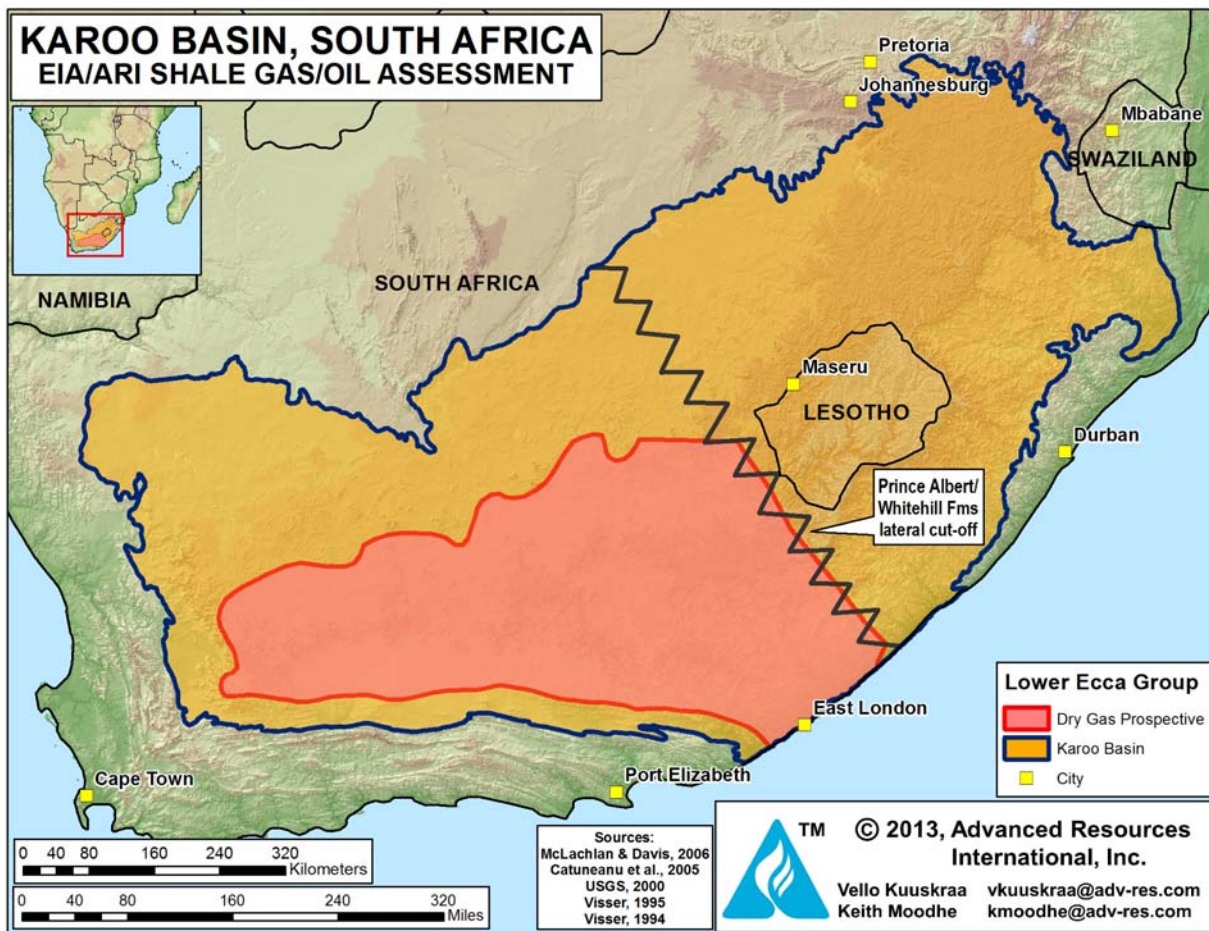


XIX. SOUTH AFRICA

SUMMARY

South Africa has one major sedimentary basin that contains thick, organic-rich shales - - the Karoo Basin in central and southern South Africa, Figure XIX-1.^{1,2,3} The Karoo Basin is large (236,400 mi²), extending across nearly two-thirds of the country, with the southern portion of the basin potentially favorable for shale gas. However, the basin contains significant areas of igneous (sill) intrusions that may impact the quality of the shale resources, limit the use of seismic imaging, and increase the risks of shale exploration.

Figure XIX -1: Outline of Karoo Basin and Prospective Shale Gas Area of South Africa



Source: ARI, 2013.

The Permian-age Eccca Group, with its organic-rich source rocks in the Lower Eccca Formation, is the primary shale formation addressed by this assessment. Of particular interest is the organic-rich, thermally mature black shale unit in the Whitehill Formation of the Lower Eccca. This shale unit is regionally persistent in composition and thickness and can be traced across most of the southern portion of the Karoo Basin.⁴

We estimate that the Lower Permian Eccca Group shales in this basin contain 1,559 Tcf of risked shale gas in-place, with 370 Tcf as the risked, technically recoverable shale gas resource, Table XIX-1. We have excluded the Upper Eccca shales in this basin from quantitative assessment because their TOC content is reported to be below the 2% TOC standard used by this resource assessment study.

