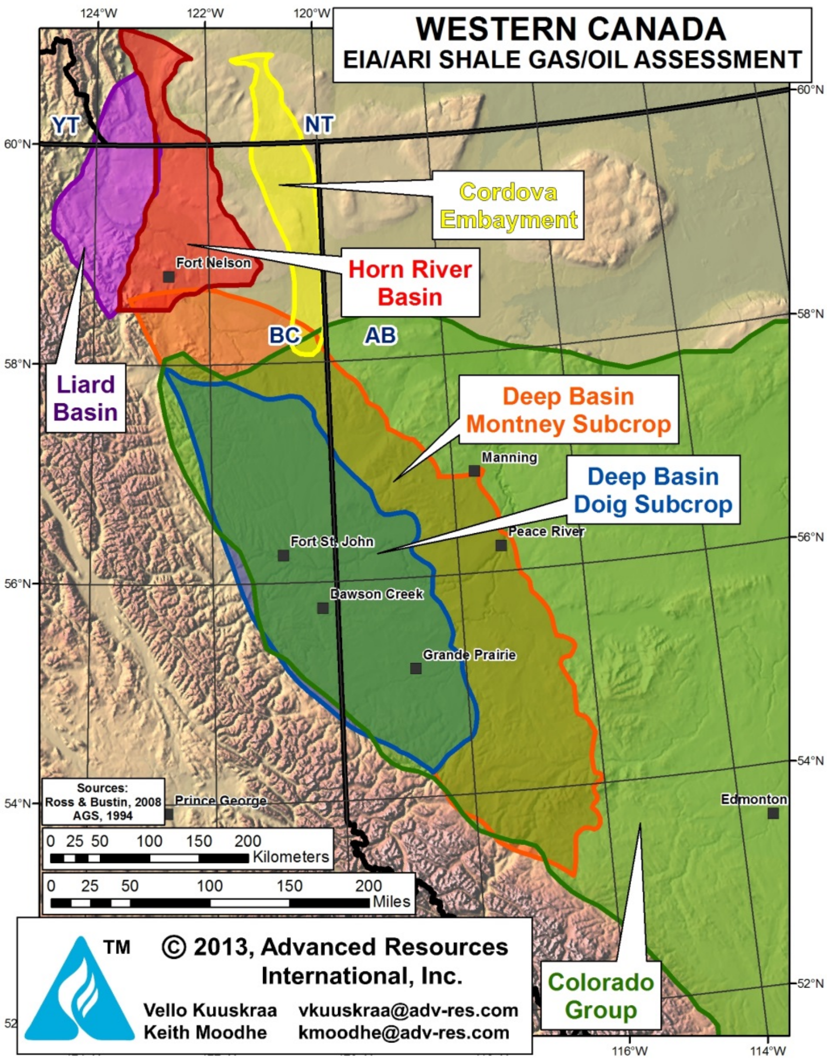
I. CANADA

SUMMARY

Canada has a series of large hydrocarbon basins with thick, organic-rich shales that are assessed by this resource study. Figure I-1 illustrates certain of the major shale gas and shale oil basins in Western Canada.

Figure I-1. Selected Shale Gas and Oil Basins of Western Canada



Source: ARI, 2012.

The full set of Canadian shale gas and shale oil basins assessed in this study include: (1) the Horn River Basin, the Cordova Embayment and the Liard Basin (located in British Columbia and the Northwest Territories) plus the Doig Phosphate Shale (located in both British Columbia and Alberta); (2) the numerous shale gas and shale oil formations and plays in Alberta, such as the Banff/Exshaw, the Duvernay, the Nordegg, the Muskwa and the Colorado Group; (3) the Williston Basin's Bakken Shale in Saskatchewan and Manitoba; and (4) the Utica Shale in Quebec and the Horton Bluff Shale in Nova Scotia.

Western Canada also contains the prolific and areally extensive Montney and Doig Resource Plays (in both British Columbia and Alberta) categorized primarily as tight sand and siltstone reservoirs. As thus, these two important unconventional gas resources are not included in this shale gas and shale oil resource assessment. In addition, Canada has a series of additional hydrocarbon-bearing siltstone and shale formations that are not included in the quantitative portion of this resource study either because of low organic content (Wilrich Shale in Alberta) or because of limited information (Frederick Brook Shale in New Brunswick).

We estimate risked shale gas in-place for Canada of 2,413 Tcf, with 573 Tcf as the risked, technically recoverable shale gas resource. In addition, we estimate risked shale oil in-place for Canada of 162 billion barrels, with 8.8 billion barrels as the risked, technically recoverable shale oil resource. Table I-1 provides a more in-depth, regional tabulation of Canada's shale gas and oil resources.

As new drilling occurs and more detailed information is obtained on these large, emerging shale plays, the estimates of the size of their in-place resources and their recoverability will undoubtedly change.

Table I-1. Shale Gas and Oil Resources of Canada

Region	Basin / Formation	Risked Resource In-Place		Risked Technically Recoverable Resource	
		Oil/Condensate (Million bbl)	Natural Gas (Tcf)	Oil/Condensate (Million bbl)	Natural Gas (Tcf)
British Columbia / Northwest Territories	Horn River (Muskwa / Otter Park)	-	375.7	-	93.9
	Horn River (Evie / Klua)	-	154.2	-	38.5
	Cordova (Muskwa / Otter Park)	-	81.0	-	20.3
	Liard (Lower Besa River)	-	526.3	-	157.9
	Deep (Doig Phosphate)	-	100.7	-	25.2
	Sub-Total	**-**	**1,237.8**	**-**	**335.8**
Alberta	Alberta (Banff / Exshaw)	10,500	5.1	320	0.3
	E/W Shale (Duvernay)	66,800	482.6	4,010	113.0
	Deep Basin (Nordegg)	19,800	72.0	790	13.3
	N.W. Alberta (Muskwa)	42,400	141.7	2,120	31.1
	S. Alberta (Colorado)	-	285.6	-	42.8
	Sub-Total	**139,500**	**987.1**	**7,240**	**200.5**
Saskatchewan / Manitoba	Williston (Bakken)	**22,500**	**16.0**	**1,600**	**2.2**
Quebec	App. Fold Belt (Utica)	**-**	**155.3**	**-**	**31.1**
Nova Scotia	Windsor (Horton Bluff)	**-**	**17.0**	**-**	**3.4**
	Total	**162,000**	**2,413.2**	**8,840**	**572.9**

*Less than 0.5 Tcf

BRITISH COLUMBIA/NORTHWEST TERRITORIES

British Columbia (BC) and the Northwest Territories (NWT) hold three "world-scale" shale basins, the Horn River Basin, the Cordova Embayment and the Liard Basin. In addition, the organic-rich Doig Phosphate Shale exists on each side of the central Alberta and BC border. In addition to these shale resources, British Columbia also has portions of the massive tight sand and siltstone Montney Resource and Doig Resource plays. These two low organic content formations, classified as tight sands by Canada's National Energy Board, are not included in this shale gas and oil resource assessment.

This resource assessment study has benefitted greatly from the extensive geological and reservoir characterization work supported by the BC Ministry of Energy and Mines on the shale basins and formations of British Columbia.[1,2] In addition, this study has drawn on the extensive well drilling and well performance information provided by Canada's oil and gas industry. These two information sources serve as foundations for the assessment of the shale gas and oil resources of British Columbia and the Northwest Territories. The four BC/NWT shale oil and gas basins assessed by this study contain 1,238 Tcf of risked shale gas in-place, with 336 Tcf as the risked, technically recoverable shale gas resource, Table I-2.

Table I-2. Shale Gas Reservoir Properties and Resources of British Columbia/NWT

Basic Data	Basin/Gross Area		Horn River ($7,100 mi^2$)		Cordova ($4,290 mi^2$)	Liard ($4,300 mi^2$)	Deep Basin ($24,800 mi^2$)
	Shale Formation		Muskwa/Otter Park	Evie/Klua	Muskwa/Otter Park	Lower Besa River	Doig Phosphate
	Geologic Age		Devonian	Devonian	Devonian	Devonian	Triassic
	Depositional Environment		Marine	Marine	Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		3,320	3,320	2,000	3,300	3,000
	Thickness (ft)	Organically Rich	420	160	230	500	165
		Net	380	144	207	400	150
	Depth (ft)	Interval	6,300 - 10,200	6,800 - 10,700	5,500 - 6,200	6,600 - 13,000	6,800 - 10,900
		Average	8,000	8,500	6,000	10,000	9,250
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Highly Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.5%	4.5%	2.0%	3.5%	5.0%
	Thermal Maturity (% Ro)		3.50%	3.80%	2.50%	3.80%	1.10%
	Clay Content		Low	Low	Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		150.9	61.9	67.5	319.0	67.1
	Risked GIP (Tcf)		375.7	154.2	81.0	526.3	100.7
	Risked Recoverable (Tcf)		93.9	38.5	20.3	157.9	25.2

Advanced Resources International, Inc.

1. HORN RIVER BASIN

1.1 Geologic Setting

The Horn River Basin covers an area of 7,100 mi^2 in northern British Columbia and the Northwest Territories, Figure I-2. The basin's western border is defined by the Bovie Fault, which separates the Horn River Basin from the Liard Basin. Its northern border, in Northwest Territories, is defined by the thinning of the shale section, and its southern border is constrained by the pinch-out of the shale. Its eastern border is defined by the Slave Point/Keg River Uplift and the thinning of the shale deposit. We have defined a higher quality, 3,320-mi^2 prospective area for the Horn River Shale in the west-central portion of the basin, Figure I-3.

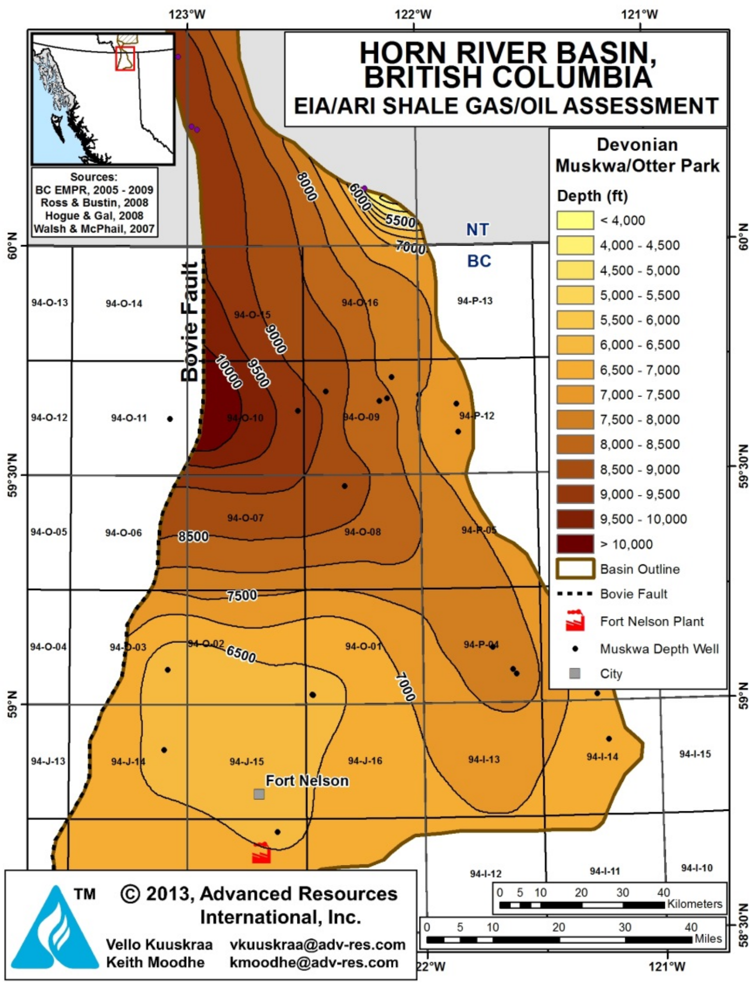
The Horn River Basin contains a series of organic-rich shales, with the Middle Devonian-age Muskwa/Otter Park and Evie/Klua most prominent, Figure I-4.[3] These two shale units were mapped in the Horn River Basin to establish a prospective area with sufficient thickness and resource concentration favorable for shale gas development. Other shales in this basin (but not included in the study) include the high organic-content, lower thermal maturity, poorly defined Mississippian Banff/Exshaw Shale and the thick, low organic-content Late Devonian Fort Simpson Shale.

1.2 Reservoir Properties (Prospective Area)

Two major shale gas formations, the Muskwa/Otter Park and the Evie/Klua, are included in the quantitative portion of our resource assessment.

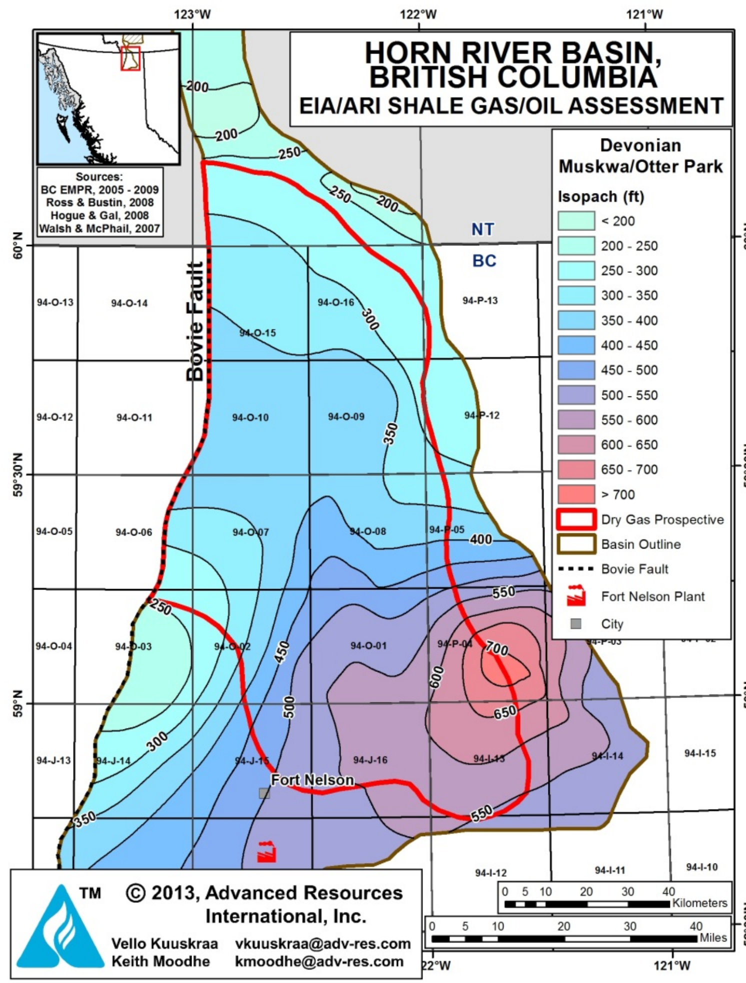
Muskwa/Otter Park. The Middle Devonian Muskwa/Otter Park Shale, the upper shale interval within the Horn River Group, is the main shale gas target in the Horn River Basin. Drilling depth to the top of the Muskwa/Otter Park Shale ranges from 6,300 to 10,200 feet, averaging 8,000 feet for the prospective area. The Muskwa/Otter Park Shale is moderately over-pressured in the center of the basin. With an organic-rich gross shale thickness of 420 feet, the Muskwa/Otter Park has a net pay of 380 feet. Total organic content (TOC) in the prospective area averages 3.5% for the net shale thickness investigated. Thermal maturity (R_o) is high, averaging about 3.5% and placing this shale gas in the dry gas window. Because of the high thermal maturity in the prospective area, the in-place shale gas has a CO_2 content of 11%. The Muskwa/Otter Park Shale has high quartz and low clay content.

Figure I-2. Horn River Basin (Muskwa/Otter Park Shale) Outline and Depth



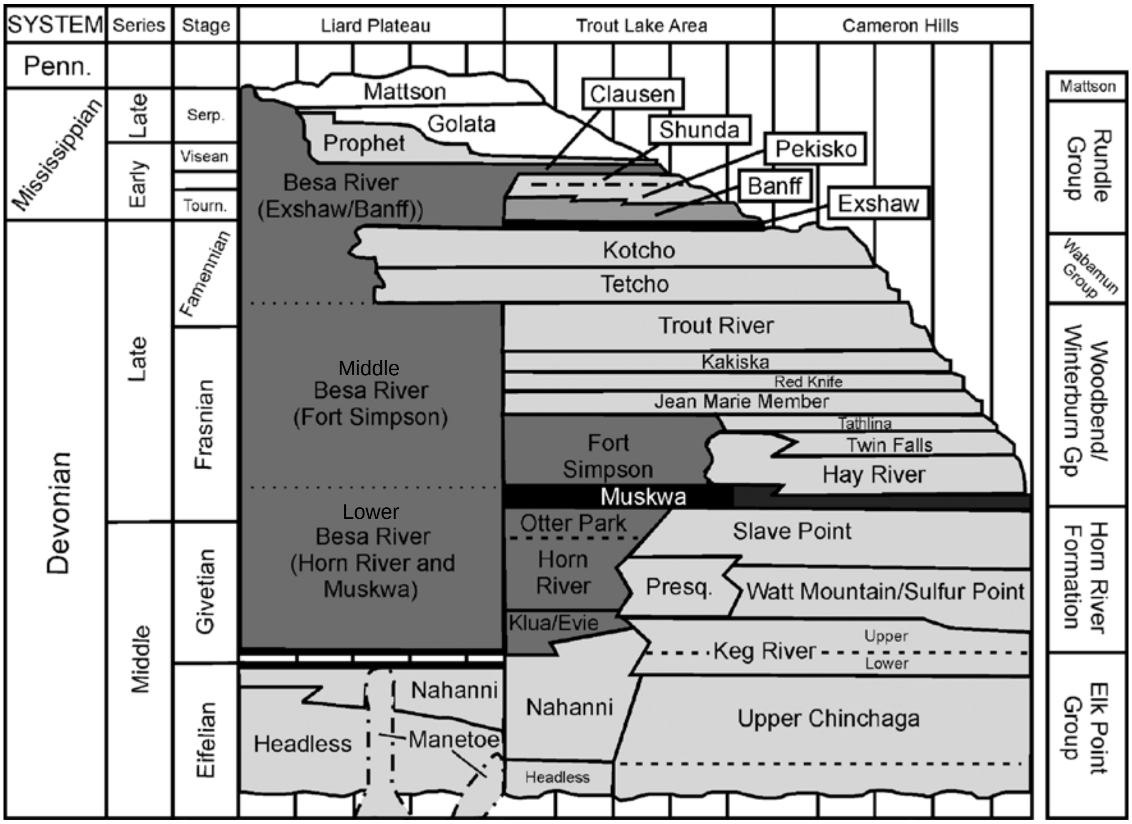
Source: ARI, 2013.

Figure I-3. Horn River Basin (Muskwa/Otter Park Shale) Isopach and Prospective Area



Source: ARI, 2013.

Figure I-4. NE British Columbia, Devonian and Mississippian Stratigraphy



Source: D. J. K. Ross and R. M. Bustin, AAPG Bulletin, v. 92, no. 1 (January 2008), pp. 87–125 JAF21300.AI

<u>Evie/Klua</u>. The Middle Devonian Evie/Klua Shale, the lower shale interval within the Horn River Group, provides a secondary shale gas target in the Horn River Basin. The top of the Evie/Klua Shale is approximately 500 feet below the top of the Muskwa/Otter Park Shale, separated by an organically-lean rock interval. The organic-rich Evie/Klua Shale, with an average TOC of 4.5%, has a thickness of about 160 feet (gross) and 144 feet (net). Thermal maturity (R_o) is high at about 3.8%, placing this shale gas in the dry gas window. The CO_2 content is estimated at 13%. The Evie/Klua Shale has a low clay content making the formation favorable for hydraulic stimulation.

<u>Other Shales</u>. The Horn River Basin also contains two shallower shales - - the Upper Devonian/Lower Mississippian Banff/Exshaw Shale and the Late Devonian Fort Simpson Shale. The Banff/Exshaw Shale, while rich in TOC (~5%) is relatively thin (10 to 30 feet). The massively thick Fort Simpson Shale, with a gross interval of 2,000 to 3,000 feet, is organically lean (TOC <1%). Because of these less favorable reservoir properties and limitations of data,

these two shale units have not been included in the quantitative portion of the Horn River Basin shale resource assessment.

1.3 Resource Assessment

The prospective area for both the Horn River Muskwa/Otter Park Shale and the Evie/Klua Shale is approximately 3,320 mi^2.

Within this prospective area, the Horn River Muskwa/Otter Park Shale has a rich resource concentration of about 151 Bcf/mi^2 and a risked gas in-place is 376 Tcf, excluding CO_2. Based on favorable reservoir mineralogy and other properties, we estimate a risked, technically recoverable shale gas resource of 94 Tcf for the Muskwa/Otter Park Shale, Table I-2.

The thinner Evie/Klua Shale has a resource concentration of 62 Bcf/mi^2 and 154 Tcf of risked gas in-place, excluding CO_2. We estimate a risked, technically recoverable shale gas resource for the Evie/Klua Shale of 39 Tcf, Table I-2.

1.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society for Unconventional Gas estimated 75 to 170 Tcf of marketable (recoverable after extraction of CO_2 and any NGLs) shale gas for the Horn River basin.[4] Subsequently, in 2011, the BC Ministry of Energy and Mines (BC MEM) and the National Energy Board (NEB) published an assessment for the shale gas resources of the Horn River Basin that identified 448 Tcf of gas in-place, with an expected marketable shale gas resource of 78 Tcf.[5]

We estimate a larger risked, technically recoverable shale gas resource of 133 Tcf for the two shale units assessed by this study, using a recovery factor of 25% of the shale gas resource in-place. Our recovery factor is consistent with the 25% recovery factor used by the BC Oil and Gas Commission in their 2011 hydrocarbon reserves report for the Horn River Basin.[6] The BC MEM/NEB Horn River Basin assessment report, with a lower 78 Tcf of marketable (recoverable) shale gas resource, implies a lower recovery factor of 17.4% of gas in-place. (The BC MEM/NEB assessment excluded CO_2 content and produced gas used as fuel from marketable shale gas.)

Consistent with the experience of shale gas development in the U.S., this study anticipates progressively increased efficiencies for shale gas recovery as industry optimizes its well completion and production practices. One example is Nexen's testing of advanced shale well completion methods in the Horn River Basin. These advanced methods are designed to increase EURs in the Horn River Basin shales from 11 Bcf/well to 16 Bcf/well.

1.5 Recent Activity

A number of major and independent companies are active in the Horn River Shale play, including Apache Canada, EnCana, EOG Resources, Nexen, Devon Canada, Quicksilver and others.

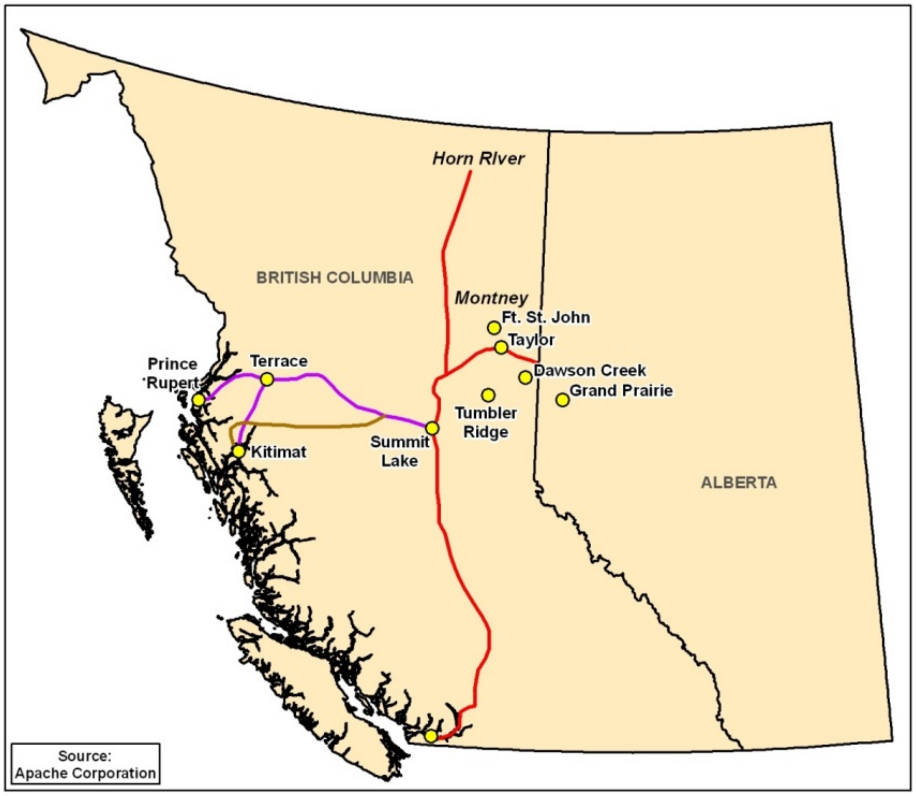
Apache Canada, the Horn River Basin's most active operator with 72 wells targeting shale gas in the basin, has full-scale development underway in the Two Island Lake area with net production of 90 million cubic feet per day (MMcfd). Apache estimates a net recoverable gas resource of 9.2 Tcf from its shale leases in the Horn River Basin. [7]

EnCana, with 68 long horizontal wells, produced a net 95 MMcfed in 2011 from its shale gas leases in the Horn River Basin. Devon, with 22 shale gas wells, is in the early stages of de-risking its 170,000 net acre lease position, which the company estimates contains nearly 10 Tcfe of net risked resource. EOG, with a 157,000 net acre lease position and 9 Tcf of potential recoverable resources, has drilled 35 shale gas wells and claims that the performance of its initial set of shale gas wells has met or exceeded expectations. Quicksilver has a 130,000 net acre lease position, 18 shale gas wells and a projected recoverable resource of over 10 Tcf. Nexen, with 90,000 acres, has drilled 42 horizontal wells and estimates 6 Tcf of recoverable resources from its lease area.[8]

Total natural gas production from the Horn River Basin was 382 MMcfd from 159 productive wells in 2011. In their 2010 report, the BC Oil and Gas Commission (BCOGC) estimated 10 Tcf of initial raw gas reserves from 40 Tcf of original gas in-place, equal to a 25% recovery factor. [8] In their 2011 report, the BCOGC increased the Horn River Shale initial recoverable raw gas reserves to 11.5 Tcf.

The gas processing and transportation capacity in the Horn River Basin is being expanded to provide improved market access for its growing shale gas production. Pipeline infrastructure is being expanded to bring the gas south to a series of proposed LNG export facilities. A 287-mile (480-km) Pacific Trail Pipeline is under construction to connect the Kitimat LNG export plant (due on line in 2017) with Spectra Energy's West Coast Pipeline System, Figure I-5. The Kitimat LNG terminal has an announced initial send-out capacity of 5 million tons of LNG per year (MTPA), expanding to 10 MTPA with a second train.

Figure I-5. Western Canada's LNG Export Pipelines and Infrastructure



TransCanada is proposing to build the 470-mile Prince Rupert Gas Transmission line with an initial capacity of 2 Bcfd (expandable to 3.6 Bcfd) to move Montney and Horn River gas to the Pacific Northwest LNG export terminal near Prince Rupert, BC. The planned in-service date is 2018. Earlier, TransCanada was selected by Shell Canada to build the 1.7 Bcfd Coastal GasLink Project, linking Horn River (and Montney) gas with Shell's planned 12 MTPA LNG export facility near Kitimat estimated to be in-service "toward the end of the decade".[9]

2. CORDOVA EMBAYMENT

2.1 Geologic Setting

The Cordova Embayment covers an area of 4,290 mi^2 in the extreme northeastern corner of British Columbia, extending into the Northwest Territories, Figure I-6. The Cordova Embayment is separated from the Horn River Basin on the west by the Slave Point Platform. The Embayment's northern and southern boundaries are defined by a thinning of the shale and its eastern boundary is the British Columbia and Alberta border. The dominant shale gas formation, the Muskwa/Otter Park Shale, was mapped to establish the 2,000-mi^2 prospective area, Figure I-7.

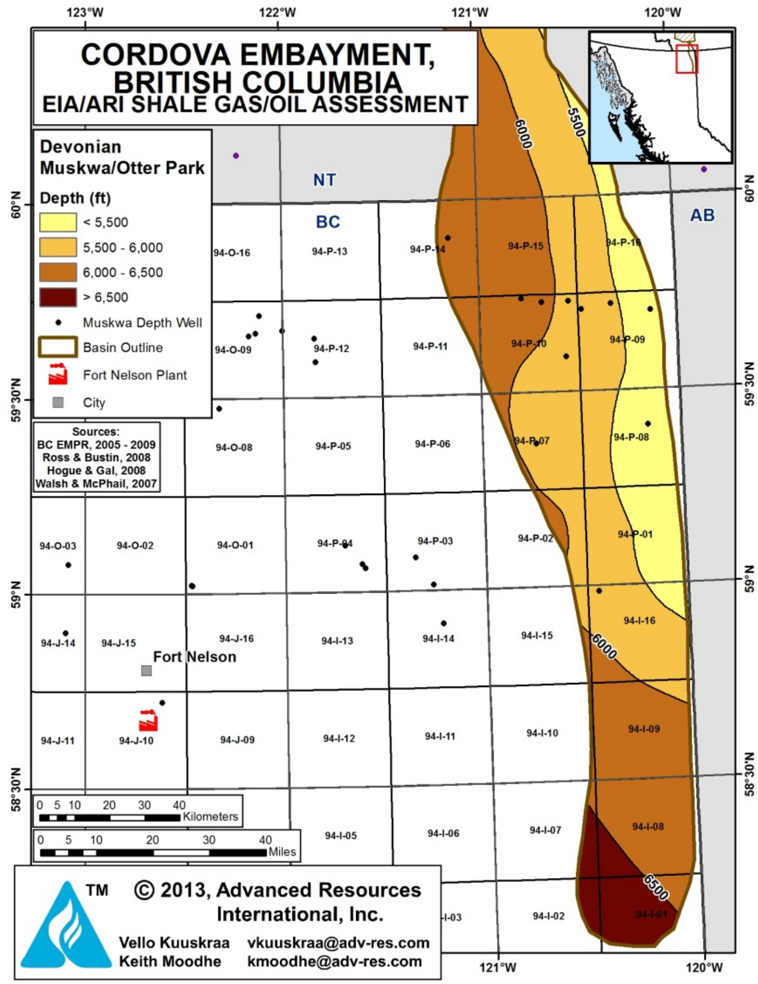
2.2 Reservoir Properties (Prospective Area)

One shale gas formation, the Muskwa/Otter Park, is included in the quantitative portion of our resource assessment.

<u>Muskwa/Otter Park</u>. The Middle Devonian Muskwa/Otter Park Shale is the main shale gas target in the Cordova Embayment. The drilling depth to the top of the Muskwa Shale in the prospective area ranges from 5,500 to 6,200 feet, averaging 6,000 feet. The reservoir is moderately over-pressured. The organic-rich gross thickness is 230 feet, with a net thickness of 207 feet. Total organic content (TOC) in the prospective area is 2.5% for the net shale thickness investigated. Thermal maturity averages 2.0% Ro, placing the shale in the dry gas window. The Muskwa/Otter Park Shale has a moderately high quartz content, favorable for hydraulic stimulation.

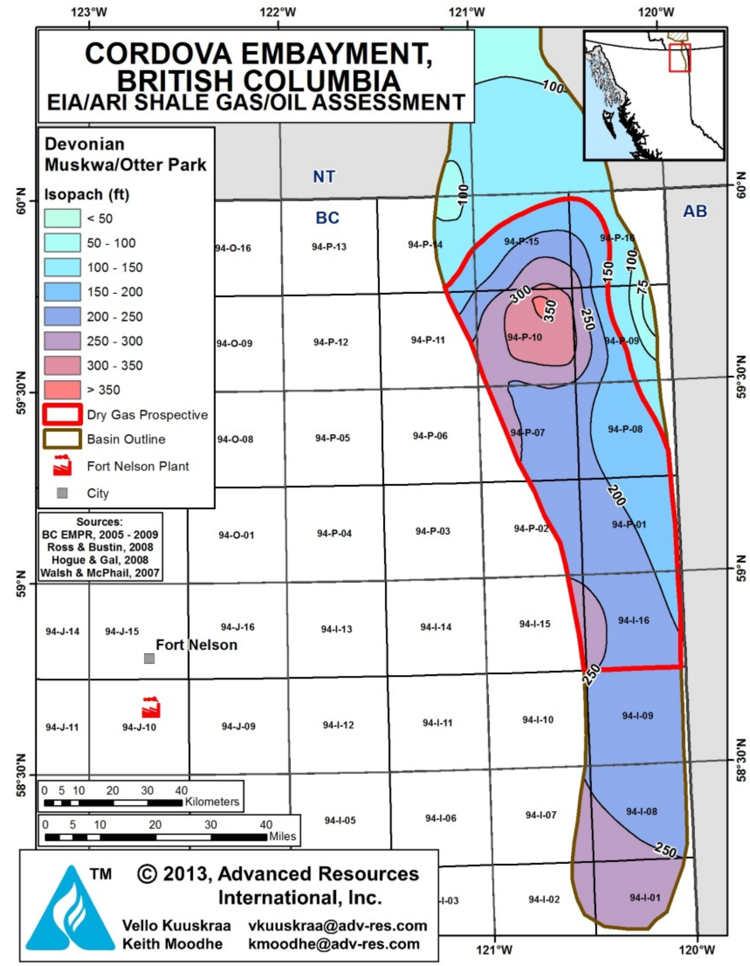
<u>Other Shales</u>. The deeper Evie/Klua Shale, separated from the overlying Muskwa/Otter Park by the Slave Point and Sulfur Point Formations, is thin, Figure I-8. The overlying Banff/Exshaw and Fort Simpson shales are shallower, thin and/or low in organics. These other shales have not been included in the quantitative portion of the Cordova Embayment resource assessment.

