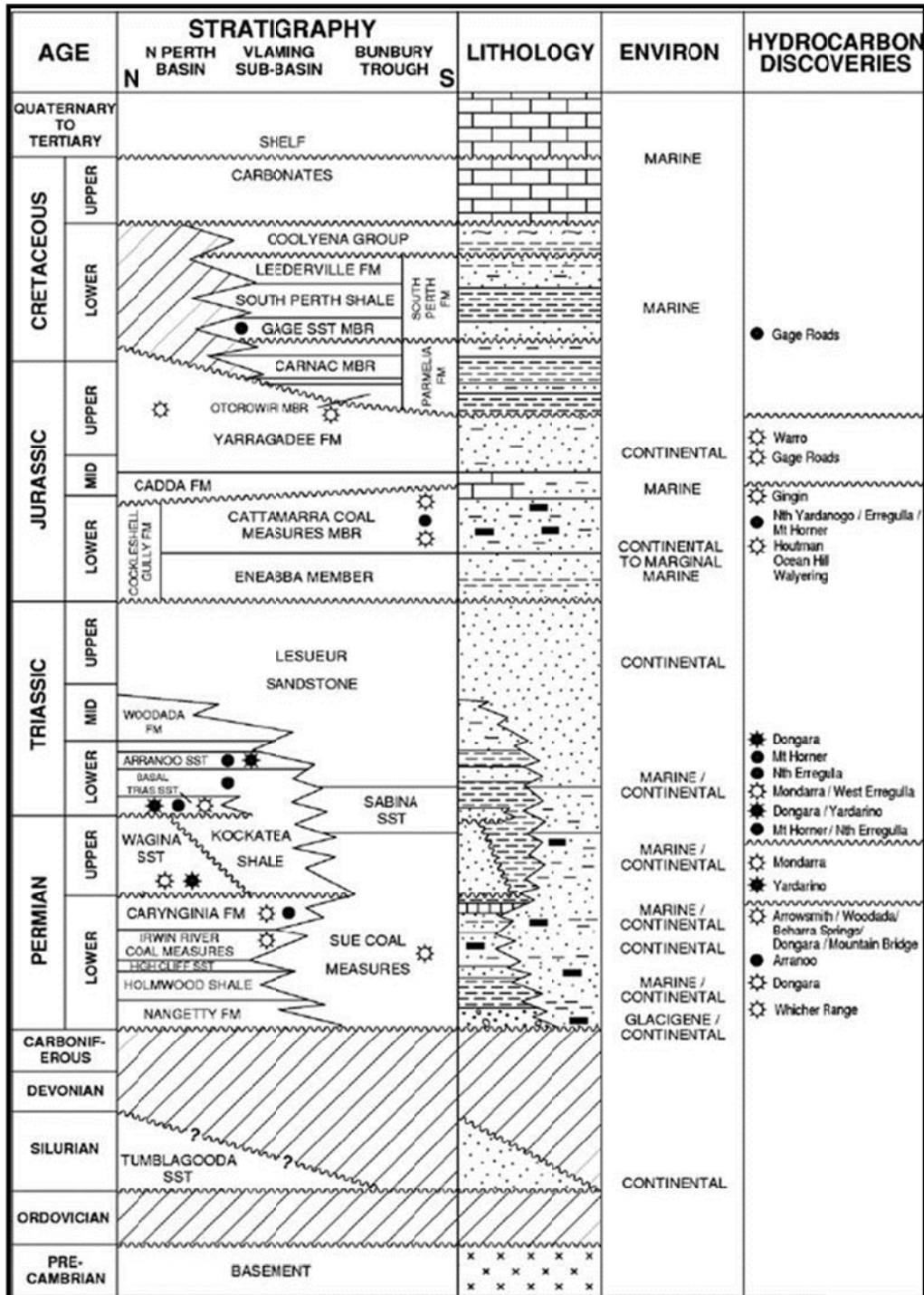
Source: AWE 2010

Tight sandstone reservoirs in the Perth Basin include the Eneabba and Yarragadee formations. These reservoirs were sourced by the Triassic and Permian source rock shales and coals, which modeling indicates are within the oil window in the far north of the Perth Basin and enter the gas window toward the southeast.

The sedimentary sequence in the Perth Basin comprises three successions: a) Lower Permian largely argillaceous glaciomarine to deltaic rocks (including the prospective Carynginia Shale); b) Upper Permian nonmarine and shoreline siliciclastics to shelf carbonates; and c) Triassic to Lower Cretaceous nonmarine to shallow marine siliciclastics (including the prospective Kockatea Shale) deposited in a predominantly regressive phase, Figure III-12.<sup>17</sup>

Other marine shales in the Perth Basin that were evaluated but rejected as prospects include the Triassic Woodada and Jurassic Cadda formations (too lean), the Jurassic Parmelia (Yarragadee) Formation (lacustrine origin, located only in the offshore), and the Cretaceous South Perth Formation (immature, offshore only).

Figure III-12. Stratigraphy of the Perth Basin Showing the Prospective Lower Triassic Kockatea and Permian Carynginia Shales

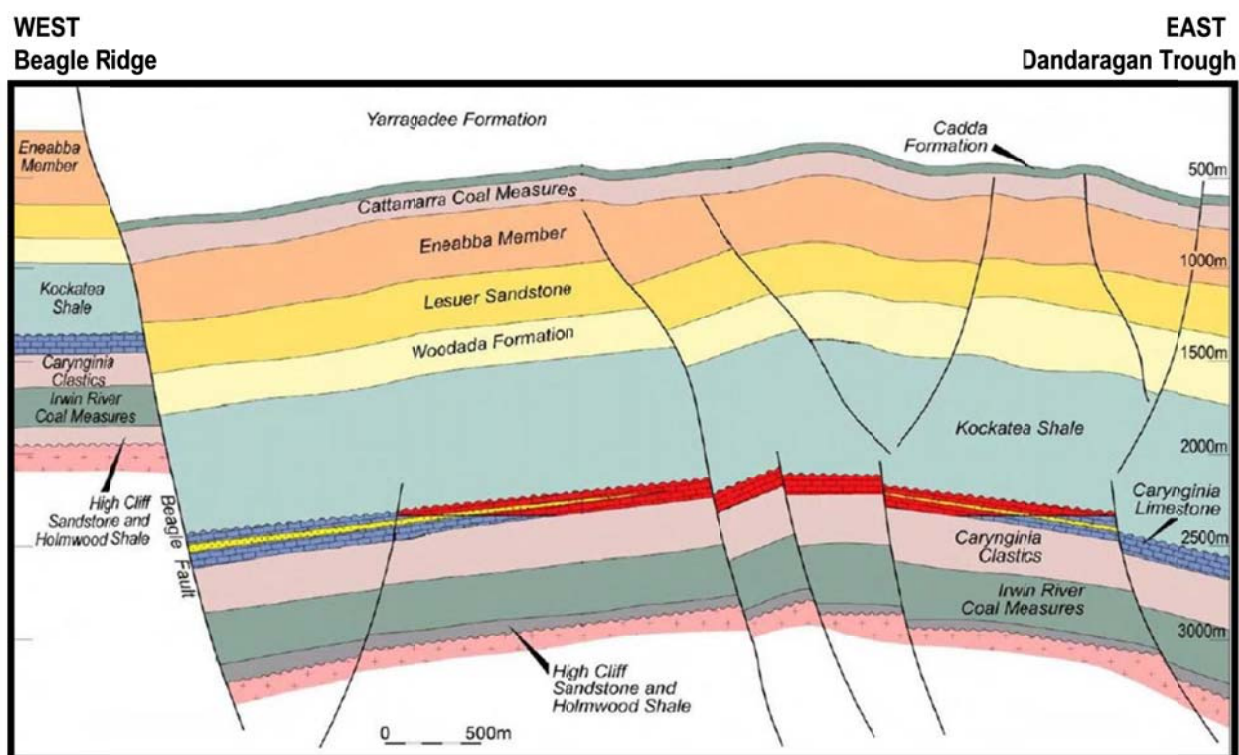


Source: Cadman et al., 1994

### 3.3 Reservoir Properties (Prospective Area)

The Lower Triassic Kockatea Shale is considered the primary oil source-rock as well as the main hydrocarbon seal in the basin. It consists of dark shale, micaceous siltstone and minor sandstone and limestone. The Kockatea Shale interval thickens to the south within the Perth Basin, reaching a maximum thickness of 3,500 ft in the Woolmulla-1 well, Figure III-13. The most organic-rich portion of this unit (Hovea Member) has recorded TOC values up to 8%.<sup>18</sup>

Figure III-13. Structural Cross-Section of the Perth Basin Showing 2,300 ft thick Kockatea and 820 ft Thick Carynginia Shales at Prospective 5,000 – 9,200 ft Depth



Source: Norwest Energy, 2010

Core samples of the Hovea Member of the Kockatea Shale, obtained from the Hovea-3 petroleum exploration well, provide data on reservoir quality.<sup>19</sup> The base of this unit contains a distinct organic-rich zone of fossiliferous dark grey mudstone, sandy siltstone and shelly storm beds. These sediments were deposited at a relatively low paleo-latitude in a shallow marine environment during the earliest stage of a marine transgression. TOC of the Kockatea Shale sampled from this well ranged from 2.31% to 7.65% (average 5.6%), consisting of inertinite-rich (Type III) kerogen.<sup>20</sup>



The clay content of the Hovea Member of the Kockatea Shale in the Hovea-3 well ranged from 24% to 42% (average 33%). Separately, AWE cored a high-TOC, 160 ft thick Hovea Member of the Kockatea Shale in the conventional Redback-2 exploration well in 2010, but reported discouragingly high clay content. The Kockatea is thermally mature for gas in the Dongara Trough, but less mature and possibly oil-prone on the Dongara Saddle and the flanks of the Beagle Ridge. CO<sub>2</sub> and N<sub>2</sub> contents tested low (0.5% and 0.4%, respectively) from a 4,750 ft deep Kockatea Shale zone in the Dongara-24 well.<sup>21</sup>

The Permian Carynginia Shale, a shallow -marine deposit present over much of the northern Perth Basin. The Carynginia Shale conformably underlies the Kockatea Shale. AWE Limited recently reported encouraging organic-shale characteristics for this 800 to 1,100 ft thick unit. A deeper-water shale member occurs near the base of the Carynginia Shale, including thin interbeds of siltstone, sandstone, and limestone.