Table XIX-1: Shale Gas Reservoir Properties and Resources of the Karoo Basin

Basic Data	Basin/Gross Area		Karoo (236,400 mi ²)		
	Shale Formation		Prince Albert	Whitehill	Collingham
	Geologic Age		L. Permian	L. Permian	L. Permian
	Depositional Environment		Marine	Marine	Marine
Physical Extent	Prospective Area (mi ²)		60,180	60,180	60,180
	Thickness (ft)	Organically Rich	400	200	200
		Net	120	100	80
	Depth (ft)	Interval	6,000 - 10,500	5,500 - 10,000	5,200 - 9,700
Average		8,500	8,000	7,800	
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		2.5%	6.0%	4.0%
	Thermal Maturity (% Ro)		3.00%	3.00%	3.00%
	Clay Content		Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi ²)		42.7	58.5	36.3
	Risked GIP (Tcf)		385.3	845.4	327.9
	Risked Recoverable (Tcf)		96.3	211.3	82.0

INTRODUCTION

South Africa is a net natural gas importer, primarily from neighboring Mozambique and Namibia. As such, South Africa has given priority to exploration for domestic gas and oil. Shale exploration is initiated via a Technical Cooperation Permit (TCP), which may lead to an Exploration Permit (EP) and eventually to a production contract. The country has a corporation tax of 28% and royalty of 7%, terms that are favorable for gas and oil development.

A number of major and independent companies have signed Technical Cooperation Permits (TCPs) to pursue shale gas in the Karoo Basin, including Royal Dutch Shell, the Falcon Oil & Gas/Chevron joint venture, the Sasol/Chesapeake/Statoil joint venture, Sunset Energy Ltd. of Australia and Anglo Coal of South Africa.

1. KAROO BASIN

1.1 Introduction

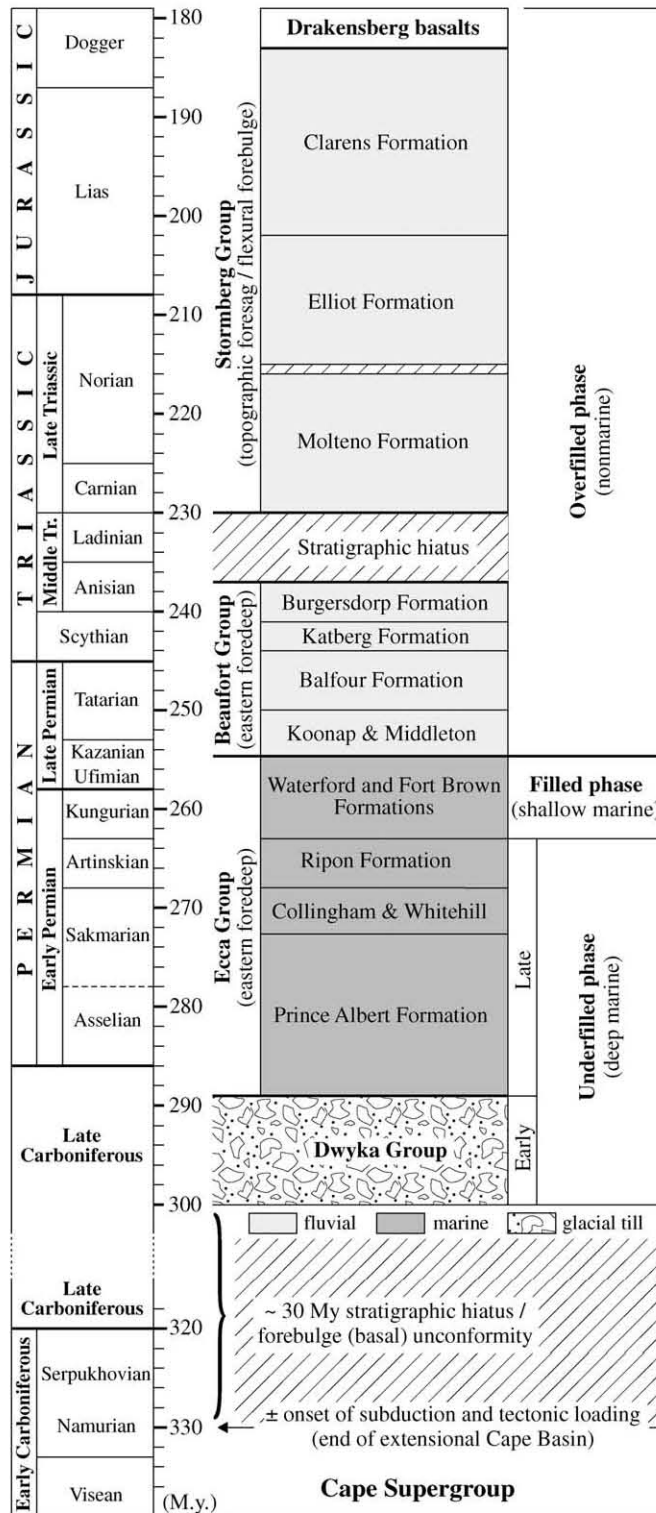
The Karoo foreland basin is filled with over 5 km of Carboniferous to Early Jurassic sedimentary strata. The Early Permian-age Ecca Group underlies much of the Karoo Basin, cropping out along the southern and western basin margins, Figure XIX-1. The Ecca Group contains a sequence of organic-rich mudstone, siltstone, sandstone and minor conglomerates.⁵

1.2 Geologic Setting

The larger Ecca Group, encompassing an interval up to 10,000 ft thick in the southern portion of the basin, is further divided into the Upper Ecca (containing the Fort Brown and Waterford Formations) and the Lower Ecca (containing the Prince Albert, Whitehill and Collingham Formations), Figure XIX-2. The three Lower Ecca formations are the subject of this shale resource assessment.