Figure I-6. Cordova Embayment (Muskwa/Otter Park Shale) Outline and Depth



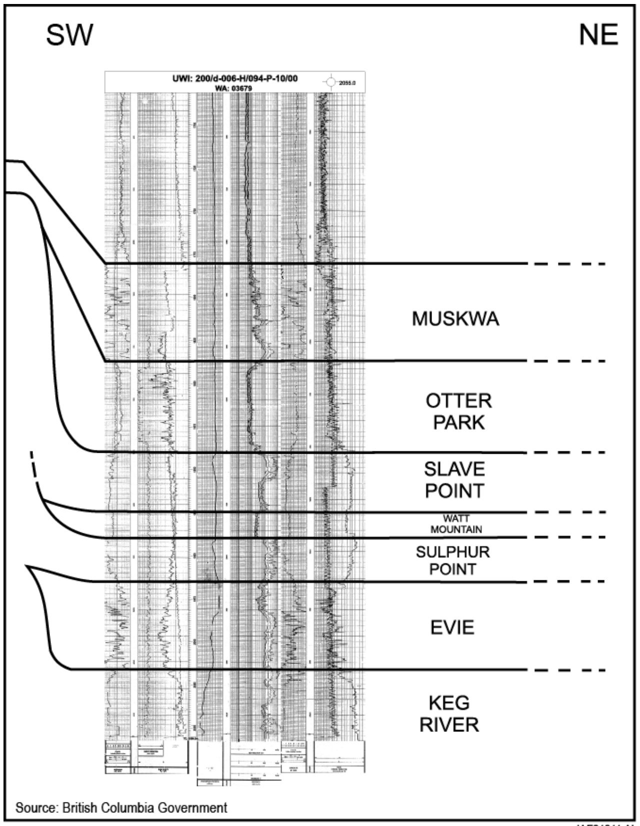
Source: ARI, 2013.

Figure I-7. Cordova Embayment - Muskwa/Otter Park Shale Isopach and Prospective Area



Source: ARI, 2013.

Figure I-8. Cordova Embayment Stratigraphic Column



2.3 Resource Assessment

The prospective area of the Cordova Embayment's Muskwa/Otter Park Shale is approximately 2,000 mi^2. Within this prospective area, the shale has a moderate resource concentration of 68 Bcf/mi^2 and a risked gas in-place of 81 Tcf. Based on favorable reservoir mineralogy and other properties, we estimate a risked, technically recoverable shale gas resource of 20 Tcf for the Muskwa/Otter Park Shale in the Cordova Embayment, Table I-2.

2.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society of Unconventional Gas (CSUG) estimated 200 Tcf of shale gas in-place and 30 to 68 Tcf of marketable (recoverable) shale gas for the Cordova Embayment.[4] In early 2012, the BC Ministry of Energy reported 200 Tcf of gas in-place for the Cordova Embayment, a number which appears to have been based on the CSUG study.[4]

2.5 Recent Activity

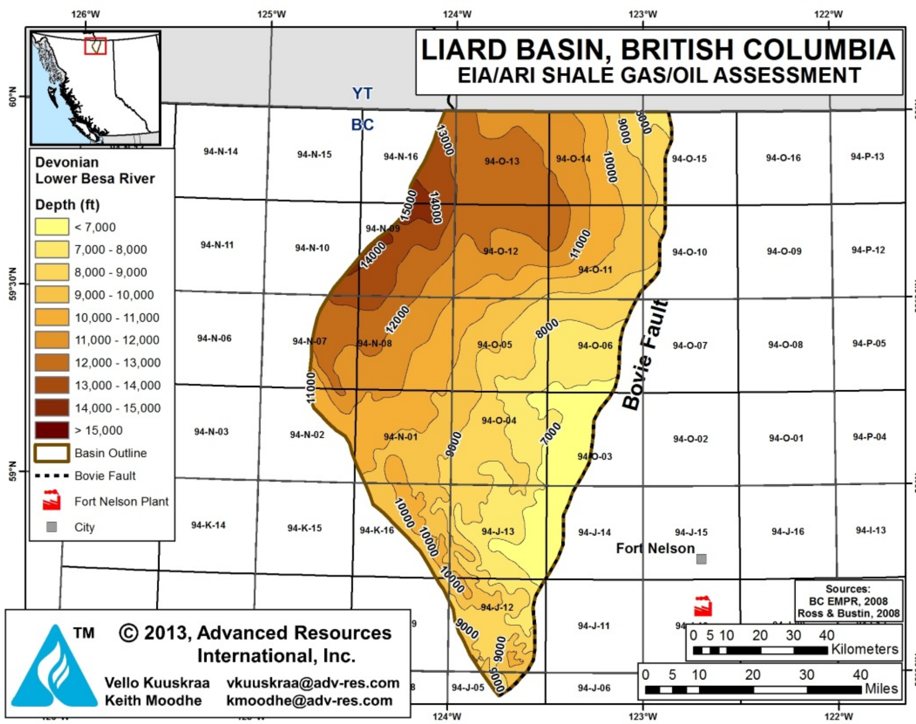
Nexen has acquired an 82,000-acre lease position in the Cordova Embayment and has drilled two vertical and two horizontal shale gas exploration wells. Nexen estimates a contingent resource of up to 5 Tcf for its lease position.[10] PennWest Exploration and Mitsubishi have formed a joint venture to develop the estimated 5 to 7 Tcf of recoverable shale gas resources on their 170,000-acre (gross) lease area.[11]

3. LIARD BASIN

3.1 Geologic Setting

The Liard Basin covers an area of 4,300 mi^2 in northwestern British Columbia, Figure I-9.[3] Its eastern border is defined by the Bovie Fault, which separates the Liard Basin from the Horn River Basin, Figure I-8. Its northern boundary is currently defined by the British Columbia and the Yukon/Northwest Territories border, and its western and southern boundaries are defined by structural folding and shale deposition.

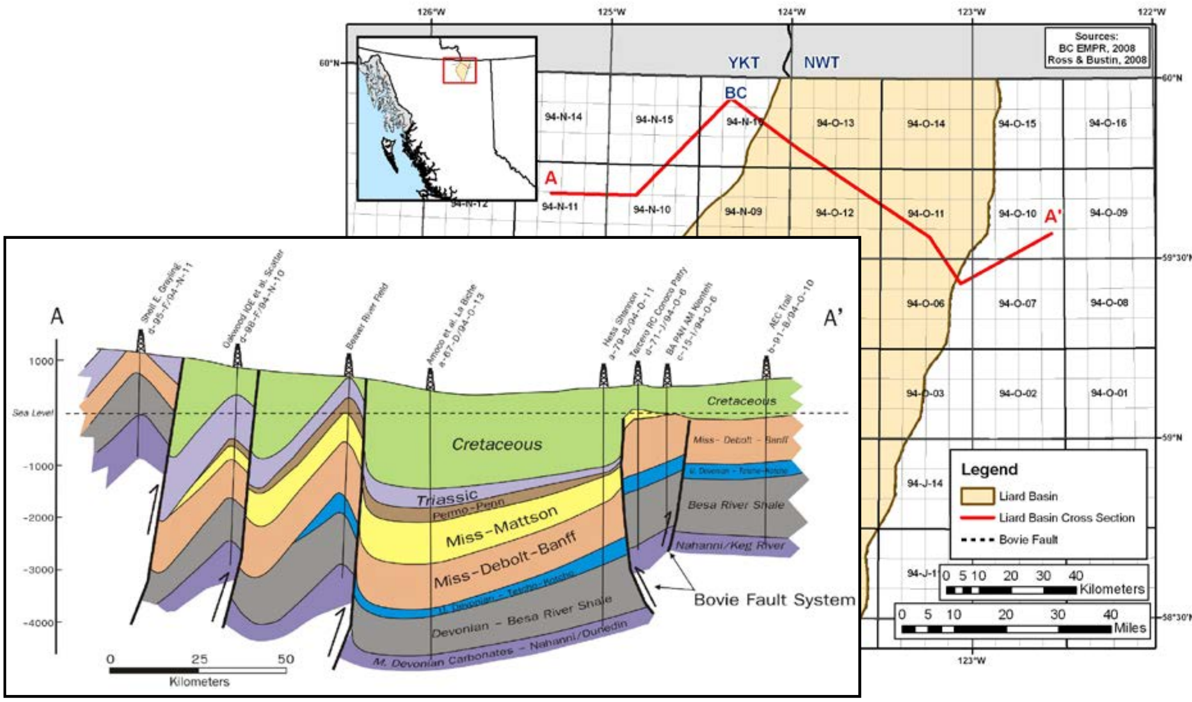
Figure I-9. Liard Basin (Lower Besa River Shale) Outline and Depth Map



Source: Modified from Ross and Bustin, 2008.

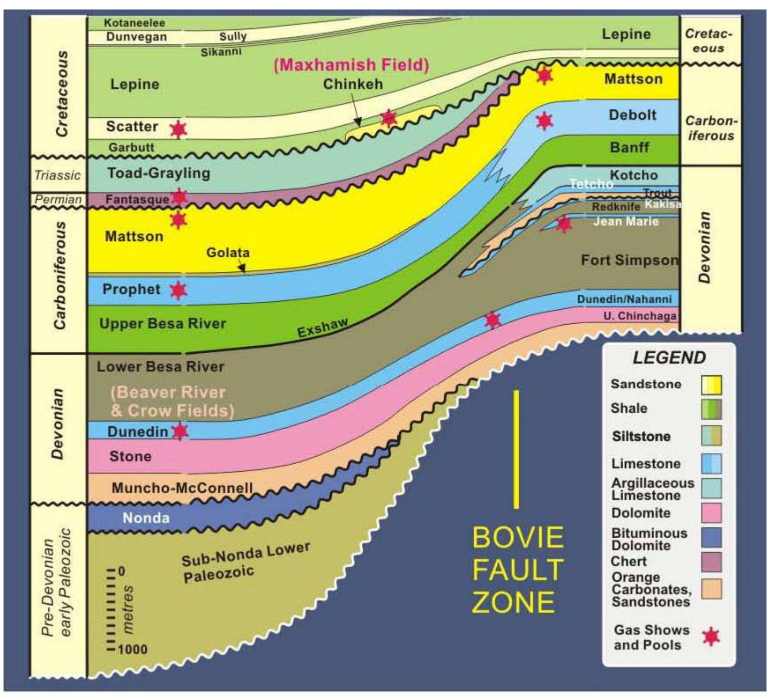
The dominant shale gas formation in the Liard Basin is the Middle Devonian-age Lower Besa River Shale, equivalent to the Muskwa/Otter Park and Evie/Klua shales in the Horn River Basin. Additional, less organically rich and less prospective shales exist in the basin's Upper Devonian- and Mississippian-age shales, such as the Middle Besa River Shale (Fort Simpson equivalent) and the Upper Besa River Shale (Exshaw/Banff equivalent), Figures I-10[12] and I-11.[13] Based on still limited data on this shale play, a prospective area of 3,300 mi^2 has been mapped for the Lower Besa River Shale in the central portion of the basin, Figure I-12.[3]

Figure I-10. Liard Basin Location, Cross-Section and Prospective Area



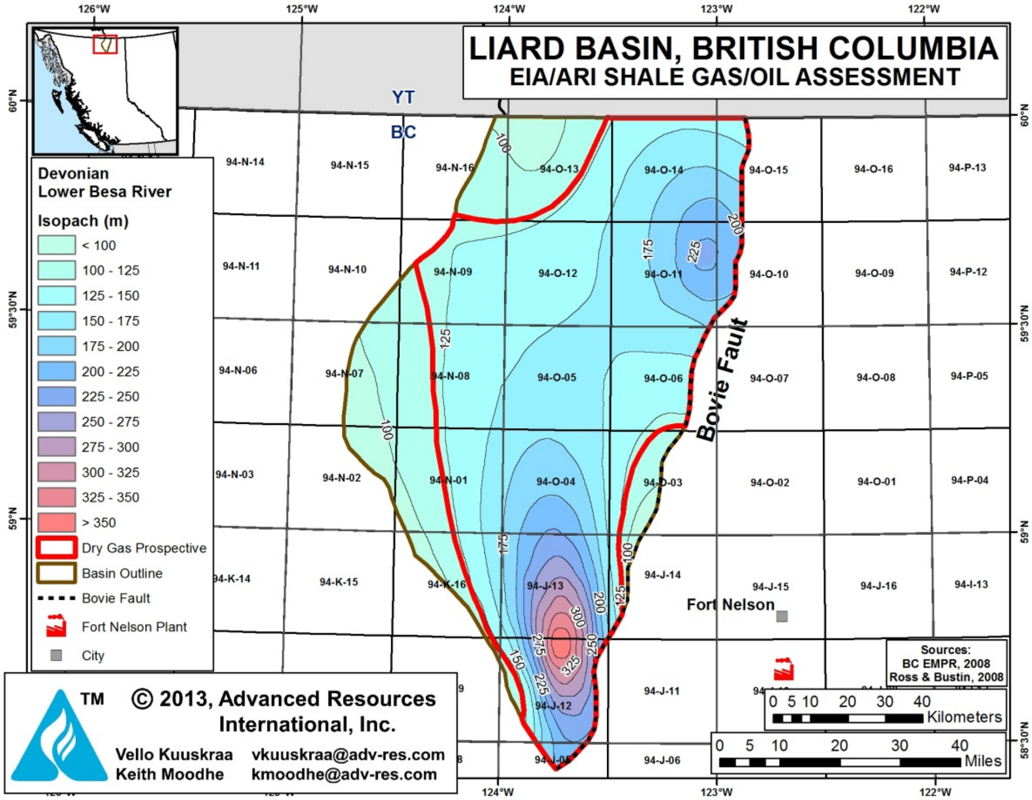
Source: Levson et al., British Columbia Ministry of Energy, Mines, and Petroleum Resources, 2009.

Figure I-11. Liard Basin Stratigraphic Cross-Section



Source: D. W. Morrow and R. Shinduke, "Liard Basin, Northeast British Columbia: An Exploration Frontier", Geological Survey of Canada (Calgary), Natural Resources Canada

Figure I-12. Liard Basin (Lower Besa River Shale) Isopach and Prospective Area



Source: Modified from Ross and Bustin, 2006.

3.2 Reservoir Properties (Prospective Area).

The Lower Besa River organic-rich shale is the main shale gas target in the Liard Basin. Drilling depths to the top of the formation in the prospective area range from 6,600 to 13,000 feet, averaging about 10,000 feet. The organic-rich Lower Besa River section has a gross thickness of 750 feet and a net thickness of 600 feet. Total organic content (TOC) in the prospective area, locally up to 5%, averages 3.5% for the net shale interval investigated. The thermal maturity of the prospective area is high, with an average Ro of 3.8%. Because of the high thermal maturity, we estimate the in-place shale gas has a CO_2 content of 13%. The geology of the Besa River Shale is complex with numerous faults and thrusts. The Lower Besa River Shale is quartz-rich, with episodic intervals of dolomite and more pervasive intervals of clay.

3.3 Resource Assessment

The Liard Basin's Lower Besa River Shale has a high resource concentration of 319 Bcf/mi^2. Within the prospective area of 3,300 mi^2, the risked shale gas in-place is approximately 526 Tcf. Based on favorable reservoir mineralogy but significant structural complexity, we estimate a risked, technically recoverable shale gas resource of 158 Tcf for the Liard Basin, Table I-2.

3.4 Recent Activity

Apache has a 430,000 acre lease position in the center of the Liard Basin's prospective area, estimating 210 Tcf of net gas in-place and 54 Tcf of recoverable raw gas (48 Tcf of marketable gas). Apache's D-34-K well, drilled to a vertical depth of 12,600 feet with a 2,900 foot lateral and 6 frac stages, had a 30-day IP of 21.3 MMcfd and a 12 month cumulative recovery of 3.1 Bcf. The well has a currently projected EUR of nearly 18 Bcf.[7]

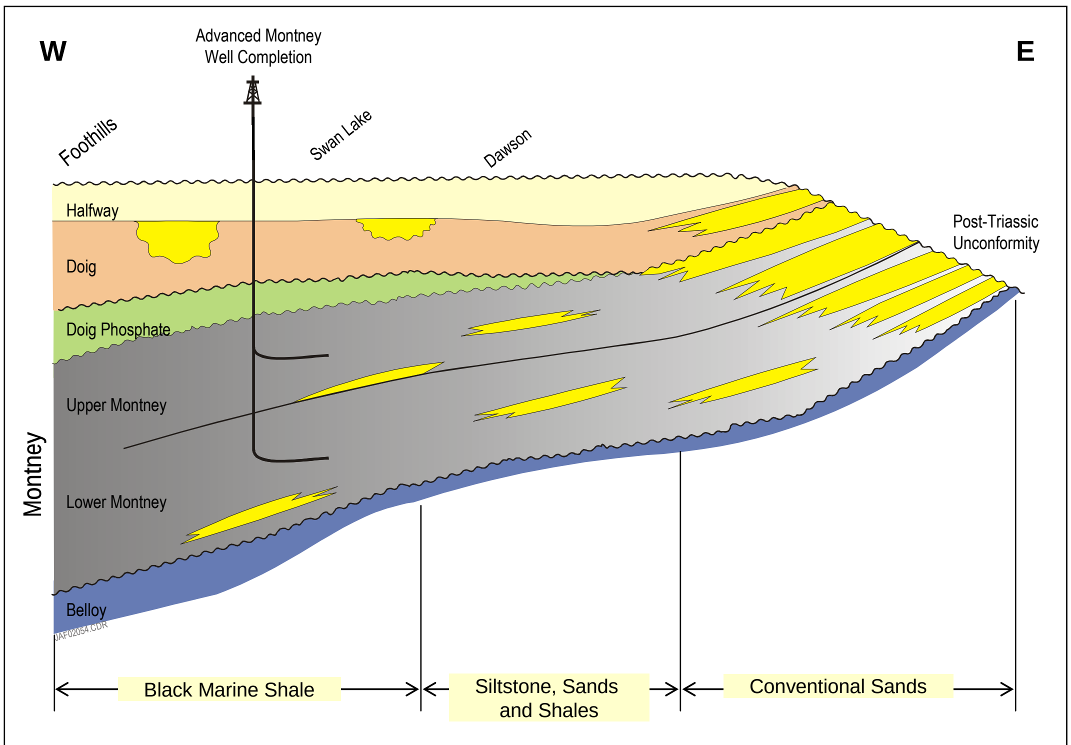
Nexen has acquired a 128,000-acre (net) land position in this basin, assigning up to 24 Tcf of prospective recoverable resource to its lease area.[10] Transeuro Energy Corp. and Questerre Energy Corp., two small Canadian operators, have completed three exploration wells in the Besa River and Mattson shale/siltstone intervals at the Beaver River Field.[14]

4. DOIG PHOSPHATE SHALE/DEEP BASIN

4.1 Geologic Setting

The Doig Phosphate Shale is located in the Deep Basin of Alberta and British Columbia. The Middle Triassic Doig Phosphate Formation serves as the base for the more extensive, predominantly siltstone and sand content Doig Resource Play, Figure I-13. The Doig Phosphate Formation, a high organic-content shale, has a prospective area of 3,000 mi^2 along the west-central portion of the Deep Basin.

Figure I-13. Deposition and Stratigraphy of Doig Phosphate and Montney/Doig Resource Plays



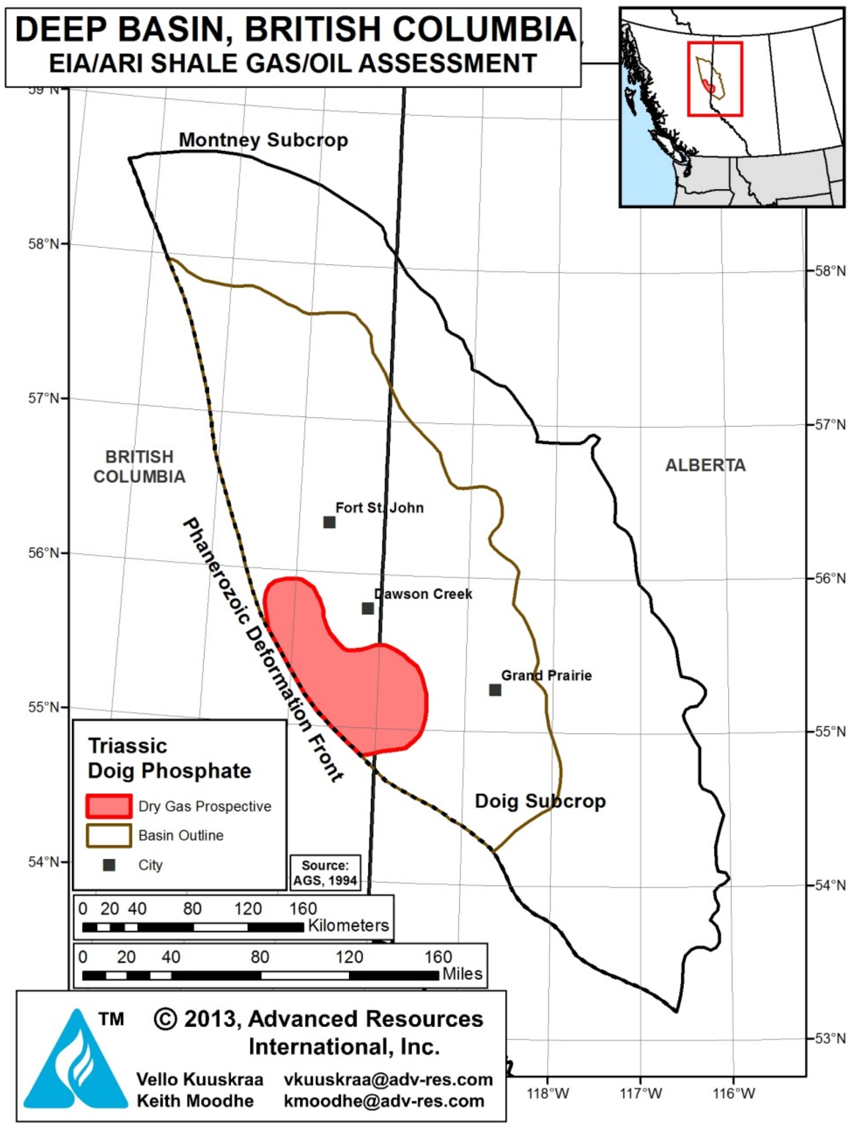
Modified from *Tristone Shale Gas Report October 2008*

JAF028245.PPT

4.2 Reservoir Properties (Prospective Area)

The Middle Triassic Doig Phosphate Shale has a thick section of organic-rich shale along the western edge of the Deep Basin that forms the prospective area, Figure I-14.[15,8] Drilling depth to the top of the shale averages 9,250 feet. The organic-rich Doig Phosphate Shale's thickness ranges from 130 to 200 feet, with a net thickness of 150 feet in the prospective area. The average thermal maturity (Ro of 1.1%) places the shale in the wet gas/condensate window. The total organic content (TOC) is moderate to high, averaging 5%. X-ray diffraction of cores taken from the Doig Phosphate Formation show significant levels of quartz with minor to moderate levels of clay and trace to minor amounts of pyrite and dolomite, making the formation favorable for hydraulic fracturing.

Figure I-14. Prospective Area for the Doig Phosphate Shale (Deep Basin)



Modified from Walsh, 2006.

4.3 Resource Assessment

The prospective area of the Doig Phosphate Shale is estimated at 3,000 mi^2, limited on the west by the Phanerozoic Deformation Fault and by the pinch-out of the shales to the north, east and south. Within the prospective area, the shale has a moderate resource concentration of 67 Bcf per mi^2 of wet gas and a risked resource in-place of 101 Tcf. Based on favorable mineralogy, we estimate a risked, technically recoverable shale gas resource of 25 Tcf for the Doig Phosphate Shale.

4.4 Comparison with Other Resource Assessments

In 2006, Walsh estimated a gas in-place for the Doig Phosphate Unit of ~70 Tcf.[15]

4.5 Recent Activity

The Doig Phosphate Shale reservoir overlies the Montney Resource Play. As such, much of the activity and appraisal of the Doig Phosphate is reported as part of exploration for the Montney and Doig Resource plays. Pengrowth Energy Corp, a small Canadian producer, tested the larger Doig interval with a vertical well in 2011 with a reported test rate of 750 Mcfd. The company plans to target the Doig with a horizontal well in 2012.[8]

5. MONTNEY AND DOIG RESOURCE PLAYS (BRITISH COLUMBIA)

The Deep Basin of British Columbia contains the Montney and Doig Resource plays. These are multi-depositional, Triassic-age hydrocarbon accumulations containing large volumes of dry and wet gas in-place in conventional, tight sand and shale formations.

The Canadian National Energy Board categorizes the Montney and Doig Resource plays as tight gas sands. Work by the BC Oil and Gas Commission, in their “Montney Formation Play Area Atlas NEBC”,[16] shows that only a very small portion of the Montney Resource play contains oil/condensate, Figure I-15. As such, we have excluded the Montney and Doig Resource plays from the shale resource assessment of Canada. (In our previous shale gas resource assessment, we speculated that a shale-rich Montney area with higher TOC values may exist in BC along the northwestern edge of the Deep Basin. However, because of lack of data confirming this speculation, we have excluded this area and resource volumes from our current shale oil and gas assessment.)

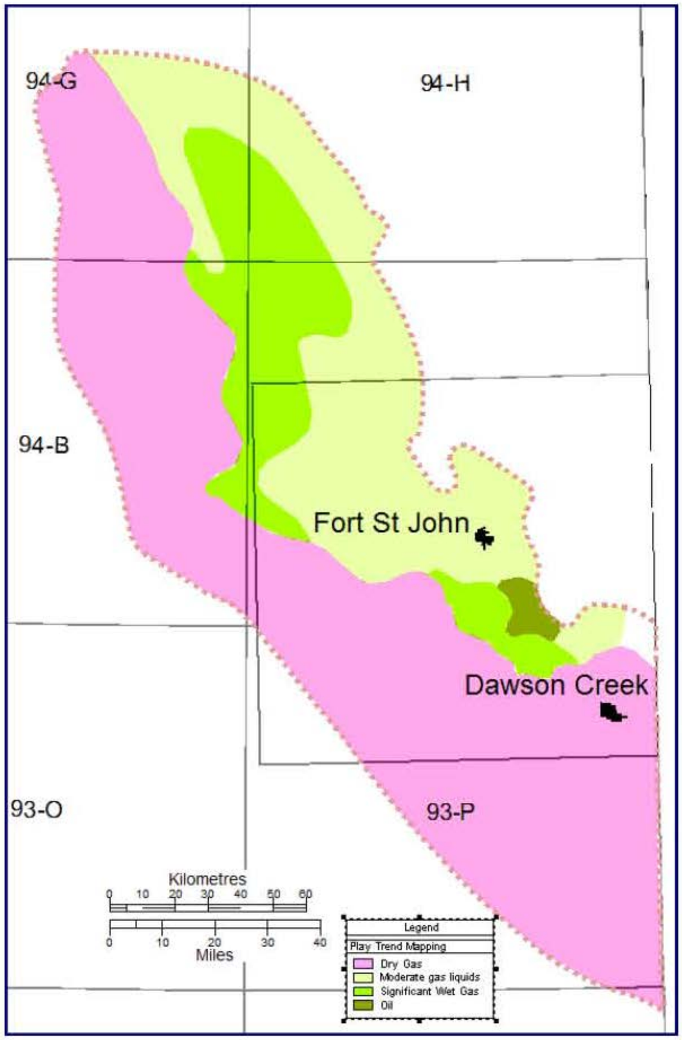
To put the potential volume of tight gas resource in the Montney and Doig Resource plays of British Columbia into perspective, the BC MEM reports a gas in-place for the BC portion of the Montney and Doig Resource plays at 450 Tcf and 200 Tcf respectively.[8]

6. CANOL SHALE

The Canol Shale is an emerging shale play located in the central Mackenzie Valley near Norman Wells, Northwest Territories. To date, only seismic and a handful of vertical wells have been drilled to explore this shale oil play. Work is underway on a multi-year study by the Northwest Territories Geoscience Office to better define this resource.

Husky Oil, having spent $376 million at the 2011 land auction, has drilled two vertical wells on its 300,000-net acre lease area and is planning on completing three wells in 2013.[17] MGM Energy Corp, with 470,000-net acres in this resource play, plans to drill one vertical well during the current winter exploration season. MGM (with Shell as its partner) withdrew plans to drill a horizontal well in 2012 to test the productivity of the Canol Shale play.[18] As information on the prospectivity of the Canol Shale is gained from the above wells, it would be timely to include this shale play in the assessment of Canada’s shale gas and oil resources.

Figure I-15. Montney Trend – Identified Gas Liquids/Oil Distribution



Source: BC Oil and Gas Commission Montney Formation Play Atlas NEBC October 2012.

ALBERTA

Alberta holds a series of significant, organic-rich shale gas and shale oil formations, including: (1) the Banff and Exshaw Shale in the Alberta Basin; (2) the Duvernay Shale in the East and West Shale Basin of west-central Alberta; (3) the Nordegg Shale in the Deep Basin of west-central Alberta; (4) the Muskwa Shale in northwest Alberta; and (5) the shale gas formations of the Colorado Group in southern Alberta. (In addition, Alberta holds the eastern portion of the Doig Phosphate Shale play, discussed previously.)

The study has benefitted greatly from the in-depth and rigorous siltstone and shale data in the ERCB/AGS report entitled, "Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential".[19] This ERCB/AGS report helped define the boundaries for the oil, wet gas/condensate and dry gas play areas used by this study. This report also provided valuable data on key reservoir properties such as porosity and net pay.

To maintain consistency with the ERCB/AGS study for Alberta, our study used the same minimum criterion of 0.8% R_o for the volatile/black oil window. However, our study used the criterion of >1.3% R_o for the dry gas window, compared to the >1.35% R_o in the ERCB/AGS study. Our study also expanded on the analytical data in ERCB/AGS's report with our independently derived estimates of prospective areas as well as our assignments of pressure gradients, gas-oil ratios (as functions of reservoir pressure and temperature), and other reservoir properties to each shale play. (The ERCB/AGS assumed normal rather than over-pressured gradients in their Alberta resource assessment and linked a constant oil-gas ratio to each thermal maturity (R_o) value, independent of reservoir pressure and depth.)

The five Alberta basins assessed by this study contain 987 Tcf of risked shale gas in-place, with 200 Tcf as the risked, technically recoverable shale gas resource, Table 1-3. These five basins also contain 140 billion barrels of risked shale oil in-place, with 7.2 billion barrels as the risked, technically recoverable shale oil resource, Table I-4.

Table I-3. Shale Gas Reservoir Properties and Resources of Alberta

Basic Data	Basin/Gross Area		Alberta Basin (28,700 mi^2)	East and West Shale Basin (50,500 mi^2)			Deep Basin (26,200 mi^2)			NW Alberta Area (33,000 mi^2)		Southern Alberta Basin (124,000 mi^2)
	Shale Formation		Banff/Exshaw	Duvernay			North Nordegg			Muskwa		Colorado Group
	Geologic Age		L. Mississippian	U. Devonian			L. Jurassic			U. Devonian		Cretaceous
	Depositional Environment		Marine	Marine			Marine			Marine		Marine
Physical Extent	Prospective Area (mi^2)		10,500	13,000	7,350	2,900	6,900	4,000	1,500	12,500	6,600	48,750
	Thickness (ft)	Organically Rich	65	45	60	70	82	72	69	70	112	523
		Net	15	41	54	63	37	31	29	25	78	105
	Depth (ft)	Interval	3,900 - 6,200	7,500 - 10,500	10,500 - 13,800	13,800 - 16,400	5,200 - 8,200	8,200 - 11,500	11,500 - 14,800	3,300 - 8,200	3,900 - 8,200	5,000 - 10,000
		Average	4,800	9,000	11,880	15,000	6,724	10,168	12,464	6,100	4,602	6,900
Reservoir Properties	Reservoir Pressure		Normal	Highly Overpress.	Highly Overpress.	Highly Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Underpress.
	Average TOC (wt. %)		3.2%	3.4%	3.4%	3.4%	11.0%	11.0%	11.0%	3.2%	3.2%	2.4%
	Thermal Maturity (% Ro)		0.90%	0.90%	1.15%	1.50%	0.90%	1.15%	1.35%	0.90%	1.10%	0.60%
	Clay Content		Medium	Low	Low	Low	Low/Med.	Low/Med.	Low/Med.	Low	Low	Low/Med.
Resource	Gas Phase		Assoc. Gas	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		1.2	12.0	47.4	63.8	4.7	19.6	22.1	4.6	34.2	20.9
	Risked GIP (Tcf)		5.1	109.1	244.1	129.5	16.2	39.2	16.6	29.0	112.7	285.6
	Risked Recoverable (Tcf)		0.3	13.1	61.0	38.8	1.3	7.8	4.1	2.9	28.2	42.8

Table I-4. Shale Oil Reservoir Properties and Resources of Alberta

Basic Data	Basin/Gross Area		Alberta Basin (28,700 mi^2)	East and West Shale Basin (50,500 mi^2)		Deep Basin (26,200 mi^2)		NW Alberta Area (33,000 mi^2)	
	Shale Formation		Banff/Exshaw	Duvernay		North Nordegg		Muskwa	
	Geologic Age		L. Mississippian	U. Devonian		L. Jurassic		U. Devonian	
	Depositional Environment		Marine	Marine		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		10,500	13,000	7,350	6,900	4,000	12,500	6,600
	Thickness (ft)	Organically Rich	65	45	60	82	72	70	112
		Net	15	41	54	37	31	25	78
	Depth (ft)	Interval	3,900 - 6,200	7,500 - 10,500	10,500 - 13,800	5,200 - 8,200	8,200 - 11,500	3,300 - 8,200	3,900 - 8,200
		Average	4,800	9,000	11,880	6,724	10,168	6,100	4,602
Reservoir Properties	Reservoir Pressure		Normal	Highly Overpress.	Highly Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		3.2%	3.4%	3.4%	11.0%	11.0%	3.2%	3.2%
	Thermal Maturity (% Ro)		0.90%	0.90%	1.15%	0.90%	1.15%	0.90%	1.10%
	Clay Content		Medium	Low	Low	Low/Med.	Low/Med.	Low	Low
Resource	Oil Phase		Oil	Oil	Condensate	Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		2.5	7.1	0.5	5.5	0.4	6.4	0.7
	Risked OIP (B bbl)		10.5	64.2	2.6	19.0	0.8	40.0	2.4
	Risked Recoverable (B bbl)		0.32	3.85	0.16	0.76	0.03	2.00	0.12

1. BASAL BANFF AND EXSHAW SHALE/ ALBERTA BASIN

1.1 Geologic Setting

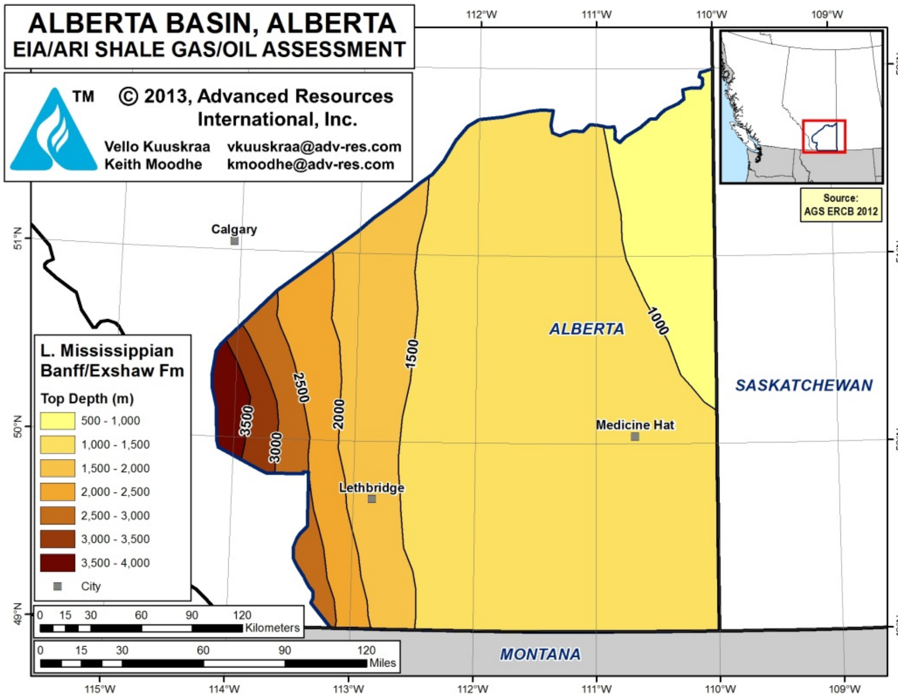
The basal Banff/Exshaw Shale assessed by this study is located in the southern Alberta portion of the Alberta Basin, Figure I-16.[19] The western boundary of this shale deposit is constrained by the Deformed Belt and its northern boundary is defined by the sub-crop erosional edge. Its eastern boundary is the Alberta and Saskatchewan border and its southern boundary is the U.S. and Canada border. Within the larger 15,360-mi^2 area of shale deposition, the Basal Banff/Exshaw Shale has a prospective area of 10,500 mi^2 for volatile/black oil, Figure I-17.[19] (The small dry gas and wet gas areas were not considered prospective.) The east to west cross-section (E-E') for the Lower Mississippian and Upper Devonian Basal Banff/Exshaw Shale shows its stratigraphic equivalence to the Bakken Formation in the Williston Basin, Figure I-18.[19]

1.2 Reservoir Properties (Prospective Area)

Similar to the Bakken Shale, the basal Banff/Exshaw Shale consists of three reservoir units. The upper and lower units are dominated by organic-rich shale. The middle unit contains a variety of lithologies including calcareous sandstone and siltstone, dolomitic siltstone and limestone. The primary reservoir is the more porous and permeable middle unit, sourced by the upper and lower organic-rich shales units. However, compared to the Bakken Shale, the prospective area of the basal Banff/Exshaw Shale is normally pressured (with higher pressures in the west) rather than over-pressured, and its middle unit appears to have considerably lower permeability and solution gas.