Overlying the Carynginia Shale is a shallow-water, shelf limestone unit that contains conventional gas reservoirs. Conventional gas is produced from the Carynginia Limestone at Woodada field, sealed by the overlying Kockatea Shale. CO<sub>2</sub> and N<sub>2</sub> tested fairly low (about 2.5%) from a 8,000 ft Carynginia Fm zone in the Elegans-1 well.

While TOC values of up to 11.4% have been recorded, the TOC in the Carynginia Shale averages 4%. The kerogen is Type III, dominated by inertinite derived from land plants. Gas-prone, the Carynginia Shale is in the dry gas window over most of the Perth Basin. Source rocks are less mature on the Dongara Saddle and the flanks of the Beagle Ridge, where the shale is partly replaced by shallow-water, limestone facies.

Geothermal gradients in the Perth Basin can be elevated, ranging from 2.0°C to 5.5°C/100 m, but the thermal gradient in the Dandaragan Trough is less extreme (2° to 2.5°C/100 m). Vitrinite reflectance data show poor relationship with depth, with extreme data scatter probably caused by subertinite and bitumen suppression.

### **3.4 Resource Assessment**

The prospective areas of the Beagle Ridge and Dandaragan Trough are located in the northern portion of the Perth Basin, where the Carynginia and Kockatea Shale source rocks are thick, deep and thermally mature, Figure III-10.

An estimated 1,030-mi<sup>2</sup> area is prospective for wet shale gas and condensate in the Kockatea Shale, defined using minimum and maximum depth criteria (3,300-16,500 ft) and vitrinite reflectance ( $R_o$  of 1.0% to 1.3%). A smaller 860-mi<sup>2</sup> area, up-dip from the wet gas prospective area, defined by  $R_o$  values between 0.7% and 1.0% and a minimum depth of 3,300 ft, appears prospective for shale oil in the Kockatea Shales. The deeper Carynginia Shale has a dry gas prospective area of 2,200 mi<sup>2</sup>. Additional portions of the southern half of the Perth Basin may be prospective but insufficient data were available for a quantitative assessment.

The Permian Carynginia Shale has a resource concentration of 94 Bcf/mi<sup>2</sup> within its 2,200-mi<sup>2</sup> dry gas prospective area. It holds a risked gas in-place of 124 Tcf, with a risked, technically recoverable shale gas resource of 25 Tcf, Table III-1B.

The Triassic Kockatea Shale has a resource concentration of 59 Bcf/mi<sup>2</sup> within its 1,030-mi<sup>2</sup> wet gas prospective area. Including associated gas, the Kockatea Shale has a risked gas in-place of 36 Tcf, with a risked, technically recoverable shale gas resource of 7 Tcf, Table III-1B. Shale oil resource concentrations in the Kockatea Shale are estimated at 19 million barrels/mi<sup>2</sup> in the oil prospective area and 6 million barrels/mi<sup>2</sup> in the condensate prospective area. Risked shale oil in-place in the two prospective areas is 14 billion barrels, with a risked, technically recoverable shale oil/condensate resource of 0.5 billion barrels, Table III-2A.

### 3.5 Recent Activity

In April 2010, AWE Limited cut five cores in the Carynginia Shale in its Woodada Deep exploration well in northern Perth Basin. The company found the upper and lower zones to have high clay content. However, the middle zone was considered more prospective, with lower clay (value not reported), 1 to 4% TOC and estimated 3 to 6% porosity at a depth between 7,780 and 7,960 ft. Zones in the Upper and Middle Carynginia were successfully hydraulically fractured in August 2012, with gas being produced during well flow-back and clean-up. AWE estimated a total 13 to 20 Tcf of gas in-place on its permit for the middle zone of the Carynginia Shale.<sup>22</sup>

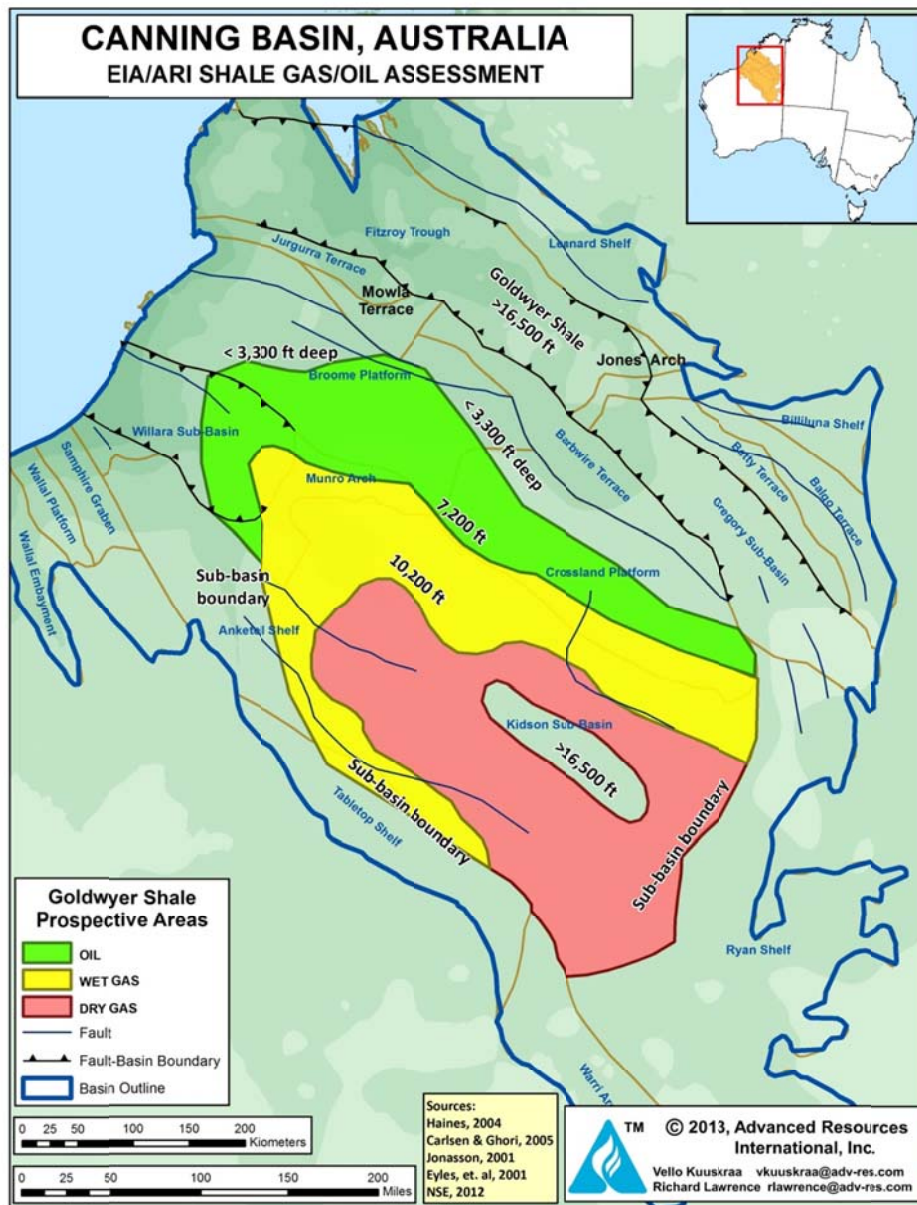
Australian independent, Norwest Energy which produces oil and gas from conventional fields in the Perth Basin, is evaluating the shale potential on its EP413 permit area, about 20 miles north of the Woodada Deep well. Norwest is partnered with AWE and has also farmed-out an interest in EP413 to an Indian firm, Bharat PetroResources. The companies have committed up to A\$15 million for shale exploration and drilling. The consortium drilled the Arrowsmith-2 well in June 2011 and fractured five stages in shale and tight sand intervals. Initial results during flowback reported gas flows from all zones including the Upper and Middle Carynginia and both oil and gas flows from the Kockatea Shale.

## 4 CANNING BASIN (WESTERN AUSTRALIA)

### 4.1 Introduction

The large, lightly explored Canning Basin in northwestern Australia contains several organic-rich shales, including the Laurel and Lower Anderson shales and the significant Goldwyer Shale, Figure III-14.

Figure III-14. Canning Basin Prospective Shale Gas and Shale Oil Areas



Source: ARI, 2013.

## 4.2 Geologic Setting

The 234,000-mi<sup>2</sup> Canning Basin (181,000 mi<sup>2</sup> onshore) is Western Australia's largest sedimentary basin. A broad intracratonic rift basin, the Canning contains up to 11 miles of Ordovician- to Cretaceous-age sedimentary rocks. The basin is separated from the Amadeus Basin to the east by a Precambrian arch. A series of northwest-trending, fault-bounded troughs within the basin, such as the Fitzroy Trough, may hold deep shale resource potential.<sup>23</sup>

Conventional exploration in the Canning Basin has focused on the Lennard Shelf, where petroleum occurs in the Hoya and Anderson formations. Only about 60 wells have intersected the principal source rocks in the basin, and most of the wells have been located on the uplifted terraces between the deeper troughs. Source rock data in the basin is limited, but the oil discoveries on the Lennard Shelf are sourced from Carboniferous and Devonian formations. In basin areas south of the Fitzroy Trough, the oil shows are sourced from Ordovician formations<sup>24</sup>.