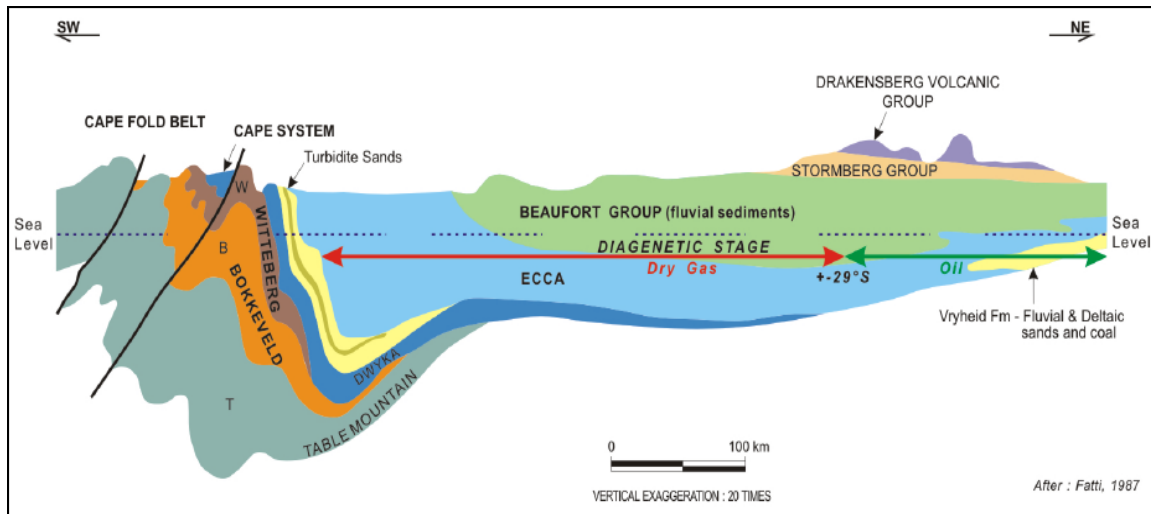
The regional southwest to northeast cross-section illustrates the structure of the Cape Fold Belt of the Ecca Group on the south and the thermal maturity for the Ecca Group on the north, Figure XIX-3.⁶

Figure XIX-2. Stratigraphic Column of the Karoo Basin of South Africa



Source: Catuneanu, O. et al., 2005.

Figure XIX-3. Schematic Cross-Section of Southern Karoo Basin and Ecca Group Shales

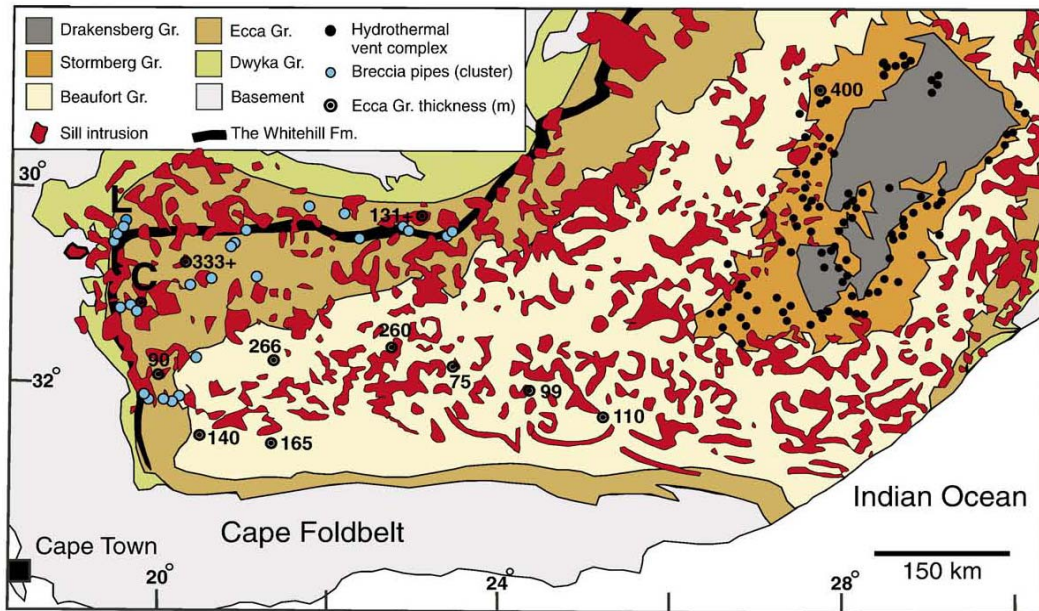


Source: McLachlan, I. and Davis, A., 2006.

Major portions of the Karoo Basin have igneous (sill) intrusions and complex geology, with the most extensive and thickest sills concentrated within the Upper Ecca and Balfour formations.⁷ This unusual condition creates significant exploration risk in pursuing the shale resources in the Karoo Basin, Figure XIX-4.⁸ (Note that this map reflects the maximum extent of intrusions, which are expected to be less within the target shale formations.) Local mapping indicates that contact metamorphism is restricted to quite close to the intrusions. As such, we removed 15% of the prospective area to account for the potential impact of igneous intrusions and significantly risked the remaining resource.