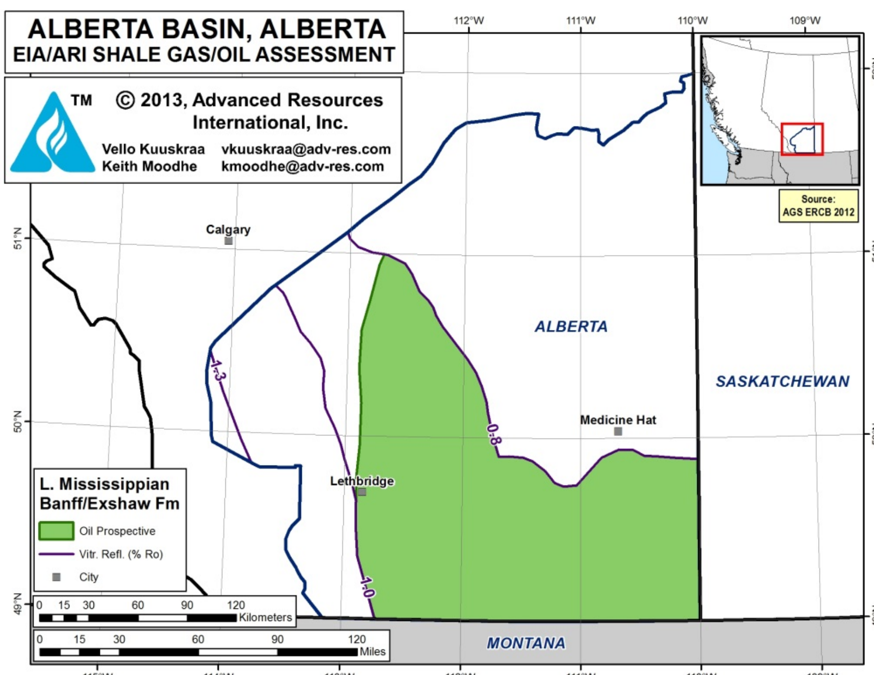
In the prospective area, the drilling depth to the top of the shale ranges from 3,300 feet on the east to about 6,600 feet on the west, averaging 4,800 feet. The upper shale unit is 3 to 5 feet thick and the lower shale unit has a gross thickness of 10 to 40 feet, providing a net, organic-rich shale pay averaging 15 feet.

Figure I-16. Outline and Depth of Basal Banff and Exshaw Shale (Alberta)



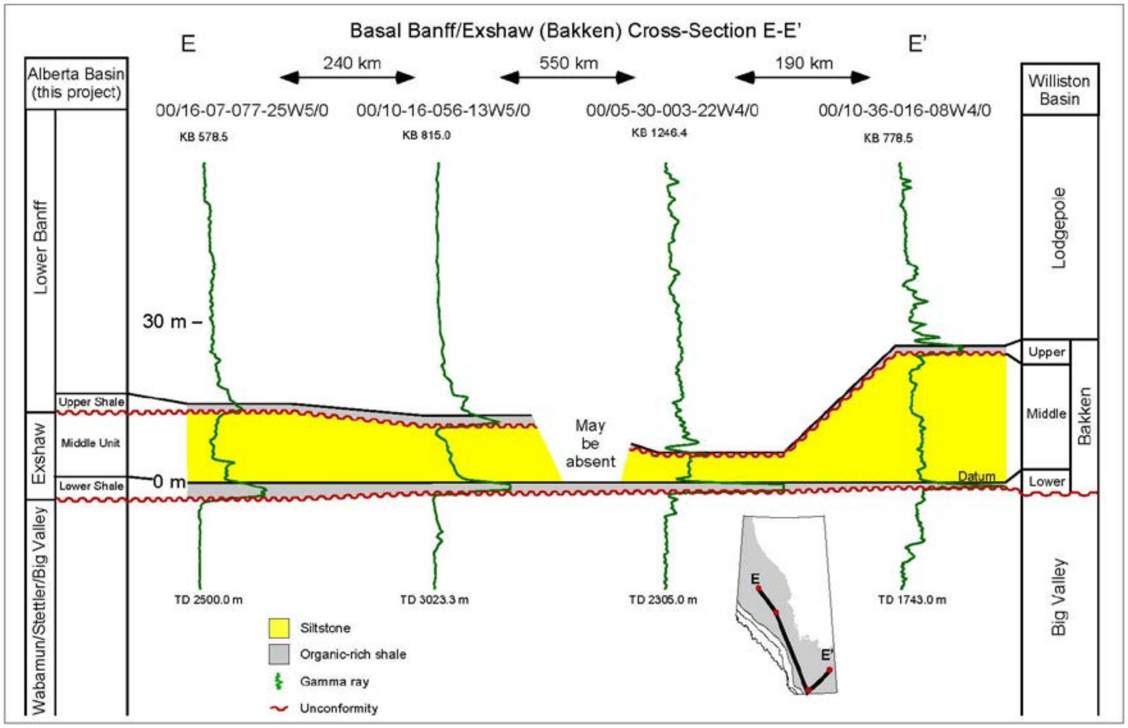
Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-17. Prospective Area for Basal Banff and Exshaw Shale (Alberta).



Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-18. Stratigraphic Cross Section E-E' of the Basal Banff and Exshaw Shale



Source: ERCB/AGS Open File Report 2012-06, October 2012.

The total organic content (TOC) in the prospective area averages 3.2% and ranges from lean to nearly 17%. The upper and lower shale units have high TOC values (3% to 17%), the middle unit has much lower TOC (lean to 3%). The thermal maturity (R_o) of the shale shows a progressive increase from immature (below 0.8% R_o) in the east to dry gas (over 1.3% R_o) in the west. However, in the western area where the thermal maturity exceeds 1.0% R_o, the shale is thin and thus has been excluded from the prospective area. As such, the basal Banff/Exshaw Shale has a prospective area for oil of 10,500 mi^2 (0.8% to 1.0% R_o) located in the center of the larger play area.

1.3 Resource Assessment

The prospective area for the Basal Banff/Exshaw Shale in the Alberta Basin is limited by depth and thermal maturity on the east and by shale thickness on the west. Within the 10,500-mi^2 prospective area for oil, the basal Banff/Exshaw Shale has a resource concentration of 2.5 million barrels of oil per mi^2 plus moderate volumes of associated gas.

The risked resource in-place for the oil prospective area is estimated at 10 billion barrels of oil plus 5 Tcf of associated natural gas. Based on recent well performance as well as reservoir properties that appear to be less favorable than for the Bakken Shale in the Williston Basin, we estimate a risked, technically recoverable resource of 0.3 billion barrels of shale oil and 0.3 Tcf of associated shale gas.

1.4 Comparison With Other Resource Assessments

The ERCB/AGS resource study, discussed above, calculated an unrisked oil in-place of 26,300 million barrels and an unrisked gas in-place of 39.8 Tcf for the basal Banff/Exshaw Shale.[19] The ERCB/AGS study did not use depth, net pay or other criteria to define a prospective area and did not estimate a risked recoverable resource.

1.5 Recent Activity

Considerable leasing occurred for the basal Banff/Exshaw Shale in 2010, sparking this southern Alberta shale play. Since then, a number of producers, such as Crescent Point and Murphy Oil, have drilled exploration wells to test the resource potential in this shale oil play. So far, of the 22 wells with reported production, only three wells have current producing rates of over 100 B/D; the remainder have rates of less than 50 B/D.

Crescent Point drilled two exploration wells into the Exshaw Shale in early 2012 with plans to drill additional wells in the area.[20] Murphy Oil has assembled a 150,000 net acre lease area. While its early exploration for this shale play has shown mixed results, Murphy's recent #15-21 well targeting the Exshaw Shale had an IP of 350 BOPD. Murphy Oil is examining the use of longer laterals, enhanced stimulation and lower costs to improve the economic viability of this shale play.[21]

2. DUVERNAY SHALE/EAST AND WEST SHALE BASIN

2.1 Geologic Setting

The East and West Shale Basin, covering an area of over 50,000 mi^2 in central Alberta, contains the organically rich Duvernay Shale, Figure I-19.[19] The western boundary of this shale deposit is defined by the Deformed Belt, the northern boundary by the Peace River Arch, the southern boundary by the Leduc Shelf, and the eastern boundary by the Grosmont Carbonate Platform. Within this larger area of shale deposition, the prospective area for the Duvernay Shale is 23,450 mi^2, primarily in the central and western portions of this basin, Figure I-20.[19]

The Upper and Middle Devonian Duvernay Shale is stratigraphic equivalent to the Muskwa Shale in northwest Alberta and northeast British Columbia. In the East Shale Basin, the Duvernay Shale is primarily an organic-rich limestone. In the West Shale Basin, the Duvernay Shale grades from a carbonate-rich mudstone in the east to an increasingly porous, organic-rich shale in the west, Figure I-21.[19]

2.2 Reservoir Properties (Prospective Area)

In the prospective area, the drilling depth to the top of the Duvernay Shale ranges from 7,500 feet in the east to 16,400 feet in the west. The gross shale thickness in the prospective area ranges from 30 feet to over 200 feet, with an average of 41 net feet in the oil prospective area, 54 net feet in the wet gas/condensate prospective area, and 63 net feet in the dry gas prospective area.

The total organic carbon (TOC) in the prospective area reaches 11%. Excluding the organically lean rock using the net to gross ratio, the average TOC is 3.4%. The thermal maturity (R_o) of the shale increases as the shales deepen, from immature (below 0.8% Ro) on the east to dry gas (1.3% to 2% R_o) in the west. As such, the Duvernay Shale has an extensive oil prospective area in the east, a wet gas/condensate prospective area in the center, and a smaller dry gas prospective area in the west.

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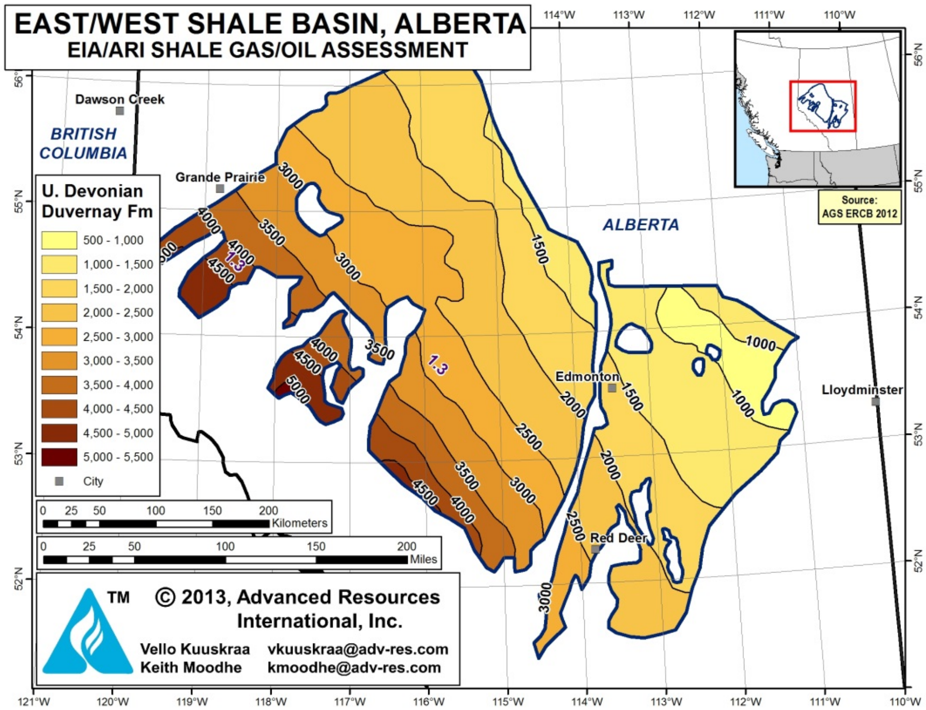
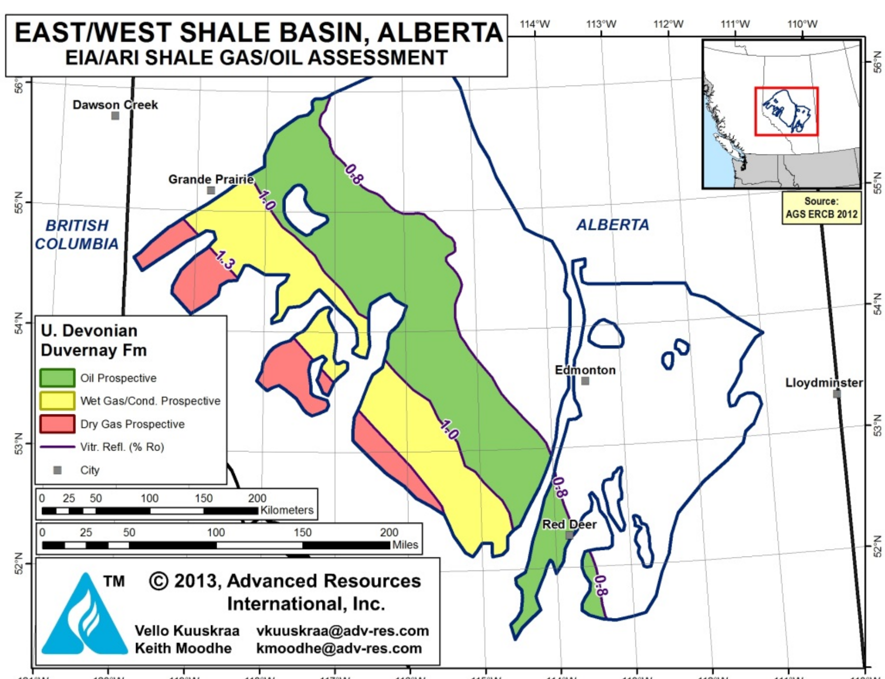
Figure I-19. Outline and Depth of Duvernay Shale (Alberta)



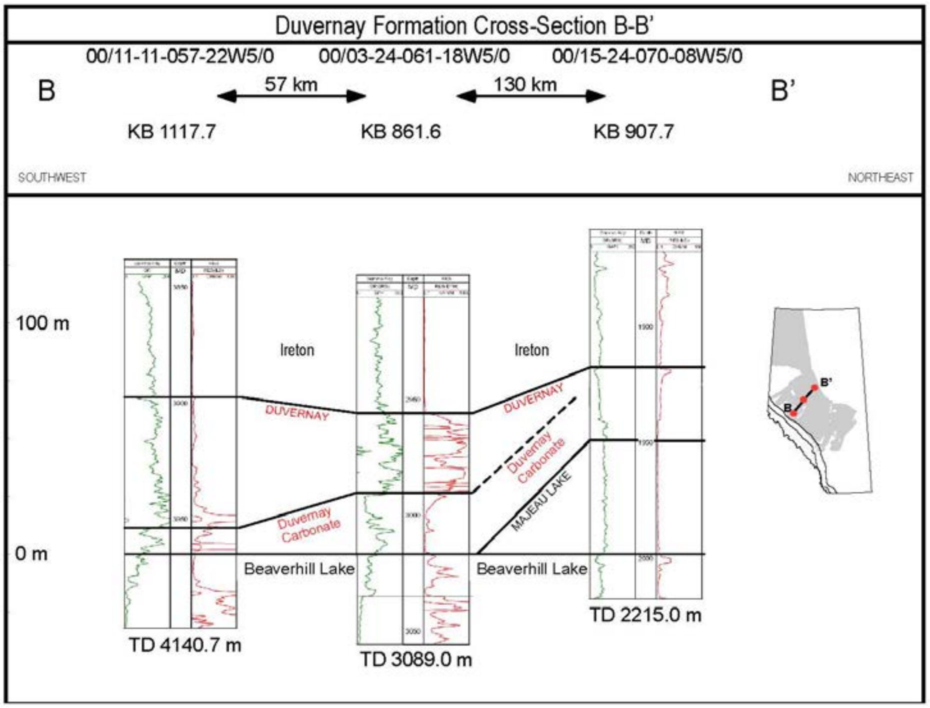
Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-20. Prospective Area for Duvernay Shale (Alberta)



Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-21. Stratigraphic Cross Section B-B' of the Duvernay Formation



Source: ERCB/AGS Open File Report 2012-06, October 2012.

2.3 Resources Assessment

The prospective area of the Duvernay Shale in the East and West Shale Basin covers 23,250 mi^2, limited on the east by low thermal maturity. Within the 13,000-mi^2 prospective area for oil, the Duvernay Shale has a resource concentration of 7.1 million barrels of oi/mi^2 plus associated gas. Within the 7,350-mi^2 wet gas/condensate prospective area, the Duvernay Shale has resource concentrations of 0.5 million barrels of condensate and 47 Bcf of wet gas per mi^2. Within the 2,900-mi^2 dry gas prospective area, the Duvernay Shale has a resource concentration of 64 Bcf/mi^2.

The risked resource in-place in the prospective areas of the Duvernay Shale is estimated at 67 billion barrels of shale oil/condensate and 483 Tcf of shale gas. Based on favorable reservoir properties and analog information from U.S. shales such as the Eagle Ford, we estimate risked, technically recoverable resources of 4.0 billion barrels of shale oil/condensate and 133 Tcf of dry and wet shale gas.

2.4 Recent Activity

The Duvernay Shale is the current “hot” shale play in Western Canada with over $2 billion spent (in 2010 and 2011) in auctions for leases. Athabasca Oil (with 1,000 mi^2) followed by Canadian Natural Resources (600+ mi^2), EnCana (580+ mi^2) and Talisman (560+ mi^2) have the dominant land positions. Twelve additional companies, ranging from Chevron to Enerplus, each hold over 100 mi^2 of leases.

Much of the current activity is in the Kaybob wet gas/condensate area. EnCana with 8 Hz wells plus one vertical well and Celtic with 7 Hz and 5 vertical wells are the most active operators. Since the first Celtic well in the Duvernay Shale in 2010, a total of 45 wells (Hz and vertical) have been drilled or are being drilled (mid-2012).

- EnCana reports that its Duvernay well tested at 2.3 MMcfd of wet gas and 1,632 barrels per day of condensate.
- Celtic’s best Duvernay well tested at 5.8 Mcfd of wet gas plus 638 barrels per day of condensate.

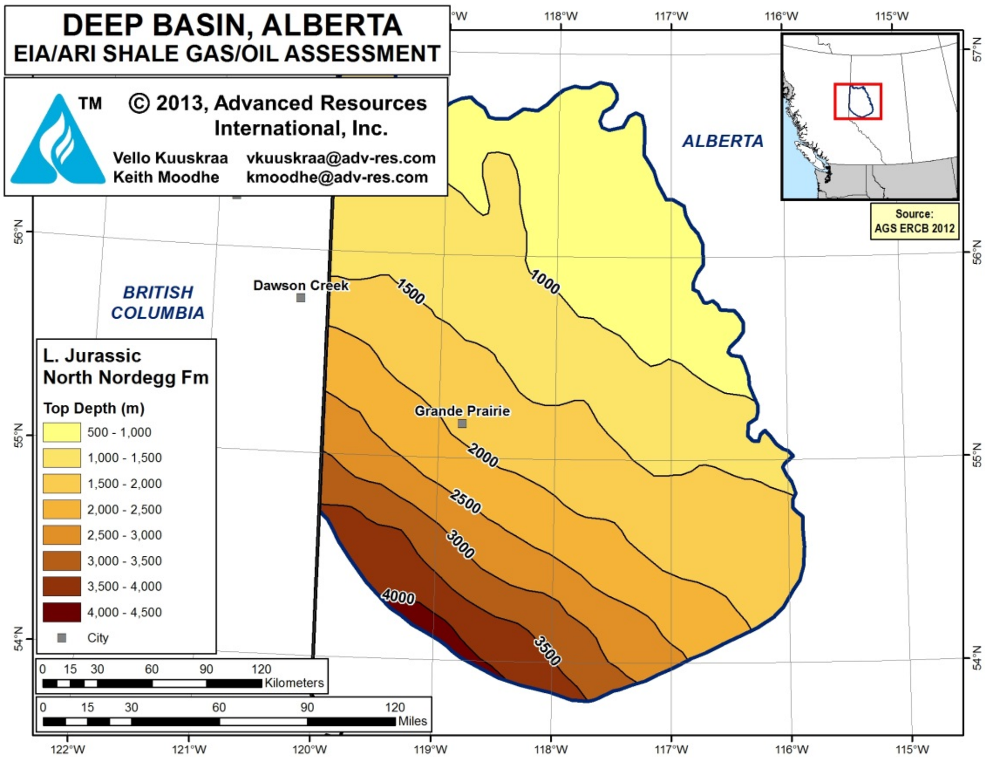
In the Pembina area, EnCana with four Hz wells and ConocoPhillips with three Hz wells are most active. In the Edson Area, where active leasing is still underway, Angle Energy, CNRL and Vermillion are drilling Duvernay Shale explorations wells.

3. NORDEGG SHALE/DEEP BASIN.

3.1 Geologic Setting.

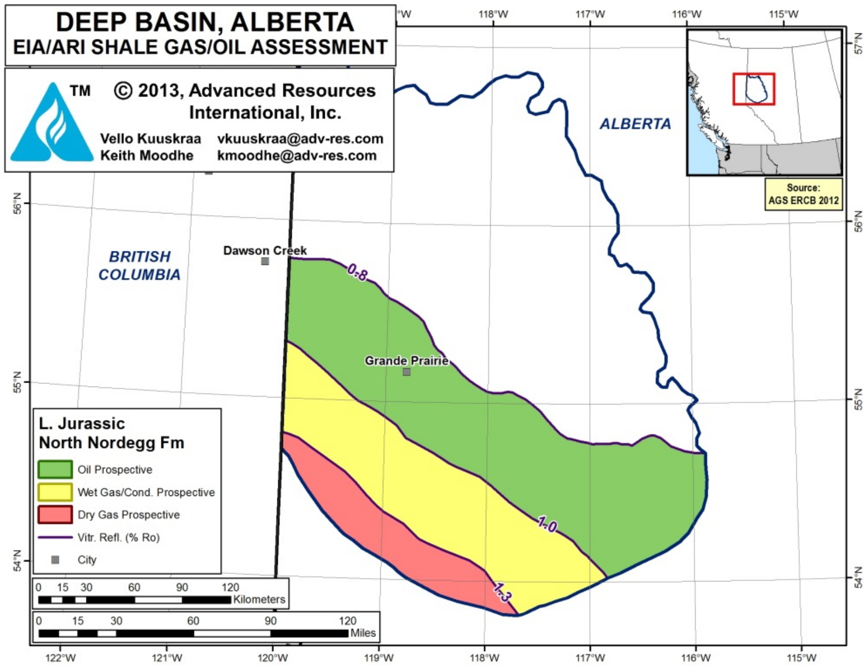
The Nordegg Shale assessed in this study is located within the Deep Basin of Alberta, Figure I-22.[19] The Lower Jurassic Nordegg Shale Member is located at the base of the Fernie Formation, shown by the cross-section on Figure I-23.[19] The Nordegg transitions from a carbonate-rich deposition on the south into a fine-grained rock on the north. In the northern area, where the shale interval is sometimes referred to as the Gordondale Member, the Nordegg Shale is an organic-rich mudstone (shale) which also includes cherty and phosphoric carbonates as well as siltstones and some sandstone, Figure 1-24.[19] The Nordegg Shale has served as a prolific source rock for shallower conventional hydrocarbon reservoirs in this portion of the Deep Basin.

Figure I-22. Outline and Depth of Nordegg Shale (Alberta).



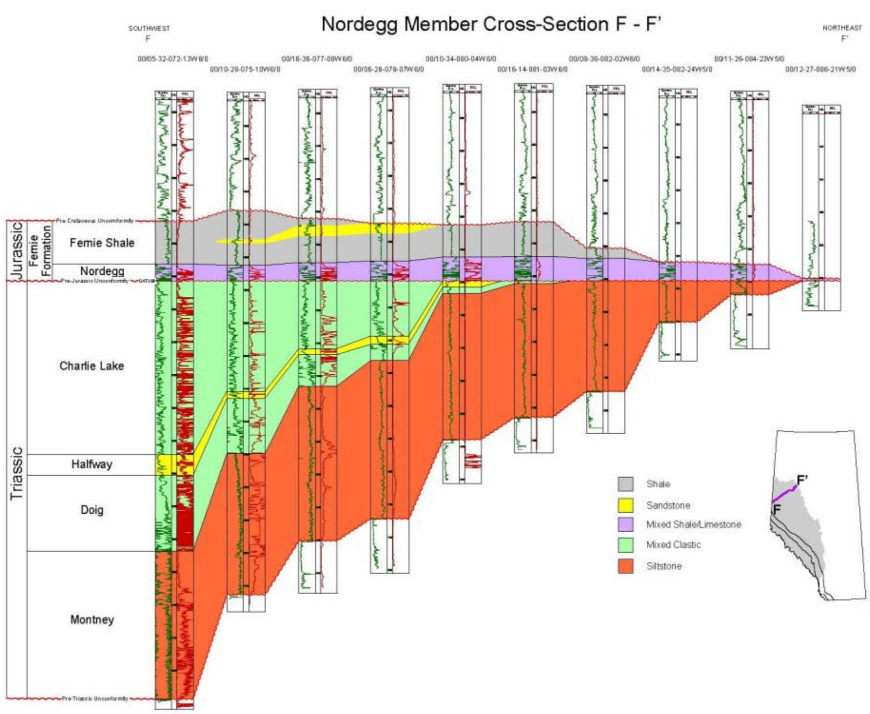
Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-23. Prospective Area for Nordegg Shale (Alberta)



Source: Modified from ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-24. Stratigraphic Cross Section F-F' of the Nordegg Member



Source: ERCB/AGS Open File Report 2012-06, October 2012.

3.2 Reservoir Properties (Prospective Area).

In the Nordegg Shale prospective area, the drilling depth to the top of the shale ranges from 3,300 feet in the north-east to about 15,000 feet in the south. Within the overall prospective area of 12,400 mi^2, the volatile/black oil prospective area is 6,900 mi^2, the wet gas/condensate prospective area is 4,000 mi^2, and the dry gas prospective area is 1,500 mi^2. The shale thickness in the overall prospective area ranges from 50 feet to 150 feet and has a high net to gross ratio of about 0.8.

The total organic carbon (TOC) in the prospective area is high, at over 11%, based on 82 samples from 16 wells. The thermal maturity (R_o) of the shale increases to the southwest in line with increasing depth. The overall Nordegg Shale prospective area has an oil prone area (R_o of 0.8% to 1.0%) on the north, a wet gas/condensate area in the center (R_o of 1.0% to 1.3%) and a dry gas area (R_o >1.3) on the south. While the data are sparse, industry information suggests that the Nordegg Shale is over-pressured.

3.3 Resource Assessment.

Within the 6,900-mi^2 oil prospective area, the Nordegg Shale has a resource concentration of 5.6 million barrels of oil per mi^2 plus associated gas. Within the 4,000-mi^2 wet gas and condensate prospective area, the Nordegg Shale has a resource concentrations of 0.4 million barrels of oil and 20 Bcf of wet gas per mi^2. Within the 1,500-mi^2 dry gas prospective area, the Nordegg Shale has a resource concentration of 22 Bcf/mi^2.

Combined, the risked resource in-place for the prospective area of the Nordegg Shale is estimated at 20 billion barrels of oil/condensate and 72 Tcf of natural gas. Based on moderate reservoir properties and analog information from U.S. shales, we estimate risked, technically recoverable resources of 0.8 billion barrels of oil/condensate and 13 Tcf of natural gas for the Nordegg Shale.

3.4 Comparison with Other Resource Assessments

The ERCB/AGS resource study, discussed above, calculated an unrisked mean oil in-place of 40,645 million barrels and an unrisked mean gas in-place of 164 Tcf for the Nordegg Shale.[19] The in-place resource values in our study are different than those reported in the ERCB/AGS study due to the following: (1) given the still emerging nature of the Nordegg Shale, we judge this resource area to be only 50% de-risked; (2) we find the Nordegg Shale to be moderately over-pressured; and (3) we have a significantly lower associated gas-oil ratio for the volatile/black oil prospective resource area than used in the ERCB/AGS study.

3.5 Recent Activity

Only a modest number of exploration wells have been completed in the Nordegg Shale. Recently, Anglo Canadian drilled a horizontal test well (Shane 07-11-77-03W6) and a vertical test well (Sturgeon Lake 05-10-68-22W5) which produced non-commercial volumes of moderately heavy, 25^o API oil. Tallgrass Energy has since acquired Anglo Canadian and its large land position, with 272 mi^2 in the Nordegg Shale.[22] The literature reports that a company active in the Nordegg oil fairway has completed one Nordegg Hz well with a multi-stage frac that produced 500 BOED, with 80% oil (42^o API), during its initial flow test and completed a second well that had a 30-day initial production rate of 78 barrels of 32^o API oil.[23]

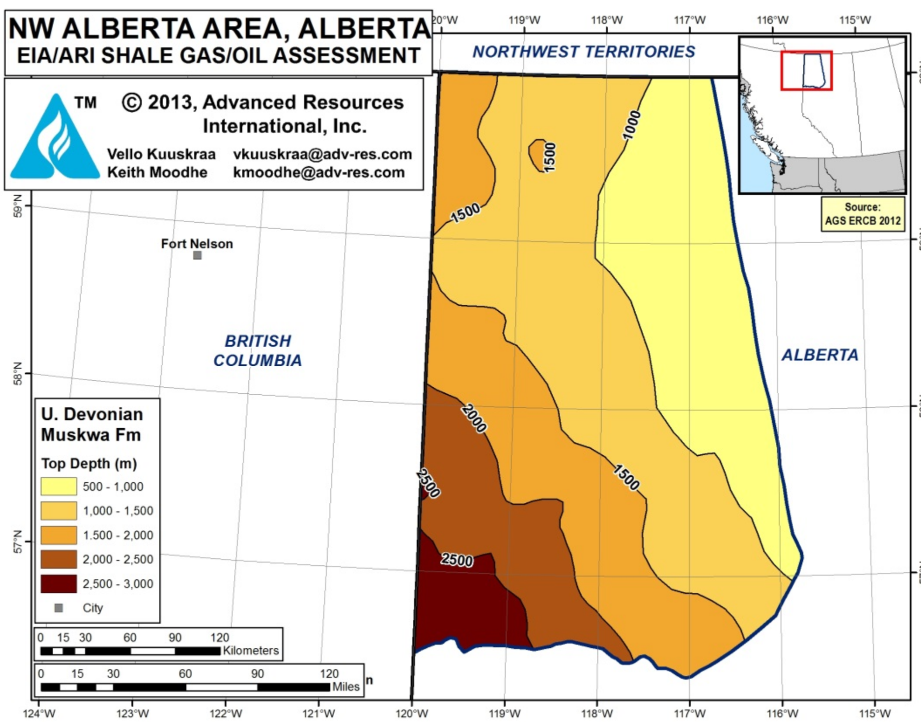
4. MUSKWA SHALE/NORTHWEST ALBERTA

4.1 Geologic Setting

The Muskwa Shale deposition in northwest Alberta is the northern continuation of the Duvernay Shale in central Alberta and the eastern continuation of Muskwa/Otter Park Shale in northeast British Columbia, Figure I-25.[19] The boundaries of the Muskwa Shale in northwest Alberta are the Alberta/British Columbia border on the west, the Alberta/NWT border on the north, the Peace River Arch on the south, and the Grosmont Carbonate Platform on the east. Within this larger depositional area, the Muskwa Shale has a prospective area of 19,100 mi^2, primarily in the western portion of the larger Muskwa Shale depositional area, Figure I-26.[19]

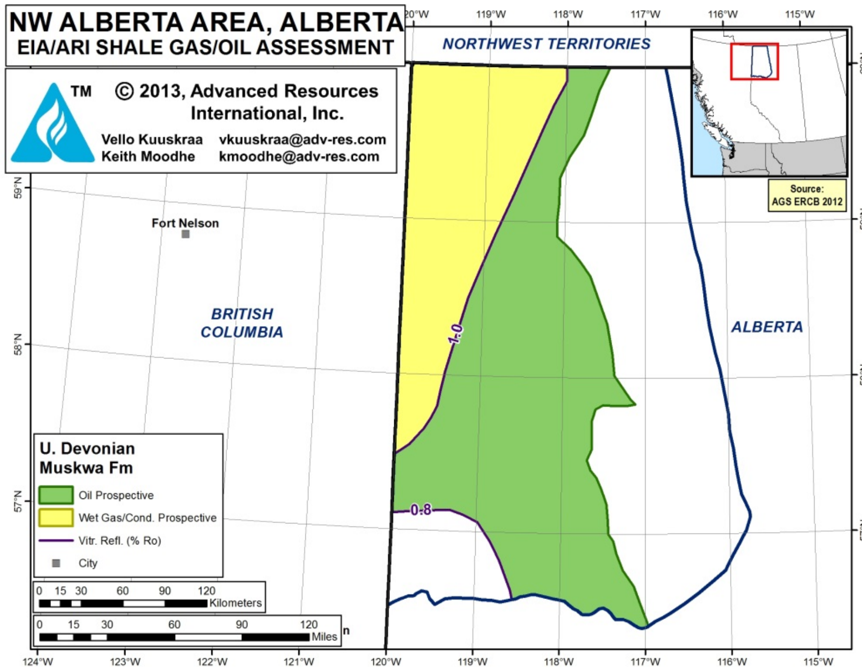
The Muskwa Shale is overlain by the Ft. Simpson Shale and is deposited on the Beaverhill Lake Formation, Figure I-27.[19] The Muskwa Shale is primarily an organic-rich limestone deposited in a deep-water marine setting.

