



Independent Statistics & Analysis
U.S. Energy Information
Administration

Technically Recoverable Shale Oil and Shale Gas Resources:

Australia

September 2015



This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Contents

Executive Summary.....	3
Introduction.....	3
Resource categories.....	3
Methodology.....	5
Key exclusions.....	6
Australia.....	III-1

Executive Summary

Introduction

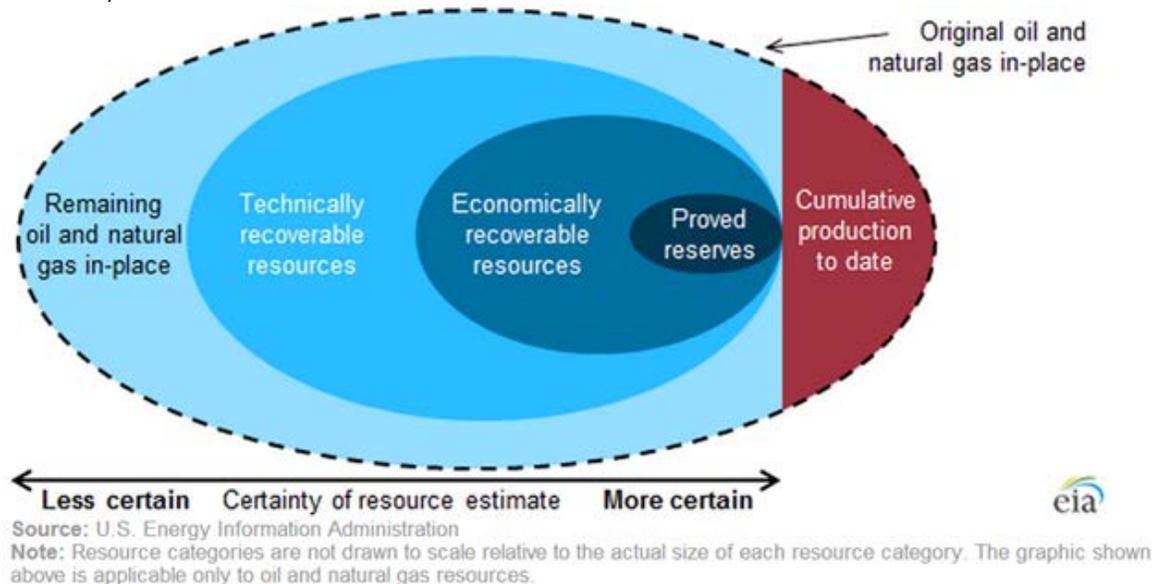
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically recoverable oil and natural gas resources. This chapter is from the 2013 EIA world shale report [Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States](#).

Resource categories

When considering the market implications of abundant shale resources, it is important to distinguish between a technically recoverable resource, which is the focus of this supplement as in the 2013 report, and an economically recoverable resource. Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Economically recoverable resources are resources that can be profitably produced under current market conditions. The economic recoverability of oil and gas resources depends on three factors: the costs of drilling and completing wells, the amount of oil or natural gas produced from an average well over its lifetime, and the prices received for oil and gas production. Recent experience with shale gas and tight oil in the United States and other countries suggests that economic recoverability can be significantly influenced by above-the-ground factors as well as by geology. Key positive above-the-ground advantages in the United States and Canada that may not apply in other locations include private ownership of subsurface rights that provide a strong incentive for development; availability of many independent operators and supporting contractors with critical expertise and suitable drilling rigs and, preexisting gathering and pipeline infrastructure; and the availability of water resources for use in hydraulic fracturing. See Figure 1.

Figure 1. Stylized representation of oil and natural gas resource categorizations

(not to scale)



Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known

ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

For many purposes, oil and natural gas resources are usefully classified into four categories:

- Remaining oil and gas in-place (original oil and gas in-place minus cumulative production at a specific date)
- Technically recoverable resources
- Economically recoverable resources
- Proved reserves

The oil and natural gas volumes reported for each resource category are estimates based on a combination of facts and assumptions regarding the geophysical characteristics of the rocks, the fluids trapped within those rocks, the capability of extraction technologies, and the prices received and costs paid to produce oil and natural gas. The uncertainty in estimated volumes declines across the resource categories (see figure above) based on the relative mix of facts and assumptions used to create these resource estimates. Oil and gas in-place estimates are based on fewer facts and more assumptions, while proved reserves are based mostly on facts and fewer assumptions.

Remaining oil and natural gas in-place (original oil and gas in-place minus cumulative production). The volume of oil and natural gas within a formation before the start of production is the original oil and gas in-place. As oil and natural gas are produced, the volumes that remain trapped within the rocks are the remaining oil and gas in-place, which has the largest volume and is the most uncertain of the four resource categories.

Technically recoverable resources. The next largest volume resource category is technically recoverable resources, which includes all the oil and gas that can be produced based on current technology, industry practice, and geologic knowledge. As technology develops, as industry practices improve, and as the understanding of the geology increases, the estimated volumes of technically recoverable resources also expand.

The geophysical characteristics of the rock (e.g., resistance to fluid flow) and the physical properties of the hydrocarbons (e.g., viscosity) prevent oil and gas extraction technology from producing 100% of the original oil and gas in-place.

Economically recoverable resources. The portion of technically recoverable resources that can be profitably produced is called economically recoverable oil and gas resources. The volume of economically recoverable resources is determined by both oil and natural gas prices and by the capital and operating costs that would be incurred during production. As oil and gas prices increase or decrease, the volume of the economically recoverable resources increases or decreases, respectively. Similarly, increasing or decreasing capital and operating costs result in economically recoverable resource volumes shrinking or growing.

U.S. government agencies, including EIA, report estimates of technically recoverable resources (rather than economically recoverable resources) because any particular estimate of economically recoverable resources is tied to a specific set of prices and costs. This makes it difficult to compare estimates made by other parties using different price and cost assumptions. Also, because prices and costs can change over relatively short periods, an estimate of economically recoverable resources that is based on the prevailing prices and costs at a particular time can quickly become obsolete.

Proved reserves. The most certain oil and gas resource category, but with the smallest volume, is proved oil and gas reserves. Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves generally increase when new production wells are drilled and decrease when existing wells are produced. Like economically recoverable resources, proved reserves shrink or grow as prices and costs change. The U.S. Securities and Exchange Commission regulates the reporting of company financial assets, including those proved oil and gas reserve assets reported by public oil and gas companies.

Each year EIA updates its report of proved U.S. oil and natural gas reserves and its estimates of unproved technically recoverable resources for shale gas, tight gas, and tight oil resources. These reserve and resource estimates are used in developing EIA's [Annual Energy Outlook](#) projections for oil and natural gas production.

- Proved oil and gas reserves are reported in EIA's [U.S. Crude Oil and Natural Gas Proved Reserves](#).
- Unproved technically recoverable oil and gas resource estimates are reported in EIA's [Assumptions](#) report of the Annual Energy Outlook. Unproved technically recoverable oil and gas resources equal total technically recoverable resources minus the proved oil and gas reserves.

Over time, oil and natural gas resource volumes are reclassified, going from one resource category into another category, as production technology develops and markets evolve.

Additional information regarding oil and natural gas resource categorization is available from the [Society of Petroleum Engineers](#) and the [United Nations](#).

Methodology

The shale formations assessed in this supplement as in the previous report were selected for a combination of factors that included the availability of data, country-level natural gas import dependence, observed large shale formations, and observations of activities by companies and governments directed at shale resource development. Shale formations were excluded from the analysis if one of the following conditions is true: (1) the geophysical characteristics of the shale formation are unknown; (2) the average total carbon content is less than 2 percent; (3) the vertical depth is less than 1,000 meters (3,300 feet) or greater than 5,000 meters (16,500 feet), or (4) relatively large undeveloped oil or natural gas resources.

The consultant relied on publicly available data from technical literature and studies on each of the selected international shale gas formations to first provide an estimate of the “risked oil and natural gas in-place,” and then to estimate the unproved technically recoverable oil and natural gas resource for that shale formation. This methodology is intended to make the best use of sometimes scant data in order to perform initial assessments of this type.

The risked oil and natural gas in-place estimates are derived by first estimating the volume of in-place resources for a prospective formation within a basin, and then factoring in the formation's success factor and recovery factor. The success factor represents the probability that a portion of the formation is expected to have attractive oil and natural gas flow rates. The recovery factor takes into consideration the capability of current technology to produce oil and natural gas from formations with similar geophysical characteristics. Foreign shale oil recovery rates are developed by matching a shale formation's geophysical characteristics to U.S. shale oil analogs. The resulting estimate is referred to as both the risked oil and natural gas in-place and the technically recoverable resource. The specific tasks carried out to implement the assessment include:

1. Conduct a preliminary review of the basin and select the shale formations to be assessed.

2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*¹ and *adsorbed gas*² that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.³ For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources⁴ represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

Based on U.S. shale production experience, the recovery factors used in this supplement as in the previous report for shale gas generally ranged from 20 percent to 30 percent, with values as low as 15 percent and as high as 35 percent being applied in exceptional cases. Because of oil's viscosity and capillary forces, oil does not flow through rock fractures as easily as natural gas. Consequently, the recovery factors for shale oil are typically lower than they are for shale gas, ranging from 3 percent to 7 percent of the oil in-place with exceptional cases being as high as 10 percent or as low as 1 percent. The consultant selected the recovery factor based on U.S. shale production recovery rates, given a range of factors including mineralogy, geologic complexity, and a number of other factors that affect the response of the geologic formation to the application of best practice shale gas recovery technology. Because most shale oil and shale gas wells are only a few years old, there is still considerable uncertainty as to the expected life of U.S. shale wells and their ultimate recovery. The recovery rates used in this analysis are based on an extrapolation of shale well production over 30 years. Because a shale's geophysical characteristics vary significantly throughout the formation and analog matching is never exact, a shale formation's resource potential cannot be fully determined until extensive well production tests are conducted across the formation.

Key exclusions

In addition to the key distinction between technically recoverable resources and economically recoverable resources that has been already discussed at some length, there are a number of additional factors outside of the scope of this report that must be considered in using its findings as a basis for projections of future

¹ Free gas is natural gas that is trapped in the pore spaces of the shale. Free gas can be the dominant source of natural gas for the deeper shales.

² Adsorbed gas is natural gas that adheres to the surface of the shale, primarily the organic matter of the shale, due to the forces of the chemical bonds in both the substrate and the natural gas that cause them to attract. Adsorbed gas can be the dominant source of natural gas for the shallower and higher organically rich shales.

³ The recovery factor pertains to percent of the original oil or natural gas in-place that is produced over the life of a production well.

⁴ Referred to as risked recoverable resources in the consultant report.

production. In addition, several other exclusions were made for this supplement as in the previous report to simplify how the assessments were made and to keep the work to a level consistent with the available funding.

Some of the key exclusions for this supplement as in the previous report include:

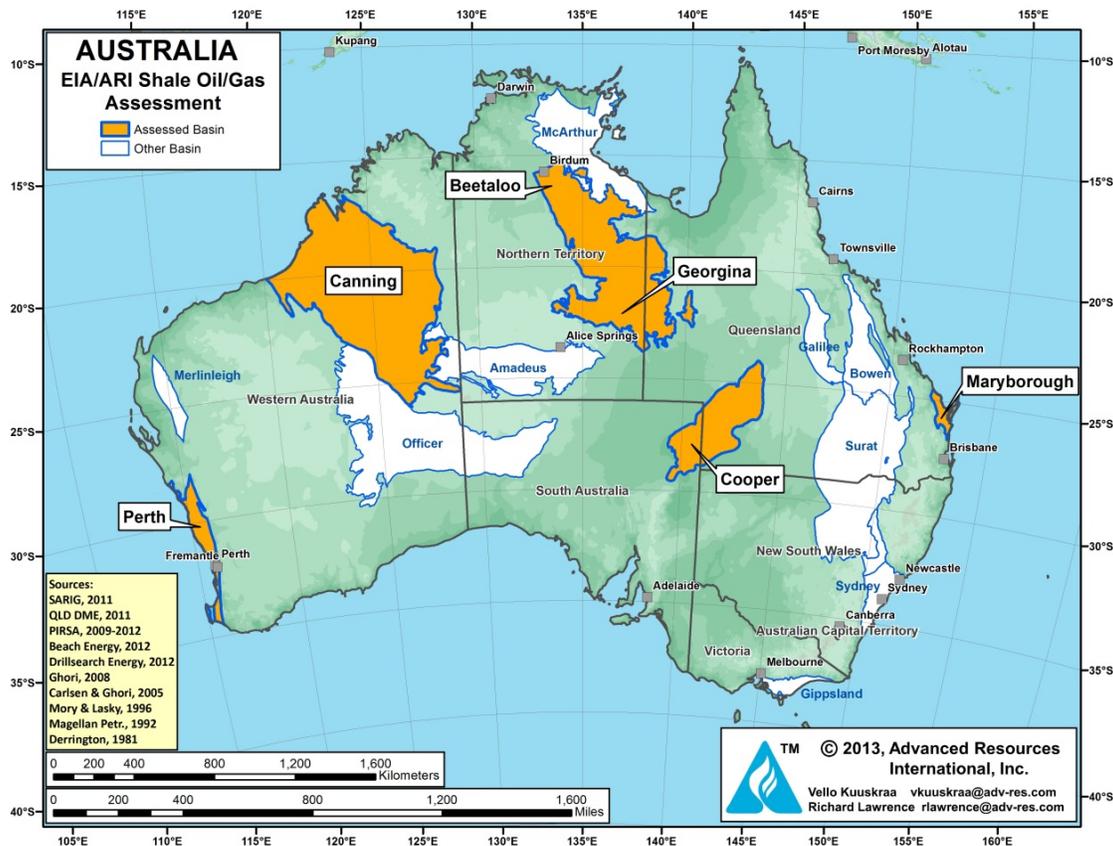
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
3. **Assessed formations without a resource estimate**, which resulted when data were judged to be inadequate to provide a useful estimate. Including additional shale formations would likely increase the estimated resource.
4. **Countries outside the scope of the report**, the inclusion of which would likely add to estimated resources in shale formations. It is acknowledged that potentially productive shales exist in most of the countries in the Middle East and the Caspian region, including those holding substantial non-shale oil and natural gas resources.
5. **Offshore portions of assessed shale oil** and shale gas formations were excluded, as were shale oil and shale gas formations situated entirely offshore.