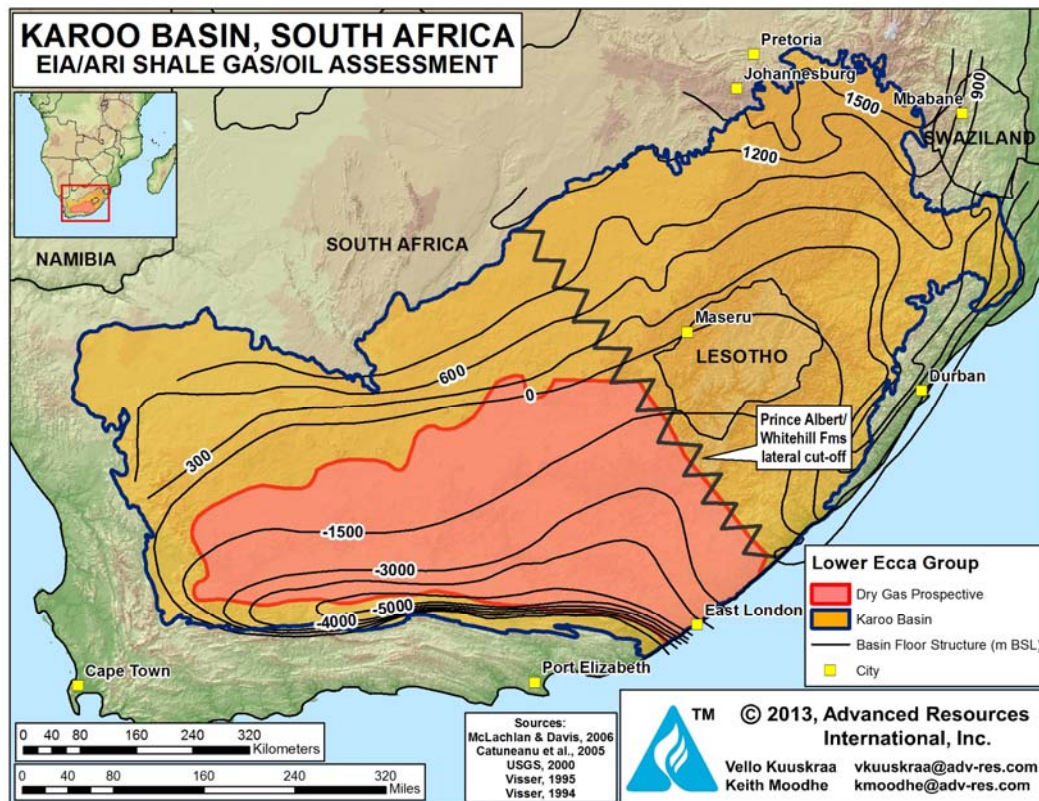
The prospective area for the Lower Ecca Group shales is estimated at 60,180 mi², Figure XIX-5. The boundaries of the prospective area are defined by the outcrop of the Upper Ecca Group on the east, south and west/northwest and the pinch-out of the Lower Ecca Group shales on the northeast, Figure XIX-1. The dry gas window is south of the approximately 29° latitude line. Given the thermal maturity information and the depositional limits of the Lower Ecca shales, the prospective area of the Lower Ecca shales is primarily in the dry gas window.

Figure XIX-4. Igneous Intrusions in the Karoo Basin, South Africa



Source: Svensen, H. et al., 2007.

Figure XIX-5. Lower Eccla Group Structure Map, Karoo Basin, South Africa



Source: ARI, 2013.

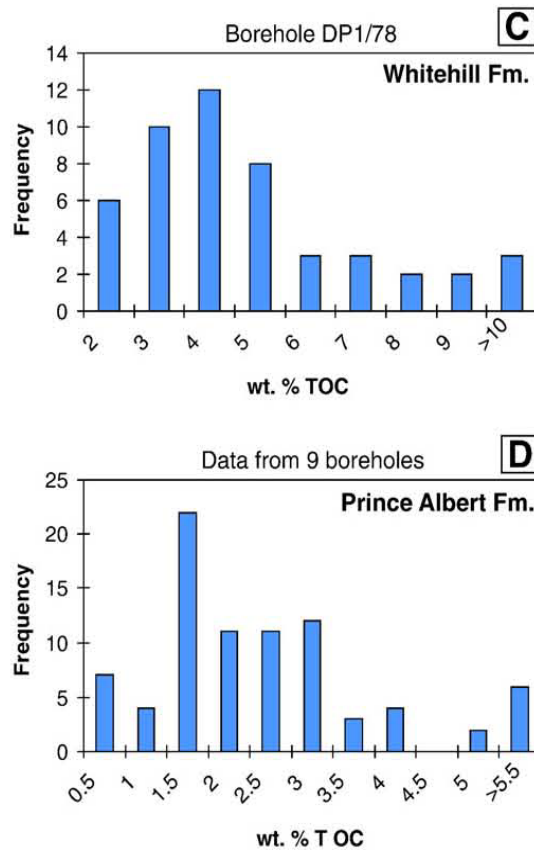
1.2 Reservoir Properties (Prospective Area)

Lower Ecca Shales. The Lower Ecca shales include the thick basal Prince Albert Formation, overlain by the thinner Whitehill and Collingham Formations. Each of these sedimentary units has been individually assessed and is discussed below.