Figure I-25. Outline and Depth of Muskwa Shale (Alberta).



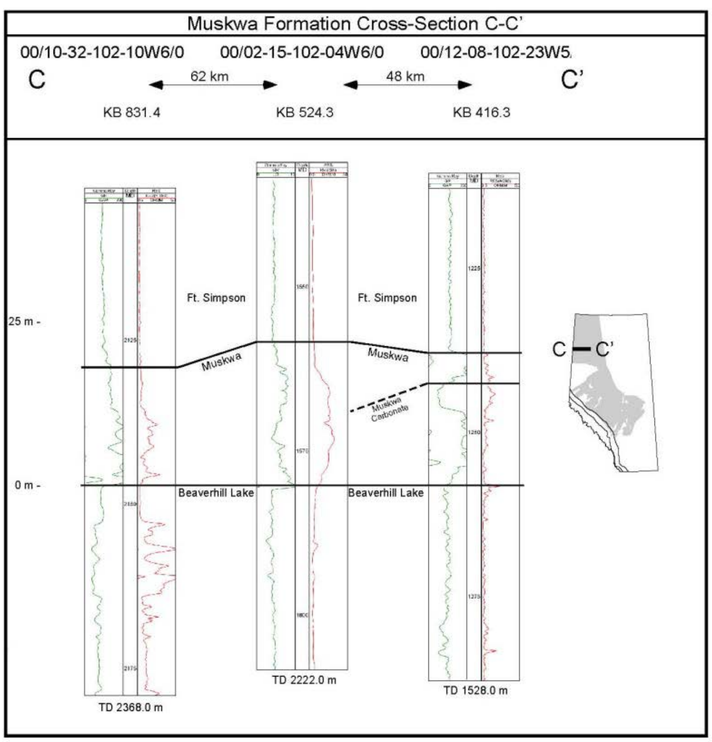
Source: ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-26. Prospective Area for Muskwa Shale (Alberta).



Source: ERCB/AGS Open File Report 2012-06, October 2012.

Figure I-27. Stratigraphic Cross Section C-C' of the Muskwa Formation



Source: ERCB/AGS Open File Report 2012-06, October 2012.

4.2 Reservoir Properties (Prospective Area)

In the prospective area, the drilling depth to the top of the Muskwa Shale ranges from 3,300 feet in the northeast to 8,200 feet in the southwest. The gross shale thickness ranges from 33 feet to nearly 200 feet, with a high net to gross pay ratio.

The total organic content (TOC) ranges from less than 1 to over 10%, with the leaner TOC pay excluded by the net to gross pay ratio. Excluding the lean TOC segments, a sample of 47 TOC measurements from 5 wells provided an average TOC value of 3.2%. The thermal maturity (R_o) of the shale increases with depth, ranging from immature (R_o < 0.8%) in the east to thermally mature for wet gas and condensate (R_o of 1.0% to 1.2%) on the west. Based on thermal maturity, the Muskwa Shale has an oil-prone area with associated gas on the east and a wet gas/condensate area on the northwest.

4.3 Resources Assessment

The overall oil and gas prospective area of the Muskwa Shale in northwest Alberta is approximately 19,100 mi^2. Within the oil prospective area of 12,500 mi^2, the Muskwa Shale has a resource concentration of 6 million barrels of oil per mi^2 plus associated gas. Within the wet gas/condensate prospective area of 6,600 mi^2, the Muskwa Shale has a resource concentration of 1 million barrels of oil/condensate per mi^2 and 34 Bcf of wet gas per mi^2.

The risked resource in-place is estimate at 42 billion barrels of oil/condensate and 142 Tcf of shale gas. Given favorable reservoir properties and analog information from the Horn River and Cordova Embayment shales, we estimate a risked, technically recoverable resource of 2.1 billion barrels of shale oil/condensate and 31 Tcf of shale gas.

4.4 Comparison with Other Resource Assessments

The ERCB/AGS resource study, discussed above, calculated an unrisked mean oil in-place of 115,903 million barrels and an unrisked mean gas in-place of 413 Tcf for the Muskwa Shale study area in NW Alberta.[19] The in-place values in our study are different than those reported in the ERCB/AGS study due to the following: (1) given the limited exploration for the Muskwa Shale in NW Alberta, we judge this resource area to be only 50% de-risked; (2) we find the Muskwa Shale in this area to be moderately over-pressured; and (3) we have a lower associated gas-oil ratio for the shale.

4.5 Recent Activity

Husky Oil Canada, currently the most active explorer in Alberta's Muskwa Shale, has a concentrated 400,000-net acre land position in the Rainbow area. Husky drilled 14 Muskwa Shale wells in 2012, completing 4 wells, with the goal of de-risking its large land position and refining its well completion practices. Husky is currently looking for a JV partner to help finance the development of this shale oil play[17].

A smaller Canadian E&P company, Mooncor Oil and Gas, drilled a pilot test well into the Muskwa Shale in early 2009 (Well #06-34-94-12W6). The Muskwa zone was reported to be over-pressured and flowed 56^{o} API condensate plus wet gas.[24]

5. COLORADO GROUP/SOUTHERN ALBERTA

5.1 Geologic Setting

The Colorado Group Shale covers a massive, 124,000-mi^2 area in southern Alberta and southeastern Saskatchewan. The western boundary of the Colorado Group is the Canadian Rockies Overthrust. The northern and eastern boundaries are defined by shallow shale depth and loss of net pay. The southern boundary is the U.S./Canada border. The Colorado Group encompasses a thick, Cretaceous-age sequence of sands, mudstones and shales. Within this sequence are two shale formations of interest - - the Fish Scale Shale Formation in the Lower Colorado Group and the Second White Speckled Shale Formation in the Upper Colorado Group, Figure I-28.[25] We selected the 5,000 to 10,000 foot depth contours for defining the 48,750-mi^2 prospective area, Figure I-29.

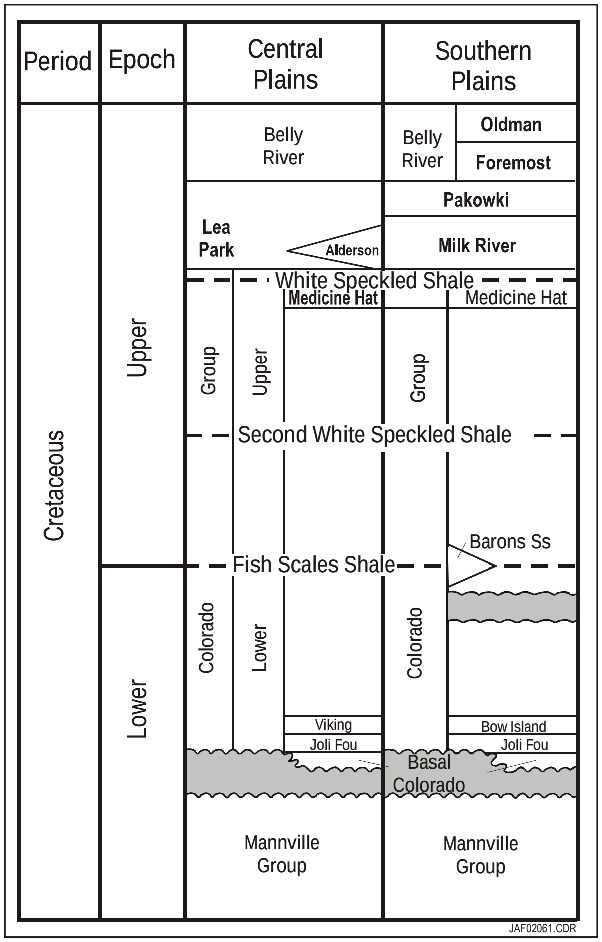
5.2 Reservoir Properties (Prospective Area)

In the prospective area, the depth to the Second White Speckled (2WS) and the Fish Scale shales ranges from 5,000 feet near Medicine Hat (on the east) to over 10,000 feet in the west. The Fish Scale Shale is generally about 200 feet deeper than the 2WS. The interval from the top of the 2WS to the base of the Fish Scales Shale ranges from 300 feet in the east to over 1,000 feet in the west, with an average gross pay of 523 feet. Assuming a conservative net to gross ratio of 20%, we estimate a net pay of 105 feet. Much of the Colorado Group Shale appears to be under-pressured, with a pressure gradient of about 0.3 psi/ft. The total organic carbon (TOC) content of the shale ranges from 2% to 3%. In the prospective area, the thermal maturity of the shale is low (R_o of 0.5% to 0.6%). However, the presence of biogenic gas appears to have provided adequate volumes of gas generation. The rock mineralogy appears to be low to moderate in clay (31%) and thus favorable for hydraulic fracturing.

5.3 Resource Assessment

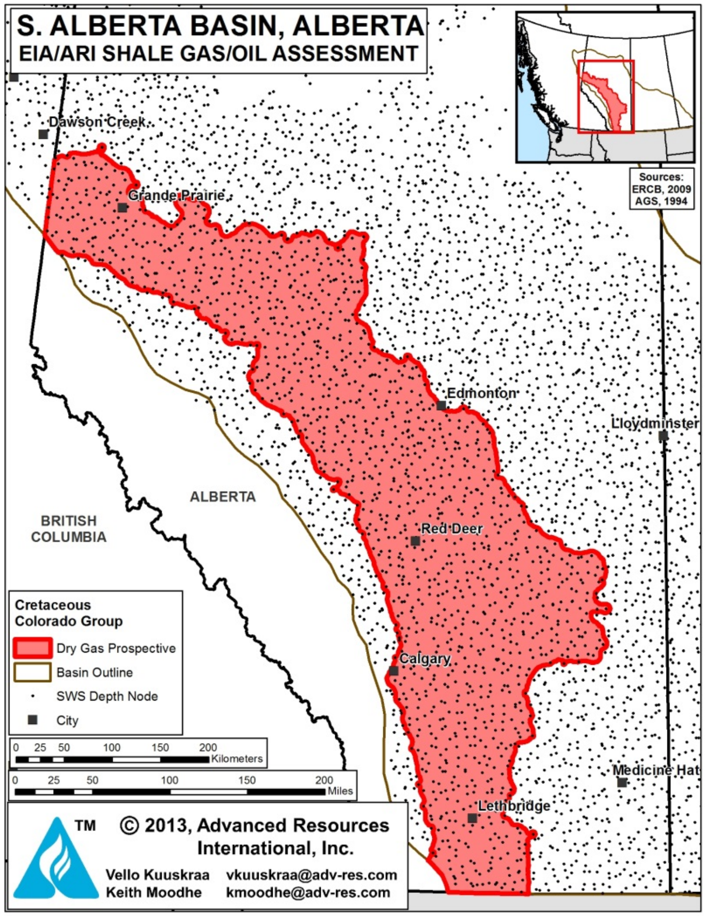
The 48,750-mi^2 prospective area of the Colorado Group Shale covers much of southwestern Alberta. Within this prospective area, the shale has a relatively low gas concentration of 21 Bcf/mi^2. The risked shale gas in-place for the Colorado Group Shale is estimated at 286 Tcf. Based on moderately favorable shale mineralogy, but other less favorable reservoir properties such as low pressure and an uncertain gas charge, we estimate a risked technically recoverable shale gas resource of 43 Tcf for the Colorado Group Shale.

Figure I-28. Colorado Group Stratigraphic Column



Source: Leckie, D.A., 1994.

Figure I-29. Colorado Group, Prospective Area



Source: ARI, 2013.

5.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society for Unconventional Gas estimated 100 Tcf of gas in-place and 4 to 14 Tcf of marketable (recoverable) shale gas for the Colorado Shale.[4]

5.5 Recent Activity

To date, the Colorado Group Shale has seen only limited exploration and development, primarily in the shallower eastern portion of the play area.

6. MONTNEY AND DOIG RESOURCE PLAYS (ALBERTA)

The Deep Basin of Canada also contains the Alberta portion of the Montney and Doig Resource plays. These multi-depositional Triassic-age hydrocarbon accumulations contain massive volumes of dry, wet and associated gas as well as oil/condensate.

We have excluded the Alberta portion of the Montney and Doig Resource Plays from our assessment because the reservoirs in the Alberta portion of the basin are generally classified as tight and conventional sands and because the organic-content (TOC) of the Montney and Doig Resource plays is low, averaging about 0.8%. Essentially all of the 170 samples taken from 43 Montney Formation wells have TOC values less than 1.5%, Figure I-30.[19] The basin average cut-off values for TOC in our study (for consistency with the USGS evaluations of shale oil and gas resources) is 2%, with individual reservoir rock intervals having to have at least 1.5% for inclusion in net, organic-rich pay.

Figure I-30. Histogram of Total Organic Carbon (TOC) of 170 Samples from the Montney Formation.

Source: ERCB/AGS Open File Report 2012-06, October 2012.

SASKATCHEWAN/MANITOBA

1. WILLISTON BASIN/BAKKEN SHALE

1.1 Geologic Setting

The Williston Basin of Canada extends northward from the U.S./Canada border into southern Saskatchewan and southwestern Manitoba and contains the Canadian portion of the Bakken Shale play, Figure I-31.[26] We estimate this basin contains 22 billion barrels of risked shale oil in-place, with 1.6 billion barrels as the risked, technically recoverable shale oil resource. The basin also contains 16 Tcf of associated shale gas in-place, with 2 Tcf as the risked, technically recoverable shale gas resource, Table I-5.

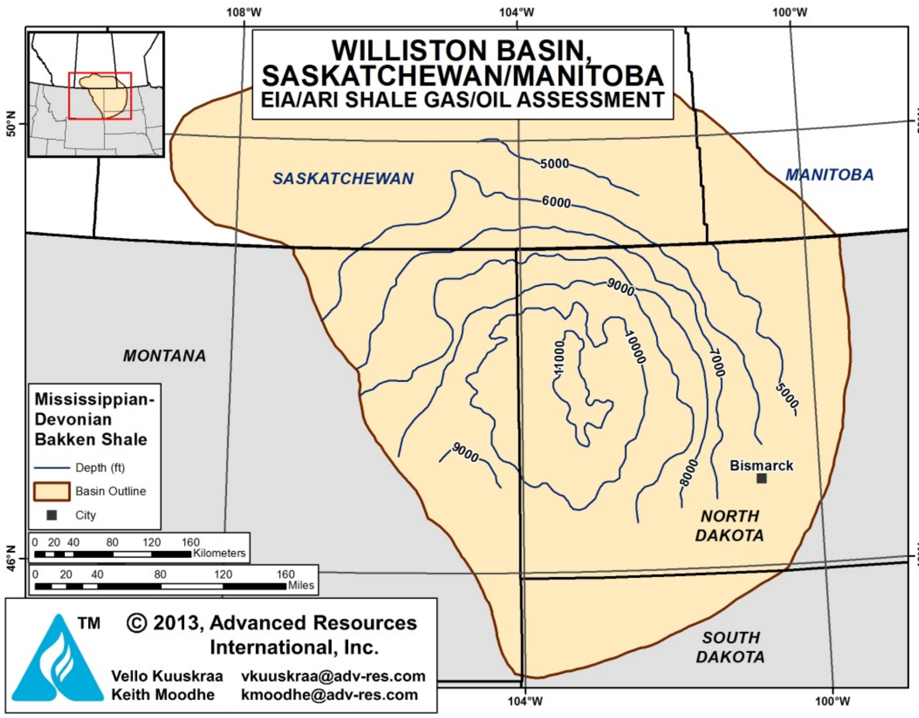
Table I-5. Shale Gas and Oil Reservoir Properties and Resources of Saskatchewan/Manitoba

Basic Data	Basin/Gross Area		Williston (110,000 mi^2)
	Shale Formation		Bakken
	Geologic Age		Devonian-Mississippian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		8,700
	Thickness (ft)	Organically Rich	50
		Net	20
	Depth (ft)	Interval	5,500 - 8,000
		Average	6,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.
	Average TOC (wt. %)		11.0%
	Thermal Maturity (% Ro)		0.64%
	Clay Content		Low/Medium
Resource	Gas Phase		Assoc. Gas
	GIP Concentration (Bcf/mi^2)		3.1
	Risked GIP (Tcf)		16.0
	Risked Recoverable (Tcf)		2.2

Basic Data	Basin/Gross Area		Williston (110,000 mi^2)
	Shale Formation		Bakken
	Geologic Age		Devonian-Mississippian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		8,700
	Thickness (ft)	Organically Rich	50
		Net	20
	Depth (ft)	Interval	5,500 - 8,000
		Average	6,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.
	Average TOC (wt. %)		11.0%
	Thermal Maturity (% Ro)		0.64%
	Clay Content		Low/Medium
Resource	Oil Phase		Oil
	OIP Concentration (MMbbl/mi^2)		4.3
	Risked OIP (B bbl)		22.5
	Risked Recoverable (B bbl)		1.57

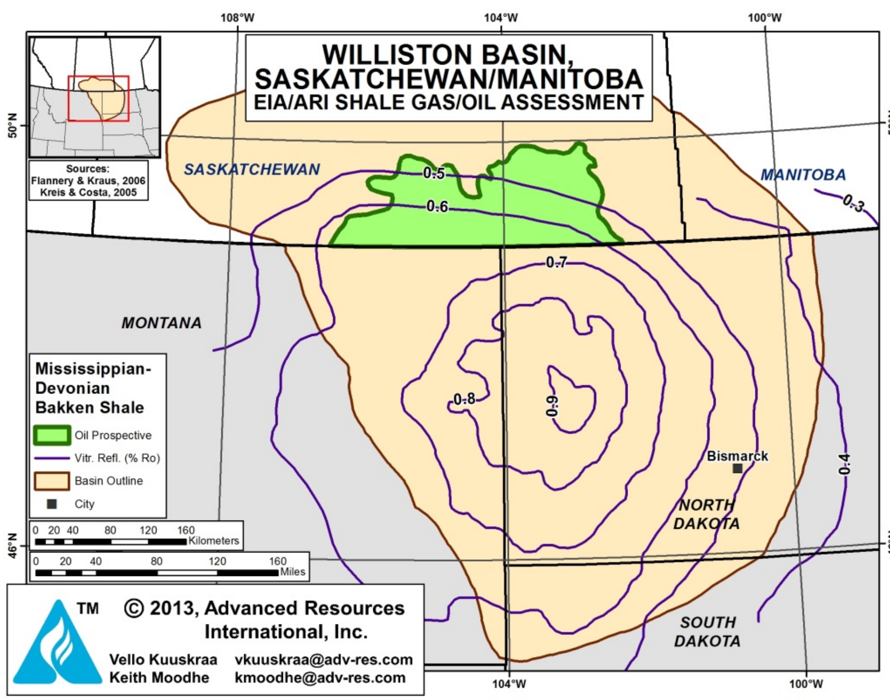
Within the larger Bakken Shale depositional area, we have defined a prospective area of 8,700 mi^2 where the shale appears to have more favorable reservoir properties and where past Bakken Shale drilling has occurred. The prospective area for the Bakken Shale in Saskatchewan and Manitoba is bounded on the north, east and west by the 30-foot shale interval contour and on the south by the U.S./Canada border, Figure I-32.[27]

Figure I-31. Outline and Depth of Williston Basin Bakken Shale (Saskatchewan/Manitoba)



Source: Modified from Saskatchewan Ministry of Energy Resources, 2010.

Figure I-32. Prospective Area for Williston Basin Bakken Shale (Saskatchewan/Manitoba)



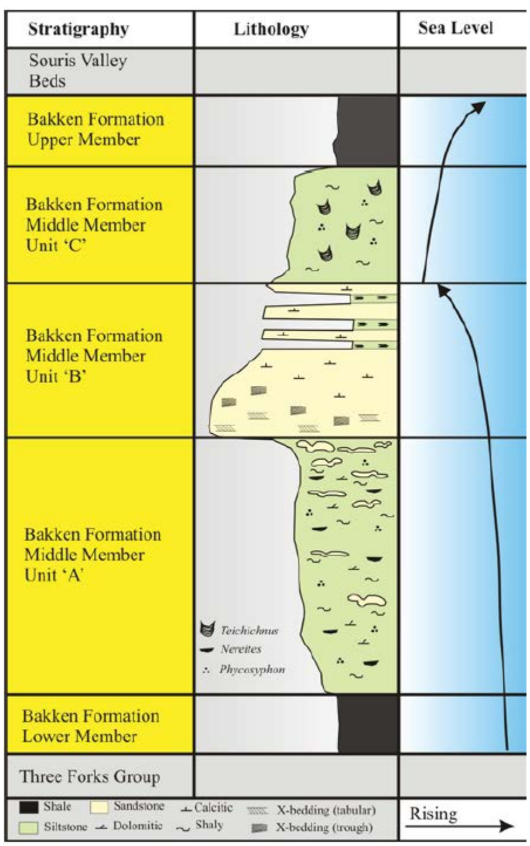
Source: AAPG Flannery & Kraus, 2006.

For this shale play, we have expanded our criteria for establishing the prospective area for oil to below our general cut-off of 0.7% thermal maturity (Ro) for two reasons. First, much of the oil in-place in this part of the Bakken Shale play is oil that has migrated from the deeper, more mature Bakken Shale in the center of the Williston Basin to the south.[28] Second, a considerable portion of the successful Bakken Shale well drilling in Canada has been in this thermally less mature area of the northern Williston Basin.

1.2 Reservoir Properties (Prospective Area).

Similar to the basal Banff/Exshaw Shale, the Late Devonian to Early Mississippian Bakken Shale consists of three reservoir units. The upper and lower units are dominated by organic-rich shale. The middle unit contains a variety of lithologies including calcareous sandstone and siltstone, dolomitic siltstone and limestone, Figure I-33.[26] The primary reservoir is the more porous and permeable middle unit, sourced by the upper and lower organic-rich shales. The Bakken Shale is over-pressured in much of its prospective area.

Figure I-33. Bakken Shale Stratigraphy (Saskatchewan)



Source: Saskatchewan Ministry of Energy Resources, 2010.

The drilling depth to the top of the Bakken Shale in the prospective area ranges from 5,500 feet on the north to about 8,800 feet on the south, averaging 6,600 feet in the prospective area. The Bakken Shale gross interval ranges from 30 to over 60 feet in the prospective area with an average net pay of about 20 feet, with favorable porosity of about 10%. The total organic content (TOC) in the prospective area averages 11% in the organic-rich upper and lower units. The Bakken Shale is prospective for oil plus associated gas.

1.3 Resource Assessment

Within the 8,700-mi^2 prospective area for oil and associated gas, the Bakken Shale has a resource concentration of 4 million barrels/mi^2 for oil plus moderate volumes of associated gas.

The risked oil resource in-place for the prospective area is estimated at 22 billion barrels plus 16 Tcf of associated natural gas. Based on recent well performance and reservoir properties, we estimate risked, technically recoverable resources of 1.6 billion barrels of oil and 2 Tcf of associated gas.

1.4 Recent Activity

The Bakken Shale in Canada is an active shale oil play with over 2,000 producing wells and about 75,000 barrels per day of oil production, as of mid-2011. The various companies active in the play have publically reported 225 million barrels of proved and probable reserves.[29]

EASTERN CANADA

Canada has four potential shale gas plays - - the Utica and Lorraine shales in the St. Lawrence Lowlands of the Appalachian Fold Belt of Quebec, the Horton Bluff Shale in the Windsor Basin of northern Nova Scotia, and the Frederick Brook Shale in the Moncton Sub-Basin of the Maritimes Basin in New Brunswick. These shale oil and gas formations and basins are in an early exploration stage. Therefore, only preliminary shale resource assessments are offered for the Utica and Horton Bluff shales. Insufficient information exists for assessing the Lorraine and Frederick Brook shales.

The two assessed Eastern Canada shale gas basins assessed by this study contain 172 Tcf of risked gas in-place, with 34 Tcf as the risked, technically recoverable shale gas resource, Table I-6.

Table I-6. Shale Gas Reservoir Properties and Resources of Eastern Canada

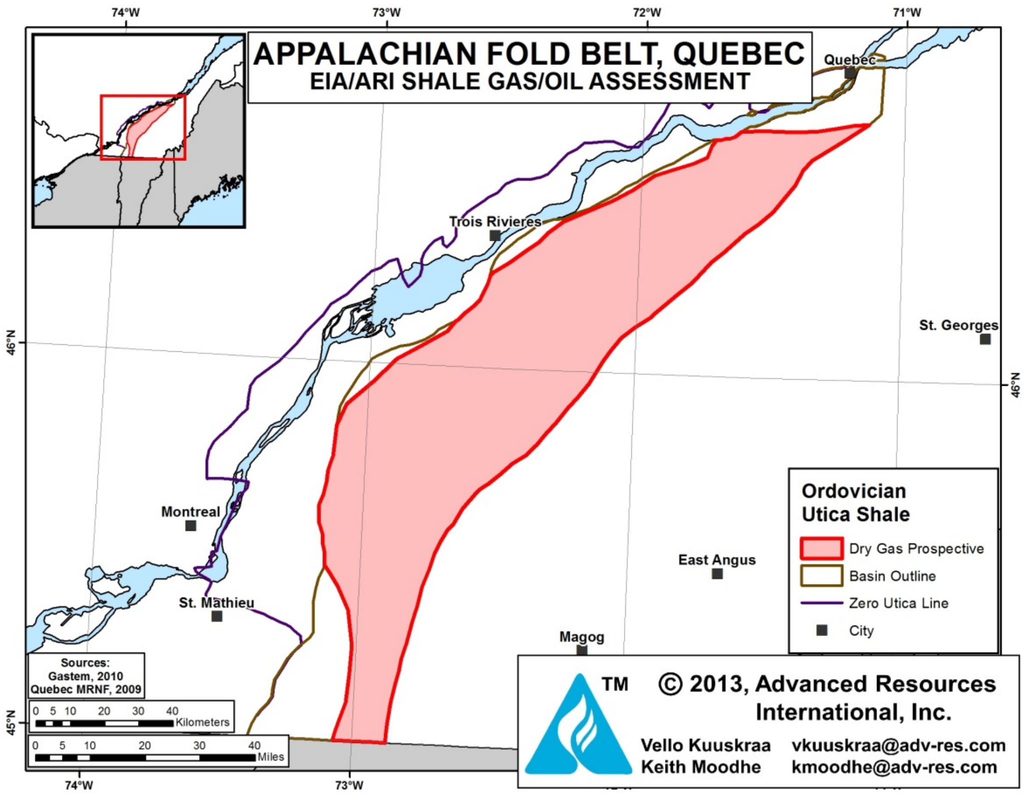
			Appalachian Fold Belt	Windsor
Basic Data	Basin/Gross Area		Appalachian Fold Belt ($3,500\ mi^2$)	Windsor ($650\ mi^2$)
Basic Data	Shale Formation		Utica	Horton Bluff
Basic Data	Geologic Age		Ordovician	Mississippian
Basic Data	Depositional Environment		Marine	Marine
Physical Extent	Prospective Area (mi^2)		2,900	520
Physical Extent	Thickness (ft)	Organically Rich	1,000	500
Physical Extent	Thickness (ft)	Net	400	300
Physical Extent	Depth (ft)	Interval	4,000 - 11,000	3,000 - 5,000
Physical Extent	Depth (ft)	Average	8,000	4,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Normal
Reservoir Properties	Average TOC (wt. %)		2.0%	5.0%
Reservoir Properties	Thermal Maturity (% Ro)		2.00%	2.00%
Reservoir Properties	Clay Content		Low	Unknown
Resource	Gas Phase		Dry Gas	Dry Gas
Resource	GIP Concentration (Bcf/mi^2)		133.9	81.7
Resource	Risked GIP (Tcf)		155.3	17.0
Resource	Risked Recoverable (Tcf)		31.1	3.4

1. APPALACHIAN FOLD BELT (QUEBEC)/UTICA SHALE

1.1 Introduction and Geologic Setting

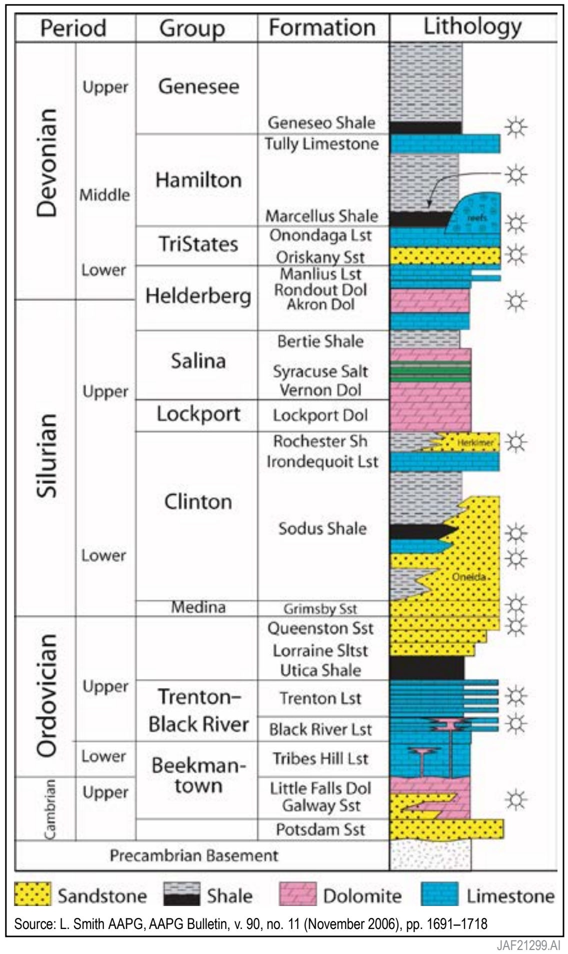
The Utica Shale is located within the St. Lawrence Lowlands of the Appalachian Fold Belt in Quebec, Canada, Figure I-34. The Utica is an Upper Ordovician-age shale, located above the conventional Trenton-Black River Formation, Figure I-35. A second, less defined, thicker but lower TOC Lorraine Shale overlies the Utica. Three major faults - - Yamaska, Tracy Brook and Logan's Line - - form structural boundaries and partitions for the Utica Shale play in Quebec.

Figure I-34. Utica Shale Outline and Prospective Area (Quebec)



Source: ARI, 2013.

Figure I-35. Utica Shale Stratigraphy (Quebec)



Source: L. Smith AAPG, AAPG Bulletin, v. 90, no. 11 (November 2006), pp. 1691–1718

1.2 Reservoir Properties (Prospective Area)

The extensive faulting and thrusting in the Utica Shale introduces considerable exploration and completion risk. The depth to the top of the shale in the prospective area ranges from 3,000 to over 11,000 feet, shallower along the southwestern and northwestern boundaries and deeper along the eastern boundary. The Utica Shale has a gross interval of 1,000 feet. With a net to gross ratio of 40%, the net organic-rich shale is estimated at 400 feet. The total organic content (TOC) ranges from 1.5% to 3%, with the higher TOC values concentrated in the Upper Utica Shale. The thermal maturity of the prospective area ranges from an R_o of 1.1% to 4% and averages 2%, placing the shale primarily in the dry gas window. Data on quartz and clay contents are not publicly available.

1.3 Resource Assessment

The prospective area of the Utica Shale in Quebec is estimated at 2,900 mi^2. Within this prospective area, the shale has a gas in-place concentration of 134 Bcf/mi^2. As such, the risked shale gas in-place is 155 Tcf. Assuming low clay content, but considerable geologic complexity within the prospective area, we estimate a risked, technically recoverable shale gas resource of 31 Tcf for the Utica Shale.