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 CO₂ 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 ²)							
	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 ²)	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 ²)	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 ²)	Perth (20,000 mi ²)		Canning (181,000 mi ²)			
	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 ²)		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 ²)		110.7	94.0	14.0	58.9	18.7	67.1	109.2
	Risked GIP (Tcf)		63.9	124.1	7.2	36.4	83.5	395.0	748.7
	Risked 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 ²)					Beetaloo (14,000 mi ²)						
	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 ²)	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 ²)	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 ²)				Perth (20,000 mi ²)		Canning (181,000 mi ²)		
	Shale Formation		Roseneath-Epsilon-Murteree (Nappamerri)		Roseneath-Epsilon-Murteree (Patchawarra)		Roseneath-Epsilon-Murteree (Tenappera)		Kockatea		
	Geologic Age		Permian		Permian		Permian		L. Triassic		
	Depositional Environment		Lacustrine		Lacustrine		Lacustrine		Marine		
Physical Extent	Prospective Area (mi ²)		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 ²)		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 ²)			Beetaloo (14,000 mi ²)			
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 ²)		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 ²)		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.¹ 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 CO₂ 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.²

Extending over a total area of about 130,000 km², 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.^{3,4}

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.

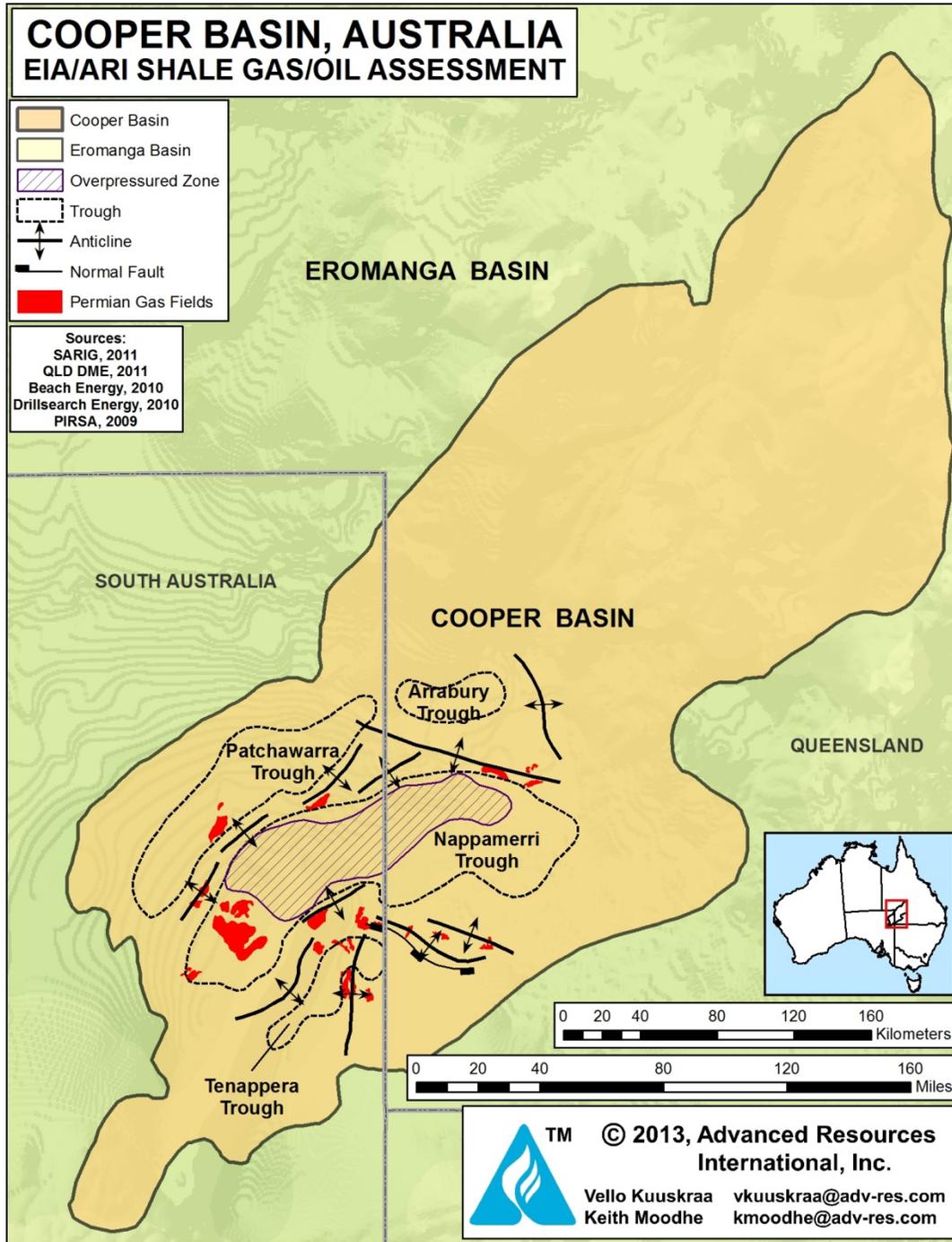
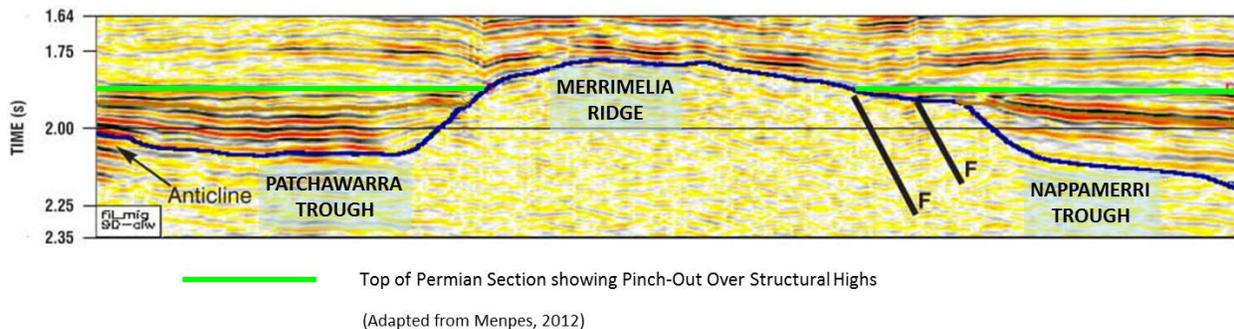


Figure III-3. Seismic Section Across the Merrimelia Ridge



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.

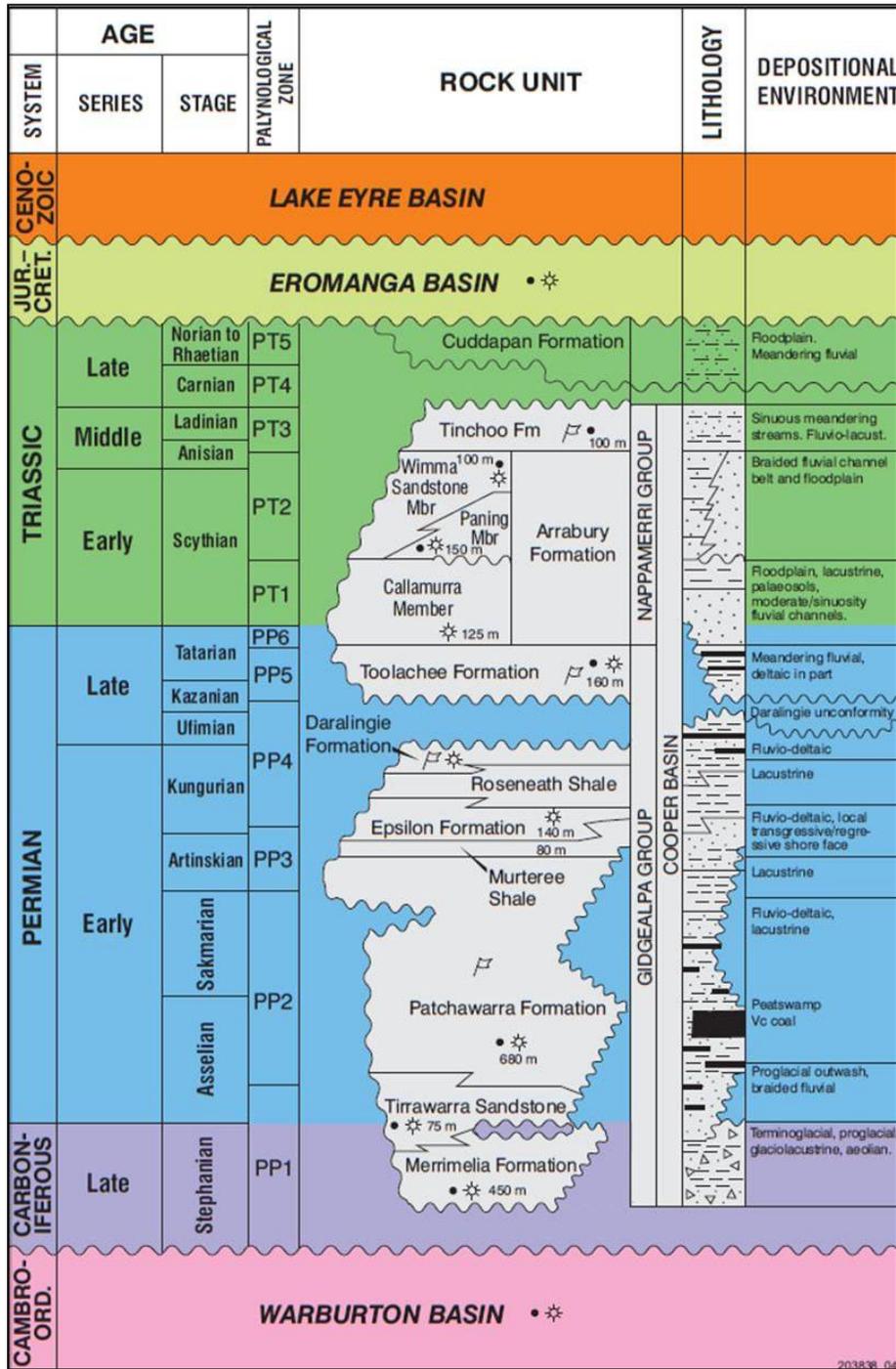
The most prospective shales in the Gidgealpa Group, with oil and gas shows during drilling and higher TOCs, are the Early Permian Roseneath and Murteree shales.⁵ Figure III-5 shows a stratigraphic cross-section of the Roseneath, Epsilon, and Murteree (collectively termed REM) sequence in the Nappamerri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

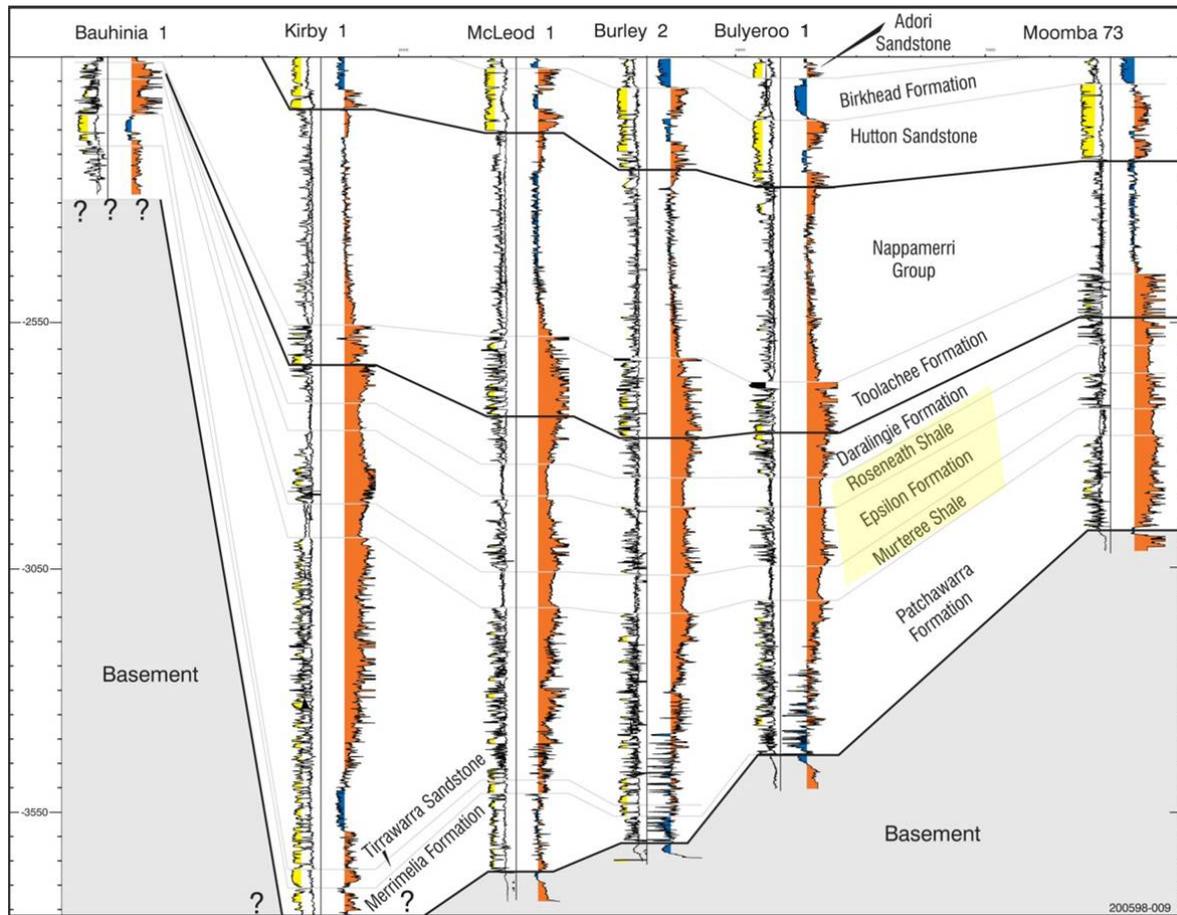
The Roseneath Shale, less widespread than the Murteree due to erosion on uplifts, averages 120 feet thick, reaching 330 feet thick in the Nappamerri Trough. The intervening Epsilon Fm consists primarily of low-permeability (0.1 to 10 mD) quartzose sandstone with carbonaceous shale and coal. The Epsilon,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

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.⁷ 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).⁸ 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 Tenappera 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.