Prince Albert Shale. The Lower Permian Prince Albert Formation has a thick, thermally mature area for shale gas in the Karoo Basin. Depth to the Prince Albert Shale ranges from 6,000 to over 10,000 ft, averaging about 8,500 ft in the deeper prospective area in the south. The Prince Albert Shale has a gross thickness that ranges from 200 to 800 ft, averaging 400 ft, with a net organic-rich thickness of about 120 ft.

The total organic content (TOC) of the Prince Albert Shale within its organic-rich net pay interval ranges from 1.5 to 5.5%, averaging 2.5%, Figure XIX-6.⁸ Local TOC values of up to 12% have been recorded.⁹ However, in areas near igneous intrusions much of the organic content may have been lost or converted to graphite.

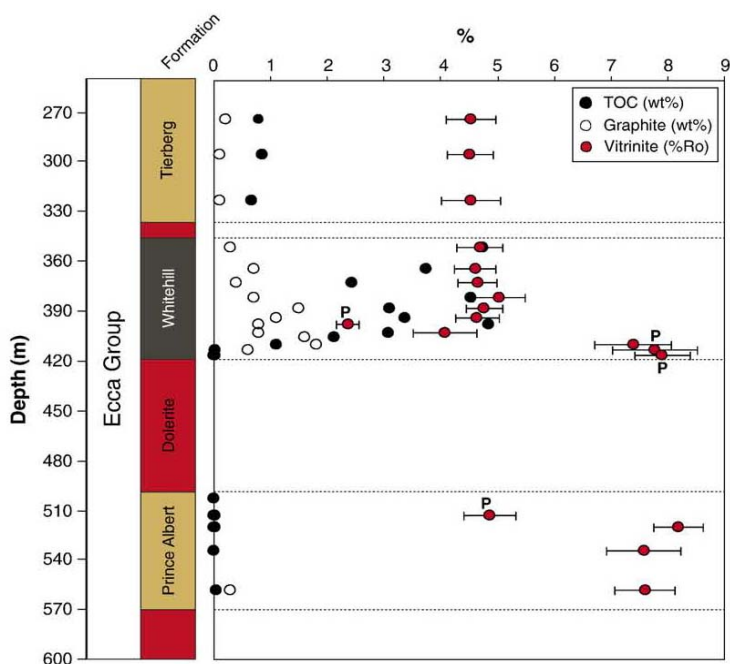
Figure XIX-6. Total Organic Content of Prince Albert and Whitehill Formations



Source: Svensen, H. et al., 2007.

Because of the presence of igneous intrusions, the thermal maturity of the Prince Albert Shale is high, estimated at 2% to 4% R_o , placing the shale well into the dry gas window. In areas near igneous intrusions, the formation is over-mature, with vitrinite reflectance (R_o) values reaching 8%, indicating that the organic content has been transformed into graphite and CO_2 , Figure XIX-7. The Prince Albert Shale was deposited as a deep marine sediment and is inferred to have mineralogy favorable for shale formation stimulation.

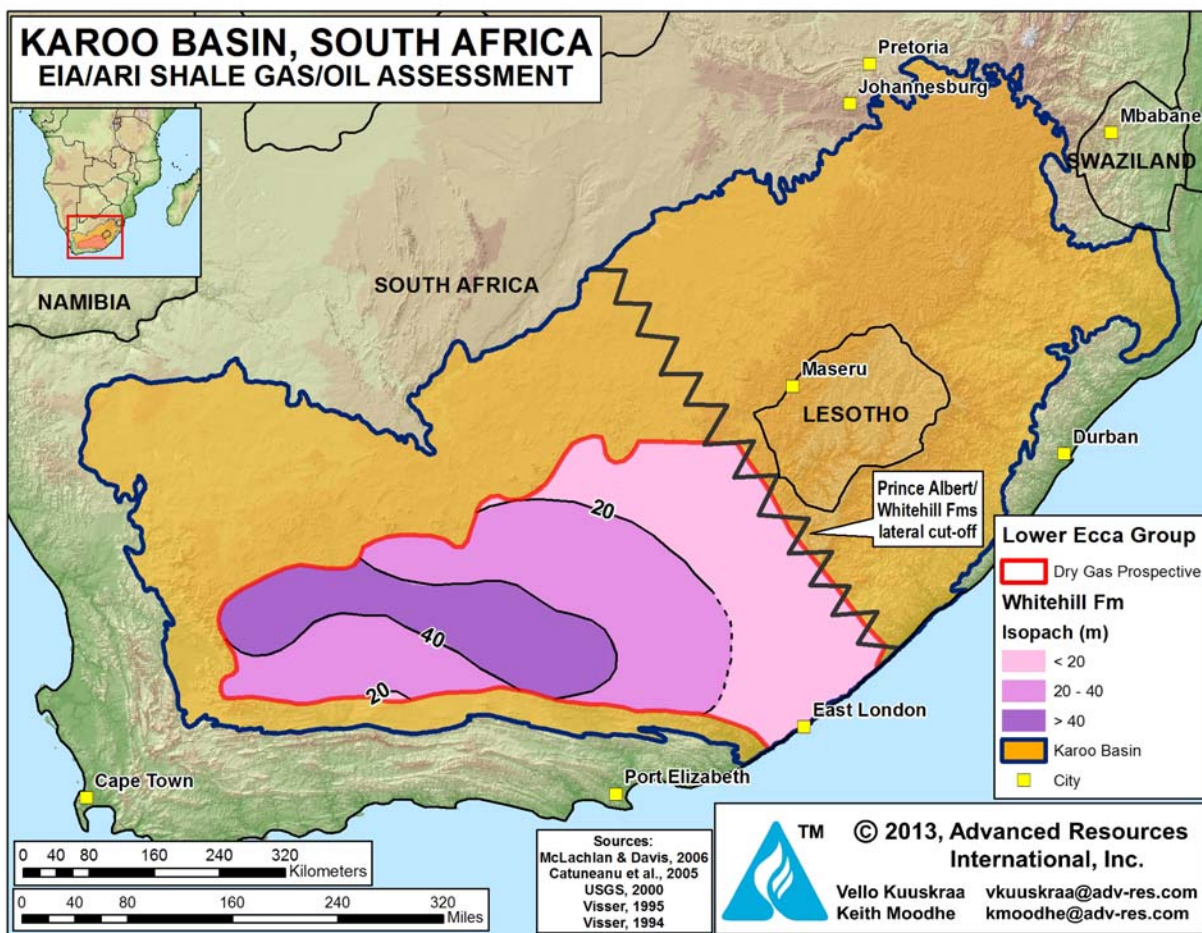
Figure XIX-7. Carbon Loss in Lower Ecca Group Metamorphic Shale