1.4 Comparison with Other Resource Assessments

In mid-2010, the Canadian Society for Unconventional Gas (CSUG) cites a gas in-place of 181 Tcf (unrisked) for the Utica Shale in Canada with 7 to 12 Tcf of marketable (recoverable) shale gas resources.[30]

1.5 Exploration Activity

Two large operators, Talisman and Forest Oil, plus numerous smaller companies such as Questerre, Junex, Gastem and Molopo, hold leases in the Utica Shales of Quebec. Approximately 25 exploration wells have been drilled with moderate results. Market access is provided by the Maritimes and Northeastern pipeline as well as the TransCanada Pipeline to markets in Quebec City and Montreal. Currently shale gas drilling in Quebec is on hold, awaiting further environmental studies.

2. WINDSOR BASIN (NOVA SCOTIA)/HORTON BLUFF SHALE

2.1 Introduction and Geologic Setting

The Horton Bluff Shale is located in north-central Nova Scotia. It is a Carboniferous (Early Mississippian) shale within the Horton Group, Figure I-36. Because the Horton Bluff Shale rests directly on the pre-Carboniferous igneous and metamorphic basement, it has experienced high heat flow and has a high thermal maturity in northern Nova Scotia. The Horton Bluff Shale geology is complex, containing numerous faults.

2.2 Reservoir Properties (Prospective Area)

The regional extent of the Horton Shale play is only partly defined as the basin and prospective area boundaries are highly uncertain. A preliminary outline and 520-mi^2 prospective area has been estimated for the Horton Bluff Shale play, Figure I-37. The depth of the shale in the prospective area ranges from 3,000 to 5,000 feet. The shale interval is thick with 500 feet of gross pay and 300 feet of organically rich net pay. The TOC is 4% to 5% (locally higher). The thermal maturity of the prospective area ranges from a R_o of 1.2% in the south to a R_o of over 2.5% in the northeastern portion of the prospective area, placing the Horton Bluff Shale primarily in the dry gas window. Data from the Kennetcook #1, drilled to test the Horton Bluff Shale in the Windsor Basin, provided valuable data on reservoir properties.

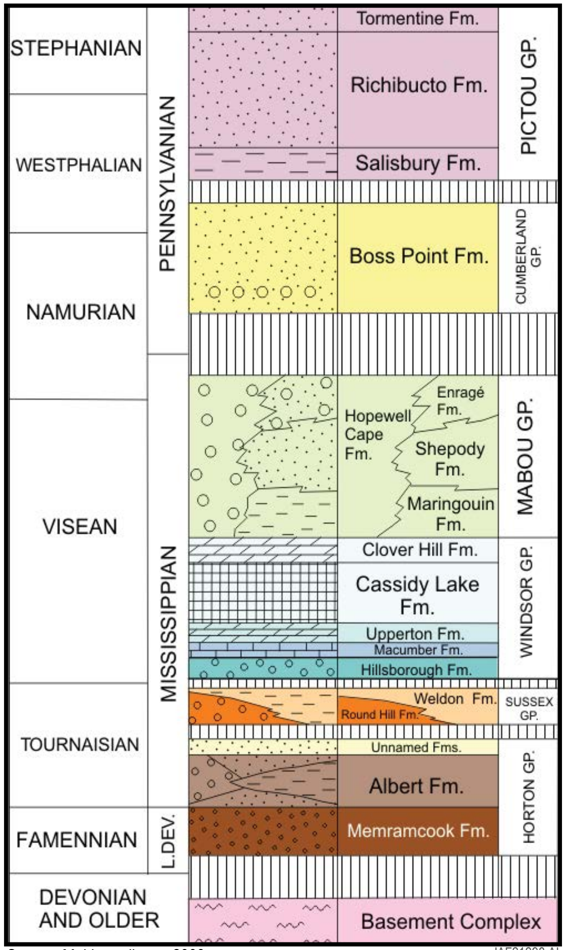
2.3 Resource Assessment

The 520-mi^2 prospective area of the Horton Bluff Shale in Nova Scotia is in the northern and eastern portions of the play area. Within this prospective area, the shale has an in-place resource concentration of 82 Bcf/mi^2. Our preliminary resource estimate is 17 Tcf of risked shale gas in-place. Given the geologic complexity in the prospective area, we estimate a risked, technically recoverable shale gas resource of 3 Tcf for the Horton Bluff Shale.

2.4 Recent Activity.

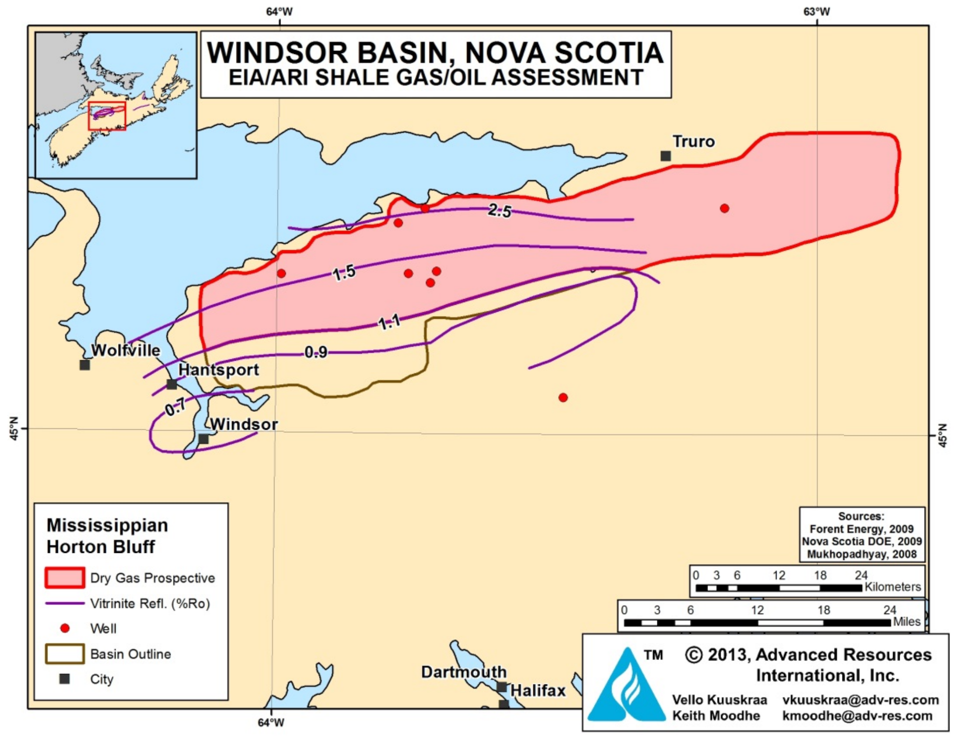
Two small operators, Triangle Petroleum and Forent Energy, have acquired leases and have begun to explore the Horton Bluff Shale.

Figure I-36. Horton and Frederick Brook Shale (Horton Group) Stratigraphy



Source: Mukhopadhyay, 2009 JAF21298.AI

Figure I-37. Outline and Prospective Area for Horton Bluff Shale (Nova Scotia)

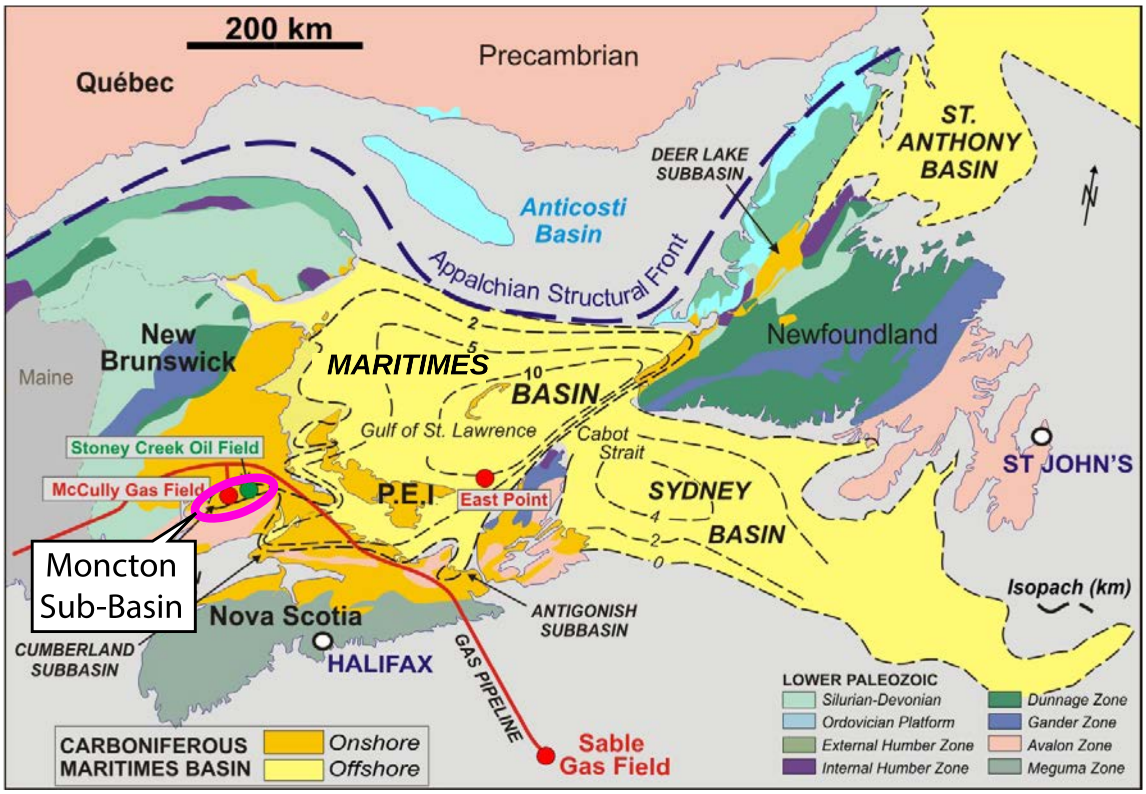


Source: ARI, 2013.

3. MONCTON SUB-BASIN (NEW BRUNSWICK)/FREDERICK BROOK SHALE

The Frederick Brook Shale is located in the Moncton Sub-Basin of the larger Maritimes Basin of New Brunswick, Figure I-38. This Mississippian-age shale is correlative with the Horton Group in Nova Scotia. The Moncton Sub-Basin is bounded on the east by the Caledonia Uplift, on the west by the Kingston Uplift, and on the north by the Westmoreland Uplift, Figure I-39. Because of limited data, the definition of the prospective area of the Frederick Brook Shale has yet to be established.

Figure I-38. Location of Moncton Sub-Basin and Maritimes Basin

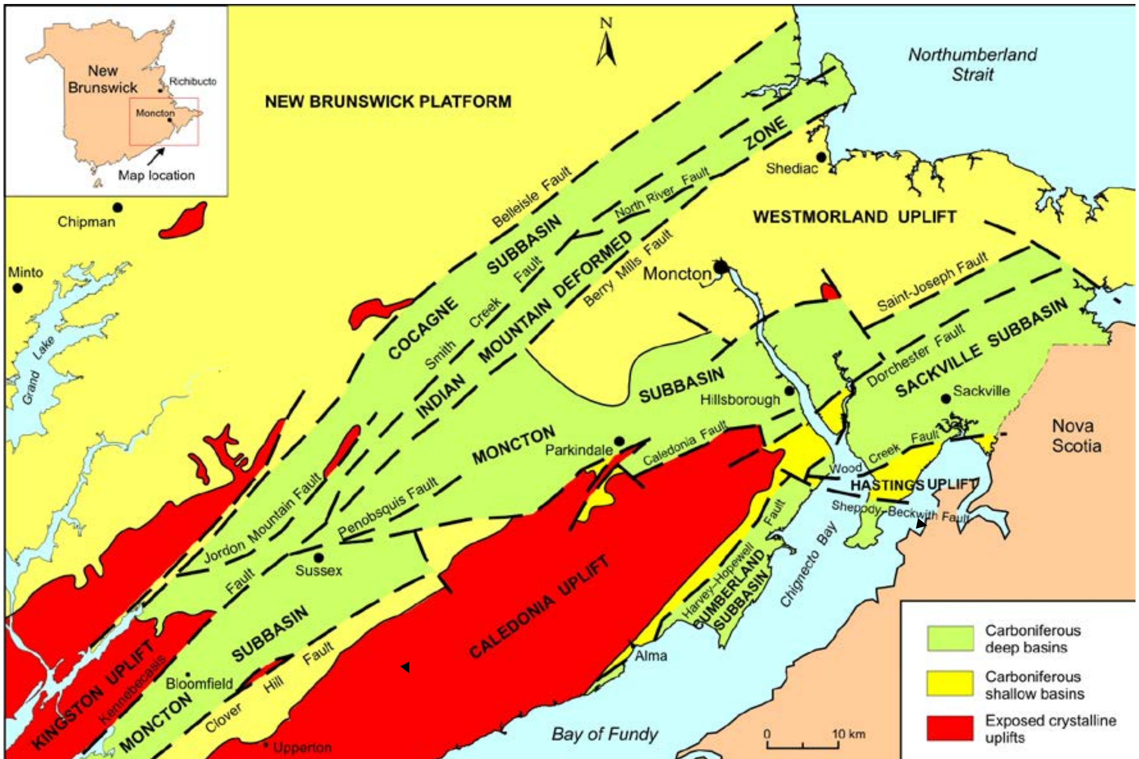


Source: Geological Survey of Canada, 2009 CSPG CSEG CWLS Convention, Canada JAF21297.AI

The Frederick Brook Shale in the Moncton Sub-Basin is structurally complex, with extensive faulting and deformation. Its depth ranges from about 3,000 feet along the basin's eastern edges to 15,000 feet in the north. The total organic content of the shale varies widely (1% to 10%), but typically ranges from 3% to 5%. No public data are available on the mineralogy of the shale. The thermal maturity ranges from immature R_o < 1% in the shallower portions of the basin to highly mature (R_o > 2%) in the deeper western and southern areas of the basin.

Much of the data for this preliminary assessment of the Frederick Brook Shale is from the McCully gas field along the southwestern edge of the Moncton Sub-Basin and from a handful of vertical exploration wells. Other areas, such as the Cocagne Sub-Basin, Figure I-39, may also be prospective for the Frederick Brook Shale but have yet to be explored or assessed.

Figure I-39. Structural Controls for Moncton Sub-Basin (New Brunswick) Canada



Source: P.K. Mukhopadhyay, Search and Discovery Article #10167 (2008)

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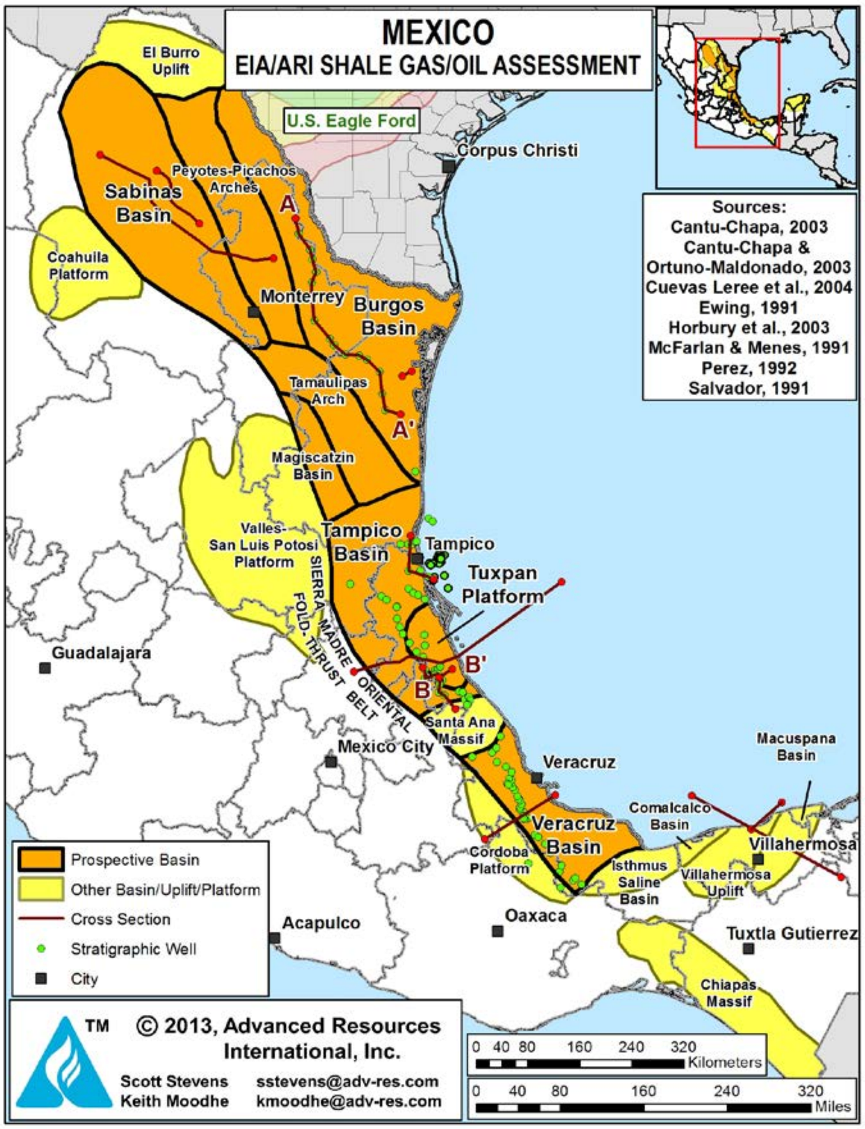
II. MEXICO

SUMMARY

Mexico has excellent potential for developing its shale gas and oil resources stored in marine-deposited, source-rock shales distributed along the onshore Gulf of Mexico region.

Figure II-1. Onshore Shale Gas and Shale Oil Basins of Eastern Mexico's Gulf of Mexico Basins.



Source: ARI, 2013.

Technically recoverable shale resources, estimated at 545 Tcf of natural gas and 13.1 billion barrels of oil and condensate, are potentially larger than the country's proven conventional reserves, Table II-1. The best documented play is the Eagle Ford Shale of the Burgos Basin, where oil- and gas-prone windows extending south from Texas into northern Mexico have an estimated 343 Tcf and 6.3 billion barrels of risked, technically recoverable shale gas and shale oil resource potential, Table II-2.

Further to the south and east within Mexico, the shale geology of the onshore Gulf of Mexico Basin becomes structurally more complex and the shale development potential is less certain. The Sabinas Basin has an estimated 124 Tcf of risked, technically recoverable shale gas resources within the Eagle Ford and La Casita shales, but the basin is faulted and folded. The structurally more favorable Tampico, Tuxpan, and Veracruz basins add another 28 Tcf and 6.8 billion barrels of risked, technically recoverable shale gas and shale oil potential from Cretaceous and Jurassic marine shales. These shales are prolific source rocks for Mexico's conventional onshore and offshore fields in this area. Shale drilling has not yet occurred in these southern basins.

PEMEX envisions commercial shale gas production being initiated in 2015 and increasing to around 2 Bcfd by 2025, with the company potentially investing $1 billion to drill 750 wells. However, PEMEX's initial shale exploration wells have been costly ($20 to $25 million per well) and have provided only modest initial gas flow rates (~3 million ft^3/d per well with steep decline). Mexico's potential development of its shale gas and shale oil resources could be constrained by several factors, including potential limits on upstream investment, the nascent capabilities of the local shale service sector, and public security concerns in many shale areas.

Table II-1. Shale Gas Reservoir Properties and Resources of Mexico

Basic Data	Basin/Gross Area		Burgos (24,200 mi^2)				Sabinas (35,700 mi^2)	
	Shale Formation		Eagle Ford Shale			Tithonian Shales	Eagle Ford Shale	Tithonian La Casita
	Geologic Age		M. - U. Cretaceous			U. Jurassic	M. - U. Cretaceous	U. Jurassic
	Depositional Environment		Marine			Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		600	10,000	6,700	6,700	9,500	9,500
	Thickness (ft)	Organically Rich	200	200	300	500	500	800
		Net	160	160	210	200	400	240
	Depth (ft)	Interval	3,300 - 4,000	4,000 - 16,400	6,500 - 16,400	7,500 - 16,400	5,000 - 12,500	9,800 - 13,100
		Average	3,500	7,500	10,500	11,500	9,000	11,500
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.	Underpress.	Underpress.
	Average TOC (wt. %)		5.0%	5.0%	5.0%	3.0%	4.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.60%	1.70%	1.50%	2.50%
	Clay Content		Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		21.7	74.4	190.9	100.3	131.9	69.1
	Risked GIP (Tcf)		7.8	446.4	767.5	201.6	501.0	118.1
	Risked Recoverable (Tcf)		0.9	111.6	230.2	50.4	100.2	23.6

Basic Data	Basin/Gross Area		Tampico (26,900 mi^2)			Tuxpan (2,810 mi^2)		Veracruz (9,030 mi^2)	
	Shale Formation		Pimienta			Tamaulipas	Pimienta	Maltrata	
	Geologic Age		Jurassic			L. - M. Cretaceous	Jurassic	U. Cretaceous	
	Depositional Environment		Marine			Marine	Marine	Marine	
Physical Extent	Prospective Area (mi^2)		9,000	3,050	1,550	1,000	1,000	560	400
	Thickness (ft)	Organically Rich	500	500	500	300	500	300	300
		Net	200	200	200	210	200	150	150
	Depth (ft)	Interval	3,300 - 8,500	4,000 - 8,500	7,000 - 9,000	6,000 - 9,500	6,600 - 10,000	9,800 - 12,000	10,000 - 12,500
		Average	5,500	6,200	8,000	7,900	8,500	11,000	11,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.40%	0.85%	0.90%	0.85%	1.40%
	Clay Content		Low	Low	Low	Low	Low	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Assoc. Gas	Assoc. Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		18.6	44.7	83.0	25.5	27.2	22.4	70.0
	Risked GIP (Tcf)		58.5	47.7	45.0	8.9	9.5	6.6	14.7
	Risked Recoverable (Tcf)		4.7	9.5	9.0	0.7	0.8	0.5	2.9

Table II-2. Shale Oil Reservoir Properties and Resources of Mexico

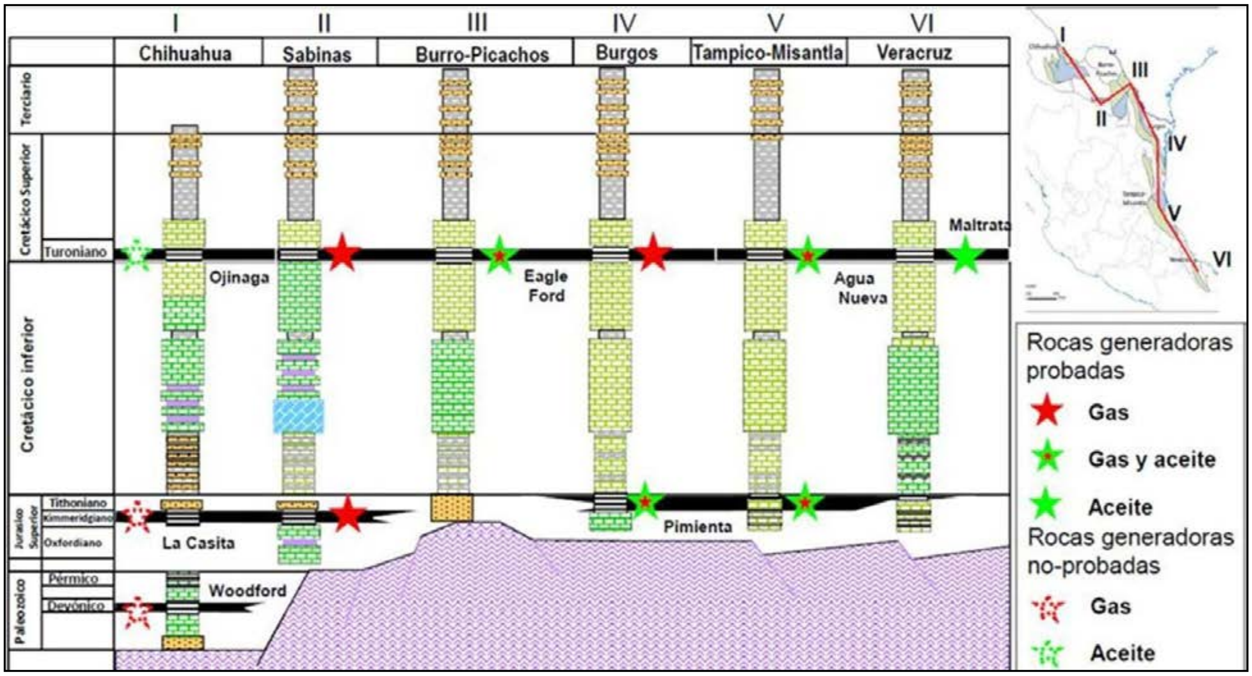
Basic Data	Basin/Gross Area		Burgos ($24,200\ mi^2$)		Tampico ($26,900\ mi^2$)		Tuxpan ($2,810\ mi^2$)		Veracruz ($9,030\ mi^2$)
	Shale Formation		Eagle Ford Shale		Pimienta		Tamaulipas	Pimienta	Maltrata
	Geologic Age		M. - U. Cretaceous		Jurassic		L. - M. Cretaceous	Jurassic	U. Cretaceous
	Depositional Environment		Marine		Marine		Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		600	10,000	9,000	3,050	1,000	1,000	560
	Thickness (ft)	Organically Rich	200	200	500	500	300	500	300
		Net	160	160	200	200	210	200	150
	Depth (ft)	Interval	3,300 - 4,000	4,000 - 16,400	3,300 - 8,500	4,000 - 8,500	6,000 - 9,500	6,600 - 10,000	9,800 - 12,000
		Average	3,500	7,500	5,500	6,200	7,900	8,500	11,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		5.0%	5.0%	3.0%	3.0%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	0.85%	0.90%	0.85%
	Clay Content		Low	Low	Low	Low	Low	Low	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Oil	Oil	Oil
	OIP Concentration ($MMbbl/mi^2$)		43.9	15.0	37.9	17.3	36.4	33.0	23.5
	Risked OIP (B bbl)		15.8	89.8	119.4	18.5	12.7	11.5	6.9
	Risked Recoverable (B bbl)		0.95	5.39	4.78	0.74	0.51	0.46	0.28

INTRODUCTION

Mexico has large, geologically prospective shale gas and shale oil resources in the northeastern part of the country within the onshore portion of the greater Gulf of Mexico Basin, Figure II-1. These thick, organic-rich shales of marine origin correlate with productive Jurassic and Cretaceous shale deposits in the southern United States, notably the Eagle Ford and Haynesville shales, Figure II-2.[1] To date, Mexico's national oil company PEMEX has drilled at least six shale gas/oil exploration wells with modest results. The company plans to accelerate shale activity during the next few years, budgeting 6.8 billion pesos (575 million USD) in 2014.

Whereas Mexico's marine-deposited shales appear to have good rock quality, the geologic structure of its sedimentary basins often is considerably more complex than in the USA. Compared with the broad and gently dipping shale belts of Texas and Louisiana, Mexico's coastal shale zone is narrower, less continuous and structurally more disrupted. Regional compression and thrust faulting related to the formation of the Sierra Madre Ranges have squeezed Mexico's coastal plain, creating a series of discontinuous sub-basins.[2] Many of Mexico's largest conventional oil and gas fields also occur in this area, producing from conventional sandstone reservoirs of Miocene and Pliocene age that were sourced by deep, organic-rich and thermally mature Jurassic and Cretaceous-age shales. These deep source rocks are the principal targets for shale gas/oil exploration in Mexico.

Figure II-2. Cross-Section of Shale Targets in Eastern Mexico.



Source: Escalera Alcocer, 2012.

Improved geologic data coverage collected since ARI's initial 2011 estimate indicates that Mexico's prospective areas for shale gas -- particularly in the structurally more complex basins – are slightly smaller than previously mapped. Furthermore, several of the previously mapped dry gas areas are now known to be within the wet gas to oil thermal maturity windows. On the other hand, geologic risk factors have been reduced due to the demonstration of the presence of productive hydrocarbons and improved geologic control. On an overall energy-equivalent basis, our updated estimate of Mexico's shale resources is about 10% lower than our earlier 2011 estimate (624 Tcfe in this study vs 681 Tcf previously).

PEMEX has identified some 200 shale gas resource opportunities in five geologic provinces in eastern Mexico, Figure II-3. According to the company, prospective regions include 1) Paleozoic shale gas in Chihuahua region; 2) Cretaceous shale gas in the Sabinas-Burro-Picachos region; 3) Cretaceous shale gas in the Burgos Basin; 4) Jurassic shale gas in Tampico-Misantla; and 5) unspecified shale gas potential in Veracruz.

Figure II-3. PEMEX Map Identifying Mexico's Shale Gas Potential (November 2012)

Source: PEMEX, 2012b.

PEMEX's initial internal evaluation estimated 150 Tcf (P90) to 459 Tcf (P10) of recoverable shale gas resources, with a median estimate of 297 Tcf. In 2012 PEMEX updated its shale gas and shale oil resource assessment to 141.5 Tcf of shale gas (comprising 104.7 Tcf dry and 36.8 Tcf wet) and 31.9 billion barrels of shale oil and condensate.

Initial shale gas and shale oil exploration began in Mexico in late 2011. PEMEX has drilled at least six wells in the Eagle Ford Shale play in northern Mexico to date, but the southern shale basins have not yet been tested. Despite some areas with favorable shale geology, Mexico faces significant obstacles to shale development. The country's upstream oil industry is largely closed to foreign investment. None of the shale-discovering independent E&P's, which unlocked the North American shale plays, are active in Mexico. And, well services for shale development are costlier than in the U.S. and Canada.

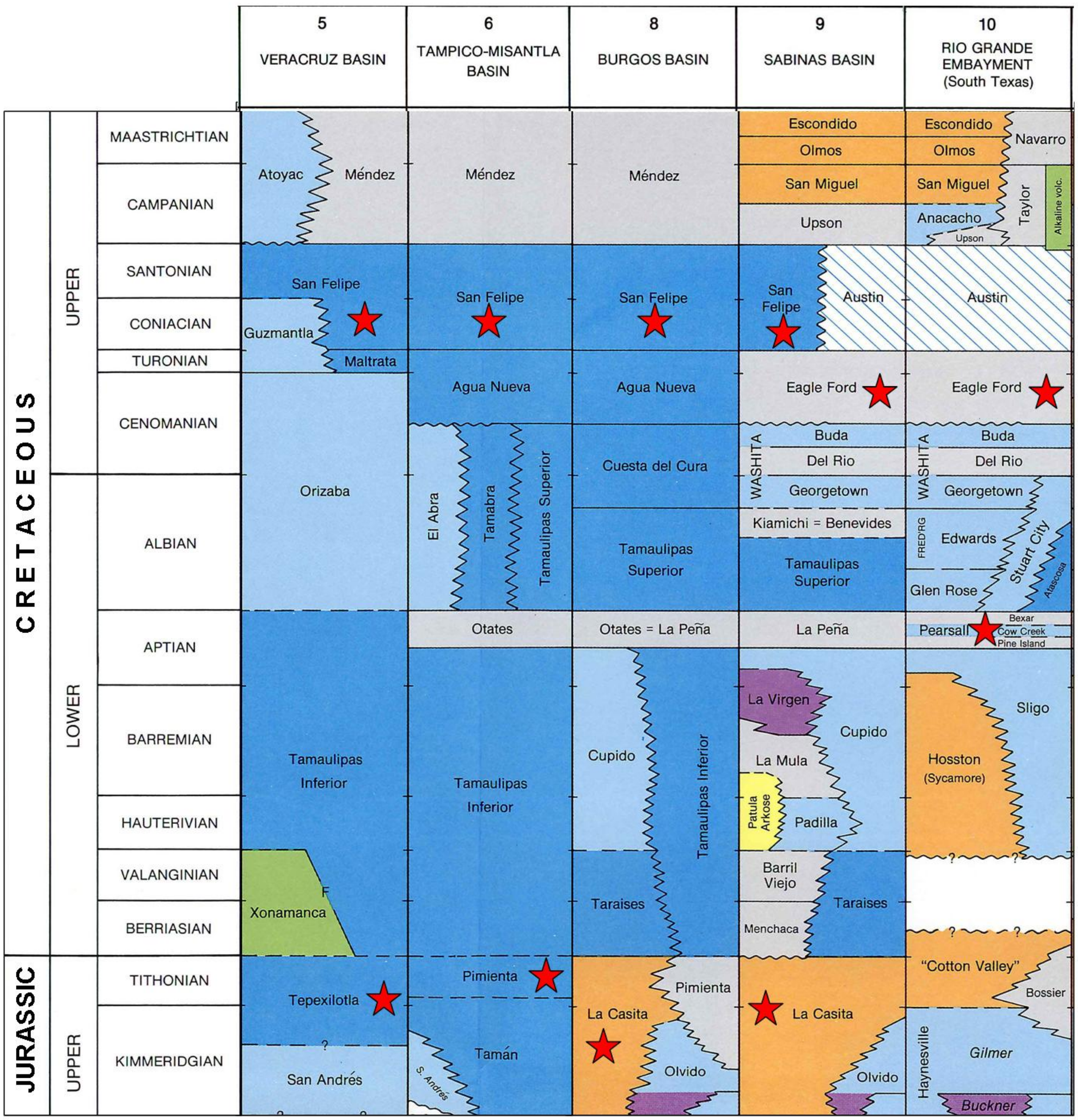
Onshore eastern Mexico contains a series of medium-sized basins and structural highs (platforms) within the larger western Gulf of Mexico Basin.[3] These structural features contain organic-rich marine shales of Jurassic and Cretaceous age that appear to be the most prospective for shale gas and oil development. The arcuate coastal shale belt includes the Burgos, Sabinas, Tampico, Tuxpan Platform, and Veracruz basins and uplifts. Because detailed geologic maps of these areas generally are not readily available, ARI constructed the general pattern of shale depth and thickness from a wide range of published local-scale maps and structural cross-sections.

Many of Mexico's shale basins are too deep in their center for shale gas and shale oil development (>5 km), while their western portions tend to be overthrusted and structurally complex. However, the less deformed eastern portions of these basins and adjacent shallower platforms are structurally more simple. Here, the most prospective areas for shale gas and shale oil development are buried at suitable depths of 1 km to 5 km over large areas.