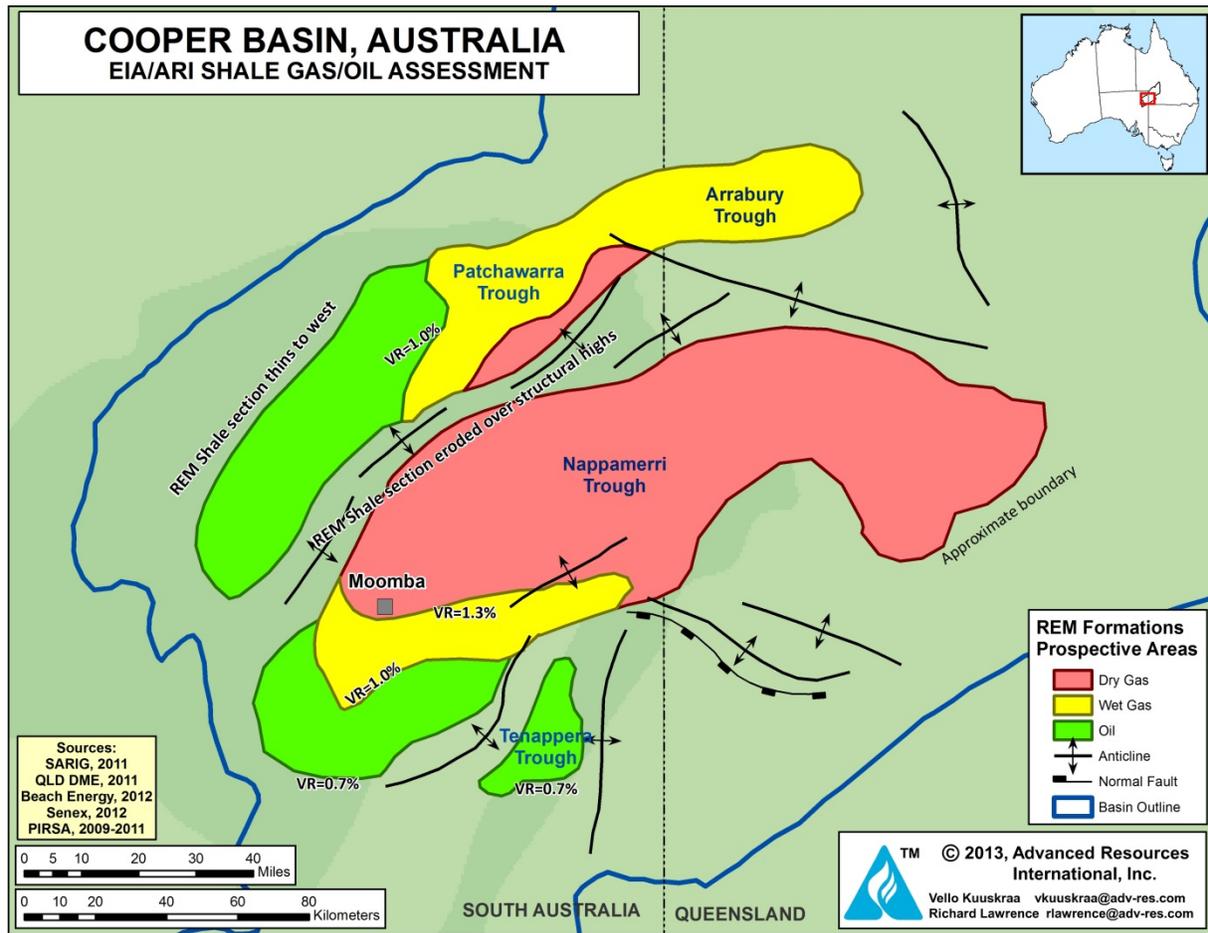
Regional hydrostatic pressure gradients are the norm in most of the Cooper Basin. However, the Nappamerri Trough becomes overpressured at depths of 9,000 to 12,000 feet, with pressure gradients of up to 0.7 psi/ft recorded in the deepest portions of the trough.⁹ High levels of carbon dioxide are also 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%).¹⁰

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/mi² 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/mi². The resource concentration in the oil prospective area of the Tenappara Trough is 22 million barrels/mi².

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 mi², covering major portions of the Nappamerri, Patchawarra and Tenapperra troughs in the Cooper Basin. Net of 15% CO₂ 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 mi² 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.¹¹

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-mi², 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-8.¹² 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.¹³ 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

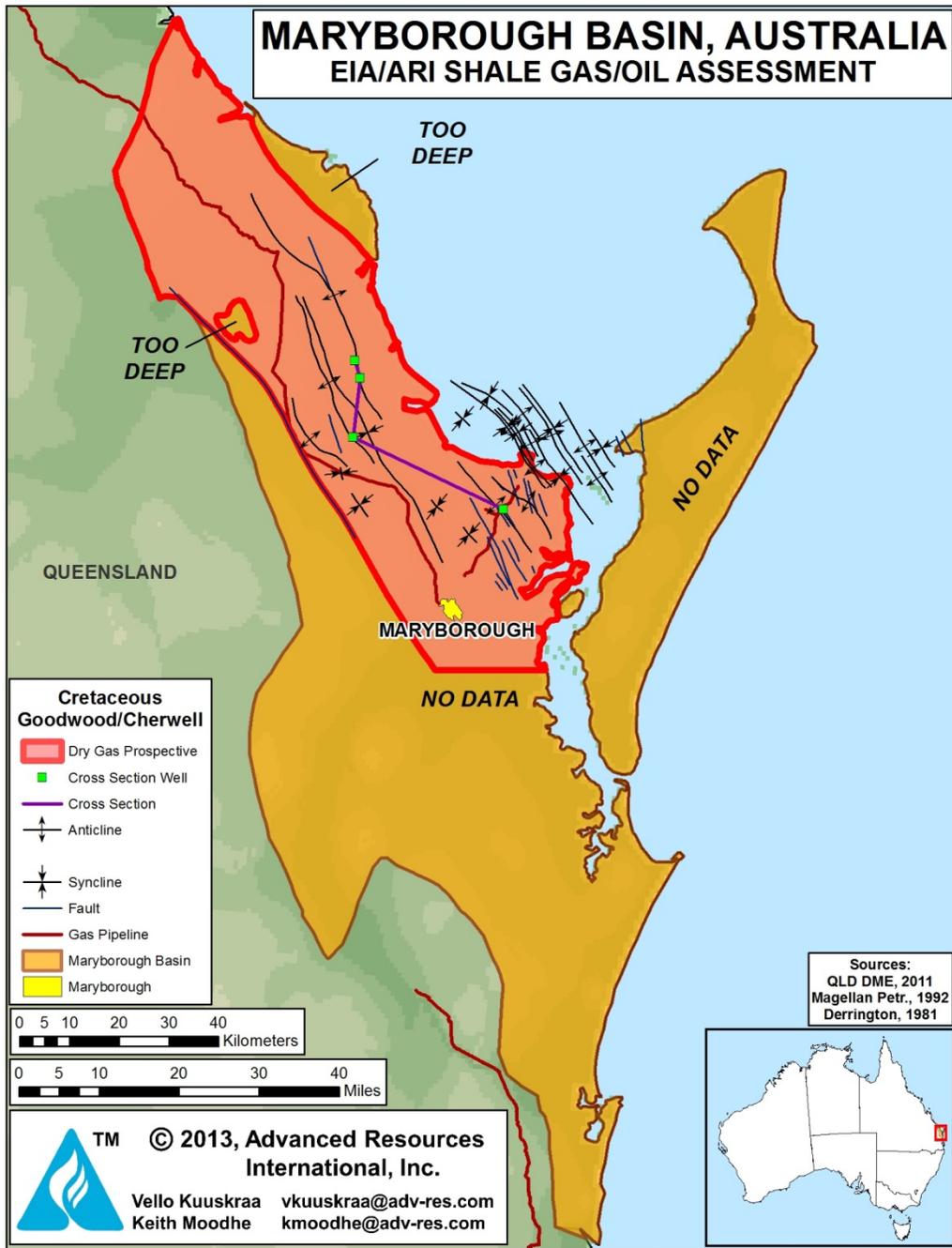


Figure III-8. Stratigraphy of the Maryborough Basin

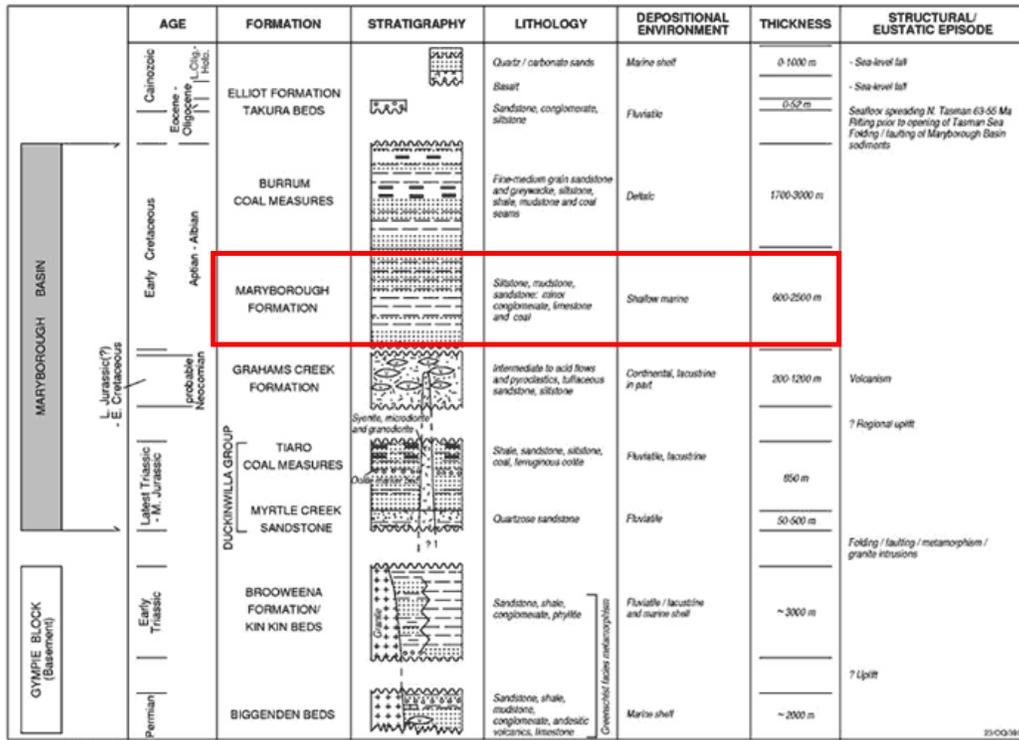
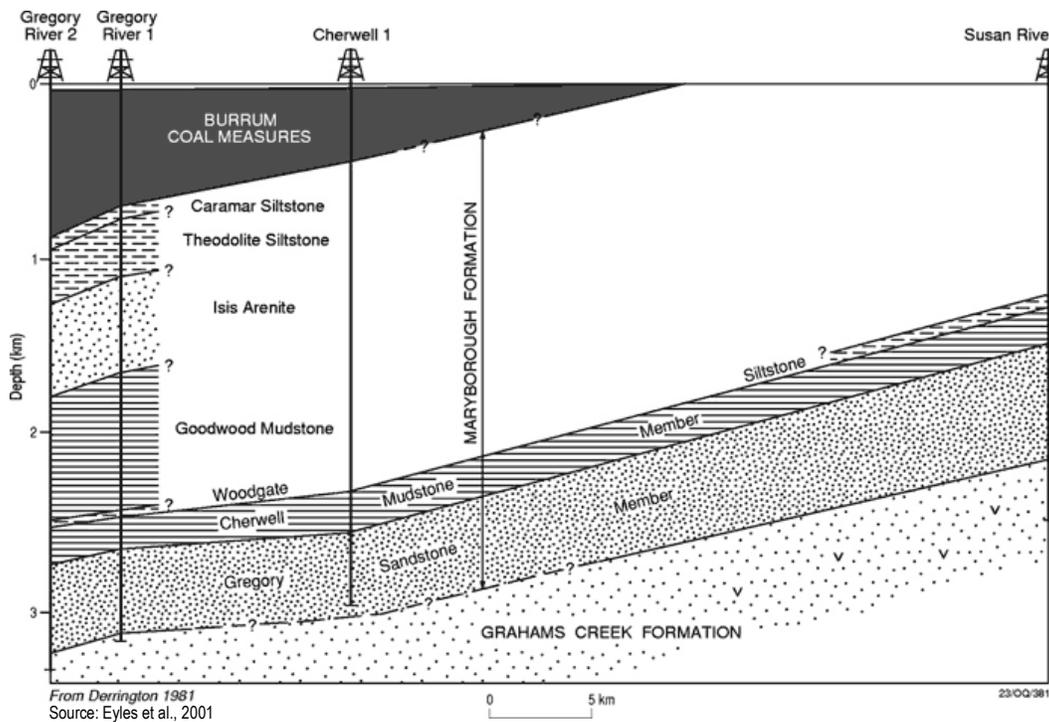


Figure III-9. Cross-Section of the Maryborough Basin and the Cretaceous Maryborough Formation.



2.4 Resource Assessment

ARI evaluated only the northern portion of the Maryborough Basin where geologic data exist. We estimate that a 1,540-mi² 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/mi². 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.¹⁴

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.