Figure III-15 shows the stratigraphy of the Canning Basin. The primary shale target in the basin is the organic-rich Ordovician Goldwyer Formation. The Carboniferous Laurel Formation could not be rigorously assessed due to insufficient data control. Other marine shales in the Canning Basin, such as the Calytrix Formation, appear to be too lean.

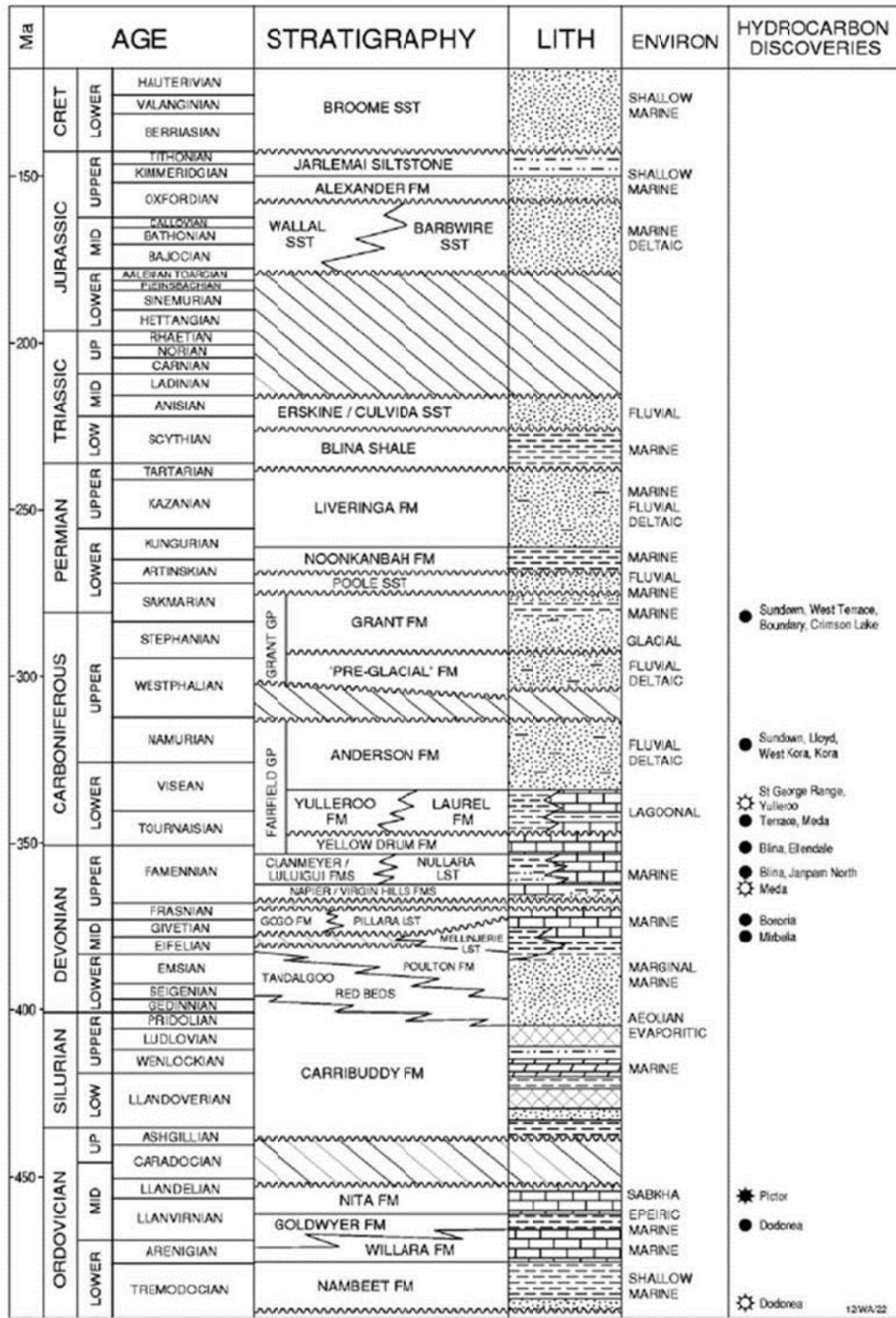
## 4.3 Reservoir Properties (Prospective Area)

The Middle Ordovician Goldwyer Formation was deposited mainly in open marine to intertidal conditions. Highly fossiliferous, the formation varies from mudstone-dominated in basinal areas to limestone-dominated in platform and terrace areas. The Goldwyer Formation averages about 1,300 feet thick, reaching a maximum thickness of 2,414 feet in the Willara-1 well in the Willara sub-basin.<sup>25</sup>

The Goldwyer Shale is dominated by mudstone and carbonate, with ratios of these components varying widely across the basin. The color of the shale ranges from grey-green to black, indicating anoxic reducing conditions.

The Goldwyer Shale contains horizons with high concentrations of the marine alga *Gloeocapsomorpha prisca*, considered to have excellent source-rock potential, similar to the Amadeus, Baltic, and Williston basins.<sup>26</sup> The Goldwyer Shale is oil prone on the uplifted platforms and terraces as shown by shallower exploration wells, but likely mature and gas prone in the adjacent deep troughs.

Figure III-15. Canning Basin Stratigraphic Column



The depth of the Goldwyer Shale in the Canning Basin varies from greater than 16,500 feet in the southern Kidson sub-basin to less than 3,000 ft on the uplifted blocks of the Barbwire and Jurgurra Terraces, Figure III-16. In the northern, very deep Fitzroy Trough and Gregory sub-basin, the Goldwyer is at depths greater than 16,500 ft.

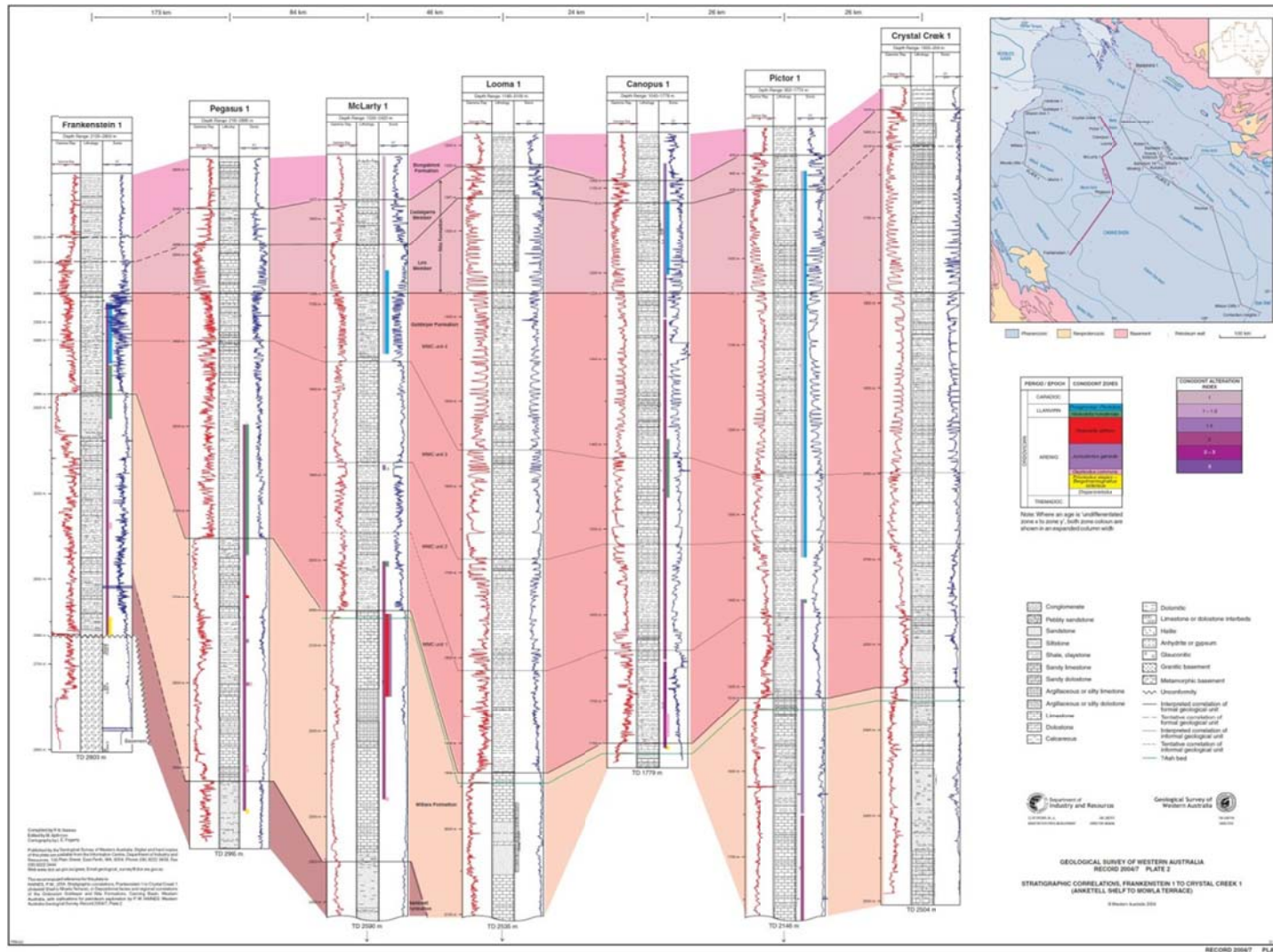
TOC in the Goldwyer Shale generally ranges from 1% to 5% (mean 3%), with some values in excess of 10%, Figure III-17.<sup>27</sup> The upper member of the Goldwyer Shale is particularly rich, with TOC up to 6.40%. Rock-Eval pyrolysis indicates this source rock is within the oil window over much of the southern Canning Basin and the mid-basin platform. The Kidson Sub-basin, where the Goldwyer deepens to 5,000 m, is in the dry gas window ( $R_o > 1.3\%$ ). In general, the Goldwyer Shale is in the oil window at depths less than 7,200 feet, in the wet gas and condensate window between 7,200 and 10,500 feet and in the dry gas window at depths over 10,500 feet.<sup>28</sup>

#### 4.4 Resource Assessment

ARI identified a prospective area in the Kidson sub-basin in the southern portion of the Canning Basin. Here, the Goldwyer Shale is thick, deep (7,200-16,500 feet), and thermally mature. An estimated 22,860-mi<sup>2</sup> area may be prospective for dry gas development with a second 19,620-mi<sup>2</sup> area prospective for wet gas and condensate. A smaller 14,900-mi<sup>2</sup> area appears prospective for shale oil. The boundaries and depth contours for the undrilled deep trough areas were extrapolated from information at adjoining uplifts.