Pyrolysis geochemistry, carbon isotope studies, and biomarker analysis of oil and gas fields identify three major Mesozoic hydrocarbon source rocks in Mexico's Gulf Coast Basin: the Upper Cretaceous (Turonian to Santorian), Lower-Mid Cretaceous (Albian-Cenomanian), and -- most importantly – Upper Jurassic (Tithonian), the latter having sourced an estimated 80% of the conventional oil and gas discovered in this region.[4] These targets, particularly the Tithonian, also appear to have the greatest potential for shale gas development, Figure II-4.

The following sections discuss the shale gas and shale oil geology of the individual sub-basins and platforms along eastern Mexico's onshore Gulf of Mexico Basin. The basins discussed start in northern Mexico near the Texas border moving to the south and southeastern regions close to the Yucatan Peninsula.

Figure II-4. Stratigraphy of Jurassic and Cretaceous rocks in the Gulf of Mexico Basin, Mexico and USA. Shale gas targets are highlighted.



Modified from Salvador and Quezada-Muneton, 1989.

1. BURGOS BASIN (Eagle Ford and Tithonian Shales)

1.1 Geologic Setting

Located in northeastern Mexico's Coahuila state, directly south of the Rio Grande River, the Burgos Basin covers an onshore area of approximately 24,200 mi^2, excluding its extension onto the continental shelf of the Gulf of Mexico, Figure II-5. The Burgos Basin is the southern extension of the Maverick Basin in Texas, the latter hosting the productive Eagle Ford and Pearsall shale plays.

The Burgos Basin expanded during the Early Jurassic and developed into a restricted carbonate platform, with thick salt accumulations that later formed a regional structural detachment as well as isolated diapirs. Structural deformation took place during the late Cretaceous Laramide Orogeny, resulting in some degree of faulting and tilting within the Burgos Basin. However, this tectonic event was focused more on the Sabinas Basin and Sierra Madre Oriental, while the Burgos remains structurally relatively simple and favorable for shale development.[5] Thick Tertiary-age clastic non-marine deposits overlie the Jurassic and Carbonate marine sequences, reflecting later alternating transgressions and regressions of sea level in northeastern Mexico.[6]

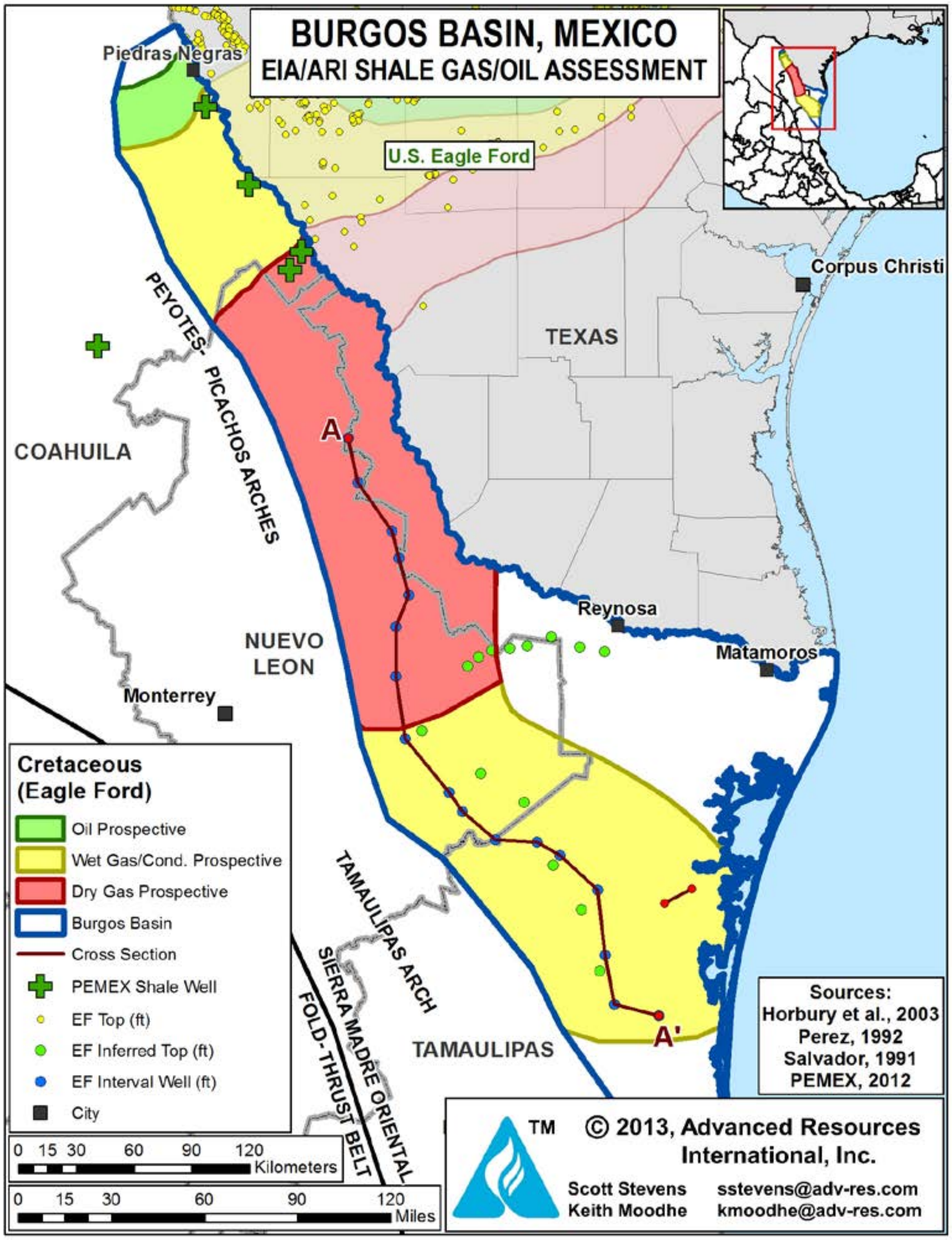
The two most prospective shale targets in Mexico are present in the Burgos Basin: the Cretaceous (mainly Turonian) Eagle Ford Shale play and the Jurassic (mainly Tithonian) La Casita and Pimienta formations, Figure II-6. The Eagle Ford Shale in Mexico is the direct extension of its commercially productive Texas equivalent, whereas the La Casita and Pimienta formations correlate with the productive Haynesville Shale of the East Texas Basin. The La Casita is believed to be the main source rock for conventional Tertiary clastic reservoirs (Oligocene Frio and Vicksburg) in the southeastern Burgos Basin, with oil transported via deep-seated normal faults.[7]

1.2 Reservoir Properties (Prospective Area)

Eagle Ford Shale. Based on analogy with the Eagle Ford Shale in Texas, industry and ARI considers the Eagle Ford Shale in the Burgos Basin to be Mexico's top-ranked shale prospect. The Eagle Ford Shale is continuous across the western margin of the Burgos Basin, where the overall formation interval ranges from 100 to 300 m thick (average 200 m).[8] Recognizing the sparse regional depth and thickness control on the Eagle Ford Shale in the

Burgos Basin,[9] we relied on a recent PEMEX shale map to estimate a prospective area of 17,300 mi^2, slightly less than our previous estimate of 18,100 mi^2, comprising three distinct areas where the shale lies within the 1 km to 5 km depth window, Figure II-5. The eastern onshore portion of the Burgos Basin is excluded as the shale is deeper than 5 km.

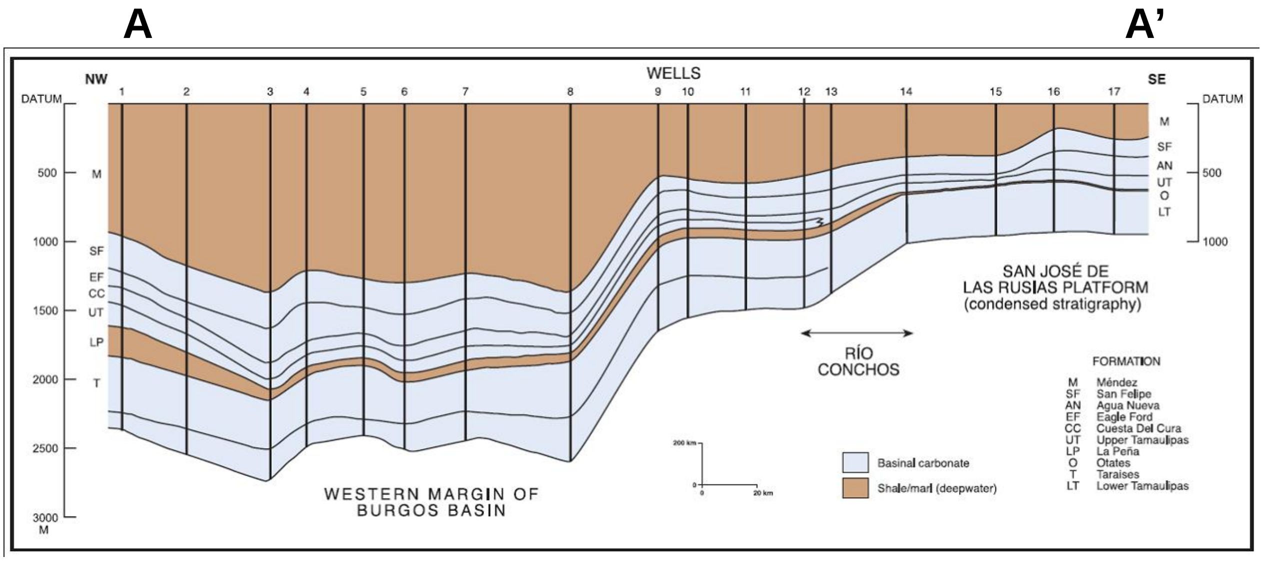
Figure II-5. Burgos Basin Outline and Shale Gas and Shale Oil Prospective Areas.



Source: ARI, 2013.

Figure II-6. Stratigraphic Cross-Section Along the Western Margin of the Burgos Basin.

Section is flattened on top Cretaceous.
The Eagle Ford Shale (EF) here ranges from about 100 to 300 m thick (average 200 m).



Modified from Horbury et al., 2003.

Net organically-rich shale thickness within the prospective area ranges from 200 to 300 ft. Total organic content (TOC) is estimated to average 5%. Vitrinite reflectance (R_o) ranges from 0.85% to 1.6% depending on depth. Over-pressured reservoir conditions are common in this basin and a pressure gradient of 0.65 psi/ft was assumed. The surface temperature in this region averages approximately 20°C, while the geothermal gradient typically is 23°C/km. Porosity is not known but assumed to be comparable to the Texas Eagle Ford Shale play at about 10%.

La Casita and Pimienta (Tithonian) Shales. Several thousand feet deeper than the Eagle Ford Shale, the La Casita and Pimienta shales (Upper Jurassic Tithonian) are considered the principal source rocks in the western Burgos Basin. Extrapolating from the structure of the younger Eagle Ford, the average depth of the Tithonian Shale is 11,500 ft, with a prospective range of 5,000 to 16,400 ft. Gross formation thicknesses can be up to 1,400 ft, with an organically rich net pay of about 200 ft. TOC of 2.6% to 4.0%, averaging 3.0%, consists mainly of Type II kerogen that appears to be entirely within the dry gas window (1.30% R_o) with little to no liquids potential.[10] Reservoir pressure and temperature conditions are similar to those in the Eagle Ford Shale play.

1.3 Resource Assessment

Eagle Ford Shale. Within its 17,300-mi^2 prospective area, the Eagle Ford Shale exhibits a high resource concentration of up to 191 Bcf/mi^2. Risked shale gas in-place (OGIP) totals 1,222 Tcf with risked shale oil in-place (OOIP) of 106 billion barrels. Risked, technically recoverable resources are estimated to be 343 Tcf of shale gas and 6.3 billion barrels of shale oil and condensate.

Tithonian Shale. Within the high-graded prospective area of 6,700 mi^2, the Tithonian La Casita and Pimienta shales are estimated to have approximately 50 Tcf of risked, technically recoverable dry gas resources from 202 Tcf of risked gas in-place. Resource concentration is about 100 Bcf/mi^2.

1.4 Recent Activity

PEMEX initiated conventional exploration in the Burgos Basin in 1942, discovering some 227 mostly natural gas fields in this basin to date. Currently, there are about 3,500 active natural gas wells producing in the Burgos Basin. These conventional reservoirs typically have low permeability with rapidly declining gas production. Due to restrictions on upstream oil and gas investment in Mexico, PEMEX is the only company that has conducted shale exploration activity in the Burgos Basin to date.

PEMEX made its first shale discovery in the Burgos Basin during late 2010 and early 2011, drilling the Emergente-1 shale gas well located a few kilometers south at the Texas/Coahuila border on a continuation of the Eagle Ford Shale trend from Texas. This initial horizontal well was drilled to a vertical depth of about 2,500 m and employed a 2,550-m lateral (although another source reported 1,364-m). Following a 17-stage fracture stimulation, the $20-25 million well tested at a modest initial rate of 2.8 million ft^3/day (time interval not reported), which would not be economic at current gas prices.[11]

As of its last report (November 2012), PEMEX had drilled four shale gas exploration wells in the Eagle Ford play of the Burgos Basin with one shale exploration well in the Sabinas basin, reporting initial production for three wells. These wells include the Nómada-1 well situated in the oil window, the Habano-1 well (IP 2.771 million ft^3/day gas with 27 bbl/day crude) and the Montañés-1 well in the wet gas window of the Burgos Basin. The dry gas window in the Burgos Basin was tested by the Emergente-1. The Percutor-1 (IP 2.17 million ft^3/day) tested the dry gas window in the Sabinas Basin. PEMEX has announced also drilled and produced gas from the Arbolero-1 well (3.2 million ft^3/day), the first test of the Jurassic shale in this basin.[12] PEMEX plans to drill up to 75 shale exploration wells in the Burgos Basin through 2015.

2. SABINAS BASIN (Eagle Ford and Tithonian Shales)

2.1 Geologic Setting

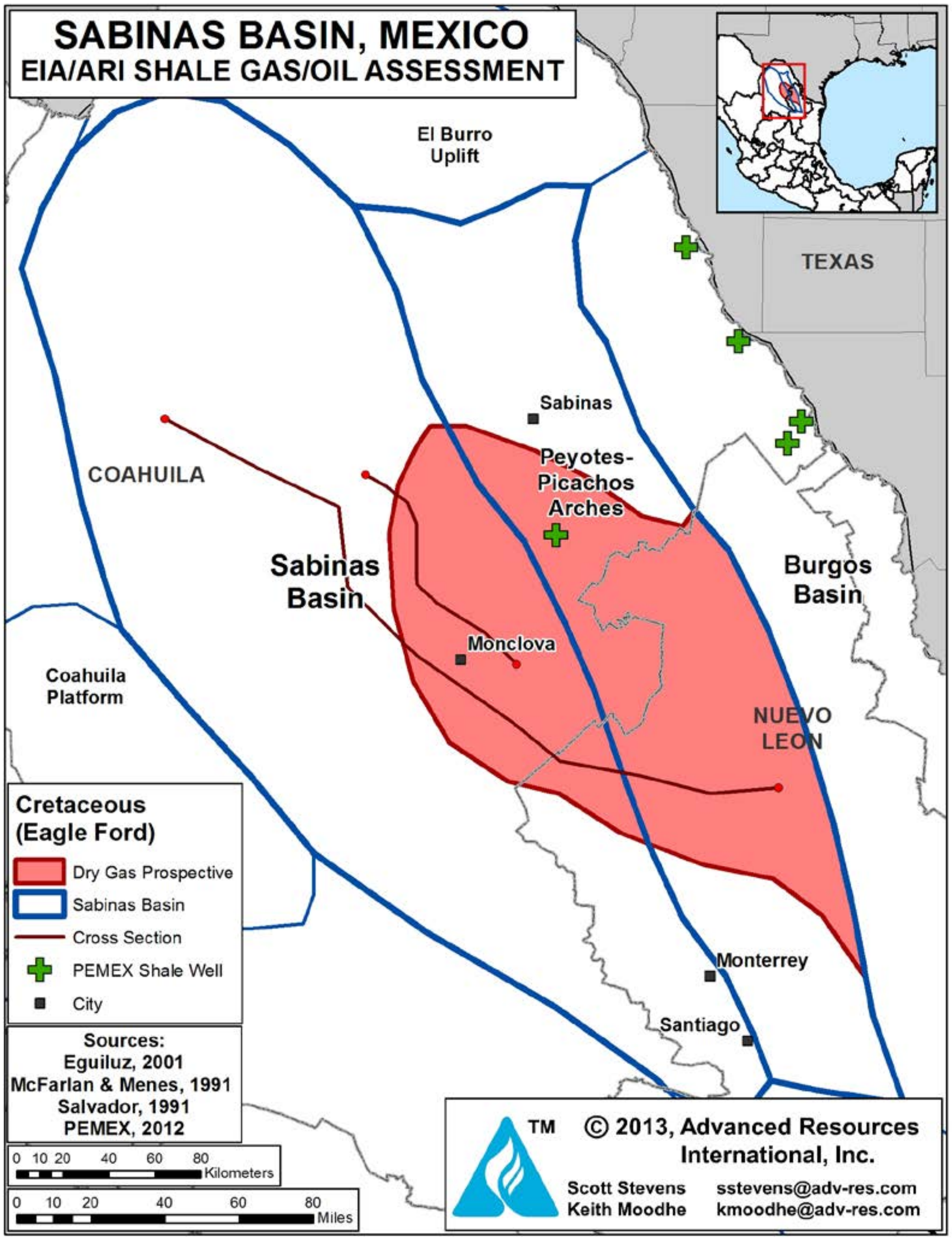
The Sabinas is one of Mexico's largest onshore marine shale basins, extending over a total area of 35,700 mi^2 in the northeast part of the country, Figure II-7. The basin initially expanded during Jurassic time with a northeast-southwest trending structural fabric and was later strongly affected by the Late Cretaceous Laramide Orogeny. Structurally complex, the Sabinas Basin has been deformed into a series of tight, NW-SE trending, evaporate-cored folds of Laramide origin called the Sabinas Foldbelt. Dissolution of Lower Jurassic salt during early Tertiary time introduced a further overprint of complex salt-withdrawal tectonics.[13] Much of the Sabinas Basin is too structurally deformed for shale gas development, but a small area on the northeast side of the basin is more gently folded and may be prospective.

Petroleum source rocks in the Sabinas Basin include the Cretaceous Olmos (Maastrichtian) and Eagle Ford Shale (Turonian) formations and the Late Jurassic (Tithonian) La Casita Formation. The latter two units contain marine shales with good petrophysical characteristics for shale development.[14] In contrast, the Olmos Formation is primarily a non-marine coaly unit that, while a good source rock for natural gas[15] as well as a coalbed methane exploration target in its own right,[16] appears to be too ductile for shale development.

2.2 Reservoir Properties (Prospective Area)

Eagle Ford Shale. The Eagle Ford Shale is distributed across the NW, NE, and central portions of the Sabinas Basin. The target is the 300-m thick sequence of black shales rhythmically interbedded with sandy limestone and carbonate-cemented sandstone. We estimated a 500-ft thick organic-rich interval with 400 feet of net pay. We considered the Eagle Ford Shale in the Maverick Basin of South Texas as the analog for reservoir properties, using a TOC of 4% and a thermal maturity of 1.50% (R_o). Our estimate of porosity was increased to 5% based on the rock fabric and correlation with the Texas Eagle Ford Shale analog. The average depth for the prospective Eagle Ford is approximately 9,000 feet. Based on reported data, mostly from coal mining areas, we use a slightly under-pressured gradient of 0.35 psi/ft for the Sabinas Basin.

Figure II-7. Sabinas Basin Outline and Shale Gas Prospective Area.



Source: ARI, 2013.

La Casita Formation. This Tithonian-age unit, regarded as the primary hydrocarbon source rock in the Sabinas Basin, consists of organic-rich shales deposited in a deepwater marine environment. The La Popa sub-basin is one of numerous sub-basins within the Sabinas Basin, Figure II-8.[17,18] The La Popa is a rifted pull-apart basin that contains thick source rock shales. Up to 370 m of black carbonaceous limestone is present overlying several km of evaporitic gypsum and halite. Total shale thickness in the La Casita ranges from 60 m to 800 m. Thick (300 m) and prospective La Casita Fm shales have been mapped at depths of 2,000 to 3,000 m in the central Sabinas Basin. Nearby, a thicker sequence (400-700 m) was mapped at greater depth (3,000 to 4,000 m).

The high-graded prospective area for the La Casita Formation averages 11,500 ft deep, about 2,500 ft deeper than the Eagle Ford Shale. The La Casita Formation averages about 240 ft of net pay thickness within an 800-ft thick organic-rich interval and has 2.0% average TOC that is gas prone (2.5% R_o). Our estimate of porosity in the La Casita was increased to 5% based on the rock fabric and correlation with the deep Texas and Louisiana Haynesville Shale analog.

2.3 Resource Assessment

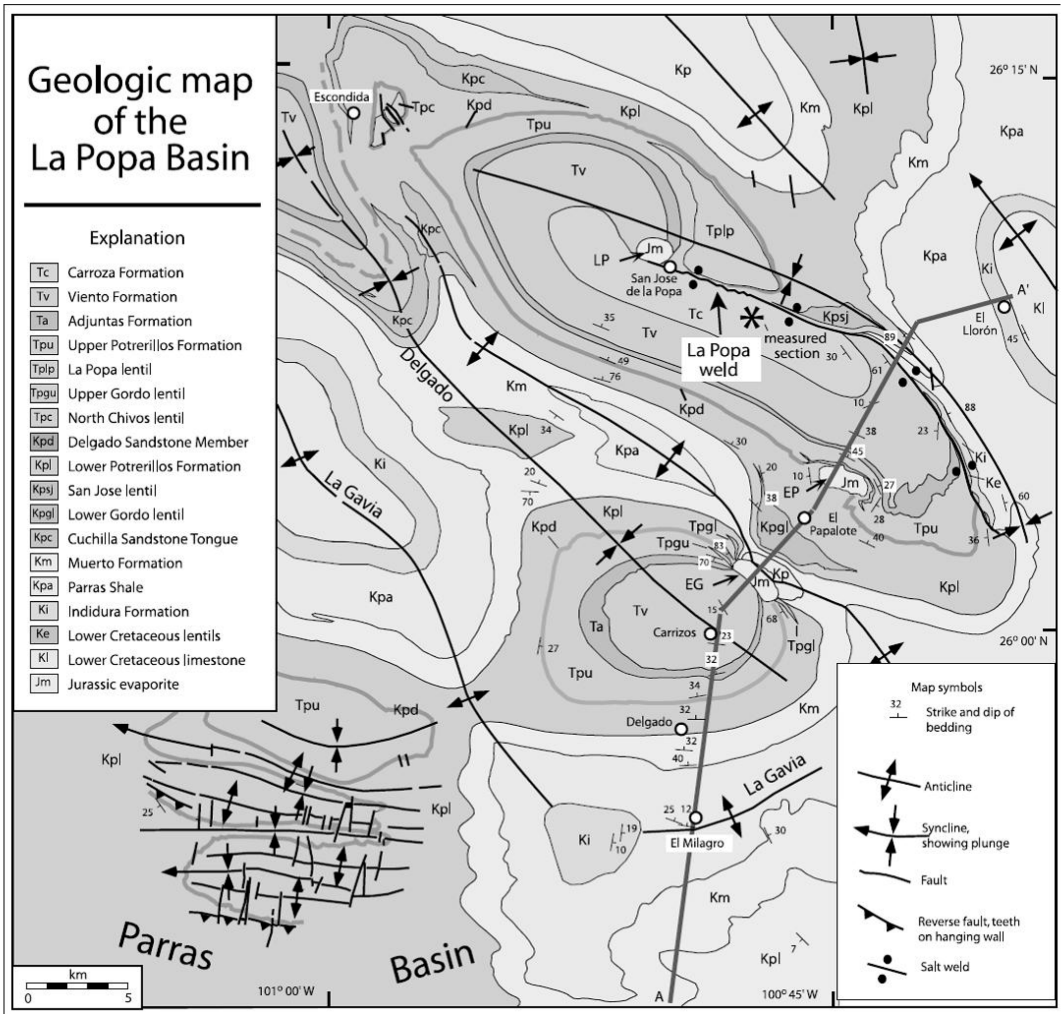
Eagle Ford Shale. The Eagle Ford Shale unit is the larger shale gas target in the Sabinas Basin, with an estimated 100 Tcf of technically recoverable shale gas resource out of 501 Tcf of risked shale gas in-place within the 9,500-mi^2 prospective area. The average resource concentration is high at 132 Bcf/mi^2.

La Casita Formation. The secondary target in the Sabinas Basin, the underlying La Casita Formation, has an estimated 24 Tcf of technically recoverable shale gas out of 118 Tcf of risked shale gas in-place. Its resource concentration is estimated at 69 Bcf/mi^2.

2.4 Recent Activity

PEMEX has drilled one shale gas exploration well in the Sabinas Basin, confirming the continuation of the Eagle Ford Shale play. The Percutor-1 horizontal well, completed in March 2012, produced dry gas from a sub-surface depth of 3,330-3,390 m. The well's initial production rate was a modest 2.17 million ft^3/day (measurement time interval not specified), with production reportedly declining rapidly.

Figure II-8. Geologic Map of the La Popa Sub-Basin, Southeastern Portion of the Sabinas Basin. Note the numerous detachment and salt-controlled folds.



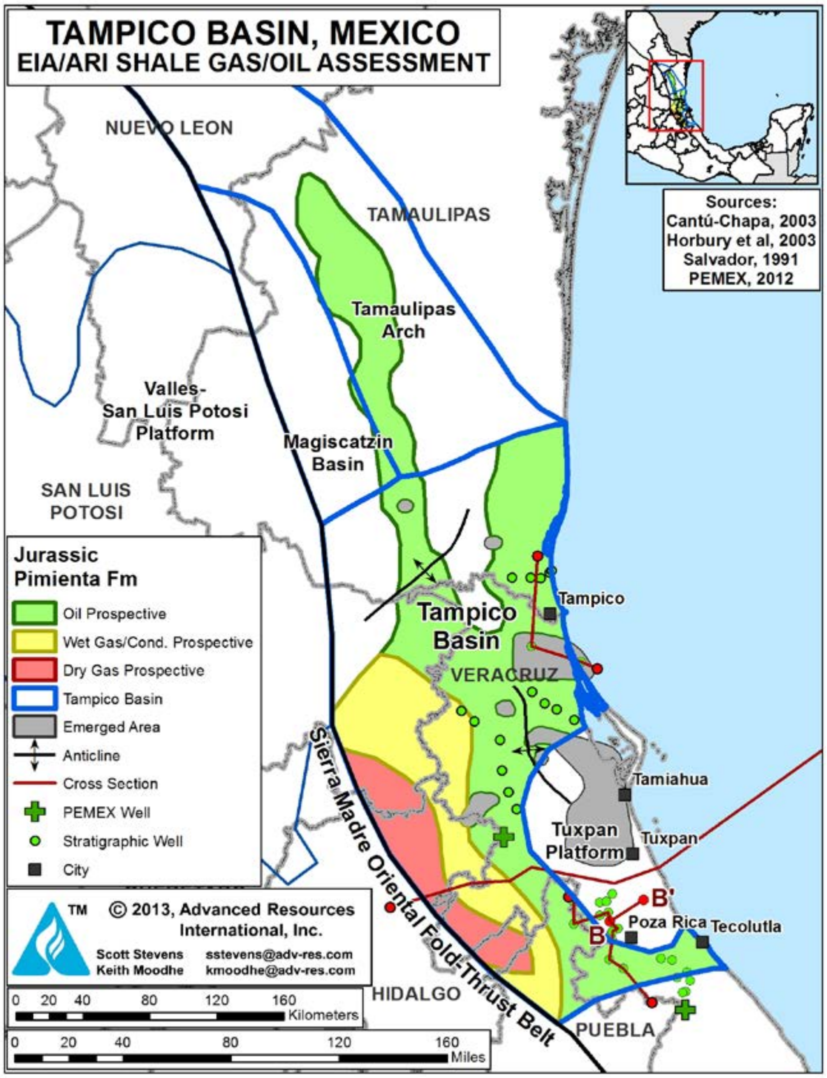
Source: Hudson and Hanson, 2010.

3. TAMPICO BASIN (Pimienta Shale)

3.1 Geologic Setting

Bounded on the west by the fold-and-thrust belt of the Sierra Madre Oriental (Laramide) and on the east by the Tuxpan platform, the Tampico-Mizatlan Basin extends north from the Santa Ana uplift to the Tamaulipas arch north of Tampico, Figure II-9. At the northern margin of the basin is an arch, limited by a series of faults extending south from the Tamaulipas arch.

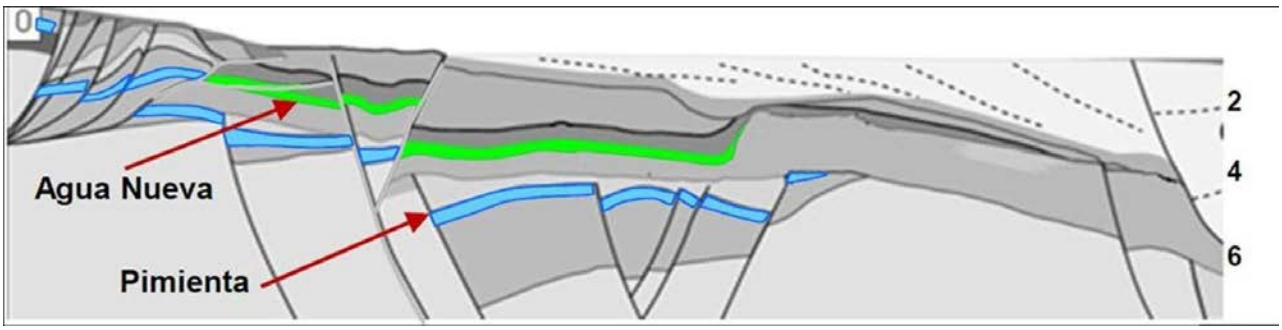
Figure II-9. Prospective Pimienta Formation (Tithonian) Shale, Tampico Basin.



Source: ARI, 2013.

The principal source rock in the Tampico Basin is the Upper Jurassic (Tithonian) Pimienta Shale, Figure II-10. Although quite deep over much of the basin, the Pimienta reaches shale-prospective depths of 1,400 to 3,000 m in the south where three uplifted structures occur. The 40-km long, NE-SW trending Piedra de Cal anticline in the southwest Bejuco area has Pimienta Shale cresting at 1,600-m depth. The 20-km long, SW-NE trending Jabonera syncline in southeast Bejuco has maximum shale depth of 3,000 m in the east and minimum depth of about 2,400 m in the west. A system of faults defines the Bejuco field in the center of the area. Two large areas (Llano de Bustos and La Aguada) lack upper Tithonian shale deposits.

Figure II-10. Structural Cross-Section of the Tampico Basin



Source: Escalera Alcocer, 2012.

3.2 Reservoir Properties

Near the city of Tampico, some 50 conventional wells have penetrated organic-rich shales of the Pimienta Formation at depths of about 1,000 to 3,000 m. Three distinct thermal maturity windows (dry gas, wet gas, and oil) occur from west to east, reflecting the gentle structural dip angle in this basin. Average shale depth ranges from 5,500 to 8,000 ft. Excluding the paleo highs, the prospective area of the Pimienta Shale totals approximately 13,600 mi^2. Detailed shale thickness data are not available, but the Pimienta Fm here generally ranges from 200 m thick to as little as 10 m thick on paleo highs. We estimate an average net shale thickness of about 200 ft, out of the total organically rich interval of 500 ft within the prospective area. Average net shale TOC is estimated at 3%, with average thermal maturity ranging from 0.85% to 1.4% R_o.

3.3 Resource Assessment

The Pimienta Shale in the Tampico Basin holds an estimated 23 Tcf and 5.5 billion barrels of risked, technically recoverable shale gas and shale oil resources, out of risked OOIP and OGIP of 151 Tcf and 138 billion barrels, respectively. The shale gas resource concentration averages 19 to 83 Bcf/mi^2 while the shale oil concentration averages 17 to 38 million bbl/mi^2.