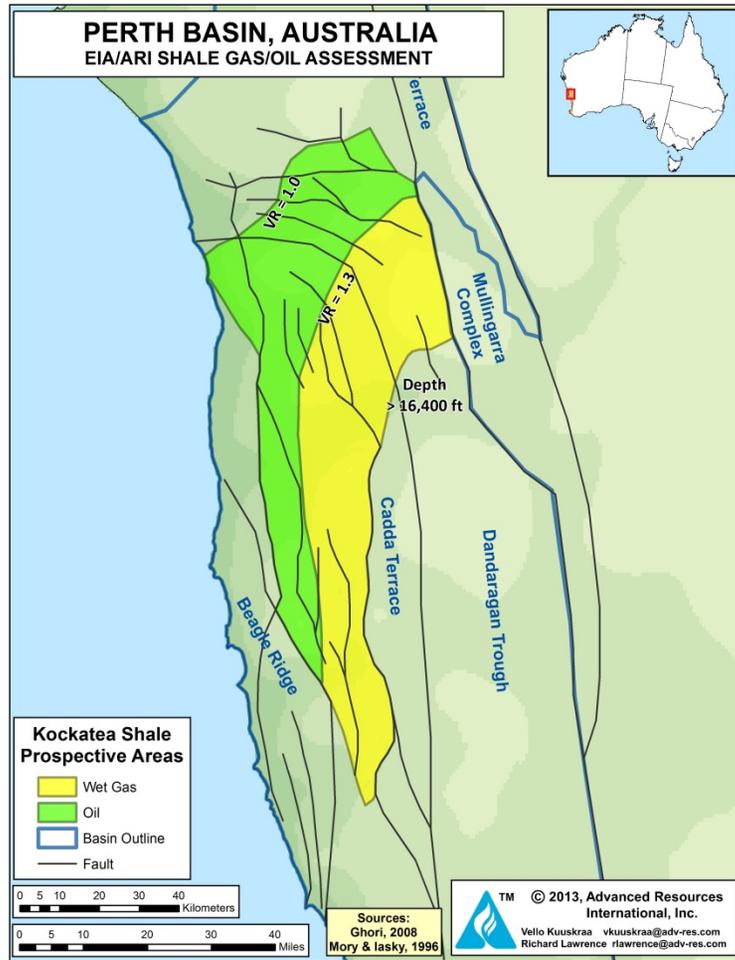
3.2 Geologic Setting

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 mi². 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-10.¹⁵

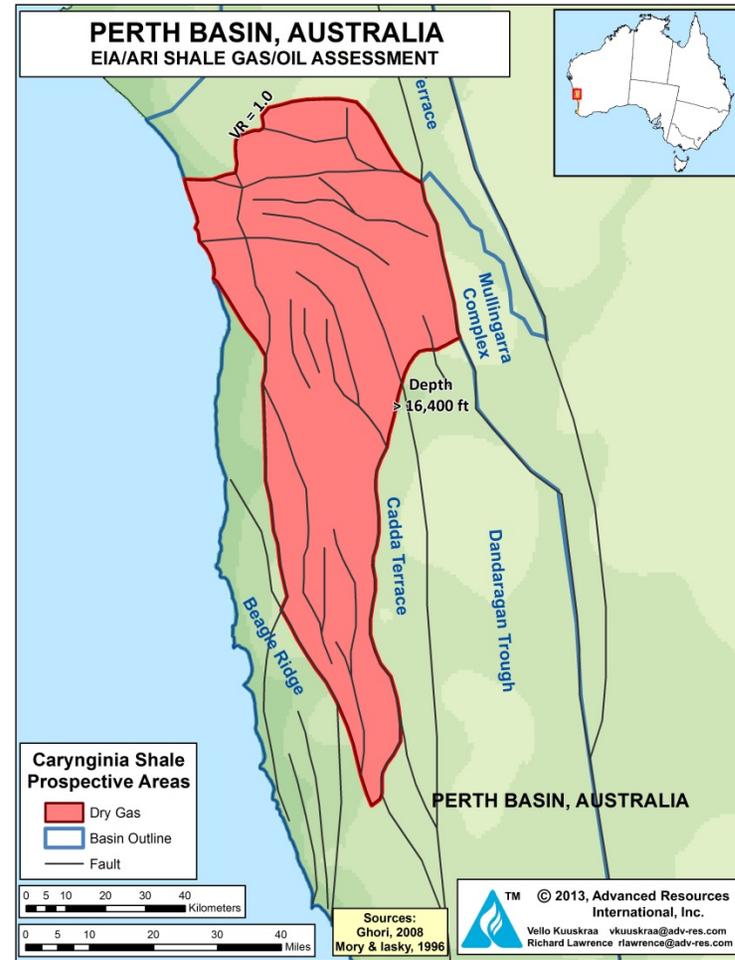
The Dandaragan Trough, a large syncline in northern Perth Basin, contains the deepest, thickest and most prospective shale gas formations. Some 300 miles long and up to 30 miles wide, the Dandaragan Trough holds as much as 9 miles of Silurian to early Cretaceous sedimentary rocks. Much of the Dandaragan 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-11.¹⁶

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. CO₂ 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

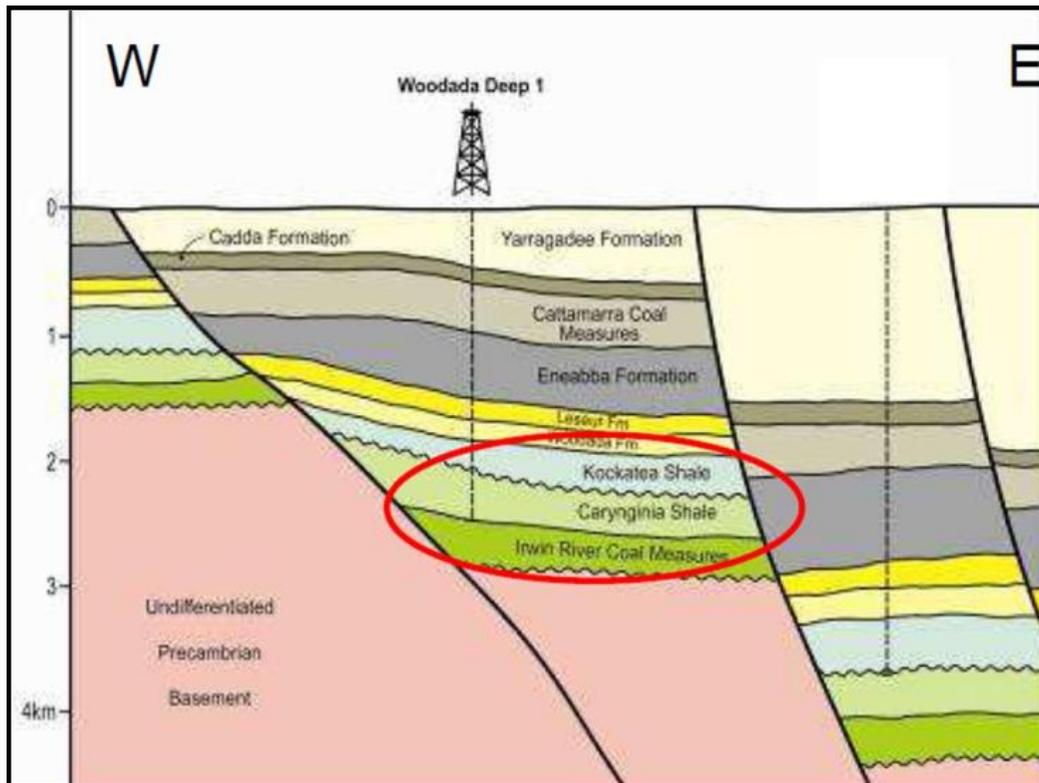


Source: ARI, 2013.



Source: ARI, 2013.

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



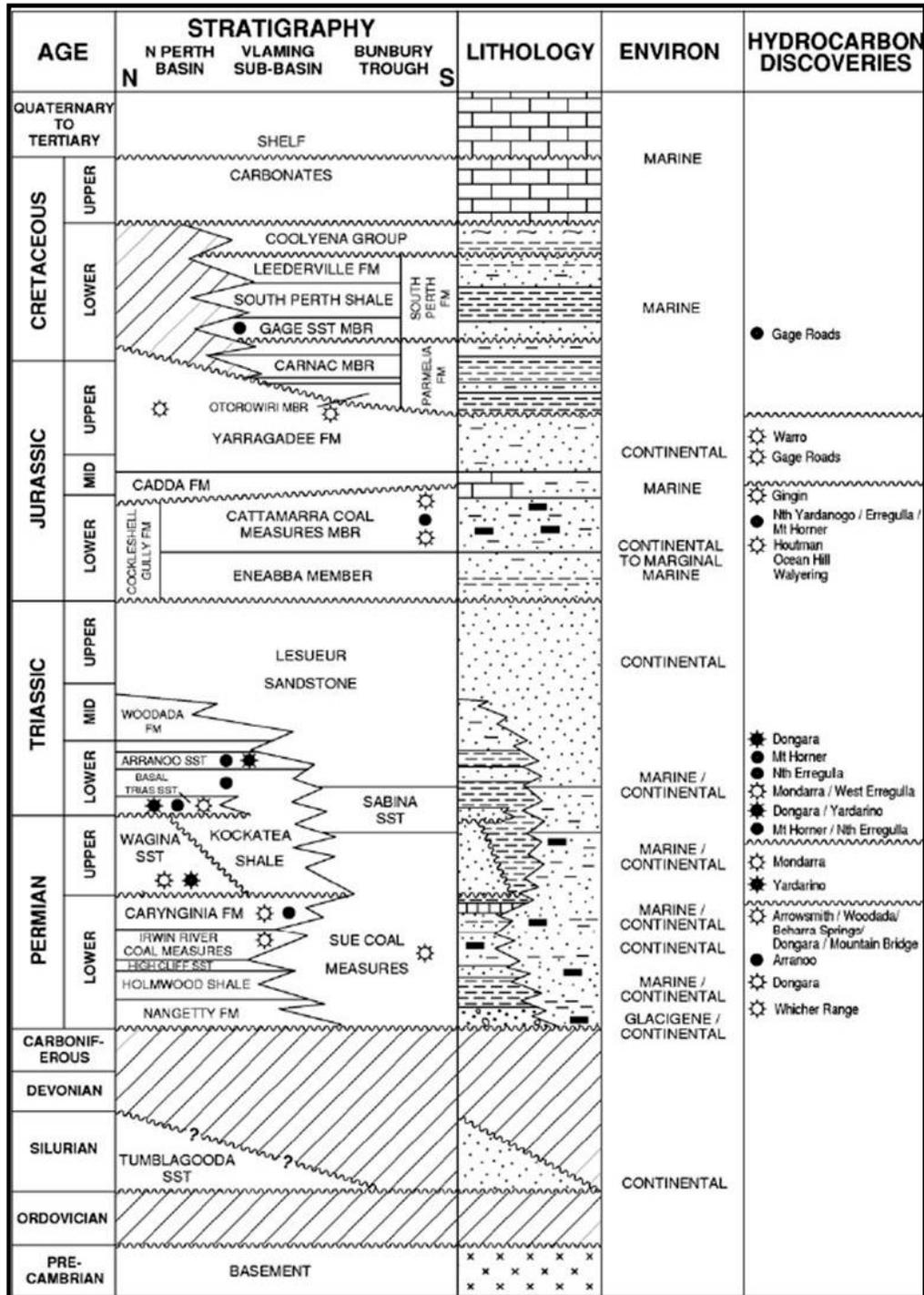
Source: AWE 2010

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-12.¹⁷

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

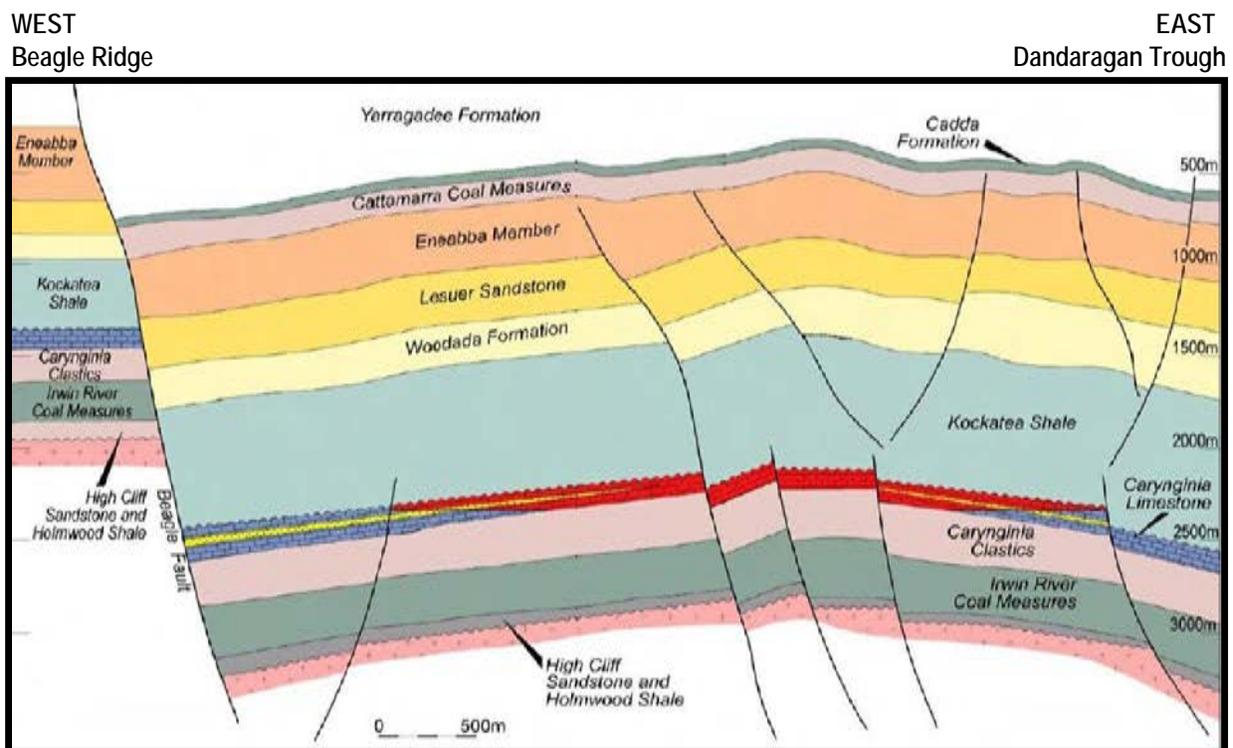


Source: Cadman et al., 1994

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%.¹⁸

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.¹⁹ 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.²⁰

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. CO₂ and N₂ contents tested low (0.5% and 0.4%, respectively) from a 4,750 ft deep Kockatea Shale zone in the Dongara-24 well.²¹