In the dry and wet gas prospective areas, the Goldwyer Shale has resource concentrations of 109 Bcf/mi<sup>2</sup> and 67 Bcf/mi<sup>2</sup>, respectively. Including associated gas, the Goldwyer Shale in the Canning Basin has a risked shale gas in-place of 1,227 Tcf, with risked, technically recoverable shale gas of 235 Tcf. The prospective areas for oil and condensate for the Goldwyer Shale have resource concentrations of 41 million barrels/mi<sup>2</sup> and 10 million barrels/mi<sup>2</sup>, respectively. Including both the oil and condensate prospective areas, the Goldwyer Shale, has risked shale oil/condensate in-place of 244 billion barrels, with risked, technically recoverable shale oil/condensate resources of 9.8 billion barrels.

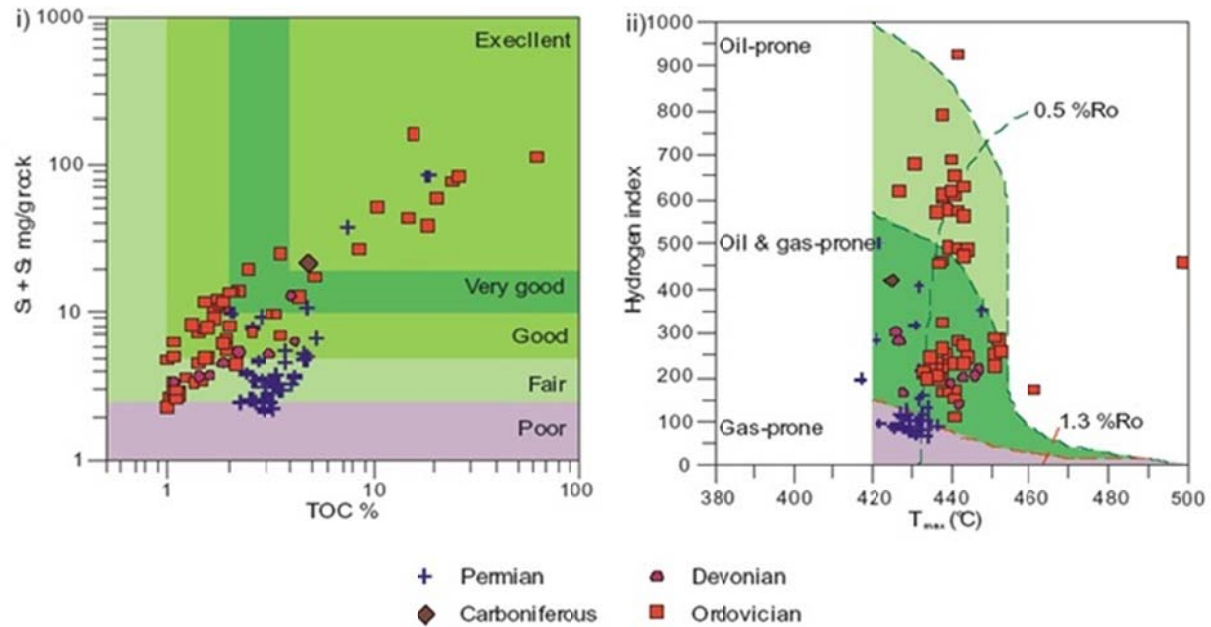
Figure III-16. North-South Cross Section of the Canning Basin



Source: Haines, 2004



Figure III-17. TOC Values in the Ordovician Goldwyer Formation



Source: Ghori and Haines, 2007

#### 4.5 Recent Activity

Buru Energy, an Australian E&P company, holds significant exploration permits in the Canning Basin. Buru reported gas-mature, organic-rich shale from cores in the Yulleroo-1 conventional exploration well drilled in 1967 on permit EP-391. In 2010, Mitsubishi agreed to fund an A\$152.4 million exploration and development program to earn a 50% interest in Buru's permits. The two companies have plans to evaluate the Goldwyer Shale in the Kidson sub-basin.

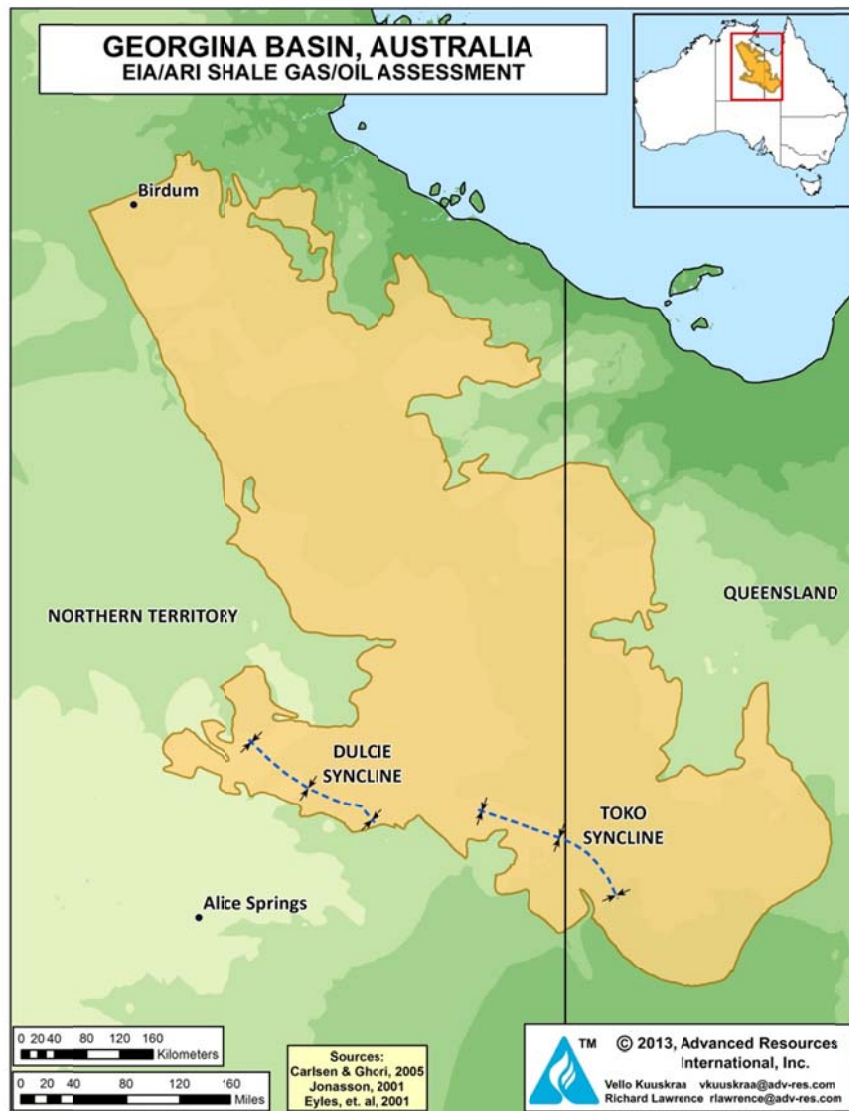
New Standard Energy (NSE), the other principal operator in the Canning Basin, holds exploration licenses covering 17,300 mi<sup>2</sup> in the northern edge of the Kidson sub-basin. In September 2011, NSE formed a joint venture with ConocoPhillips to accelerate exploration of the Goldwyer Shale. ConocoPhillips has announced that it will fund an exploration program over four years for up to \$US119 million. Three wells will be drilled vertically and not fractured, but will have a detailed program of mud logging, full coring and wireline logs over the shale section. The first well in the program, the Nicolay #1, was spud on August 8, 2012 and is proposed to be drilled to a target depth of 11,300 feet.<sup>29</sup>

## 5. GEORGINA BASIN

### 5.1 Introduction

The Georgina Basin is a large, 125,000-mi<sup>2</sup> mainly unexplored basin in Northern Australia straddling the Northern Territory/Queensland border.<sup>30</sup> Twenty-nine test wells have been drilled, all in the southern third of the basin in the vicinity of the basin’s two major depositional centers, the Toko and Dulcie Synclines, Figure III-18.

Figure III-18. Georgina Basin Location Map



Source: ARI, 2013.

### 5.2 Geologic Setting

The Georgian Basin is filled with sediments deposited in a restricted anaerobic environment which supports the accumulation and preservation of organic matter. Two major depocenters consisting of downfaulted blocks and half-grabens on the southern margin of the basin contain up to 7,200 feet of Cambrian to Devonian section, Figure III-19.<sup>31</sup> The basin shallows northwards with the depth to top of the Cambrian Arthur Creek Shale becoming less than 3,000 feet along its northeastern border.