Based on limited well data, primarily from the Cranemere CR 1/68 well completed in the Upper Ecca interval, the Prince Albert Shale appears to be overpressured and has a high thermal gradient.

Whitehill Shale. The organic-rich Lower Permian Whitehill Formation contains one of the main shale gas targets in the Karoo Basin of South Africa. The depth to the Whitehill Shale ranges from 5,500 to 10,000 ft, averaging 8,000 ft in the prospective area. The Whitehill Shale has an estimated gross organic thickness of 100 to 300 ft,¹⁰ with an average net thickness of 100 ft within the prospective area, as shown by the isopach map on Figure XIX-8.¹¹

Figure XIX-8. Isopach Map of the Whitehill Formation



Source: ARI, 2013.

The total organic content (TOC) for the Whitehill Shale in the prospective area ranges from 3% to 14%, averaging 6%. Local areas have TOC contents up to 15%.⁴ In areas near igneous intrusions, portions of the organic content may have been converted to graphite. The main minerals in the Whitehill Formation are quartz, pyrite, calcite and chlorite, making the shale favorable for hydraulic stimulation. The Whitehill Shale is assumed to be overpressured. The thermal maturity (R_o) of the Whitehill Shale in the prospective area ranges from 2% to 4%, placing the shale into the dry gas window.

The hydrogen and oxygen indexes of the Whitehill Formation indicate a mixture of Type I and Type II kerogen.⁹ The Whitehill Shales was deposited in deep marine, anoxic setting and contains minor sandy interbeds from distal turbidites and storm deposits.^{12,13}

Collingham Shale. The Lower Permian Collingham Formation (often grouped with the Whitehill Formation) contains the third shale formation addressed by this resource study. The Collingham Formation has an upward transition from deep-water submarine to shallow-water deltaic deposits.⁹ The depth to the Collingham Shale averages 7,800 ft within the prospective area. Except for total organic content, the shale has reservoir properties similar to the Whitehill Shale. It has an estimated gross organic thickness of 200 ft, a net thickness of 80 ft, and TOC of 2% to 8%, averaging 4%. Thermal maturity is high, estimated at 3% R_o , influenced by igneous intrusions. The shale is assumed to be overpressured based on data from the Upper Eccla Group.

Upper Eccla Shales. The Upper Eccla Formation extends over a particularly thick, 1,500 m (~5,000 ft) vertical interval in the central and northern Karoo Basin. The Upper Eccla contains two shale sequences of interest - - the Waterford and the Fort Brown. The Fort Brown Formation accounts for the great bulk of the vertical interval of the Upper Eccla. These shales are interpreted by some investigators to have been deposited in a shallow marine environment,² although others categorize them as lacustrine.¹⁴

The organic content and thermal maturity of the Upper Eccla shales are considerably less than for the Lower Eccla shales. The total organic content (TOC) is reported to range from about 1% to 2%. With a thermal maturity ranging from 0.9% to 1.1% R_o , the Upper Eccla shales area is in the oil to wet gas window.¹⁵

In the materials below, we provide a qualitative description for the Upper Eccla shales. However, because their average TOC is below the 2% criterion set for the study, these shales have been excluded from our quantitative assessment.

The boundaries of the prospective area for the Upper Eccla shales are defined by the outcrop of the Upper Eccla on the east, south and west and the shallowing of the Lower Eccla shales on the northeast. The shale oil window is north of the approximately 29° latitude line. A significant basalt intrusion area of about 10,000 mi² in the center of the prospective area has been excluded. Major portions of the prospective area have igneous intrusions that have locally destroyed portions of the organics, creating significant exploration risk.