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. CO₂ and N₂ tested fairly low (about 2.5%) from a 8,000 ft Caryngia 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-mi² 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-mi² 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 mi². 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/mi² within its 2,200-mi² 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/mi² within its 1,030-mi² 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/mi² in the oil prospective area and 6 million barrels/mi² 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.²²

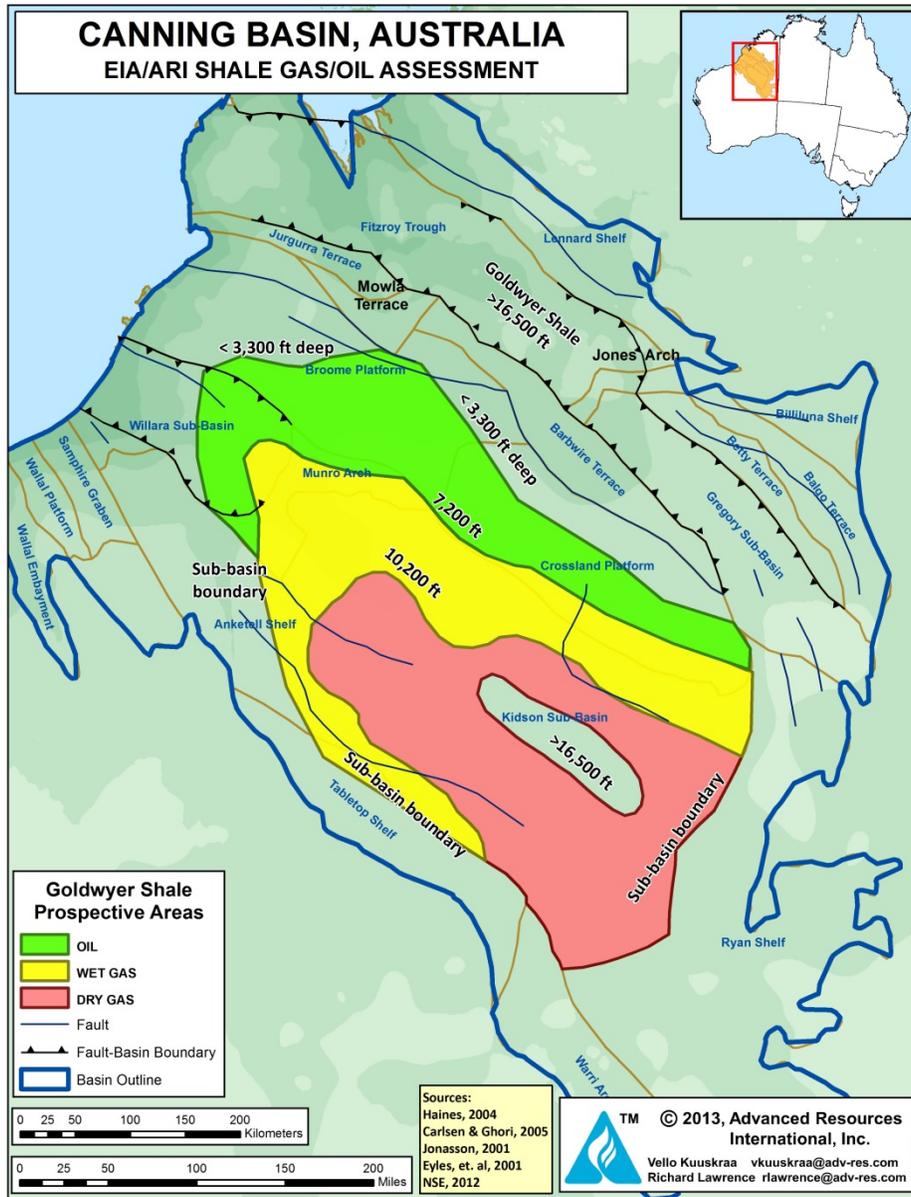
Australian independent, Norwest Energy which produces oil and gas from conventional fields in the Perth Basin, is evaluating the shale potential on its EP413 permit area, about 20 miles north of the Woodada Deep well. Norwest is partnered with AWE and has also farmed-out an interest in EP413 to an Indian 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-mi² Canning Basin (181,000 mi² 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.²³

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 formations²⁴.

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.

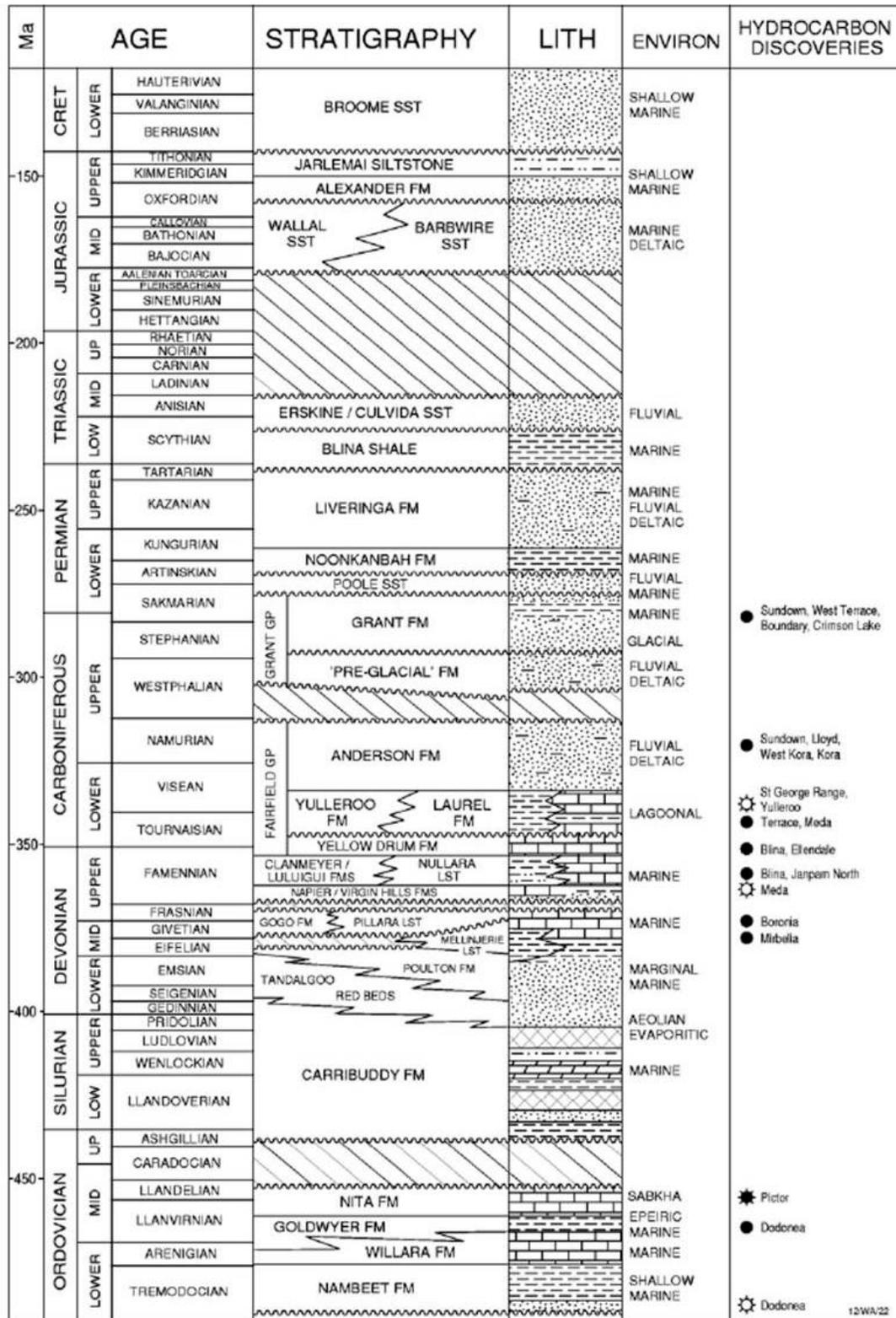
4.3 Reservoir Properties (Prospective Area)

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.²⁵

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.²⁶ 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.

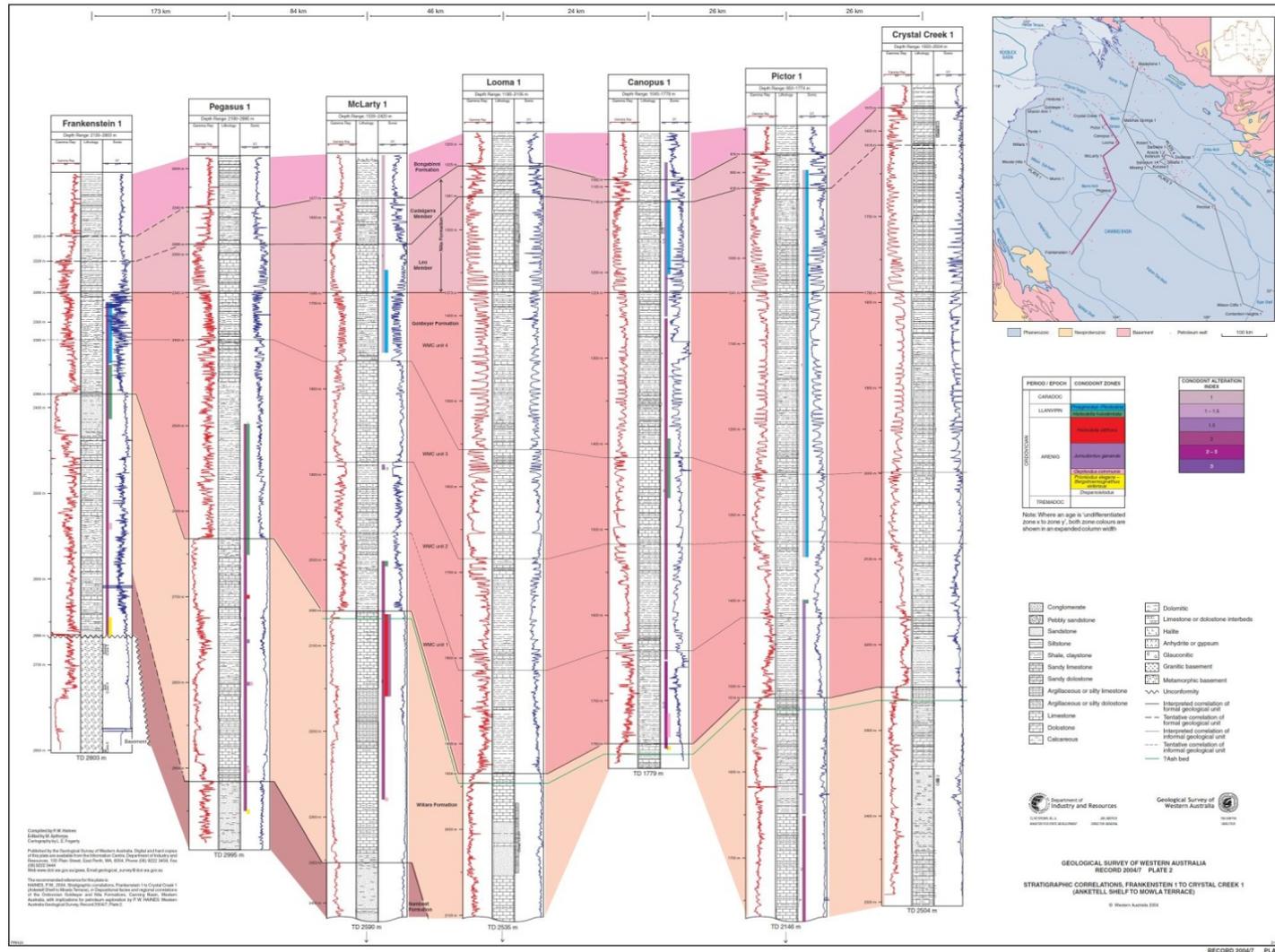
TOC in the Goldwyer Shale generally ranges from 1% to 5% (mean 3%), with some values in excess of 10%, Figure III-17.²⁷ The upper member of the Goldwyer Shale is particularly rich, with TOC up to 6.40%. Rock-Eval pyrolysis indicates this source rock is within the oil window over much of the southern 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.²⁸

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-mi² area may be prospective for dry gas development with a second 19,620-mi² area prospective for wet gas and condensate. A smaller 14,900-mi² area appears prospective for shale oil. The boundaries and depth contours for the undrilled deep trough areas were extrapolated from information at adjoining uplifts.

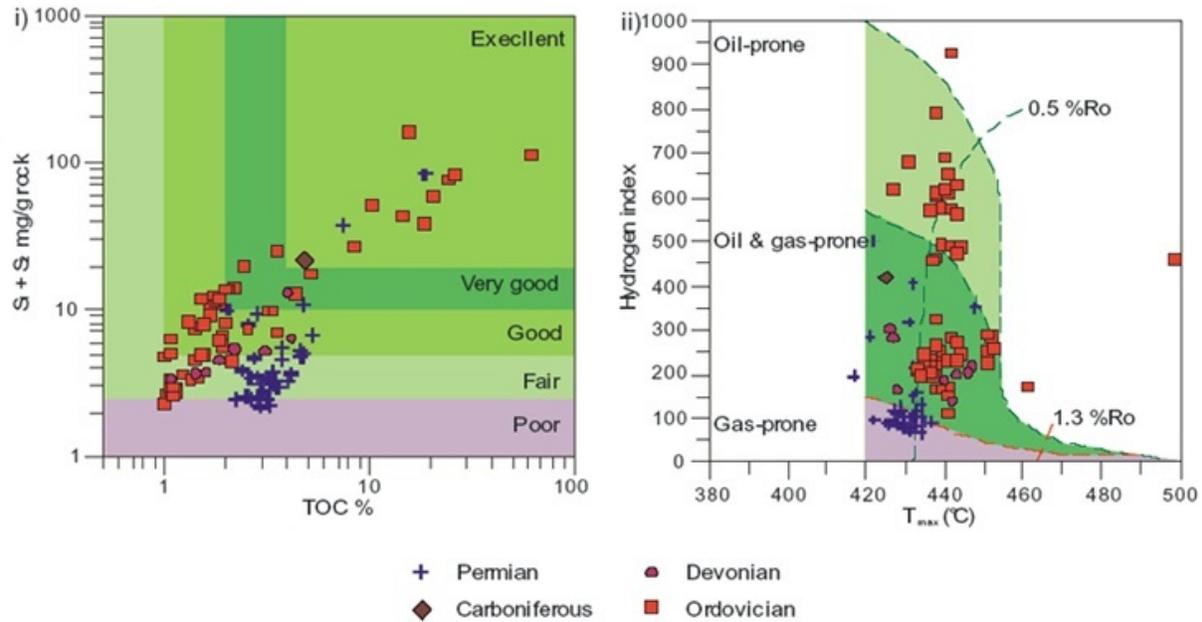
In the dry and wet gas prospective areas, the Goldwyer Shale has resource concentrations of 109 Bcf/mi² and 67 Bcf/mi², respectively. Including associated gas, the Goldwyer Shale in the Canning Basin has a risked shale gas in-place of 1,227 Tcf, with risked, technically recoverable shale gas of 235 Tcf. The prospective areas for oil and condensate for the Goldwyer Shale have resource concentrations of 41 million barrels/mi² and 10 million barrels/mi², 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.