3.4 Recent Activity

PEMEX reported that it is evaluating the shale geology of the Tampico Basin and plans to drill up to 80 shale exploration wells through 2015.[19]

4. TUXPAN PLATFORM (Pimienta and Tamaulipas Shales)

4.1 Geologic Setting

The Tuxpan Platform, located southeast of the Tampico Basin, is a subtle basement high that is capped with a well-developed Early Cretaceous carbonate platform.[20] A particularly prospective and relatively well defined shale gas deposit is located in the southern Tuxpan Platform. Approximately 50 km south of the city of Tuxpan, near Poza Rica, a dozen or so conventional petroleum development wells in the La Mesa Syncline area penetrated thick organic-rich shales of the Pimienta (Tithonian) and Tamaulipus (Lower Cretaceous) Formations.[21]

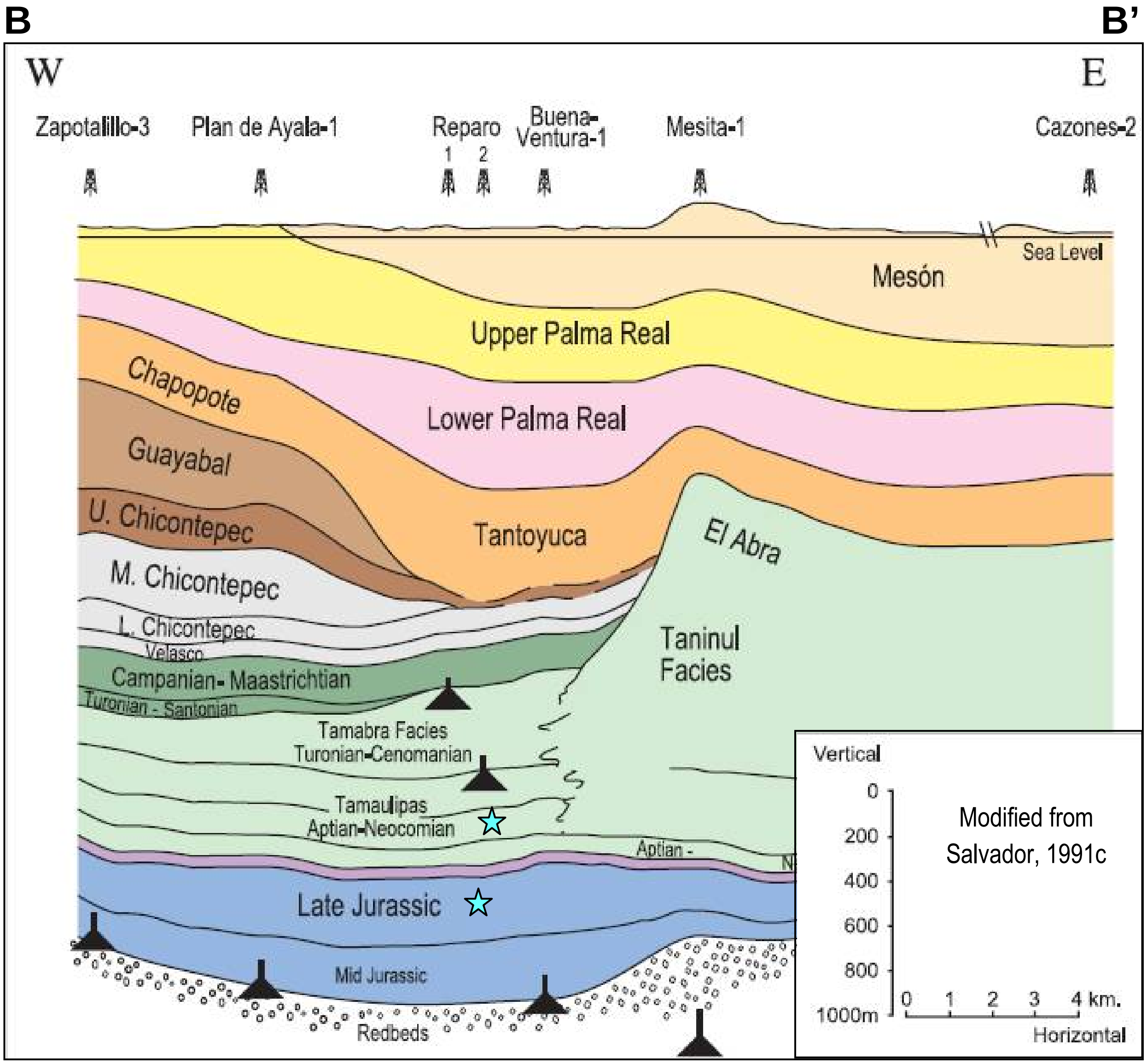
A detailed cross-section of the Tuxpan Platform shows thick Lower Cretaceous and Upper Jurassic source rocks dipping into the Gulf of Mexico Basin, Figure II-11. These source rocks reach prospective depths of 2,500 m. Thermal maturity ranges from oil- to gas-prone.

4.2 Reservoir Properties (Prospective Area)

Pimienta Fm. The organically rich portion of the Jurassic Pimienta Shale averages about 500 ft thick in the high-graded area, with net thickness estimated at 200 ft. However, southeast of Poza Rica some areas the shale is thin or absent, probably due to submarine erosion or lack of deposition, Figure 12. The gamma ray log response in the organic-rich Pimienta Shale indicates moderate TOC of 3.0%, which is in the oil to wet gas window (average R_o of 0.9%). Depth ranges from 6,600 to 10,000 ft, averaging about 8,500 ft.

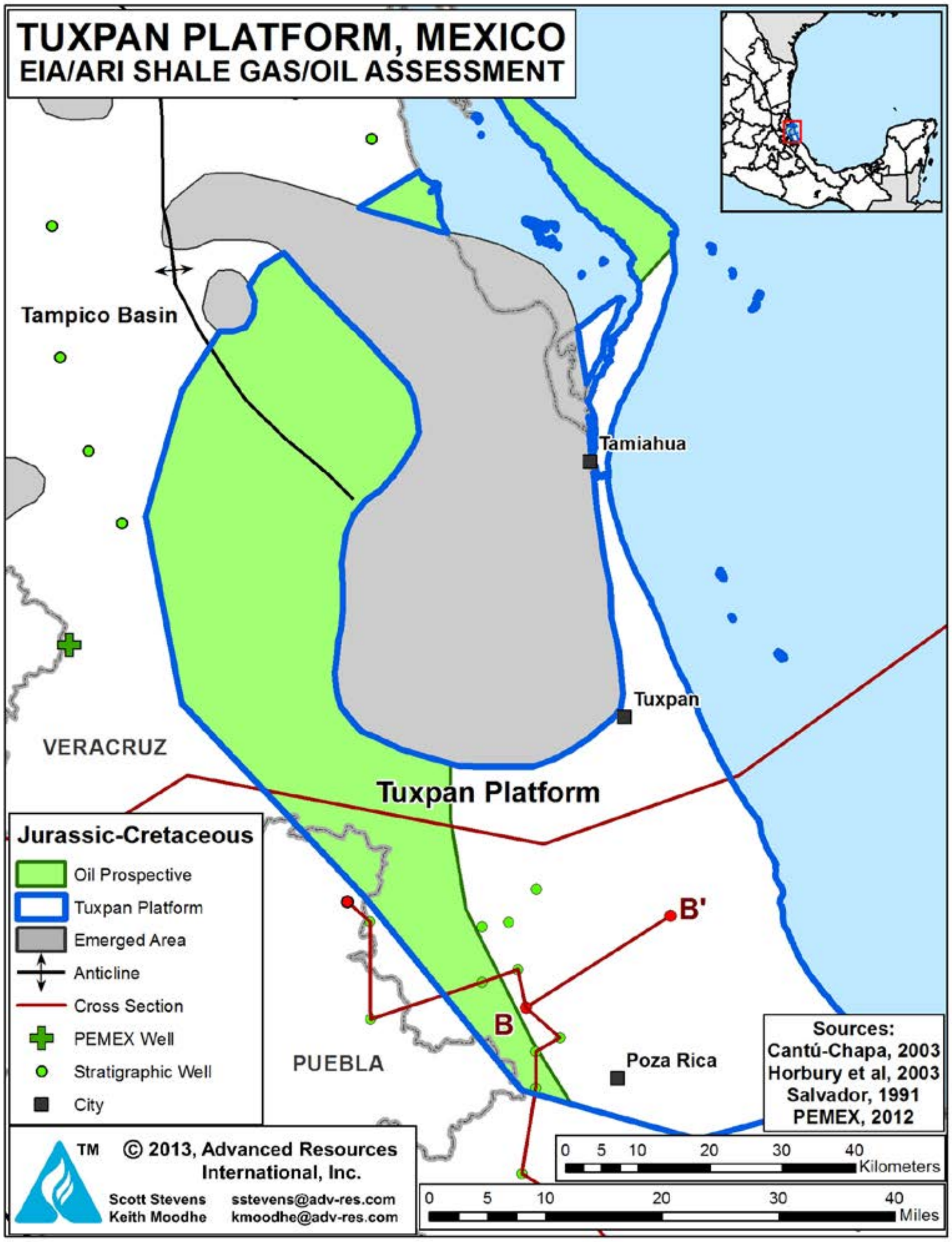
Tamaulipas Fm. The Lower Cretaceous Tamaulipas Fm spans a depth range of 6,000 to 9,500, averaging about 7,900 ft. The organic-rich interval averages 300 ft thick, with net pay estimated at about 210 ft. TOC is estimated to be 3.0%. The average thermal maturity is slightly lower than for the deeper Pimienta, at 0.85% R_o.

Figure II-11. Cross-Section of the Tuxpan Platform.



Modified from Salvador, 1991c.

Figure II-12. Potentially Prospective Shale Gas and Shale Oil Areas of the Tuxpan Platform.



Source: ARI, 2013.

4.3 Resource Assessment

Pimienta Fm. In the Tuxpan Platform, the prospective area of the Pimienta Fm shale is estimated to be approximately 1,000 mi^2. Risked, technically recoverable resources are estimated to be about 1 Tcf of shale gas and 0.5 billion barrels of shale oil and condensate. Risked shale resource in-place is estimated at 10 Tcf and 12 billion barrels.

Tamaulipas Fm. Due to limited data on the younger Tamaulipas Fm the same prospective area of the Pimienta Shale was assumed (1,000 mi^2). The Tamaulipas Shale is estimated to have risked technically recoverable resources of about 1 Tcf of shale gas and 0.5 billion barrels of shale oil and condensate, out of risked shale resources in-place of 9 Tcf and 13 billion barrels.

4.4 Recent Activity

No shale gas or oil exploration activity has been reported on the Tuxpan Platform.

5. VERACRUZ BASIN (Maltrata Shale)

5.1 Geologic Setting

The Veracruz Basin extends over an onshore area of 9,030 mi^2, near its namesake city. The basin's western margin is defined by thrusted Mesozoic carbonates (early Tertiary Laramide Orogeny) of the Cordoba Platform and Sierra Madre Oriental, Figure II-13. The basin is asymmetric in cross section, with gravity showing the deepest part along the western margin, Figure II-14.[22] The basin comprises several major structural elements, from west to east: the Buried Tectonic Front, Homoclinal Trend, Loma Bonita Anticline, Tlacotalpan Syncline, Anton Lizardo Trend, and the highly deformed Coatzacoalcos Reentrant in the south.[23]

A recent shale exploration map released by PEMEX indicates the prospective area of the Veracruz Basin is much smaller than previously assumed in the 2011 EIA/ARI study. This is because the shale is shown to be dipping at a steeper angle than previously mapped. In addition, both shale gas and oil thermal maturity windows are present.

5.2 Reservoir Properties (Prospective Area)

Maltrata Fm. The Upper Cretaceous (Turonian) Maltrata Formation is a significant source rock in the Veracruz Basin, containing an estimated 300 ft of organic-rich, shaly marine limestone. TOC ranges from 0.5% to 8%, averaging approximately 3%, and consists of Type II kerogen. Thermal maturity ranges from oil-prone (R_o averaging 0.85%) within the oil window at depths of less than 11,000 ft, to gas-prone (R_o averaging 1.4%) within the gas window at average depths below 11,500 ft.

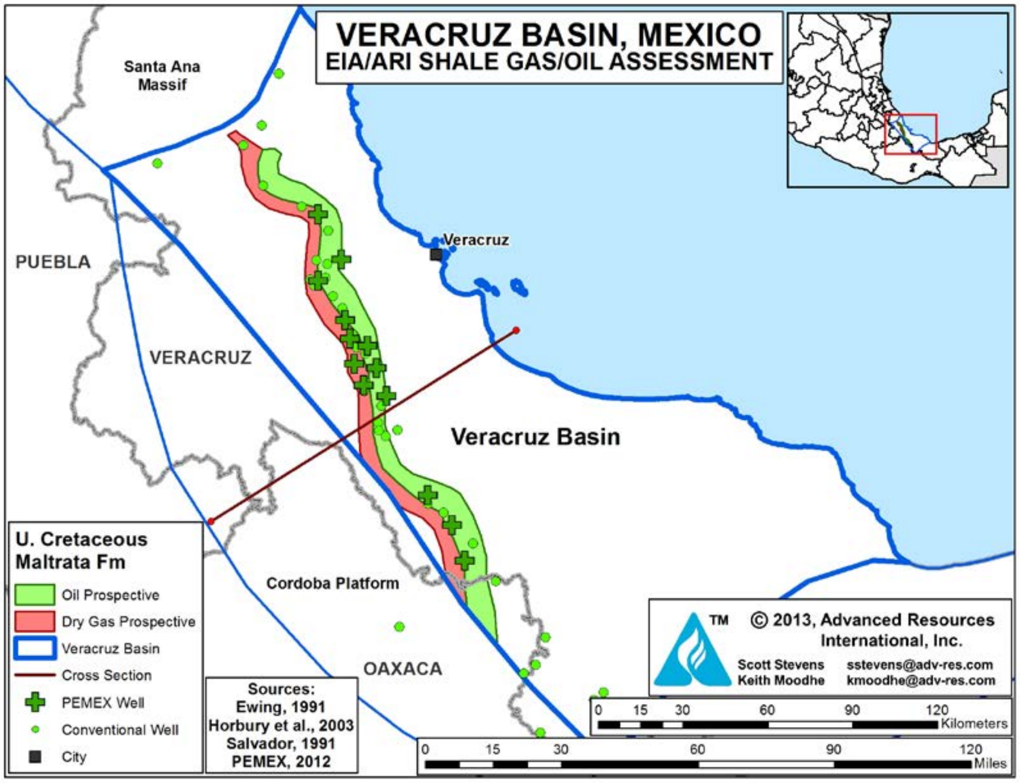
5.3 Resource Assessment

Maltrata Fm. Whereas we previously had assumed that 90% of the Veracruz Basin (8,150 mi^2) is in a favorable depth range, based on available cross-sectional data, the new PEMEX map indicates that the true prospective area in the Veracruz Basin could be much smaller, perhaps only 960 mi^2. This yields a reduced estimate of 3 Tcf and 0.3 billion barrels of risked technically recoverable shale gas and shale oil resources for the Maltrata Formation in the Veracruz Basin, out of 21 Tcf and 7 billion barrels of risked shale gas and shale oil in-place.

5.4 Recent Activity

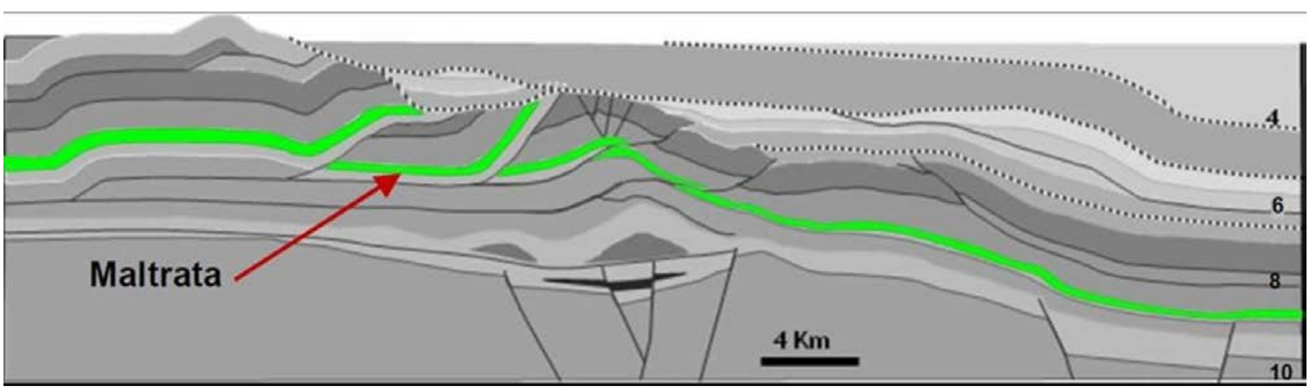
PEMEX plans to drill up to 10 shale exploration wells in the Veracruz Basin in the next three years.

Figure II-13. Veracruz Basin Outline and Shale Gas and Shale Oil Prospective Area.



Source: ARI, 2013.

Figure II-14. Veracruz Basin Cross Section Showing the Maltrata Shale



Source: Escalera Alcocer, 2012.

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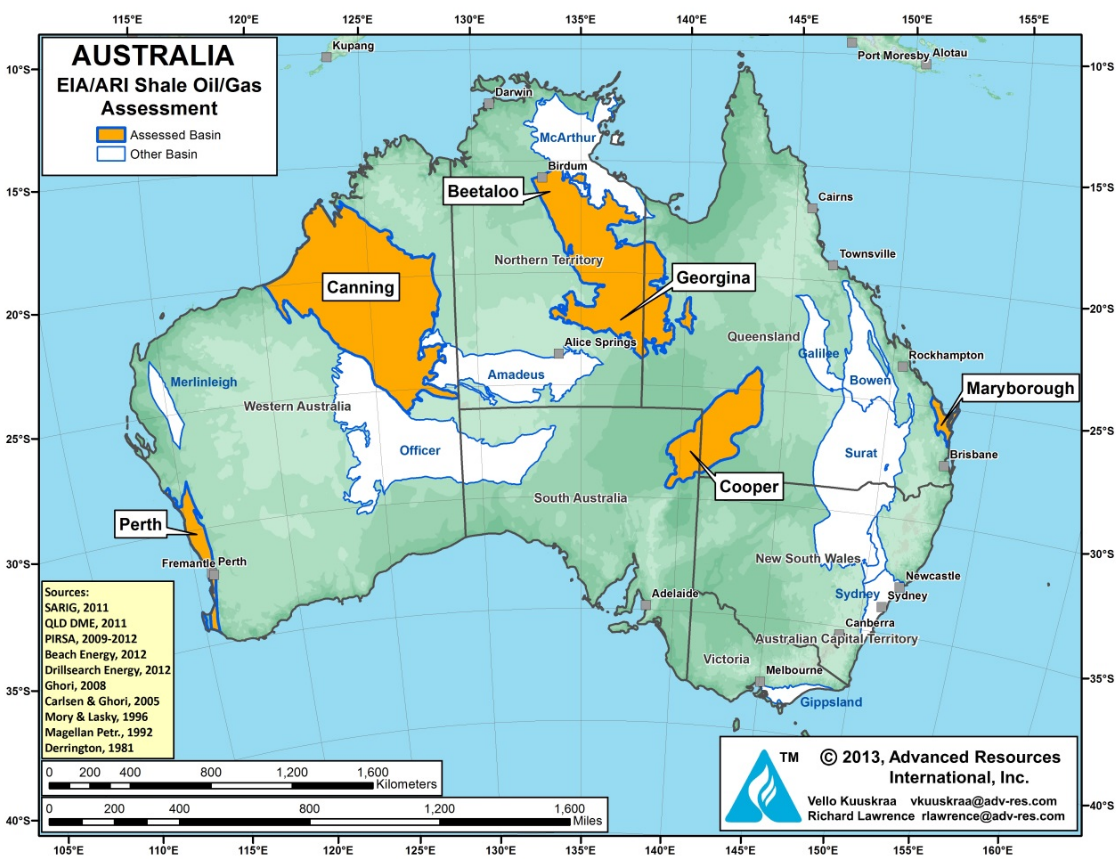
III. AUSTRALIA

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) depositionals and the shale gas appears to have elevated CO_2 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 ($4,290 \text{ mi}^2$)	Perth ($20,000 \text{ mi}^2$)			Canning ($181,000 \text{ mi}^2$)		
	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 mi²)					Beetaloo (14,000 mi²)					
	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 (mi²)		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/mi²)		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		Goldwyer	
	Geologic Age		Permian		Permian		Permian	L. Triassic		M. Ordovician	
	Depositional Environment		Lacustrine		Lacustrine		Lacustrine	Marine		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
Risked OIP (B bbl)		2.9	17.7	3.9	22.1	5.7	54.4	10.7
Risked Recoverable (B bbl)		0.12	0.71	0.16	1.11	0.28	2.72	0.54

Advanced Resources International, Inc.

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 CO_2 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 km^2, 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.

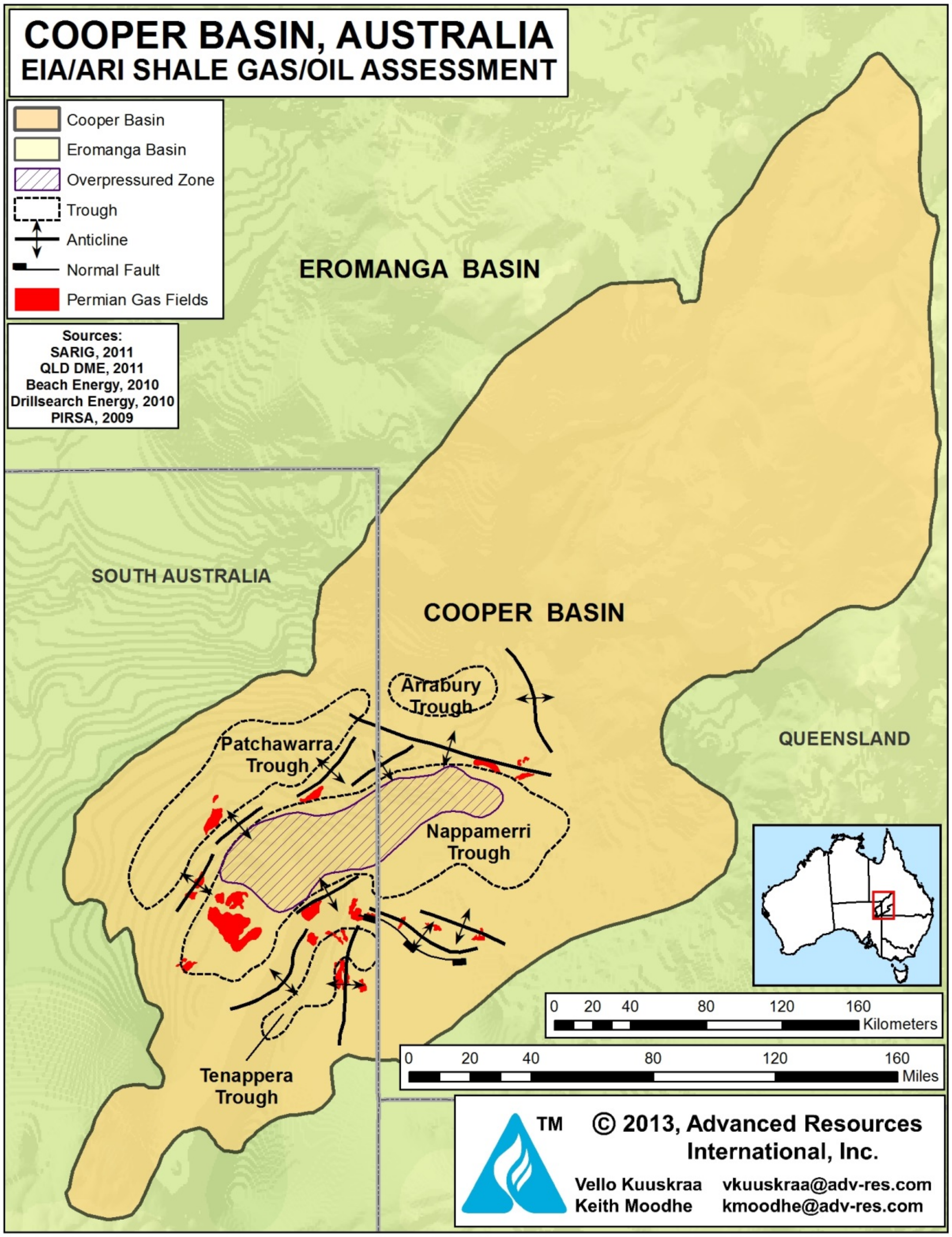
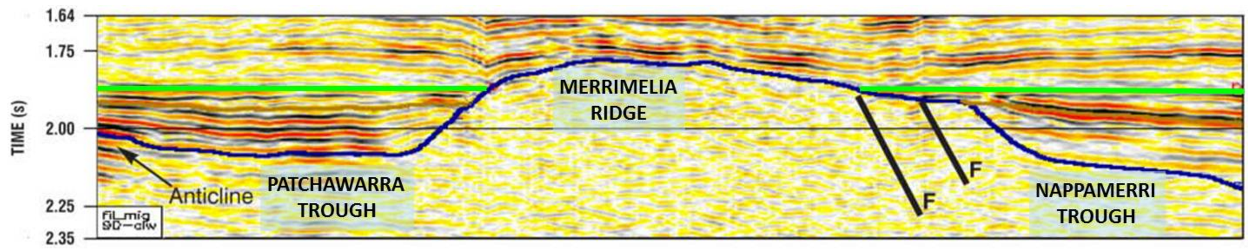


Figure III-3. Seismic Section Across the Merrimelia Ridge



Top of Permian Section showing Pinch-Out Over Structural Highs

(Adapted from Menpes, 2012)

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.

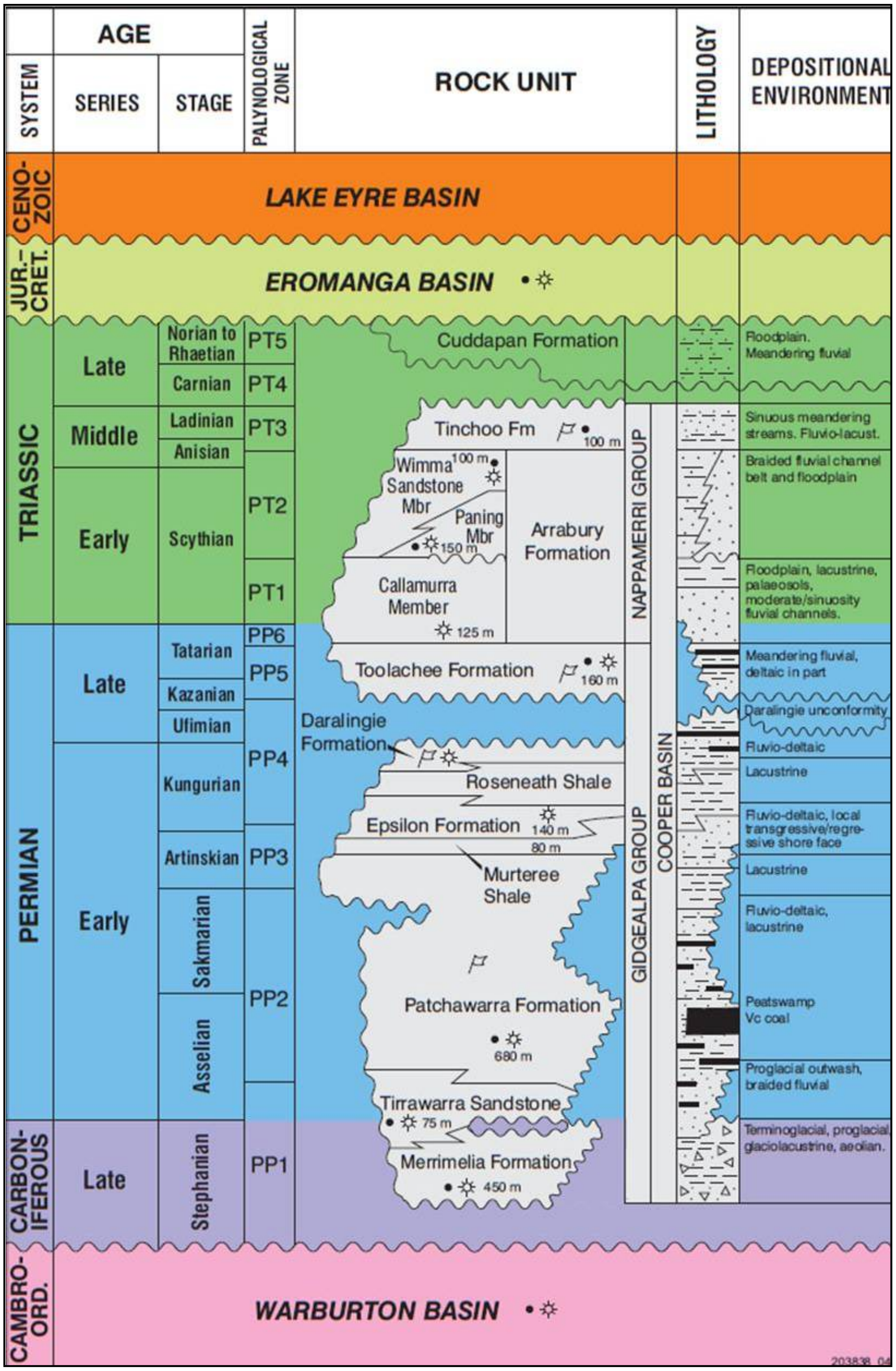
The most prospective shales in the Gidgealpa Group, with oil and gas shows during drilling and higher TOCs, are the Early Permian Roseneath and Murteree shales.[5] Figure III-5 shows a stratigraphic cross-section of the Roseneath, Epsilon, and Murteree (collectively termed REM) sequence in the Nappamerri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

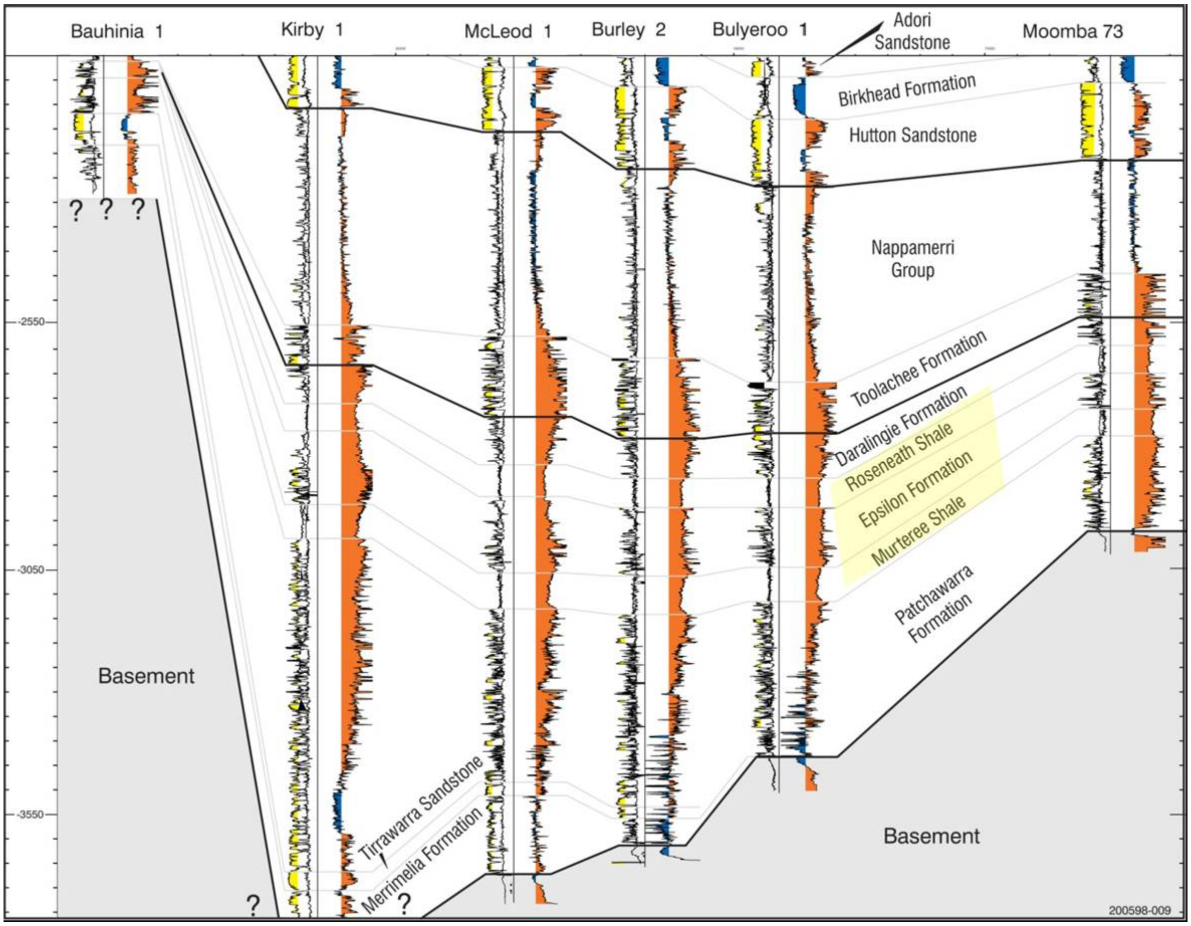
The Roseneath Shale, less widespread than the Murteree due to erosion on uplifts, averages 120 feet thick, reaching 330 feet thick in the Nappamerri Trough. The intervening Epsilon Fm consists primarily of low-permeability (0.1 to 10 mD) quartzose sandstone with carbonaceous shale and coal. The Epsilon, 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 300º 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.

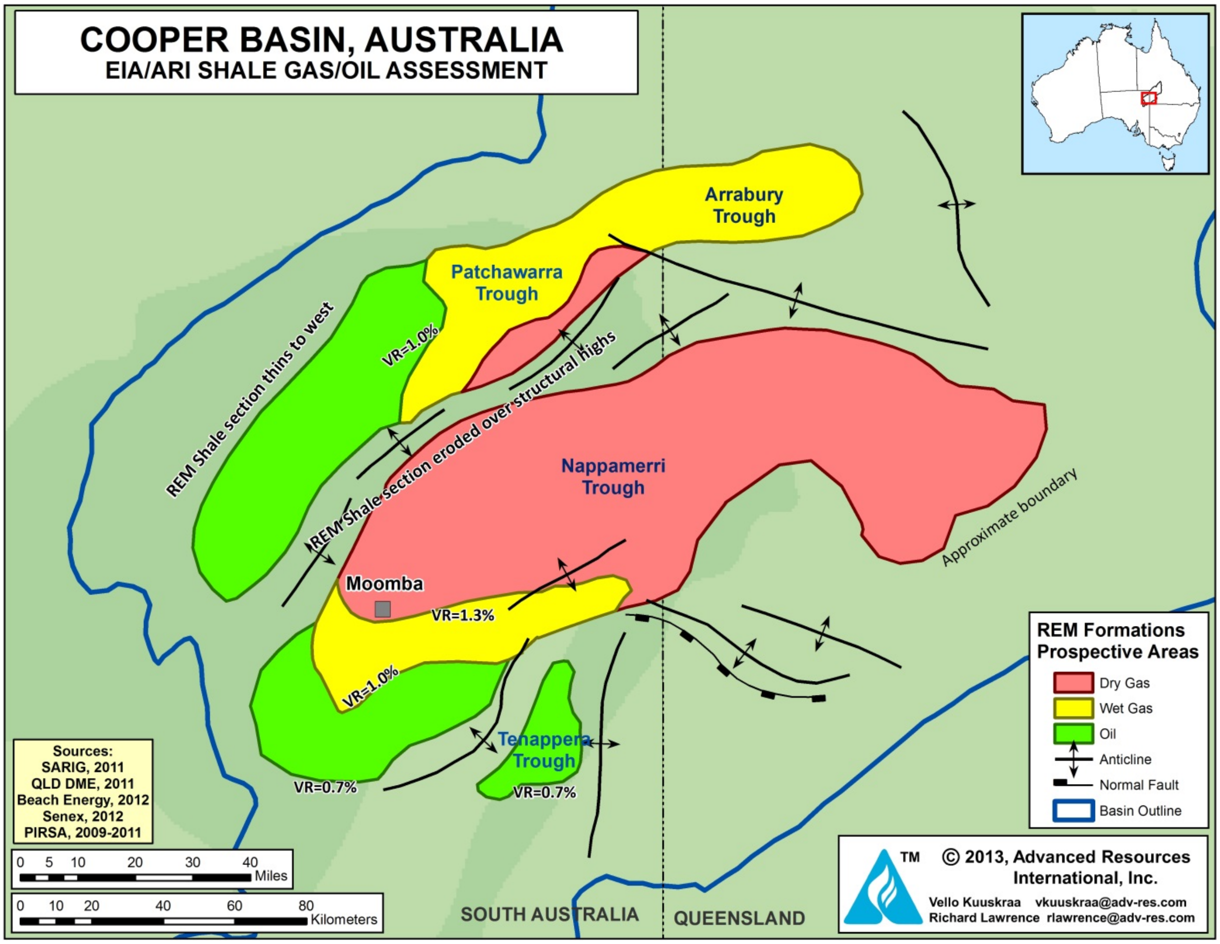
Regional hydrostatic pressure gradients are the norm in most of the Cooper Basin. However, the Nappamerri Trough becomes overpressured at depths of 9,000 to 12,000 feet, with pressure gradients of up to 0.7 psi/ft recorded in the deepest portions of the trough.[9] High levels of carbon dioxide are also 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/mi^2 in the Nappamerri Trough, benefitting from favorable thickness, moderate TOC and overpressuring, but reduced by 15% for CO_2 content. In contrast, the shale gas resource concentrations in the dry and wet gas prospective areas of the Patchawarra Trough are much less, from 16 to 19 Bcf/mi^2. The resource concentration in the oil prospective area of the Tenappara Trough is 22 million barrels/mi^2.