Figure III-19. Southern Georgina Basin Stratigraphic Column

AGE	DULCIE SYNCLINE (WEST)	WESTERN TOKO SYNCLINE (NT)	
TERTIARY	UNDIFFERENTIATED	UNDIFFERENTIATED	
LATE JURASSIC CRETACEOUS		UNDIFFERENTIATED	
DEVONIAN	DULCIE SANDSTONE	CRAVENS PEAK BEDS	ALICE SPRINGS OROGENY
LATE ORDOVICIAN SILURIAN			
EARLY MIDDLE ORDOVICIAN		ETHABUKA SST	RODINGAN MOVEMENT
		MITHAKA FM	
		CARLO SST	
		NORA FM	
	NORA FM	COOLBAH FM	
	KELLY CREEK FM	KELLY CREEK FM	
	TOMAHAWK FM	NINMAROO FM	
LATE CAMBRIAN			DELAMERIAN OROGENY
	ARRINTHRUNGA FM		
	EUROWIE SST MBR	EUROWIE SST MBR	
	CHABALOWE FM	ARRINTHRUNGA FM	
	HAGEN MBR		
MIDDLE CAMBRIAN		STEAMBOAT SST	
	ARTHUR CREEK FM 'HOT SHALE'	ARTHUR CREEK FM 'HOT SHALE'	
	THORNTONIA LST	THORNTONIA LST	
EARLY CAMBRIAN	RED HEART DOLOSTONE	RED HEART DOLOSTONE	PETERMANN OROGENY
	MOUNT BALDWIN FM	ADAM SHALE	
NEOPROTEROZOIC	ELKERA FM		
	MOPUNGA GP	MOPUNGA GP	

Source: Ambrose and Putnam, 2007, modified after Ambrose et al 2001

The lower section of the Cambrian sediments in the southern synclines contains the Arthur Creek “hot” black shale, so called because of its high gamma ray response seen on electric logs. The thickness of the “hot” shale, derived from seismic interpretation and well data, thickens from west to east, Figure III-20. The shale section is interbedded with higher porosity clastic and carbonate intervals, somewhat comparable to the Bakken Shale in the U.S.

### 5.3 Reservoir Properties (Prospective Area)

The Arthur Creek Shale is a Middle Cambrian sequence comprised of dolomitic sands/silts, shales, dolomites and a basal black anoxic “hot shale”.<sup>32,33</sup> Modern electric logs run over the vertical section of the “hot shale” show log porosities up to 22% for the silt/sand stringers, averaging 10% over the whole section. The larger Arthur Creek Shale interval contains a high proportion of carbonates and has low clay content. Logs also show water saturations of less than 25% and intervals with natural fractures and small faults.

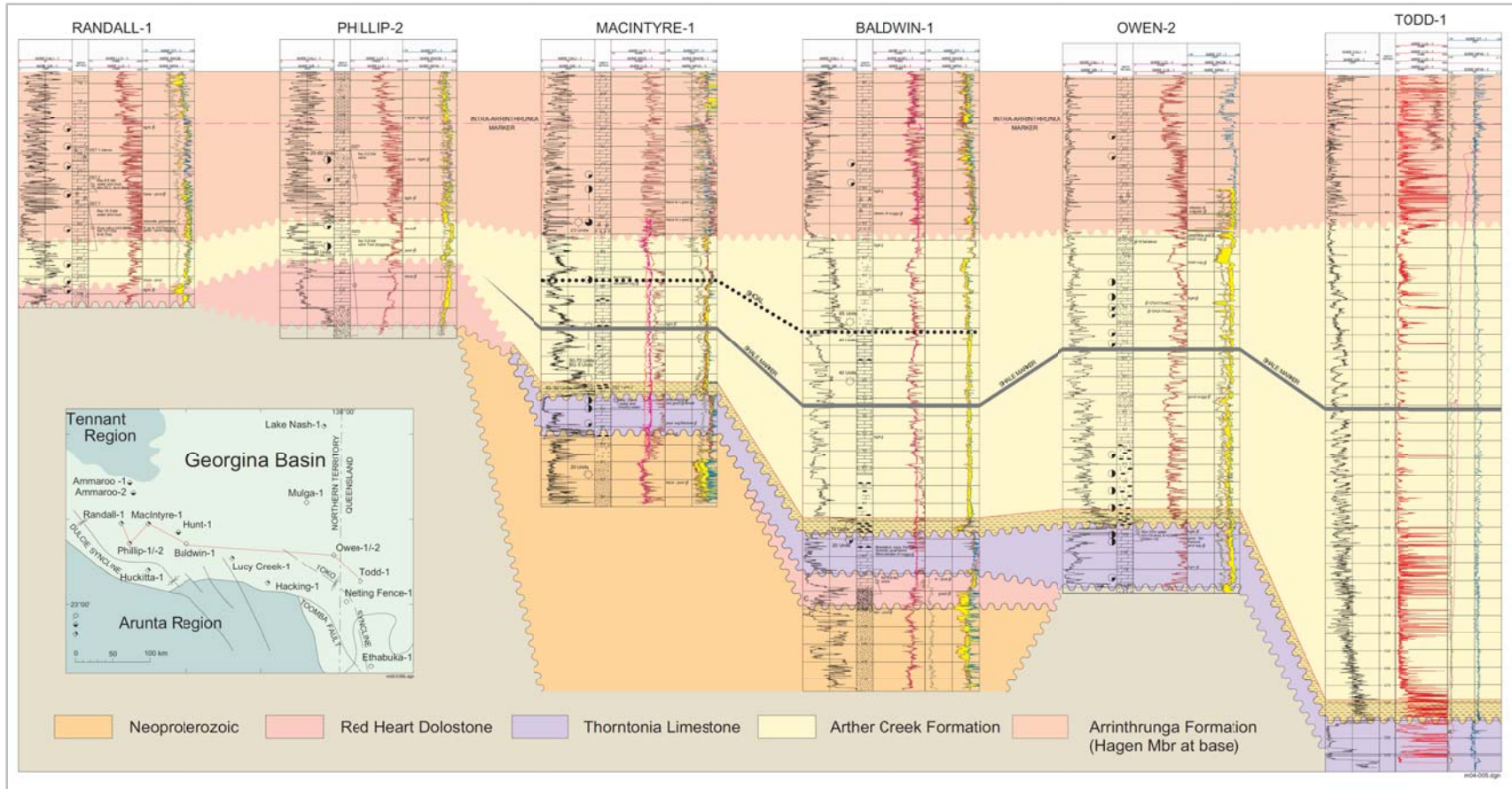
Geoscience Australia studied thirteen samples of core from four wells in the Georgina Basin, mainly from the Lower Arthur Creek Shale. The TOC of these samples ranged from 2% to 16%, with an average TOC of 5.5%.<sup>34</sup> The organic matter is composed of oil and wet gas prone Type I and II kerogen.

### 5.4 Resource Assessment

The prospective oil and gas shale areas for the Lower Arthur “Hot Shale” were confined by a minimum shale thickness of 30 feet on the southern side of the Dulcie and Toko synclines and by a vitrinite ( $R_o$ ) value of 0.7% on the northern side of these two depositional center. The south-eastern boundary of the Toko Syncline prospective area is uncertain because of lack of data, Figure III-22.

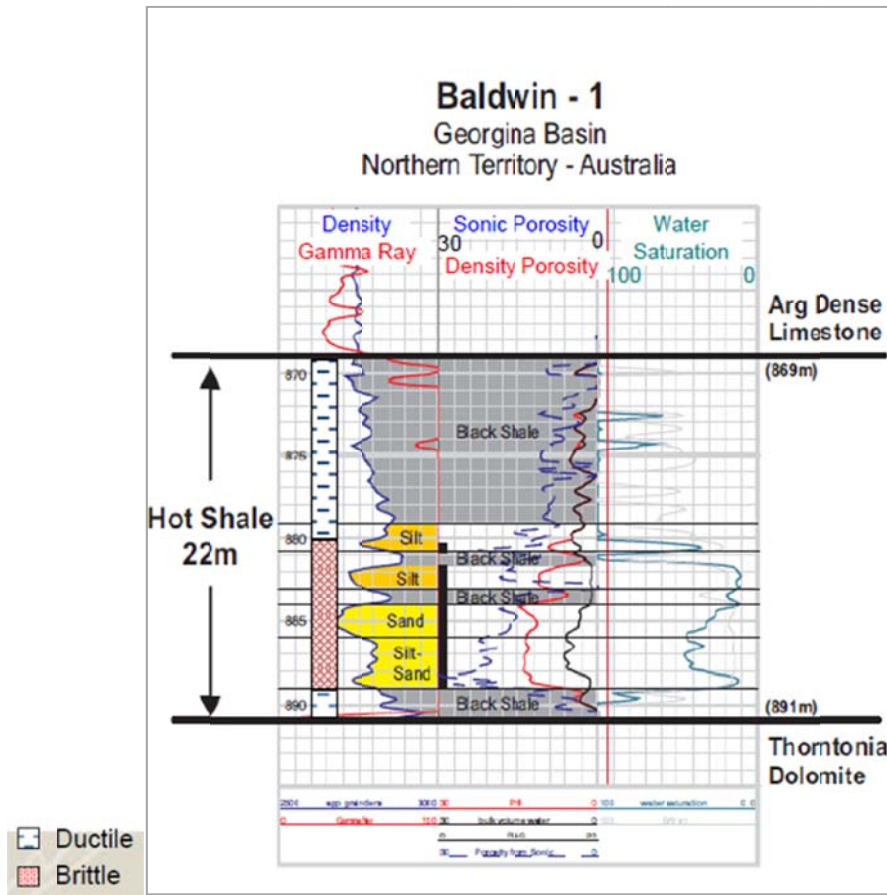
Oil and gas resources were estimated for two prospective areas: an eastern region covering the Dulcie Syncline and surrounding area, and a western region covering the Toko Syncline and surrounding area. Total risked wet and dry shale gas in-place (in both synclines and including associated gas) is estimated at 67 Tcf, with a risked, technically recoverable shale gas resource of 13 Tcf, Table III-1C. Total risked shale oil and condensate in-place is estimated at 25 billion barrels, with a risked, technically recoverable shale oil and condensate resource of 1.0 billion barrels, Table III-2B.