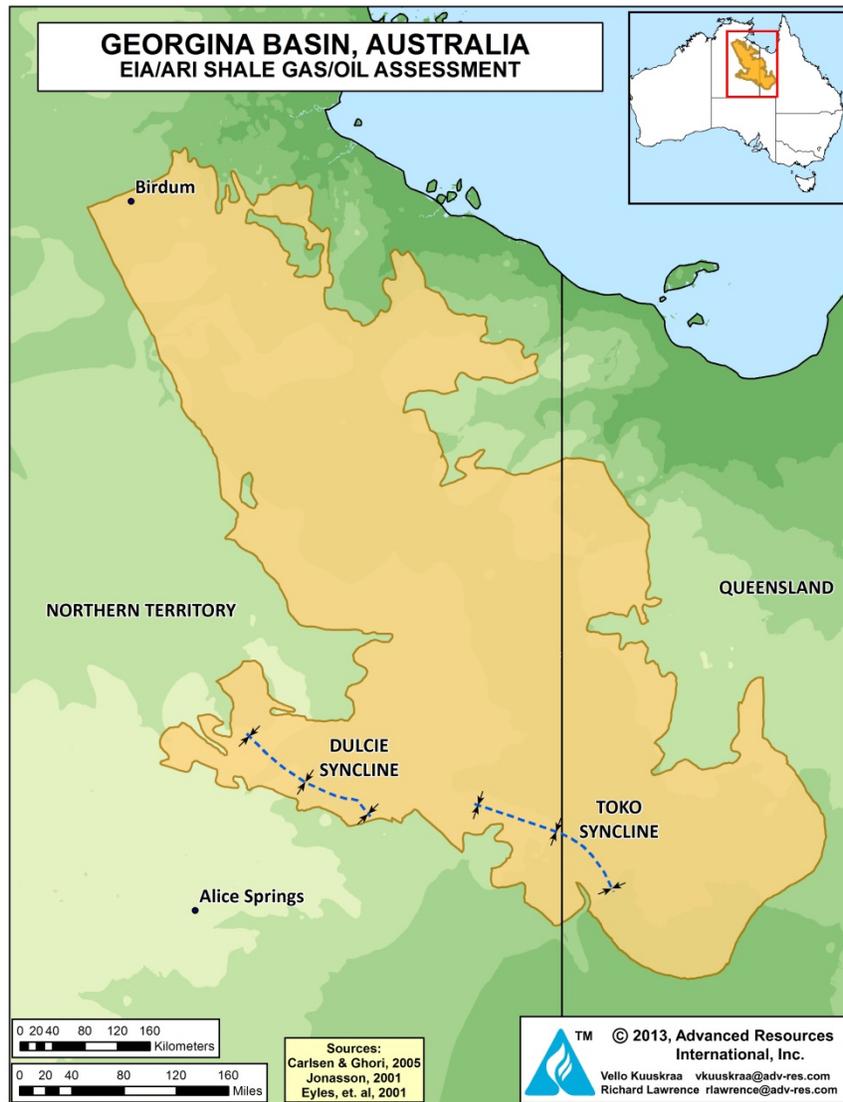
New Standard Energy (NSE), the other principal operator in the Canning Basin, holds exploration licenses covering 17,300 mi² in the northern edge of the Kidson sub-basin. In September 2011, NSE formed a joint venture with ConocoPhillips to accelerate exploration of the Goldwyer Shale. ConocoPhillips 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.²⁹

5. GEORGINA BASIN

5.1 Introduction

The Georgina Basin is a large, 125,000-mi² mainly unexplored basin in Northern Australia straddling the Northern Territory/Queensland border.³⁰ 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-19.³¹ 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	
	KELLY CREEK FM	COOLIBAH FM	
	TOMAHAWK FM	KELLY CREEK 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	
	MOUNT BALDWIN FM	ADAM SHALE	
NEOPROTEROZOIC	ELKERA FM		PETERMANN OROGENY
	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”.^{32,33} 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.

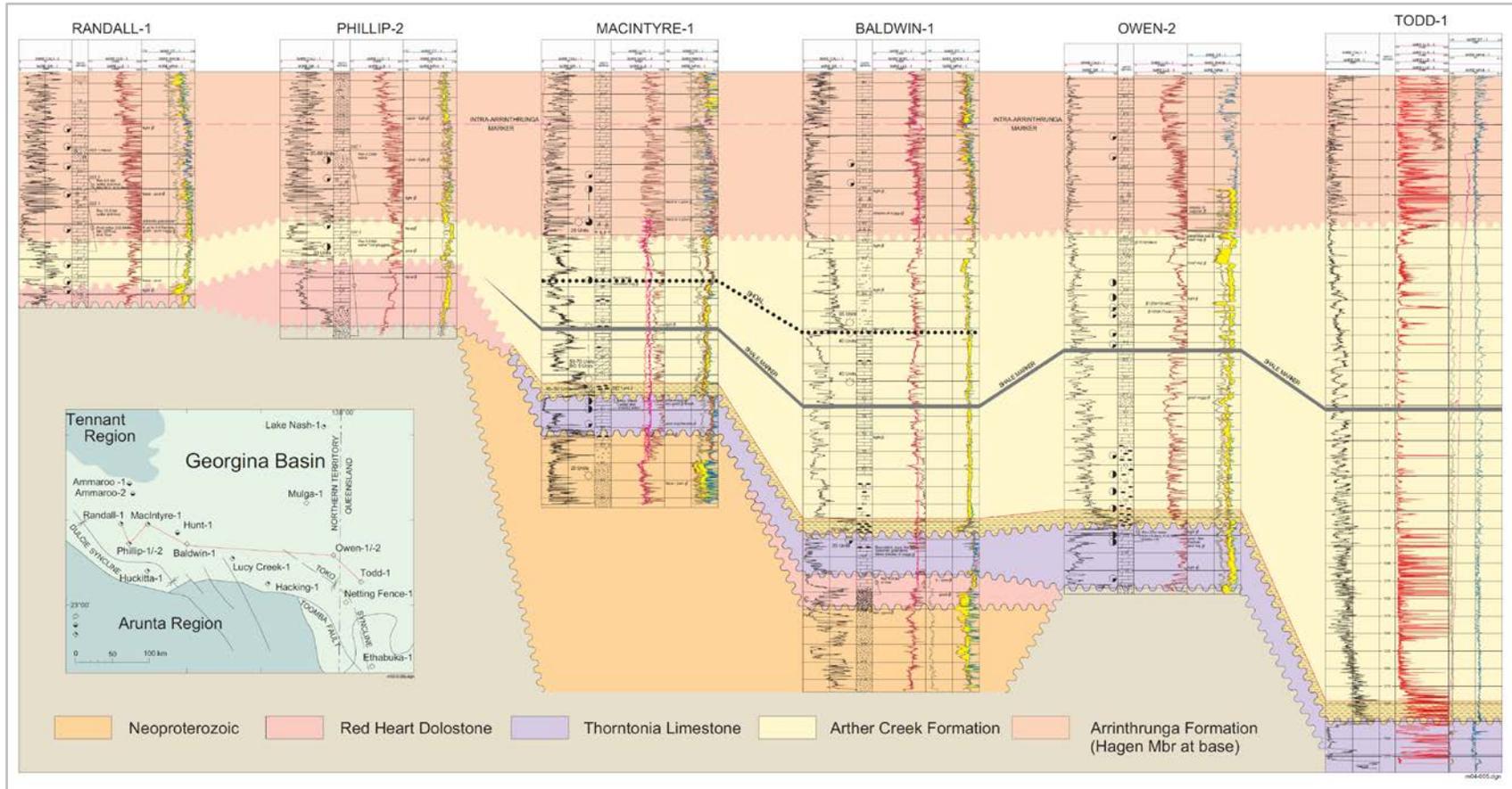
Geoscience Australia studied thirteen samples of core from four wells in the Georgina Basin, mainly from the Lower Arthur Creek Shale. The TOC of these samples ranged from 2% to 16%, with an average TOC of 5.5%.³⁴ The organic matter is composed of oil and wet gas prone Type I and II kerogen.

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.

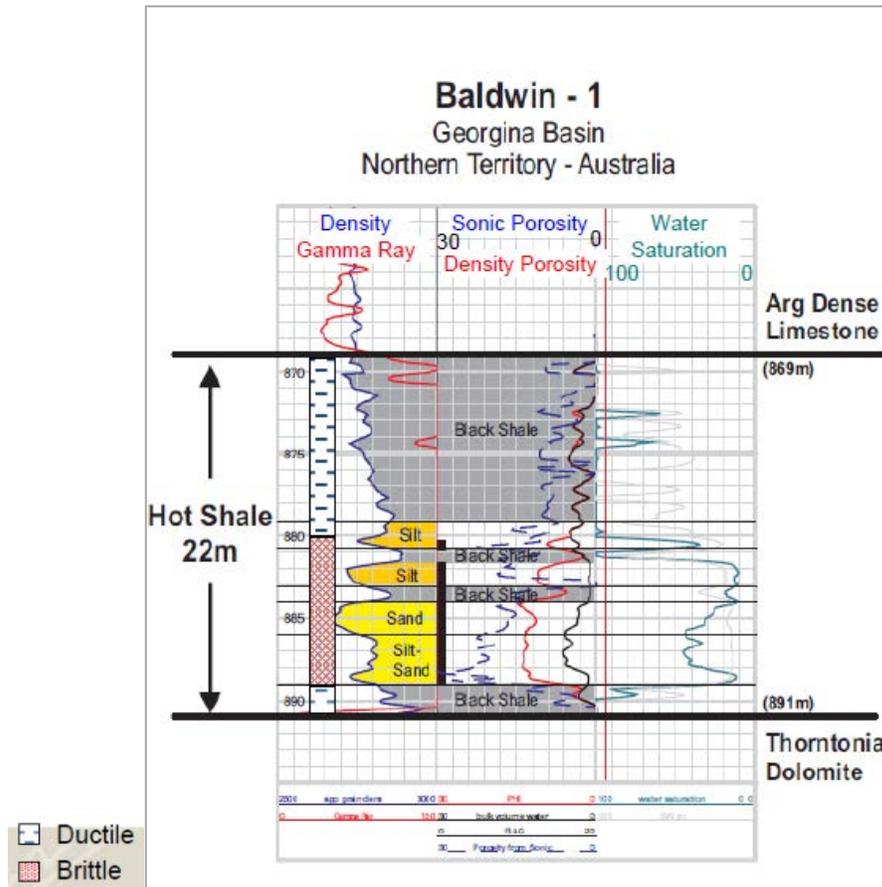
Oil and gas resources were estimated for two prospective areas: an eastern region covering the Dulcie Syncline and surrounding area, and a western region covering the Toko Syncline and surrounding area. Total risked wet and dry shale gas in-place (in both synclines and including associated gas) is estimated 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