Fort Brown Shale. The Fort Brown Shale, as described in the Cranemere CR 1/68 well, is a dark gray to black shale with occasional siltstone stringers. In this well, the Fort Brown Shale exists over a gross interval of nearly 5,000 ft (1,500 m) from 7,012-11,997 ft. Sunset

Energy, the current permit holder in the area surrounding the Cranemere CR 1/68 well, reports that 24-hour DST testing in one interval of the Fort Brown shale, from 8,154-8,312 ft, had a flow rate of 1.84 MMcfd. The well is reported to have blown out at a depth of about 8,300 ft (2,500 m), requiring 10.5 pound per gallon mud to bring the well under control.

The prospective area for the Upper Ecca Fort Brown Shale is estimated at 31,700 mi². The Fort Brown Shale in the prospective area has an average depth of 6,000 ft and ranges from 3,000 to 9,000 ft. The shale has an estimated 600 ft of net organic rich thickness, based on using a net to gross ratio of 20% and an average gross thickness of 3,000 ft. The shale has a total organic content (TOC) that ranges from 1 to 2% and an estimated average thermal maturity of 1.1% R_o (based on limited data).

Waterford Shale. The prospective area for the Upper Ecca Waterford Shale is estimated at 20,800 mi². The Waterford Shale in the prospective area has an average depth of 4,500 ft, ranging from 3,000 to 6,000 ft. The shale has an estimated 100 ft of net organic rich thickness within an average gross thickness of 500 ft. Total organic content ranges from 1 to 2%, with average thermal maturity, based on very limited data, of 0.9% R_o.

1.3 Resource Assessment

Prince Albert Shale. Within its 60,180-mi² dry gas prospective area, the Prince Albert Shale has a resource concentration of about 43 Bcf/mi². Given limited exploration data, the risked shale gas in-place is estimated at 385 Tcf. Based on favorable TOC and reservoir mineralogy, balanced by complex geology and volcanic intrusions in the prospective area, ARI estimates a risked, technically recoverable shale gas resource of 77 Tcf for the Prince Albert Shale in the Karoo Basin.

Whitehill Shale. Within its 60,180-mi² dry gas prospective area, the Whitehill Shale has a resource concentration of about 59 Bcf/mi². While somewhat more defined than the Prince Albert Shale, the exploration risk for the Whitehill Shale is still substantial, leading to a risked shale gas in-place of 845 Tcf. Based on favorable reservoir mineralogy but complex geology, ARI estimates a risked, technically recoverable shale gas resource of 211 Tcf for the Whitehill Shale in the Karoo Basin.

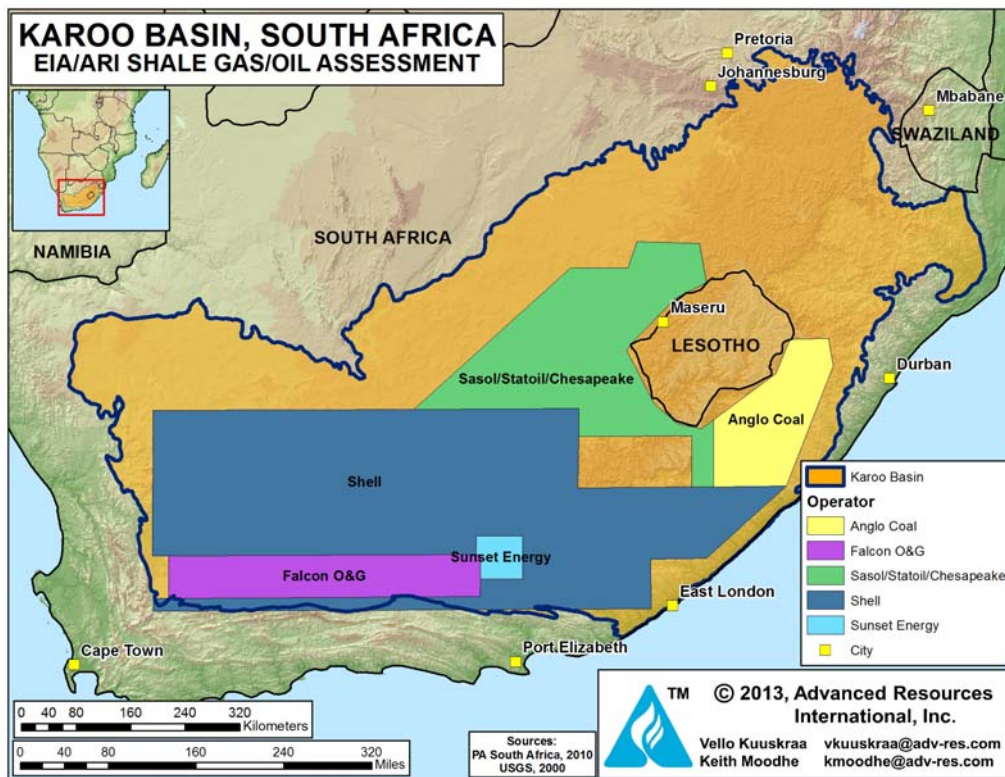
Collingham Shale. With a prospective area of 60,180 mi² and with a resource concentration of 36 Bcf/mi², the risked gas in-place for the Collingham Shale is estimated at 328 Tcf, with a risked, technically recoverable shale gas resource of 82 Tcf.

Considerable uncertainty surrounds the characterization and assessment of the shale oil resources of South Africa, particularly for the net organic-rich thickness and the vertical and areal distribution of thermal maturity. Shale exploration is just starting in the Karoo Basin and few data points exist, particularly for the Upper Ecca group of formations.