Figure III-20. East-West Cross-Section of the Southern Georgina Basin



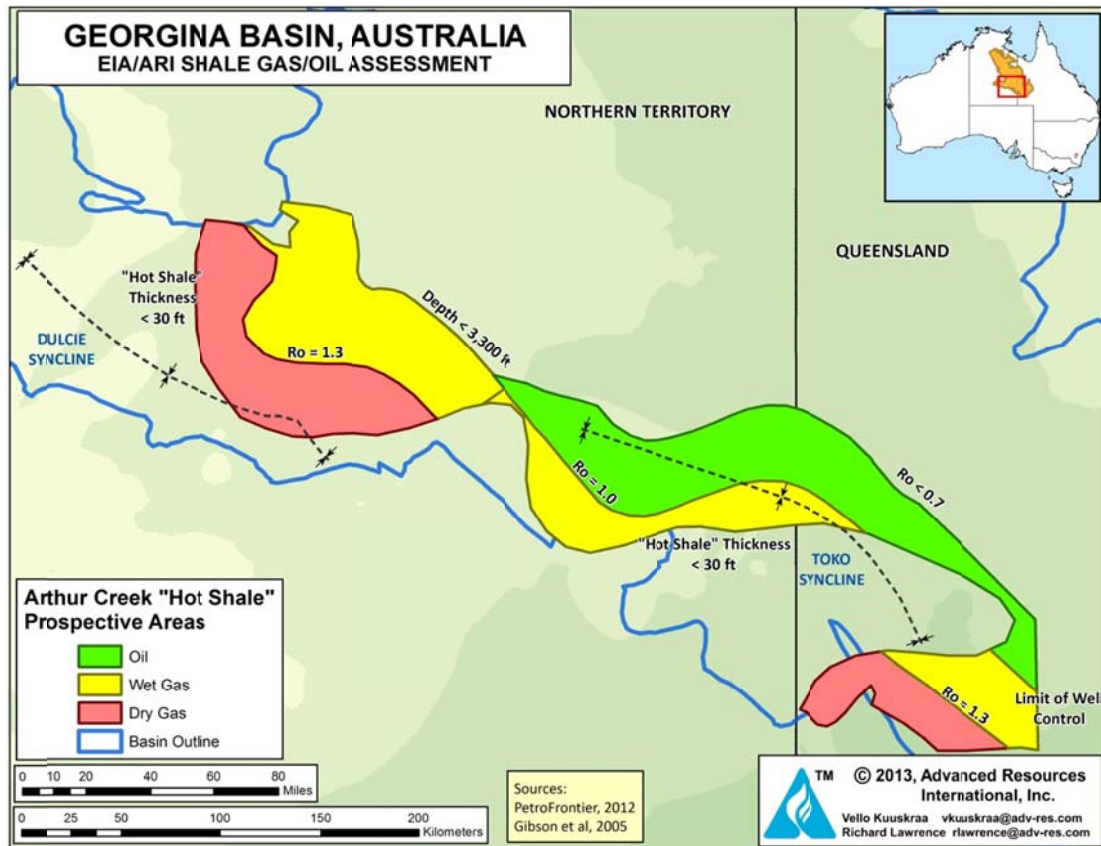
Source: Ambrose and Putnam, 2007

Figure III-21. Log Response of Lower Arthur "Hot Shale"



Source: ARI 2012

Figure III-22. Georgina Basin Prospective Shale Gas and Shale Oil Areas



Source: ARI, 2013.

## 5.5 Recent Activity

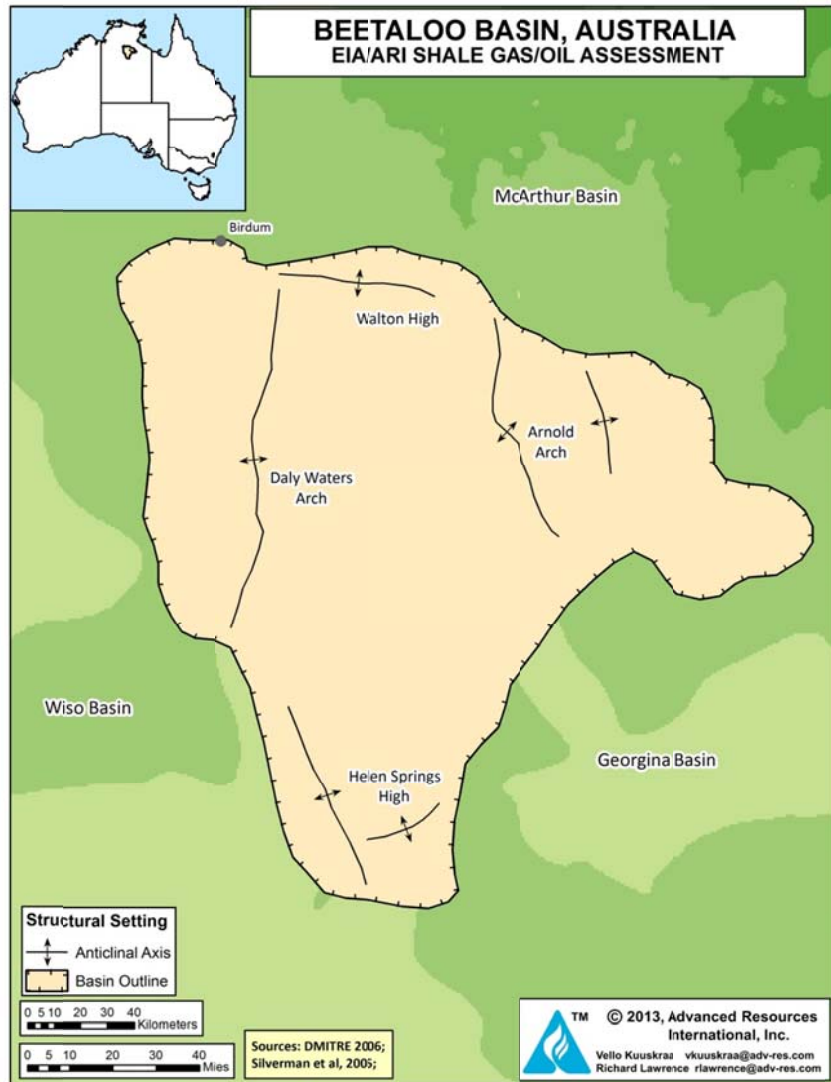
PetroFrontier Corporation, a Canadian company, holds several exploration permits in the southern portion of the Georgina Basin. A farm-in with Statoil Australia was established in 2012 with both companies committing to spending \$25 million on an exploration program. Two horizontal exploration wells testing the Lower Arthur Creek “hot shale” section were drilled in the first half of 2012. The Baldwin-2Hst1 and the MacIntyre-2H were drilled in the gas-prone Dulcie Trough. A third well, the Owen-3 well is currently (August 2012) drilling its horizontal leg in the oil-prone area of the Arthur Creek “hot shale” on the flank of the Toko Trough. The vertical section of the Owen-3 was drilled to a measured depth of 3,870 feet and over 100 feet of core was cut from the “hot shale” and deeper Thornton Carbonate section. The core seeped oil on retrieval and had extensive fluorescence throughout. Wireline logging indicated over 80 feet of hydrocarbon bearing formation. <sup>35</sup>

## 6. BEETALOO BASIN (NORTHERN TERRITORY)

### 6.1 Introduction

The Beetaloo Basin is a 14,000-mi<sup>2</sup> rift basin located in the Northern Territory, approximately 400 miles southeast of Darwin, Figure III-23. The basin outline is defined by the Walton High to the north, the Helen Springs High in the south, and the Batten Trough in the east. Its western margin is projected to extend to the Daly Waters Arch.<sup>36</sup>

Figure III-23. Beetaloo Basin Location Map

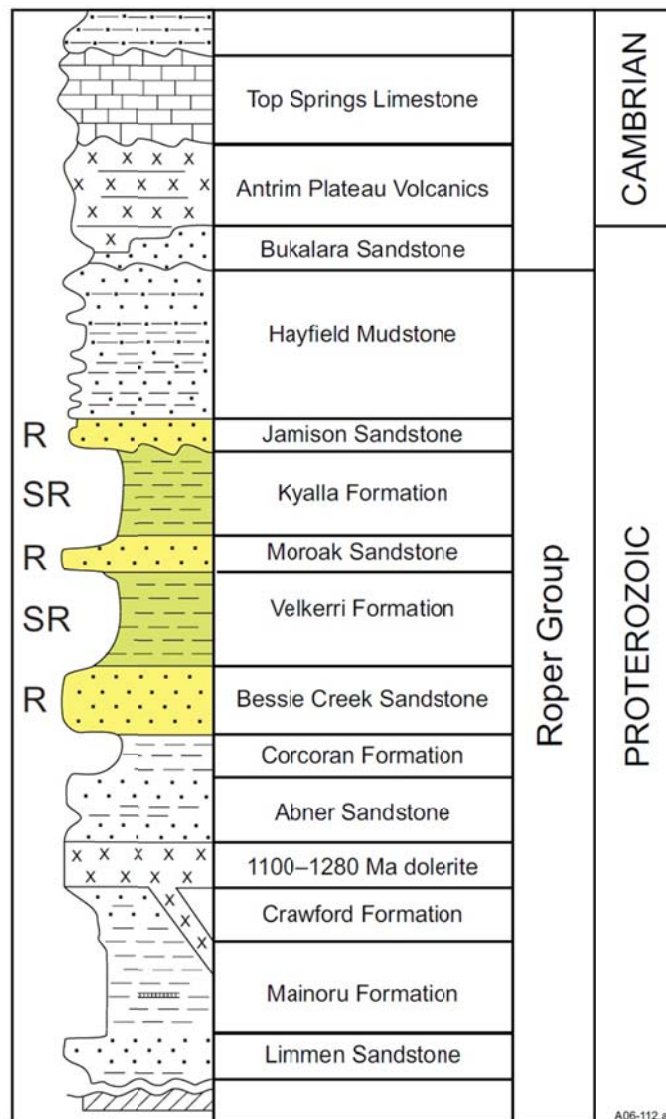


Source: ARI, 2013



Well tests and cores from twelve exploratory wells, of late 1980s and early 1990s vintage, have identified oil and gas bearing organic-rich shales in the Pre-Cambrian Roper Group, Figure III-24. The Roper Group is up to 9,000 feet thick in the center of the Beetaloo Basin. Oil and gas shows have been observed in the Kyalla and Middle Velkerri shales, along with shows in adjoining conventional sandstone formations. These two shale formations, if prospective, would be some of the oldest producing source-rock formations in the world, on par with source rocks found in Oman and Siberia.