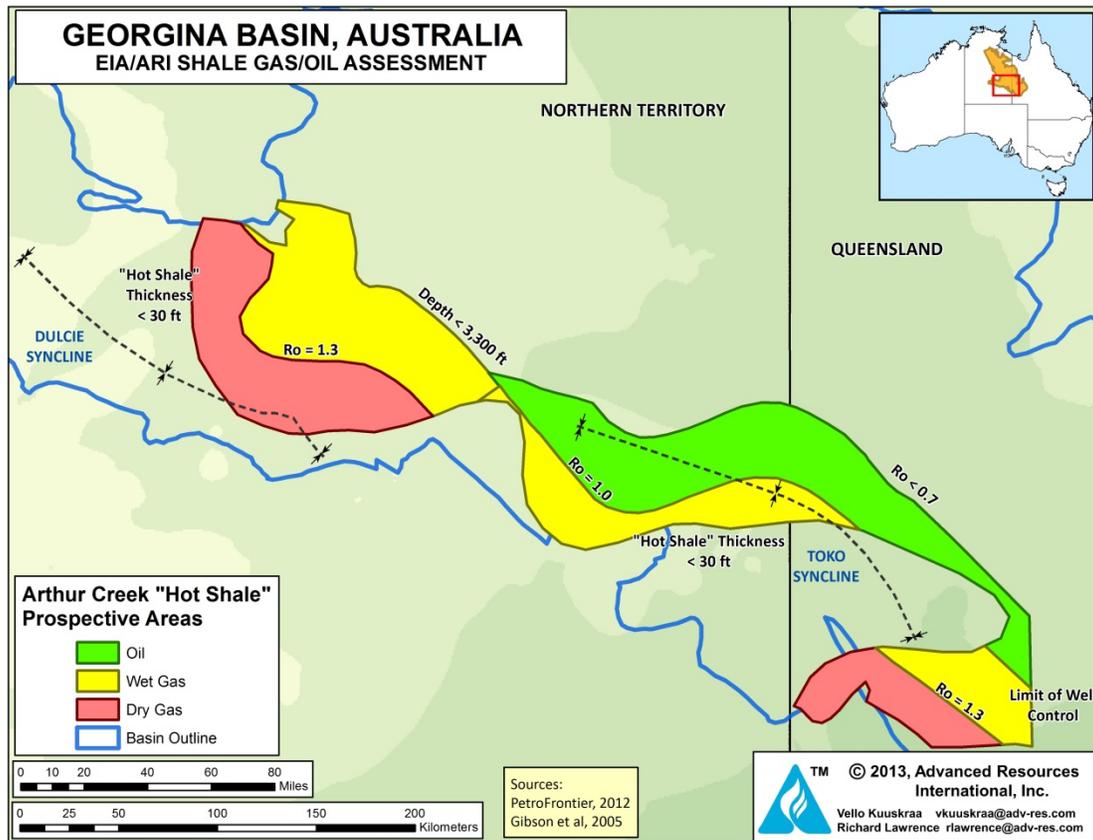
Source: Ambrose and Putnam, 2007

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

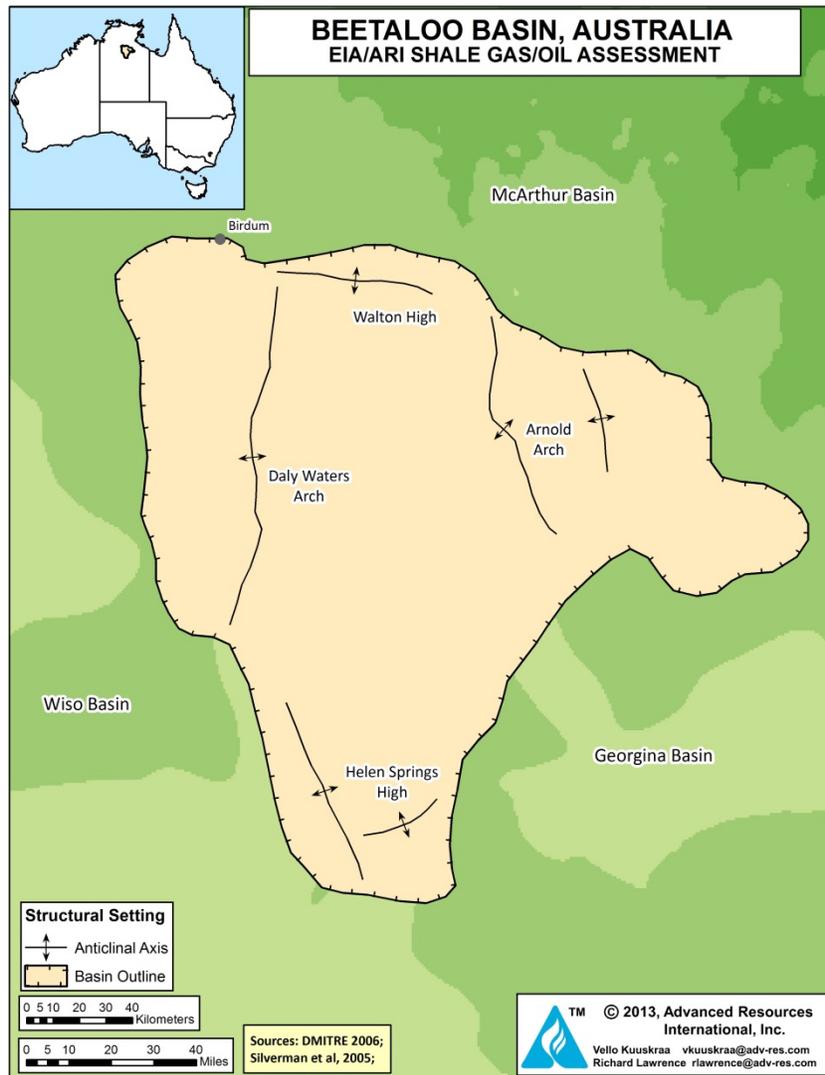
PetroFrontier Corporation, a Canadian company, holds several exploration permits in the southern portion of the Georgina Basin. A farm-in with Statoil Australia was established in 2012 with both companies committing to spending \$25 million on an exploration program. Two horizontal exploration wells 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. ³⁵

6. BEETALOO BASIN (NORTHERN TERRITORY)

6.1 Introduction

The Beetaloo Basin is a 14,000-mi² 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.³⁶

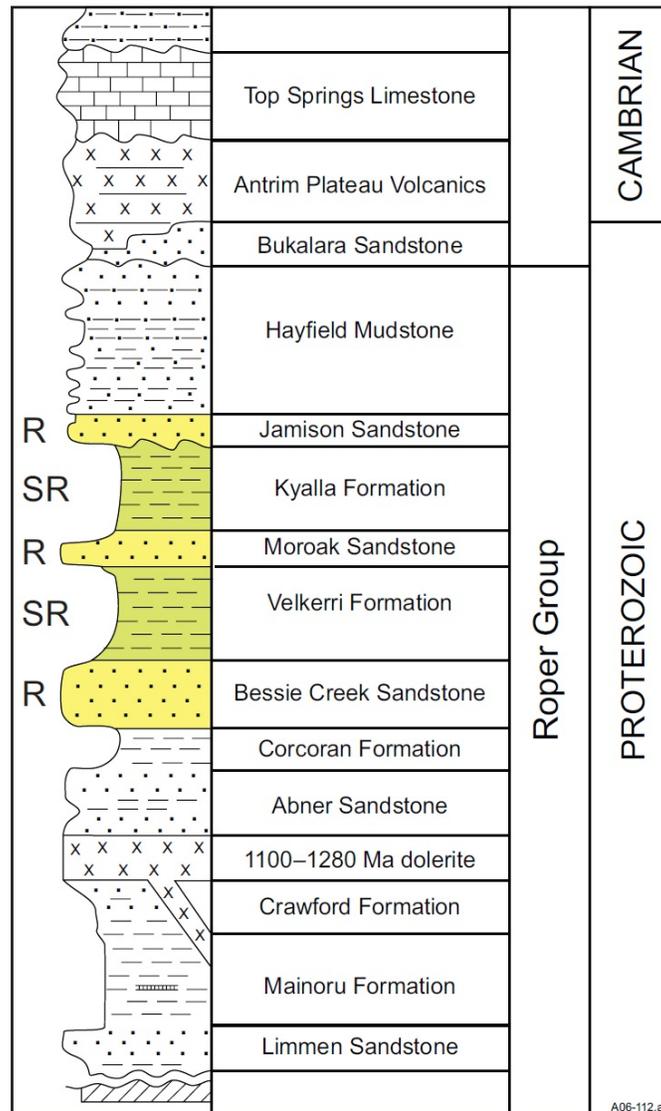
Figure III-23. Beetaloo Basin Location Map



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

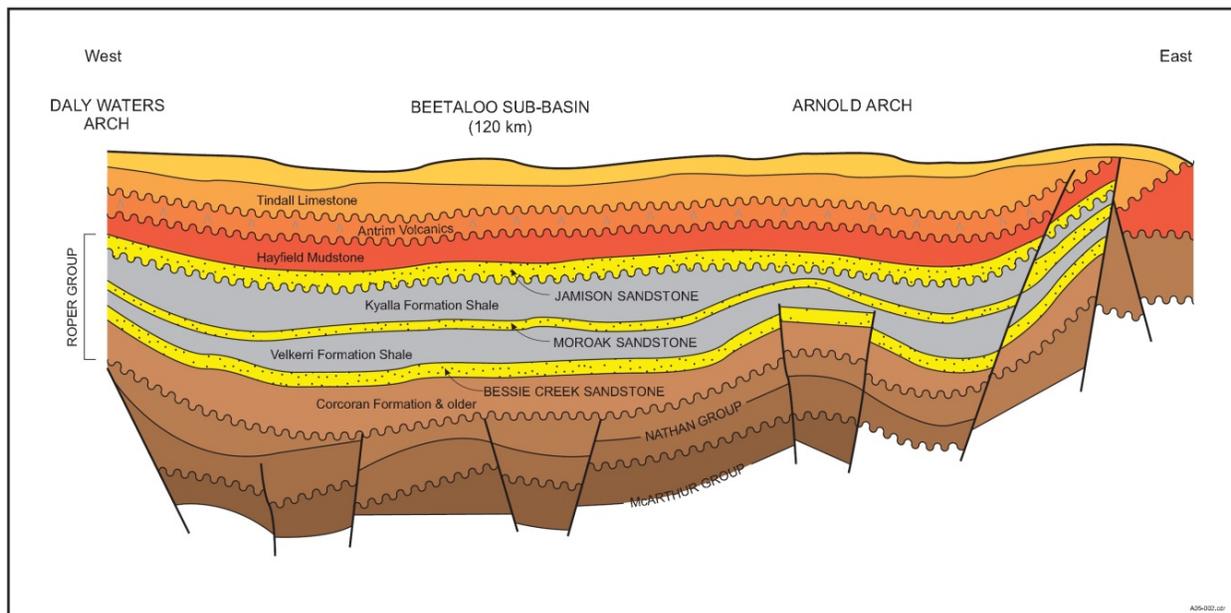


Source: Silverman et al, 2005

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 basin³⁷, 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.

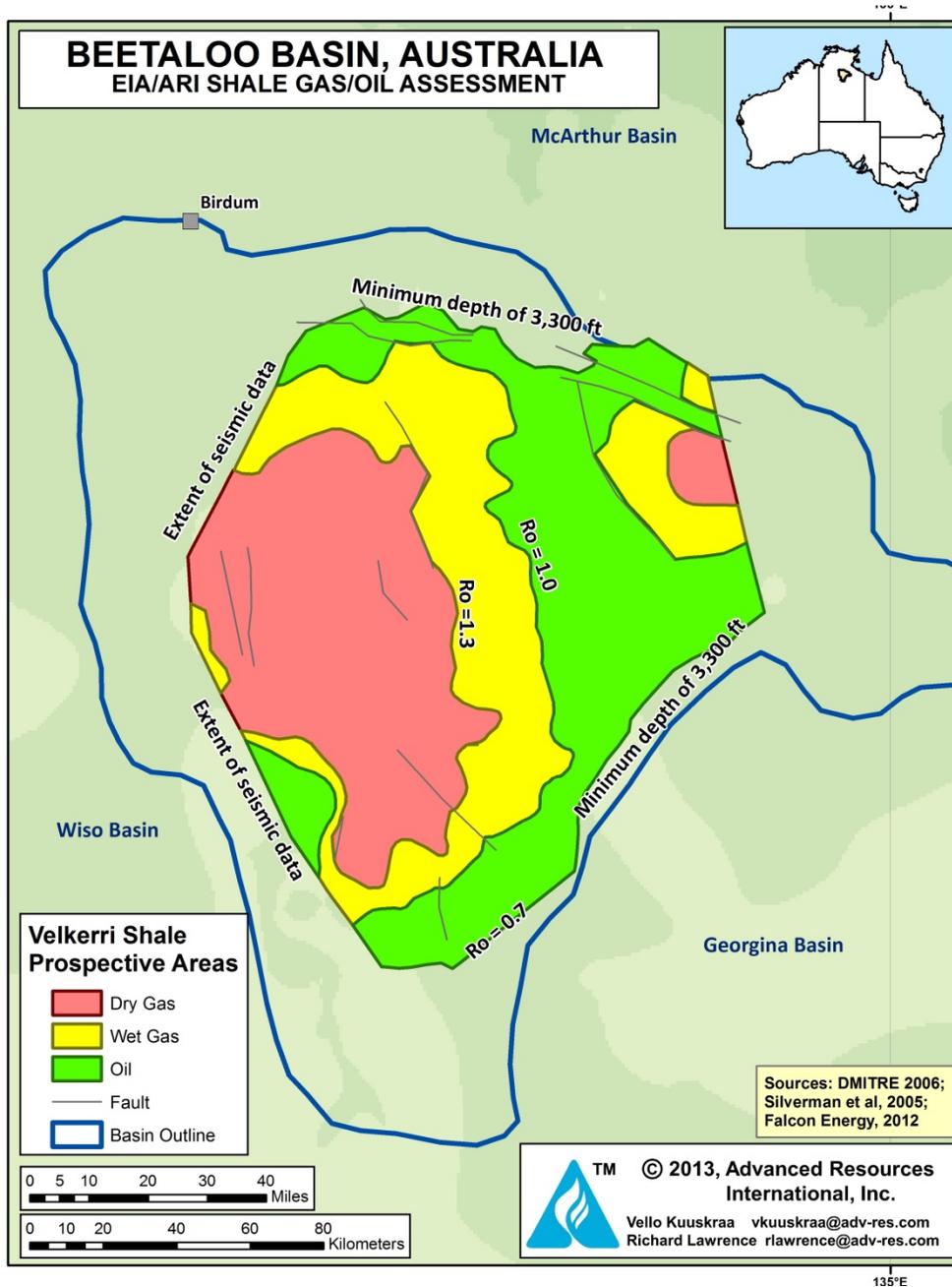
Figure III-25. East-West Cross-Section of the Beetaloo Basin