1.4 Recent Activity

Falcon Oil & Gas Ltd., an early entrant into the shale gas play of South Africa, obtained an 11,600-mi² TCP along the southern edge of the Karoo Basin. Shell obtained a larger 71,400-mi² TCP surrounding the Falcon area. Sunset Energy holds a 1,780-mi² TCP to the west of Falcon. The Sasol/Chesapeake/Statoil JV TCP area of 34,000 mi² and the Anglo Coal TCP application area of 19,300 mi² are to the north and east of Shell's TPC, Figure XIX-9. ¹⁶

Figure XIX-9. Map Showing Operator Permits in the Karoo Basin, South Africa



Source: ARI, 2013.

Recently, Chevron announced that it would partner with Falcon Oil & Gas to pursue the shale resources of the Karoo Basin, starting with seismic studies.¹⁷

Five older (pre-1970) wells have penetrated the Ecca Shale interval. Each of the wells had gas shows, while one of the wells - - the Cranemere CR 1/68 well - - flowed 1.84 MMcf/d from a test zone at 8,154 to 8,312 ft. The gas production, considered to be from fractured shale, depleted relatively rapidly during the 24-hour test. The CR 1/68 well was drilled to 15,282 ft into the underlying Table Mountain quartzite and had gas shows from six intervals, starting at 6,700 ft and ending at 14,650 ft, indicating that the shales in this area are gas saturated.

REFERENCES

-
- ¹ McLachlan, I. and Davis, A., "Petroleum Exploration In The Karoo Basins, South Africa." Petroleum Agency SA, 2006.
 - ² Catuneanu, O. et al., 2005. "The Karoo Basins of South-Central Africa." *Journal of African Earth Sciences*, vol. 43, p. 211-253.
 - ³ U.S. Geological Survey Digital Data Series 60, World Petroleum Assessment 2000, <http://pubs.usgs.gov/dds/dds-060/>.
 - ⁴ Branch, T. et al., 2007. "The Whitehill Formation – A High Conductivity Marker Horizon in the Karoo Basin." *South African Journal of Geology*, vol. 110, p. 465-476.
 - ⁵ Johnson, M.R. et al., 1997. "The Foreland Karoo Basin, South Africa." In: Selley, R.C., (ed.), *African Basins – Sedimentary Basins of the World*, Elsevier, Amsterdam.
 - ⁶ McLachlan, I. and Davis, A., 2006.
 - ⁷ Chevallier, L. and Woodford, A.C., 1999. "Morpho-Tectonics and Mechanisms of Emplacement of the Dolerite Rings and Sills of the Western Karoo, South Africa." *South African Journal of Geology*, vol. 102, p. 43-54.
 - ⁸ Svensen, H. et al., 2007. "Hydrothermal Venting of Greenhouse Gases Triggering Early Jurassic Global Warming." *Earth and Planetary Science Letters*, vol. 256, p. 554-566.
 - ⁹ Faure, K. and Cole, D., 1999. "Geochemical Evidence for Lacustrine Microbial Blooms in the Vast Permian Main Karoo, Parana, Falkland Islands and Haub Basins of Southwestern Gondwana." *Palaeogeography and Palaeoclimatology*, vol. 152, p. 189-213.
 - ¹⁰ Visser, J.N.J., 1992. "Deposition of the Early to Late Permian Whitehill Formation During Sea-Level Highstand in a Juvenile Foreland Basin." *South African Journal of Geology*, vol. 95, p. 181-193.
 - ¹¹ Visser, J.N.J., 1994. "A Permian Argillaceous Syn- to Post-Glacial Foreland Sequence in the Karoo Basin, South Africa." In: Deynoux, M., Miller, J.M.G., Domack, E.W., Eyles, N., Fairchild, I.J., and Young G.M. (eds.), *Earth's Glacial Record: International Geological Correlation Project 260*. Cambridge University Press, Cambridge, p. 193-203.
 - ¹² Smith, R.M.H., 1990. "A Review of the Stratigraphy and Sedimentary Environments of the Karoo Basin of South Africa." *Journal of African Earth Science*, vol.10, p. 117-137.
 - ¹³ Cole, D.I. and McLachlan, I.R., 1994. "Oil Shale Potential and Depositional Environment of the Whitehill Formation in the Main Karoo Basin." Council for Geoscience (South Africa) Report, vol. 1994-0213.

-
- ¹⁴ Horsfeld, B. et al., 2009. "Shale Gas: An Unconventional Resource in South Africa? Some Preliminary Observations." 11th SAGA Biennial Technical Meeting and Exhibition, Swaziland, 16-18 September, p. 546.
- ¹⁵ Raseroka, A.L., 2009. "Natural Gas and Conventional Oil Potential in South Africa's Karoo Basin." AAPG International Conference and Exhibition, 15-18 November, Rio de Janeiro, Brazil.
- ¹⁶ Petroleum Exploration and Production Activities in South Africa, Petroleum Agency South Africa, September 2010, http://www.petroleumagencysa.com/files/Hubmap_09-10.pdf.
- ¹⁷ Maylie, D., 2012. "Chevron Joins Shale Hunt in South Africa". Wall Street Journal, December 14, www.wsj.com accessed March 29, 2013.