Figure III-24. Beetaloo Basin Stratigraphic Column

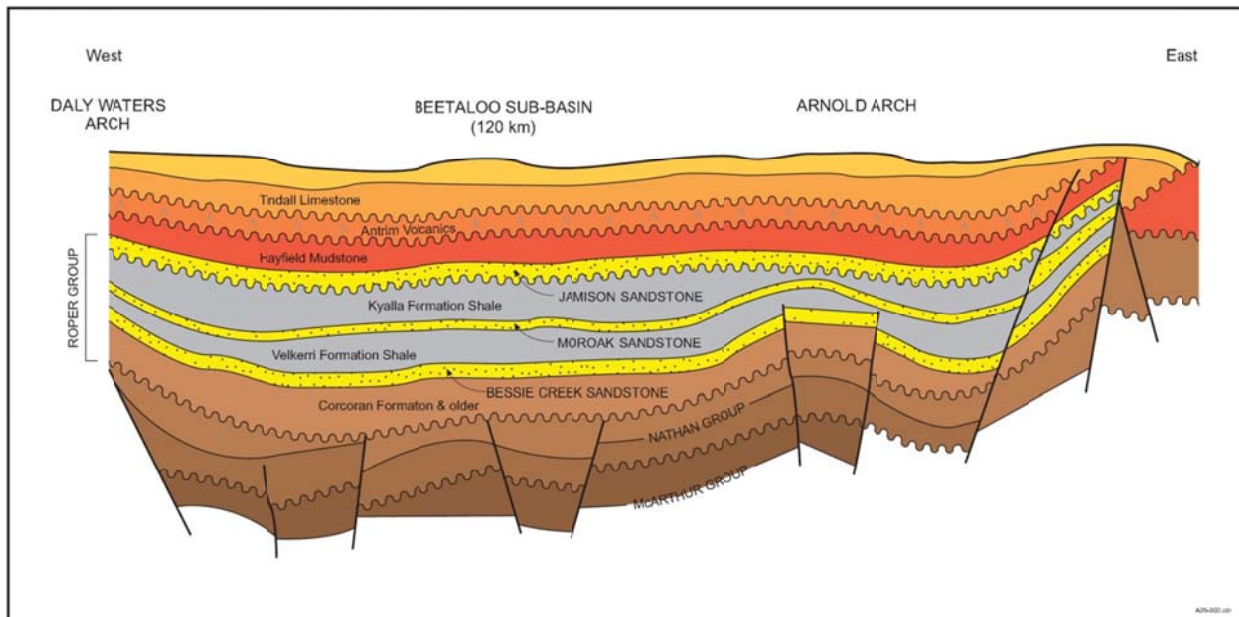


Source: Silverman et al, 2005

## 6.2 Geologic Setting

The structural characteristics of the Beetaloo Basin have been determined from gravity and magnetic data, along with recent reprocessing and reinterpretation of 2D seismic lines. Latest interpretations classify the basin as a rift basin<sup>37</sup>, formed during the late Pre-Cambrian and unconformably overlying the western portion of the McArthur Basin. North-south trending faults, observed in the McArthur Basin, are thought to extend into the Beetaloo Basin Figure III-25. A 110 mile long regional gravity high bounding the west side of the basin, the Daly Waters Arch, is a thrust belt with over 3,000 feet of relief.

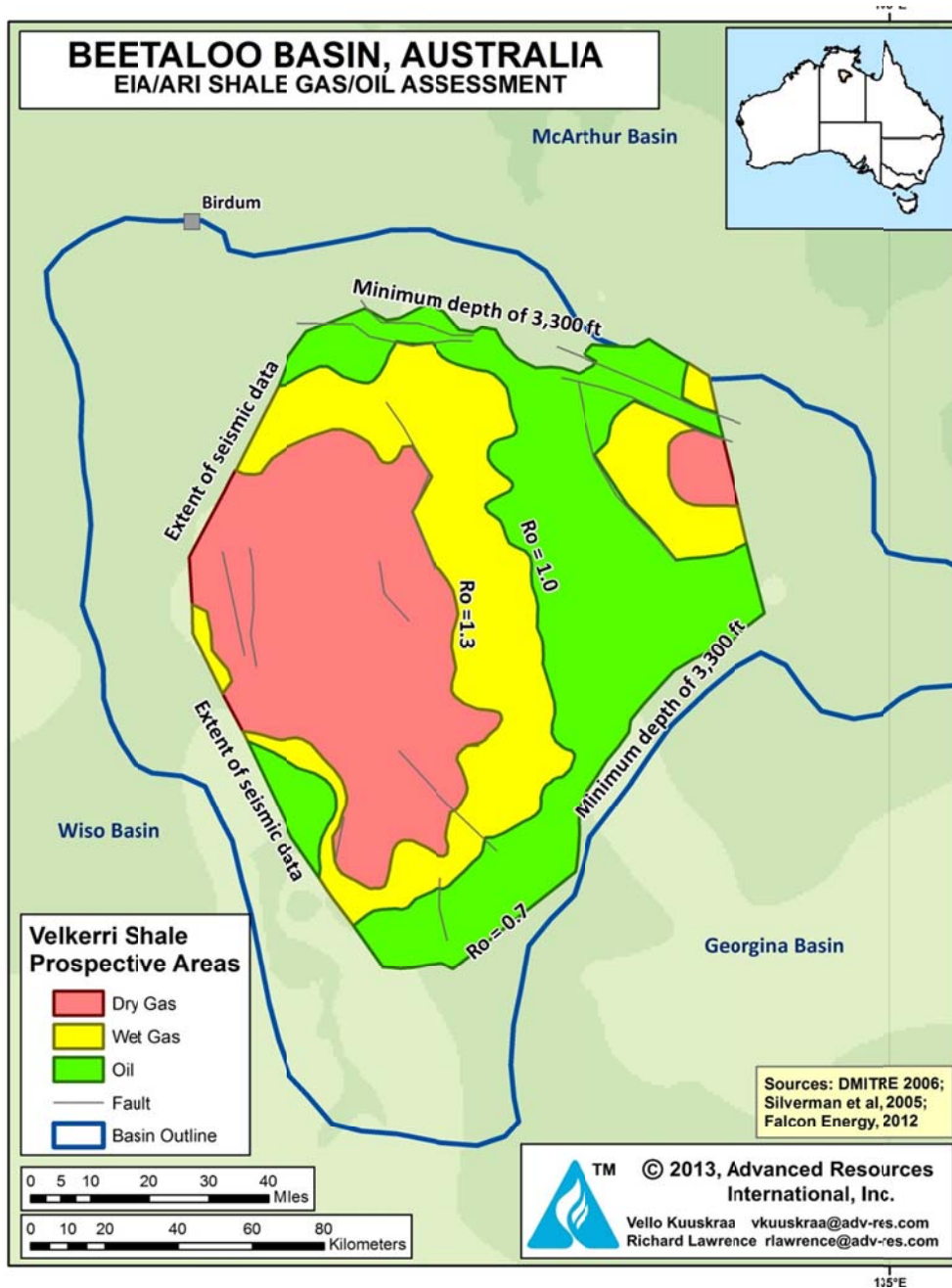
Figure III-25. East-West Cross-Section of the Beetaloo Basin