Source: Ambrose and Silverman, 2006³⁸

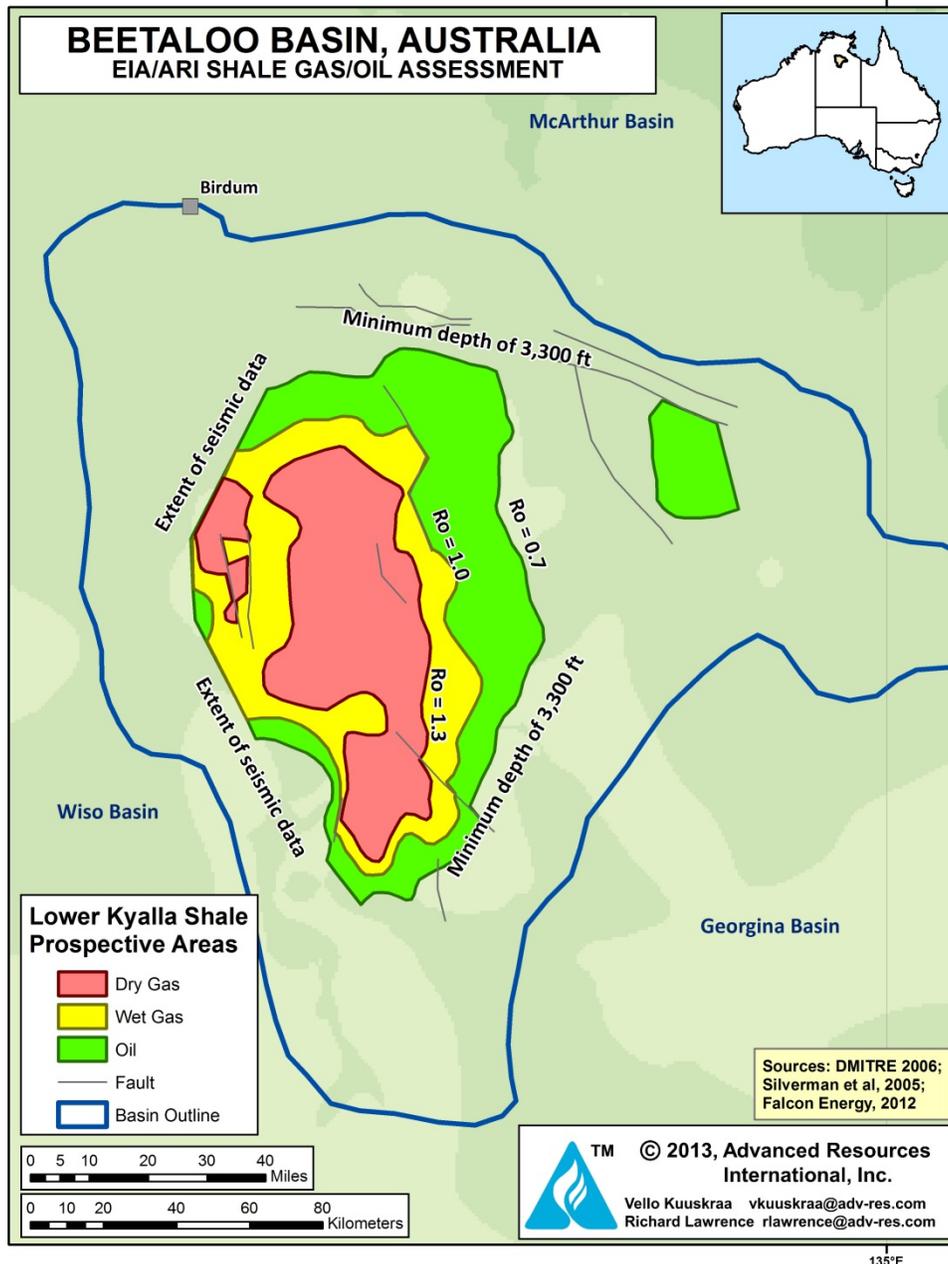
The Velkerri and the Kyalla shales have dry gas, wet gas/condensate and oil windows, based primarily on formation depth. The dry gas prospective area is 2,480 mi² for the Velkerri Shale and 1,310 mi² for the Kyalla Shale. The wet gas/condensate prospective area covers 2,130 mi² for the Velkerri Shale and 2,400 mi² Kyalla Shale. The shale oil prospective area is 2,650 mi² for the Velkerri Shale and 4,010 mi² 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.³⁹ 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.

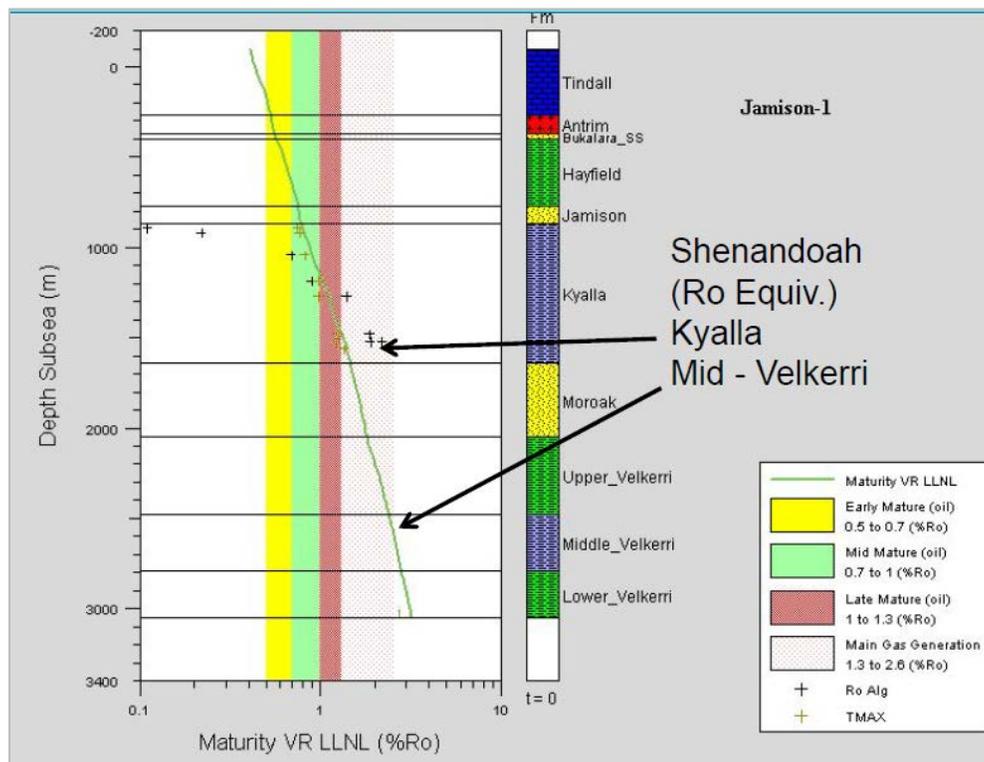
The Middle Velkerri has a maximum total organic carbon (TOC) content of 12%, averaging 4%. The organic matter is composed of oil prone Type I and II kerogens. The Upper and Lower Velkerri shales, with TOC contents of less than 2%, have not been included in the resource assessment.

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.⁴⁰ 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.⁴¹ Falcon is seeking another partner to explore their fourth permit area which covers 700,000 acres.

REFERENCES

-
- ¹ PIRSA, 2011. "Cooper Basin Fact Sheet." Petroleum and Geothermal Division, Department of Primary Industries and Resources of South Australia, Government of South Australia.
 - ² South Australia Department of Mineral and Energy Resources, 2010. "Petroleum & Geothermal in South Australia." 17 p.
 - ³ Menpes, 2012. "Emerging Continuous Gas Plays in the Cooper Basin, South Australia." Sandy Menpes, Government of South Australia, Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE). APPEA 2012 Conference and Exhibition
 - ⁴ Apak, S.N., Stuart, W.J., Lemon, N.M. and Wood, G., 1997. "Structural Evolution of the Permian-Triassic Cooper Basin, Australia: Relation to Hydrocarbon Trap Styles." American Association of Petroleum Geologists, Bulletin, vol. 81, p. 533-555.
 - ⁵ Lindsay, J., 2000. "South Australia Source Rock Potential and Algal-Matter Abundance, Cooper Basin, South Australia." South Australia Department of Primary Industries and Resources, Report Book 2000/00032, 172 p.
 - ⁶ Smith, M., 1983. "Nature of Source Materials for Hydrocarbon in Cooper Basin, Australia." American Association of Petroleum Geologists, Bulletin, vol. 67, p. 1422-1428.
 - ⁷ Beach Energy, presentation, 5-6 October 2010.
 - ⁸ Beach Energy, 2010.
 - ⁹ Reynolds, S.D., Mildren, S.D., Hillis, R.R., and Meyer, J.J., 2006. "Constraining Stress Magnitudes Using Petroleum Exploration Data in the Cooper-Eromanga Basins, Australia." Tectonophysics, vol. 415, p. 123-140.
 - ¹⁰ McGowan et al., 2007.
 - ¹¹ Stephenson, A.E. and Burch, G.J., 2004. "Preliminary Evaluation of the Petroleum Potential of Australia's Central Eastern Margin." Geoscience Australia Department Of Industry, Tourism & Resources. Geoscience Australia Record 2004/06, 117 p.

- ¹² Hill, P.J., 1994. "Geology and geophysics of the offshore Maryborough, Capricorn and northern Tasman basins: results of AGSO Survey 91." Canberra, Australian Geological Survey Organization, Record 1994/1.
- ¹³ Lane, P.B., 1983. "Geology and Petroleum Potential of ATP 229P, Onshore Maryborough Basin, Queensland, Australia." Unpublished report, 30 p.
- ¹⁴ Blue Energy Ltd, 2012. "Quarterly Activities Report" June 2012.
- ¹⁵ Cadman, S.J. Pain, L. and Vuckovic, V., 1994. "Australian Petroleum Accumulations Report 10: Perth Basin, Western Australia." 116 p.
- ¹⁶ Cawood, P.A. and Nemchin, A.A., 2000. "Provenance Record of a Rift Basin: U/Pb Ages of Detrital Zircons from the Perth Basin, Western Australia." *Sedimentary Geology*, vol. 134, p. 209-234.
- ¹⁷ Mory, A.J. and Iasky, R.P., 1996. "Stratigraphy And Structure Of The Onshore Northern Perth Basin Western Australia." Geological Survey of Western Australia, Department of Minerals and Energy, Report 46, 126 p.
- ¹⁸ Thomas, B.M., 1979. "Geochemical Analysis of Hydrocarbon Occurrences in Northern Perth Basin, Australia." *American Association of Petroleum Geologists*, vol. 63, p. 1092-1107.
- ¹⁹ Nabbefeld, B., Grice, K., Schimmelmann, A., Summons, R.E., Troitzsch, U., Twitchett, R.J., 2010. "A Comparison of Thermal Maturity Parameters Between Freely Extracted Hydrocarbons (Bitumen I) and a Second Extract (Bitumen II) from Within the Kerogen Matrix of Permian and Triassic Sedimentary Rocks." *Organic Geochemistry*, vol. 41, p. 78-87.
- ²⁰ Dawson, D., Grice, K., and Alexander, R., 2005. "Effect of Maturation on the Indigenous dD Signatures of Individual Hydrocarbons in Sediments and Crude Oils from the Perth Basin (Western Australia)." *Organic Geochemistry*, vol. 36, p. 95-104.
- ²¹ Boreham, C.J. and Edwards, D.S., 2008. "Abundance and Carbon Isotopic Composition of Neo-Pentane in Australian Natural Gases." *Organic Geochemistry*, vol. 39, p. 550-566.
- ²² AWE, announcement, November 9, 2010.
- ²³ Cadman, S.J. Pain, L., Vuckovic, V., and le Poidevin, S.R., 1993. "Australian Petroleum Accumulations Report 9: Canning Basin, Western Australia." 88 p.
- ²⁴ Ghori, K.A.R. and Haines, P.W., 2007. "Paleozoic Petroleum Systems of the Canning Basin, Western Australia: A review." *American Association of Petroleum Geologists, Search and Discovery Article No. 10120*, 7 p.
- ²⁵ Haines, P. W., 2004. "Depositional Facies And Regional Correlations Of The Ordovician Goldwyer And Nita Formations, Canning Basin, Western Australia, with Implications for Petroleum Exploration." *Western Australia Geological Survey, Record 2004/7*, 45p.
- ²⁶ Foster, C. B., O'Brien, G. W., and Watson, S. T., 1986, Hydrocarbon Source Potential of the Goldwyer Formation, Barbwire Terrace, Canning Basin, Western Australia." *APEA Journal*, vol. 26, p. 142-155.
- ²⁷ Ghori, K.A.R. and Haines, P.W., 2007. "Paleozoic Petroleum Systems of the Canning Basin, Western Australia: A review." *American Association of Petroleum Geologists, Search and Discovery Article No. 10120*, 7 p.
- ²⁸ New Standard Energy, 2011. "Potential Liquids Rich Zone Identified in Goldwyer Project". ASX Announcement, February 10, 2011.
- ²⁹ New Standard Energy, 2012. "Nicolay #1 Weekly Drilling Update" ASX Announcement, August 20, 2012.
- ³⁰ Pegum, D.M. 1997. "An Introduction to the Petroleum Geology of the Northern Territory of Australia." Department of Mines and Energy, Northern Territory Geological Survey. 46 p.
- ³¹ Dunster JN, Kruse PD, Duffett ML and Ambrose GJ, 2007. "Geology and resource potential of the southern Georgina Basin." Northern Territory Geological Survey, Digital Information Package DIP007.

-
- ³² Bennett, P.J., Philpchuk, Freeman, A. 2010. "Arthur Creek "Hot Shale": A Bakken Unconventional Oil Analogy in the Georgina Basin of Northern Territory, Australia." American Association of Petroleum Geologists, Search and Discovery Article # 80125, December 31, 2010.
- ³³ Volk et al, 2005.
- ³⁴ Vu Thi Anh Tiem, Brian Horsfield and Rolando di Primio., 2011. Gas shale potential of the Amadeus and Georgina Basins, Australia: preliminary insights, Geoscience Australia Record 2011/10, 39pp.
- ³⁵ PetroFrontier Corp, 2012. "PetroFrontier Corp. provides "Owen-3" drilling update in Southern Georgia Basin, Australia. TSX Announcement August 9, 2012.
- ³⁶ Silverman, M.R., Landon, S.M., Leaver, J.S., Mather, T.J., and Berg, E. 2005. "No Fuel Like an Old Fuel: Proterozoic Oil and Gas Potential in the Beetaloo Basin, Northern Territory, Australia." Proceedings of the Central Australian Basins Symposium, Special Publications 2, p. 205-215. Edited by TJ Munson and GJ Ambrose. Northern Territory Geological Survey.
- ³⁷ Silverman, M. and Ahlbrandt, T. 2011. "Mesoproterozoic Unconventional Plays in the Beetaloo Basin, Australia: The World's Oldest Petroleum Systems." American Association of Petroleum Geologists (AAPG), Search and Discovery Article #10295, January 21, 2011.
- ³⁸ Ambrose and Silverman, 2006. "Onshore Hydrocarbon Potential of the Beetaloo Sub-Basin." Northern Territory Geological Survey. Record 2006-003.
- ³⁹ Warren et al, 1998. "Proterozoic Source Rocks: Sedimentology and Organic Characteristics of the Velkerri Formation, Northern Territory, Australia." AAPG Bulletin Vol 82 (1998), Issue 3, Pages 442-463
- ⁴⁰ Silverman, M. and Ahlbrandt, T. 2011. "Mesoproterozoic Unconventional Plays in the Beetaloo Basin, Australia: The World's Oldest Petroleum Systems." American Association of Petroleum Geologists (AAPG), Search and Discovery Article #10295, January 21, 2011.
- ⁴¹ Falcon Oil and Gas, 2012. "Falcon Oil and Gas Ltd. Announces Australian Operational Update." August 20, 2012