Source: Ambrose and Silverman, 2006<sup>38</sup>

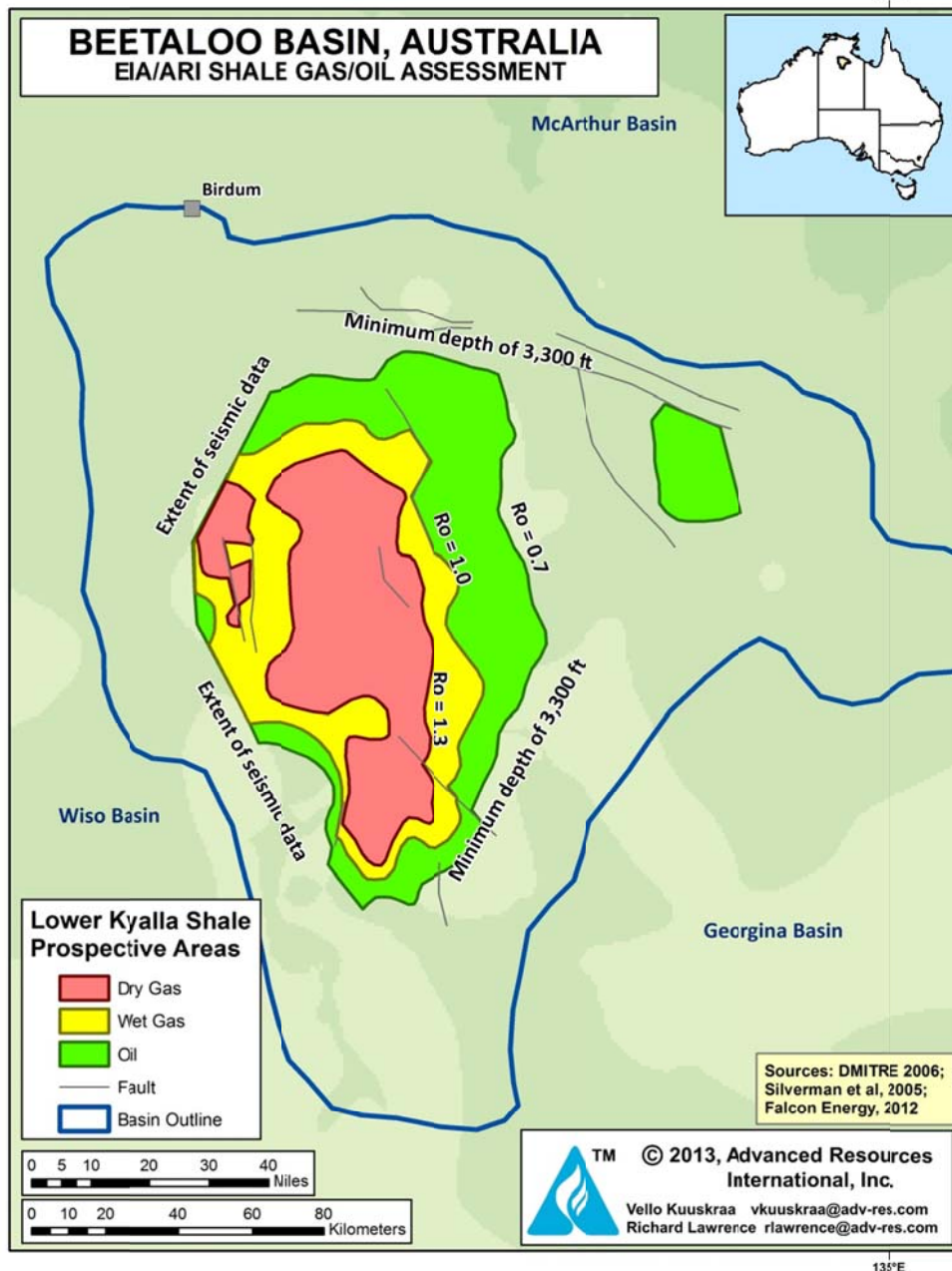
The Velkerri and the Kyalla shales have dry gas, wet gas/condensate and oil windows, based primarily on formation depth. The dry gas prospective area is 2,480 mi<sup>2</sup> for the Velkerri Shale and 1,310 mi<sup>2</sup> for the Kyalla Shale. The wet gas/condensate prospective area covers 2,130 mi<sup>2</sup> for the Velkerri Shale and 2,400 mi<sup>2</sup> Kyalla Shale. The shale oil prospective area is 2,650 mi<sup>2</sup> for the Velkerri Shale and 4,010 mi<sup>2</sup> for the Kyalla Shale, Figures III-26 and III-27.

Figure III-26. Beetaloo Basin Prospective Velkerri Shale Gas and Shale Oil Areas



Source: ARI, 2013.

Figure III-27. Beetaloo Basin Prospective Lower Kyalla Shale Gas and Shale Oil Areas



Source: ARI, 2013.

### 6.3 Reservoir Properties (Prospective Area)

The Velkerri Formation is composed of black organic-rich shales layered with gray-green organic-lean shales and interbedded with thin siltstone and sandstone units. The Middle Velkerri Shale, a marine shale deposited in shallow to moderate depth environments, is considered prospective based on exploration wells drilled in the basin.<sup>39</sup> The depth of the prospective area of Middle Velkerri Shale ranges from 3,300 ft on the Walton High to 8,700 ft in the basin center. The organic-rich net pay of the Middle Velkerri Shale averages 100 feet across the basin.

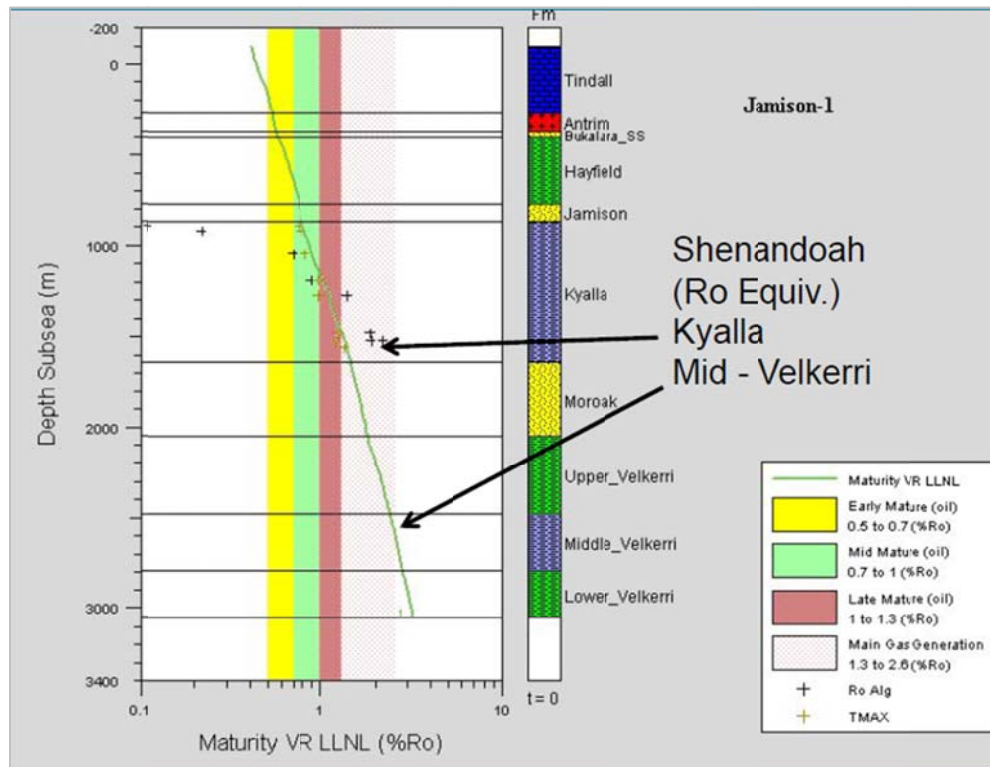
The Middle Velkerri has a maximum total organic carbon (TOC) content of 12%, averaging 4%. The organic matter is composed of oil prone Type I and II kerogens. The Upper and Lower Velkerri shales, with TOC contents of less than 2%, have not been included in the resource assessment.

The Kyalla Formation has an upper and a lower shale section, separated by the thin Kyalla Sandstone. The combined section is 600 to 2,500 ft thick, with the Upper Kyalla thinning considerably from west to east. Only the Lower Kyalla Shale has been included in the resource assessment. Shale depth in the prospective area ranges from 3,300 feet in the north and east to the 8,000 ft in the basin center. The Kyalla Shale is mature with  $R_o$  values of 0.7% to 1.6% depending on depth. While some organic-rich sections of the Lower Kyalla shale reach 9% TOC in the basin center, the TOC of the shale averages 2.5%.

The prospective areas in the Velkerri and Kyalla shales were estimated using data from well logs, thermal maturity models and seismic data, Figure III-28. The Middle Velkerri Shale is projected to be in the oil window (with  $R_o$  between 0.7% and 1.0%) from a depth of 3,300 ft to 5,000 ft. At depths greater than 5,000 ft the Middle Velkerri Shale enters the wet gas/condensate window with  $R_o$  between 1.0% and 1.3%. As the formation deepens to below 7,000 feet, the Velkerri Shale enters the dry gas window with  $R_o > 1.3\%$ .

The Lower Kyalla Shale is in the oil window from 3,300-5,000 feet, enters the wet gas/condensate window below 5,000 feet, and reaches the dry gas window below 6,000 feet. The areas are constrained by the extent of the seismic data from which depths to formation were derived. Pay thickness and reservoir properties were estimated from well log data, with emphasis on the most recently drilled Shenandoah-1A well.

Figure III-28. Thermal Maturity Model for Jamison #1 Well



Source: Silverman and Ahlbrandt, 2011

### 6.4 Resource Assessment

The risked dry, wet and associated shale gas in-place for the Middle Velkerri Shale is 94 Tcf, with a risked, technically recoverable shale gas resource of 22 Tcf, Table III-1C. The risked shale oil/condensate in-place for the Middle Velkerri Shale is 28 billion barrels, with a risked, technically recoverable shale oil/condensate resource of 1.4 billion barrels, Table III-2B.

The Lower Kyalla Shale is calculated to have risked dry, wet and associated shale gas in-place of 100 Tcf, with a risked, technically recoverable shale gas resource of 22 Tcf, Table III-1C. The risked shale oil and condensate in-place and the risked, technically recoverable resource from the Lower Kyalla Shale are 65 billion barrels and 3.3 billion barrels respectively, Table III-2B.

## 6.5 Recent Activity

Falcon Oil and Gas Ltd has four exploration permits covering most of the Beetaloo Basin. In 2009, the company deepened the Shenandoah-1, a vertical test well located in the center of the basin. Drilled in 2007 by PetroHunter Energy, the original well had a total depth of 5,084 ft and intersected the Upper Kyalla Shale. Falcon deepened the well to 8,900 ft through the Lower Kyalla Shale, the Moroak Sandstone and the Velkerri Shale with gas shows noted in each formation.<sup>40</sup> The well was fractured and tested in November 2011, with reported gas and condensate flows from the Kyalla and Velkerri shales.

Falcon entered a Joint Venture with Hess in July 2011, covering the majority of the area in the exploration permits. Hess has committed up to \$57.5 million to acquire 2,200 miles of 2D seismic. Two seismic crews are currently deployed in the basin with plans to finish surveying by the end of 2012. Hess has until June 2013 to commit to drilling five exploratory wells and earn a 62.5% interest in three of Falcon's exploration permits.<sup>41</sup> Falcon is seeking another partner to explore their fourth permit area which covers 700,000 acres.

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