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



The total shale gas and shale oil prospective area for the Permian REM section is estimated at 7,235 mi^2, covering major portions of the Nappamerri, Patchawarra and Tenappera troughs in the Cooper Basin. Net of 15% CO_2 content, the estimated risked shale gas in-place is 325 Tcf, with a risked, technically recoverable shale gas resource of 93 Tcf, including associated gas in the shale oil prospective area, Table III-A. The risked shale oil in-place in the Cooper Basin is 29 billion barrels, with a risked, technically recoverable resource of 1.6 billion bbls, Table III-2A.

1.5 Recent Activity

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

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

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

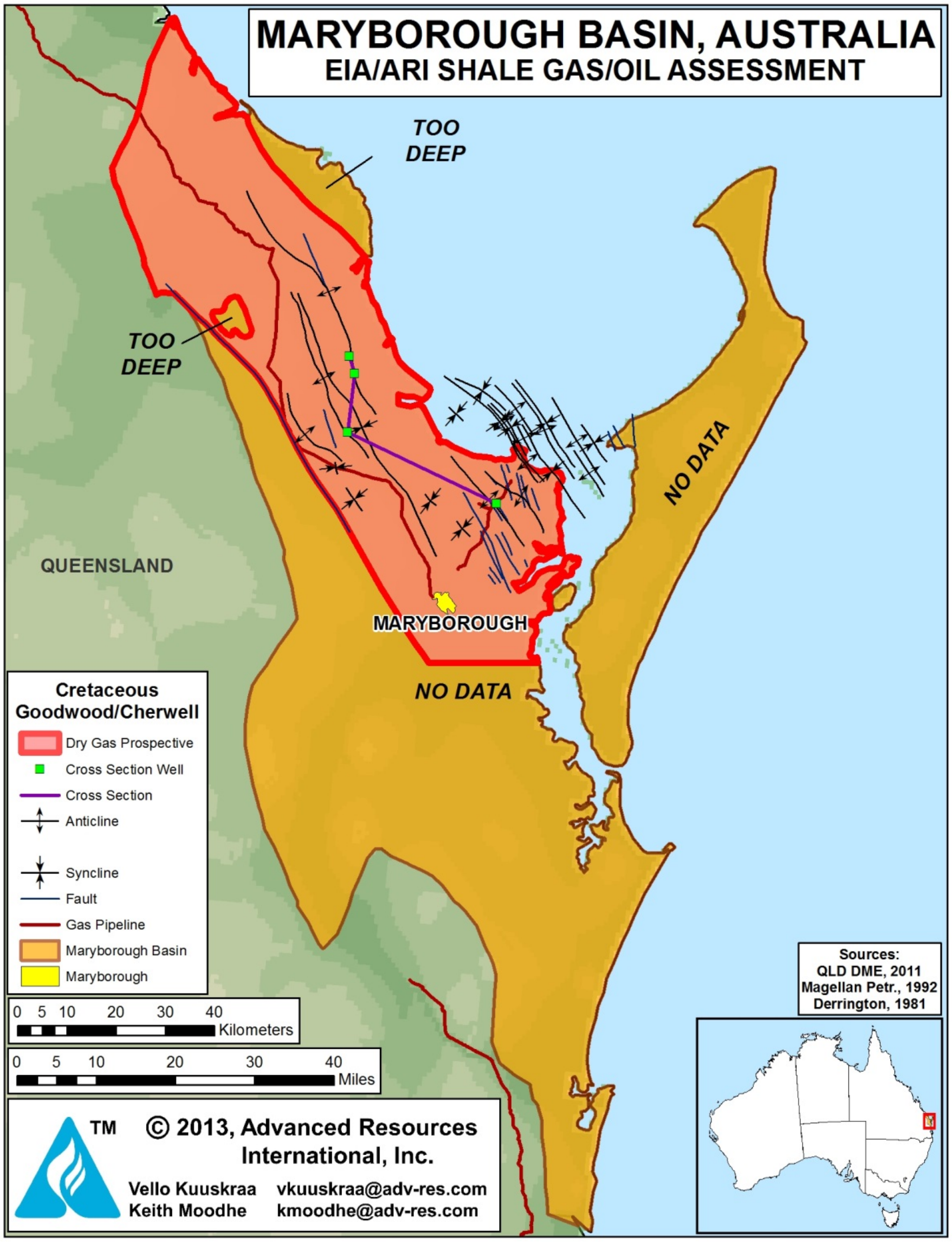
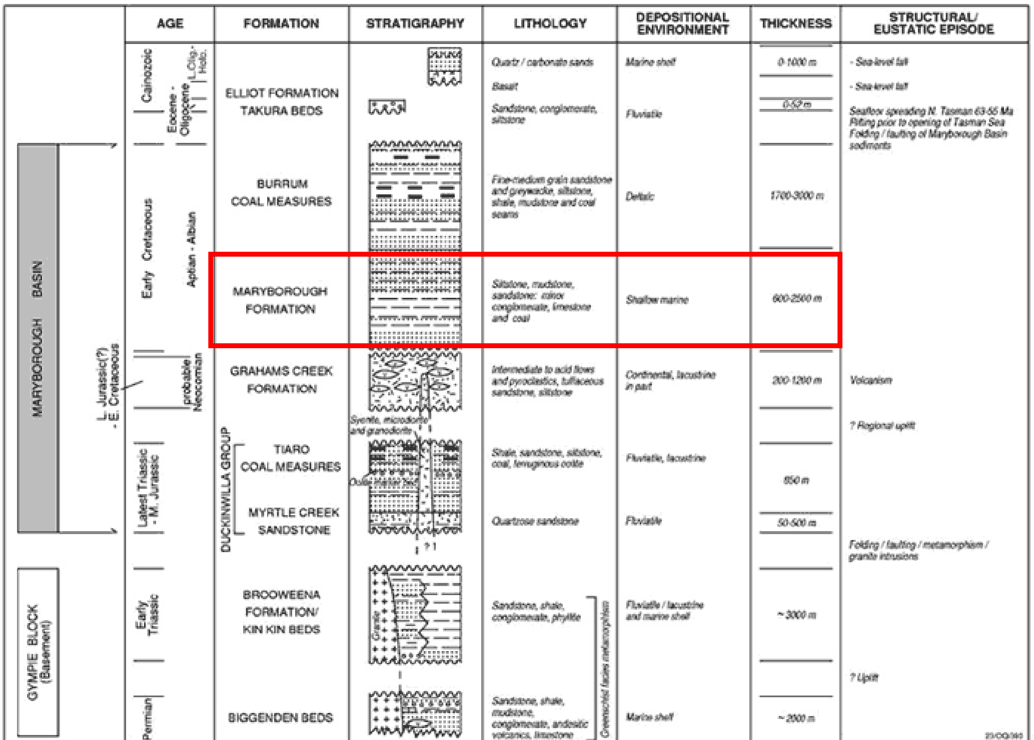
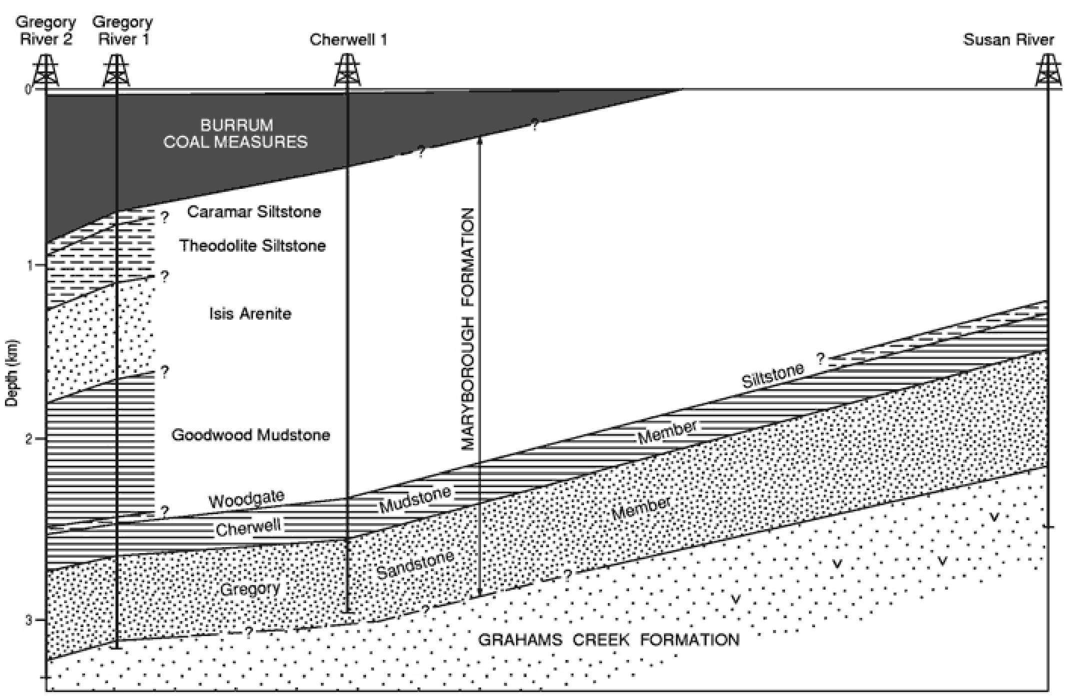


Figure III-8. Stratigraphy of the Maryborough Basin



Source: Hill 1994

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



From Derrington 1981
Source: Eyles et al., 2001

2.4 Resource Assessment

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

The basal shales of the Maryborough Formation (Cherwell and Goodwood shales) have an estimated gas in-place concentration of 111 Bcf/mi^2. 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.

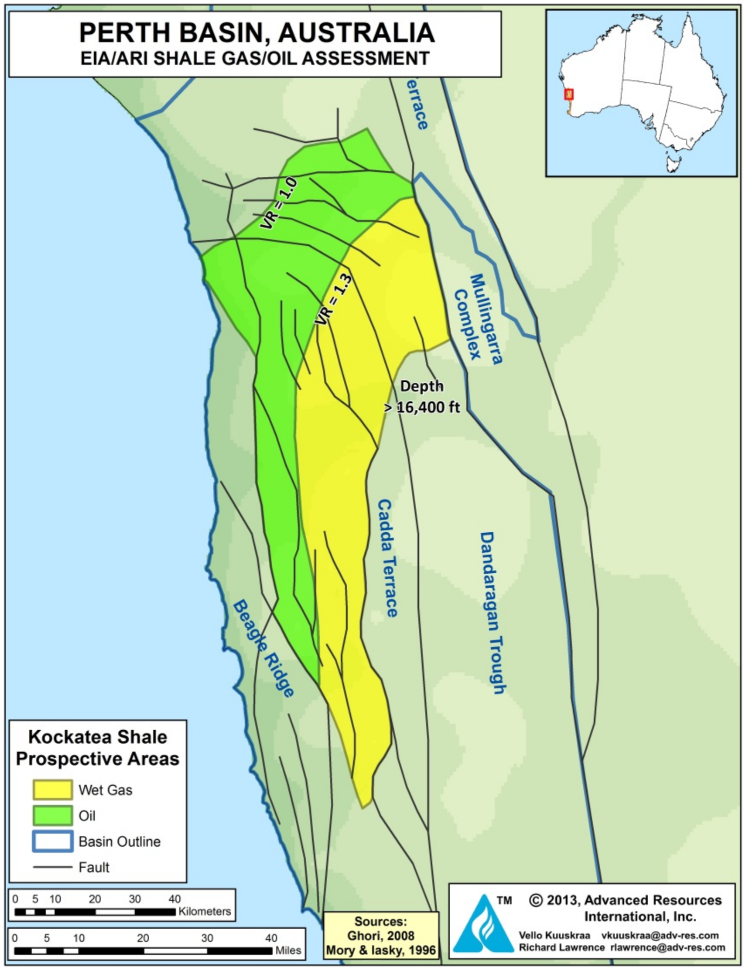
3.2 Geologic Setting

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 mi^2. 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]

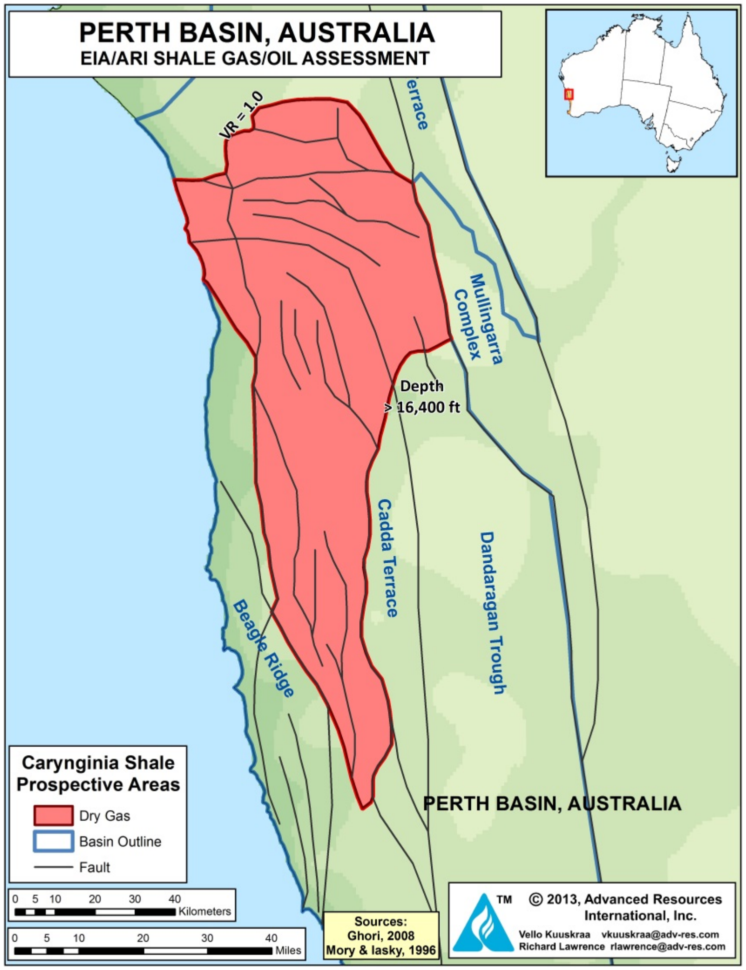
The Dandaragan Trough, a large syncline in northern Perth Basin, contains the deepest, thickest and most prospective shale gas formations. Some 300 miles long and up to 30 miles wide, the Dandaragan Trough holds as much as 9 miles of Silurian to early Cretaceous sedimentary rocks. Much of the Dandaragan 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. CO_2 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

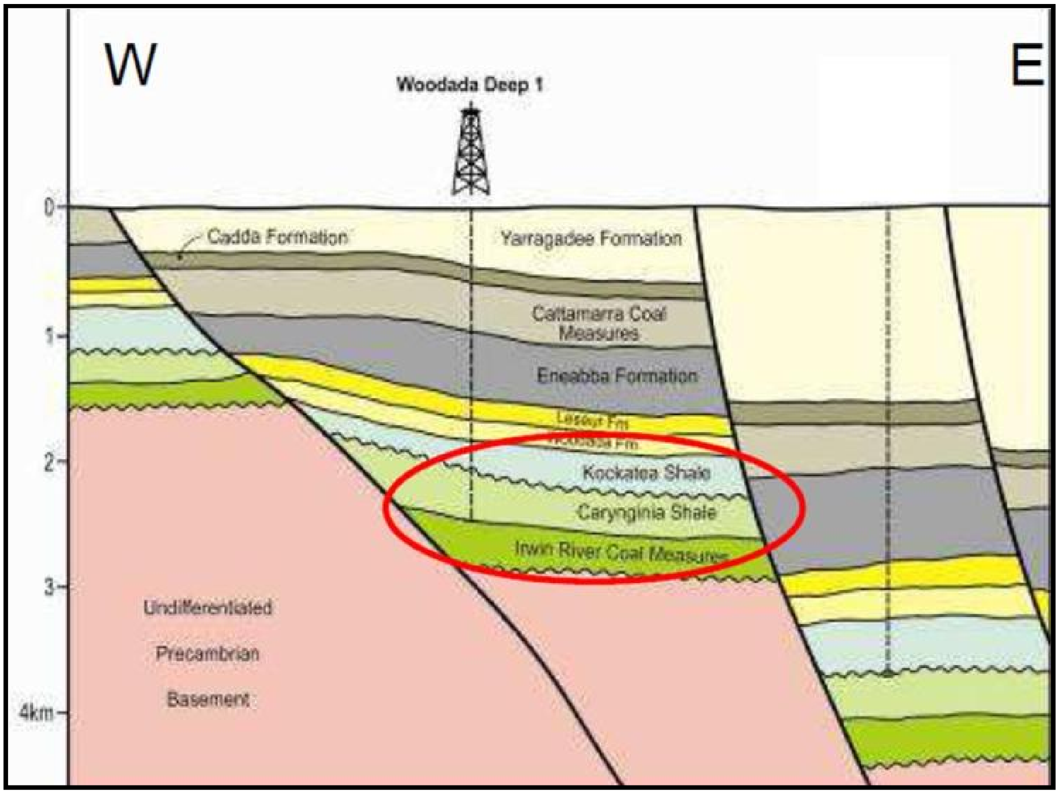


Source: ARI, 2013.



Source: ARI, 2013.

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



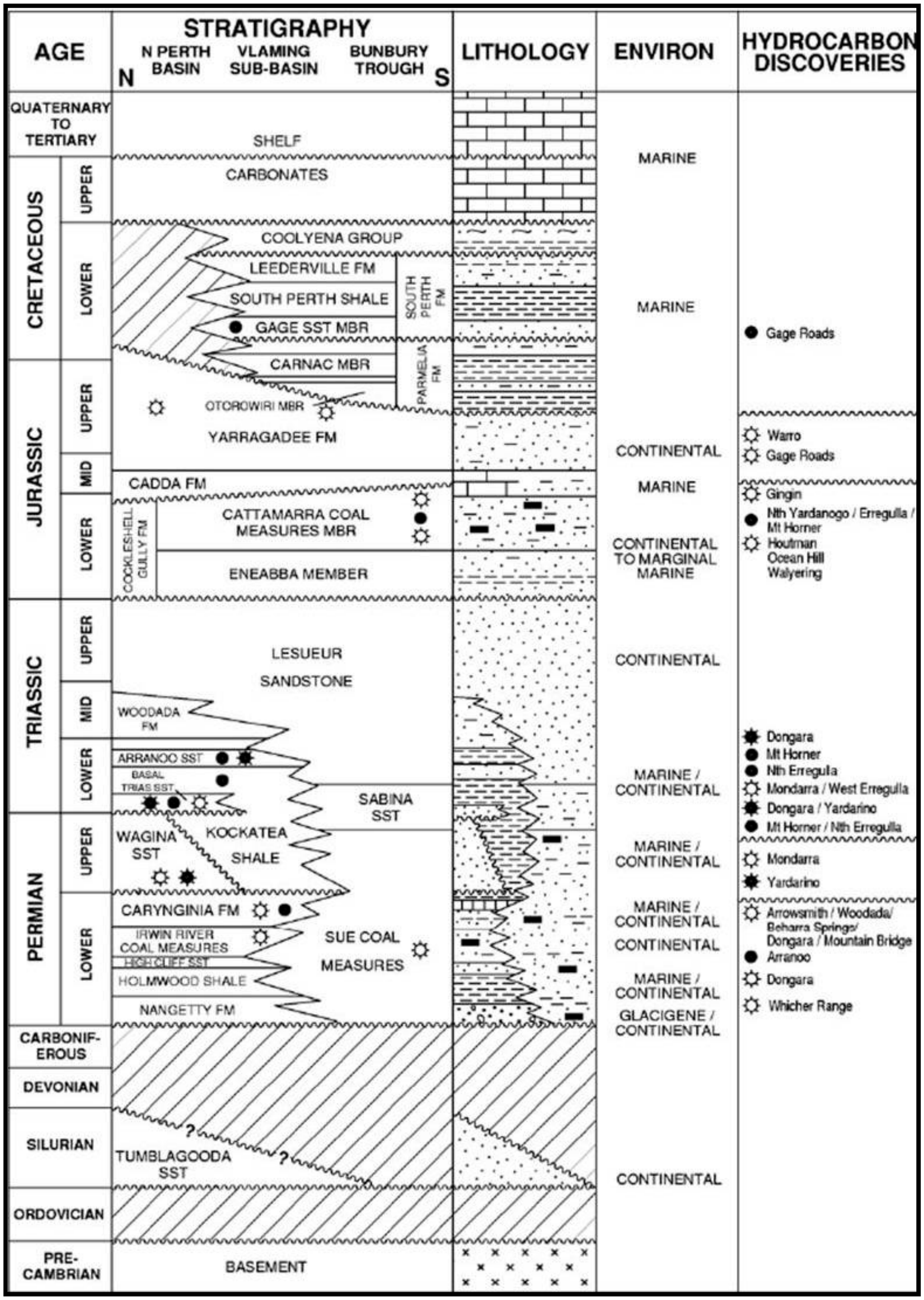
Source: AWE 2010

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

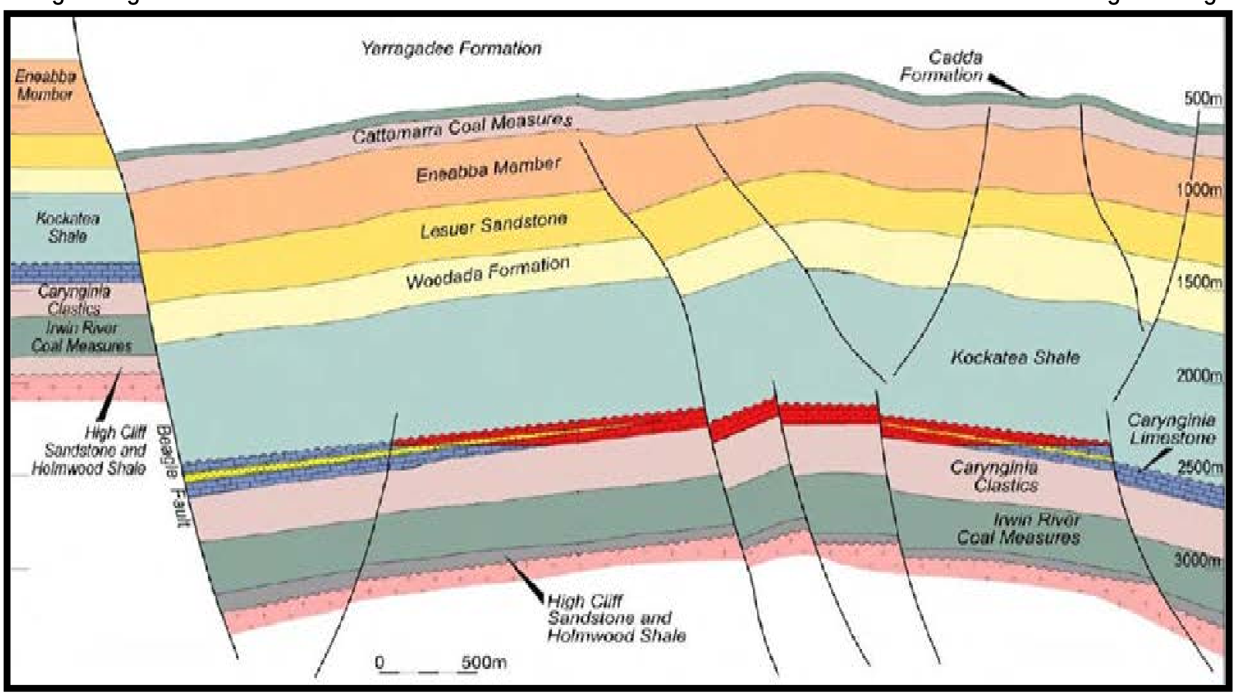
3.3 Reservoir Properties (Prospective Area)

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

WEST
Beagle Ridge

EAST
Dandaragan Trough



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. CO_2 and N_2 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. CO_2 and N_2 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-mi^2 area is prospective for wet shale gas and condensate in the Kockatea Shale, defined using minimum and maximum depth criteria (3,300-16,500 ft) and vitrinite reflectance (R_o of 1.0% to 1.3%). A smaller 860-mi^2 area, up-dip from the wet gas prospective area, defined by R_o values between 0.7% and 1.0% and a minimum depth of 3,300 ft, appears prospective for shale oil in the Kockatea Shales. The deeper Carynginia Shale has a dry gas prospective area of 2,200 mi^2. Additional portions of the southern half of the Perth Basin may be prospective but insufficient data were available for a quantitative assessment.

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

The Triassic Kockatea Shale has a resource concentration of 59 Bcf/mi^2 within its 1,030-mi^2 wet gas prospective area. Including associated gas, the Kockatea Shale has a risked gas in-place of 36 Tcf, with a risked, technically recoverable shale gas resource of 7 Tcf, Table III-1B. Shale oil resource concentrations in the Kockatea Shale are estimated at 19 million barrels/mi^2 in the oil prospective area and 6 million barrels/mi^2 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]

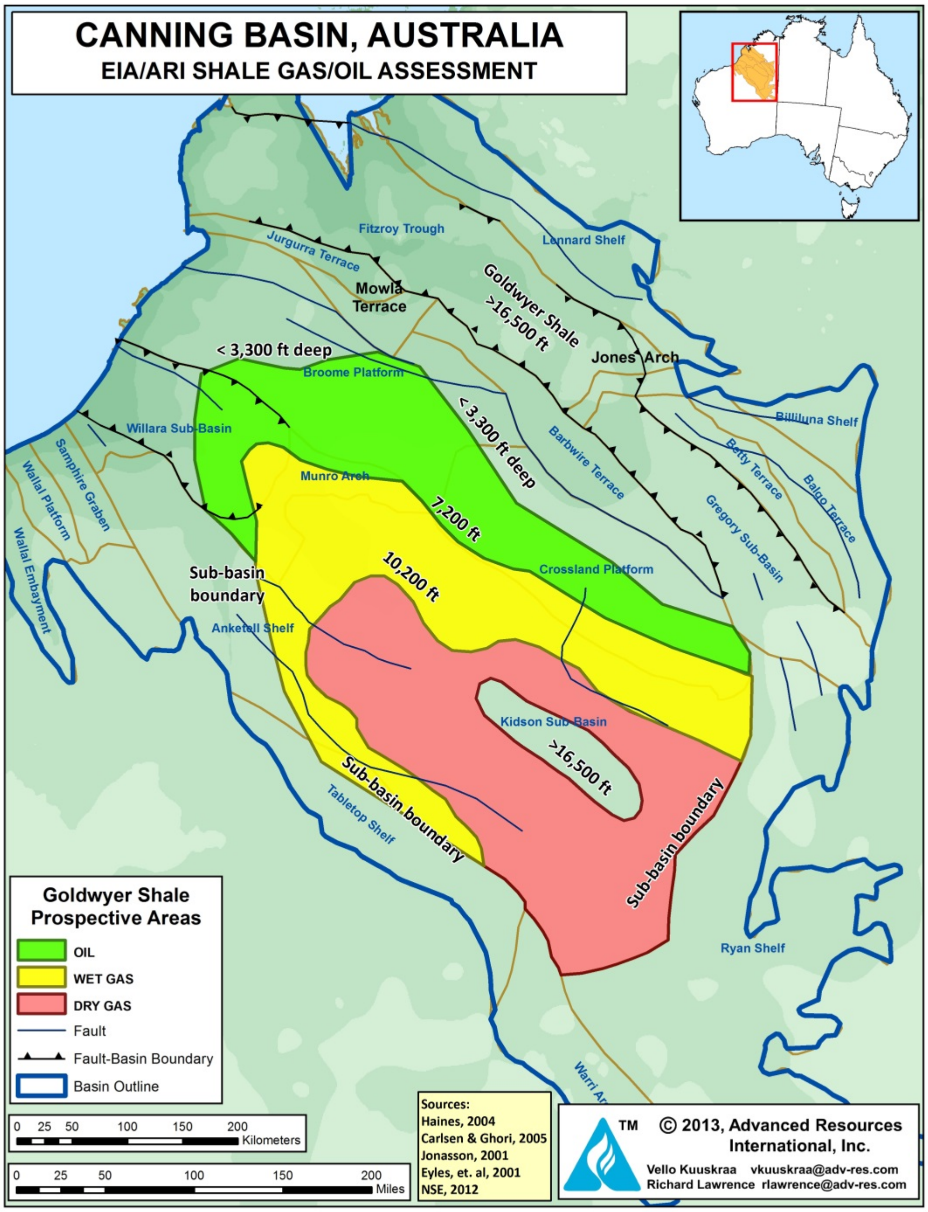
Australian independent, Norwest Energy which produces oil and gas from conventional fields in the Perth Basin, is evaluating the shale potential on its EP413 permit area, about 20 miles north of the Woodada Deep well. Norwest is partnered with AWE and has also farmed-out an interest in EP413 to an Indian 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-mi^2 Canning Basin (181,000 mi^2 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 formations[24].

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.

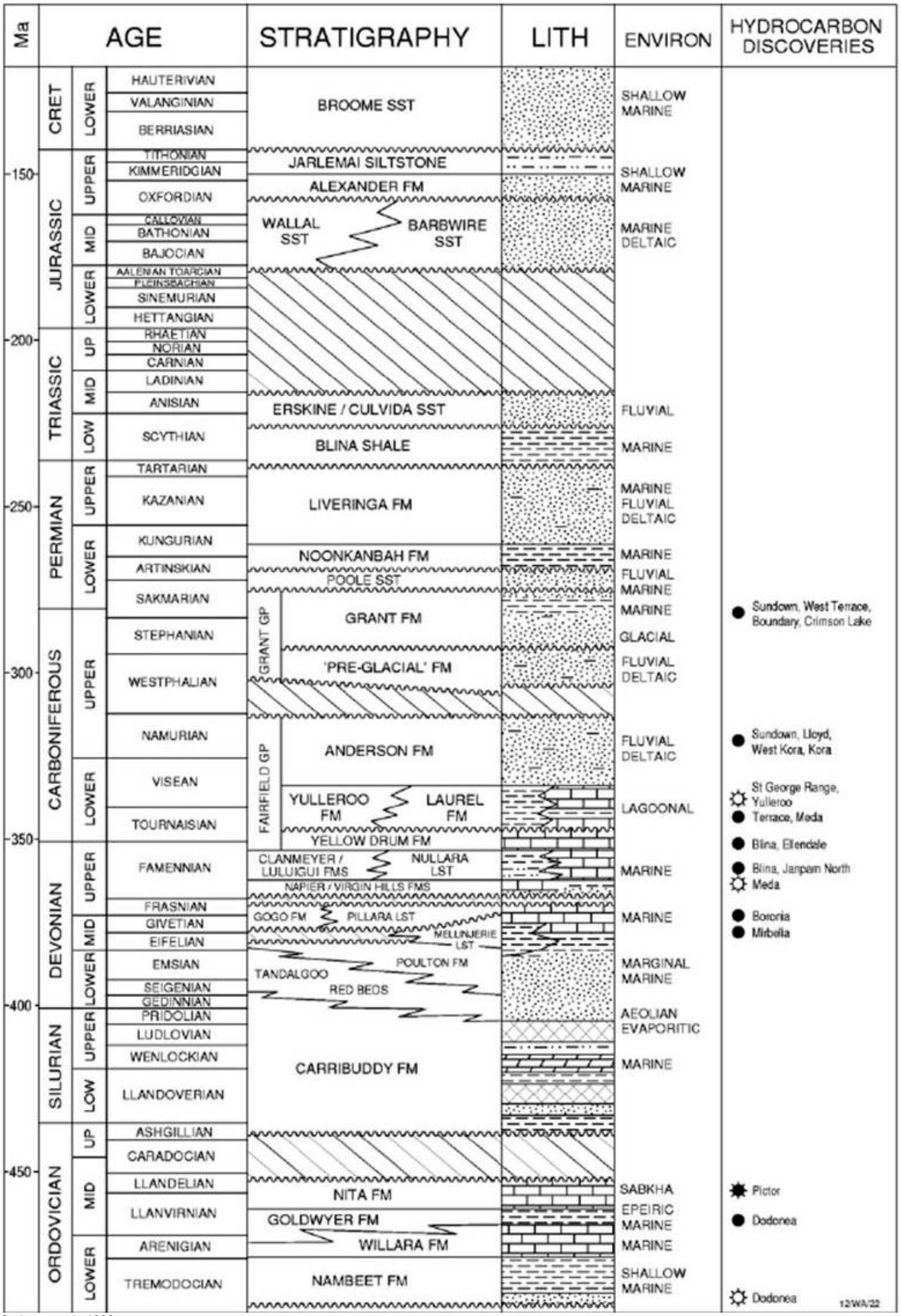
4.3 Reservoir Properties (Prospective Area)

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



Cadman et al., 1993

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.

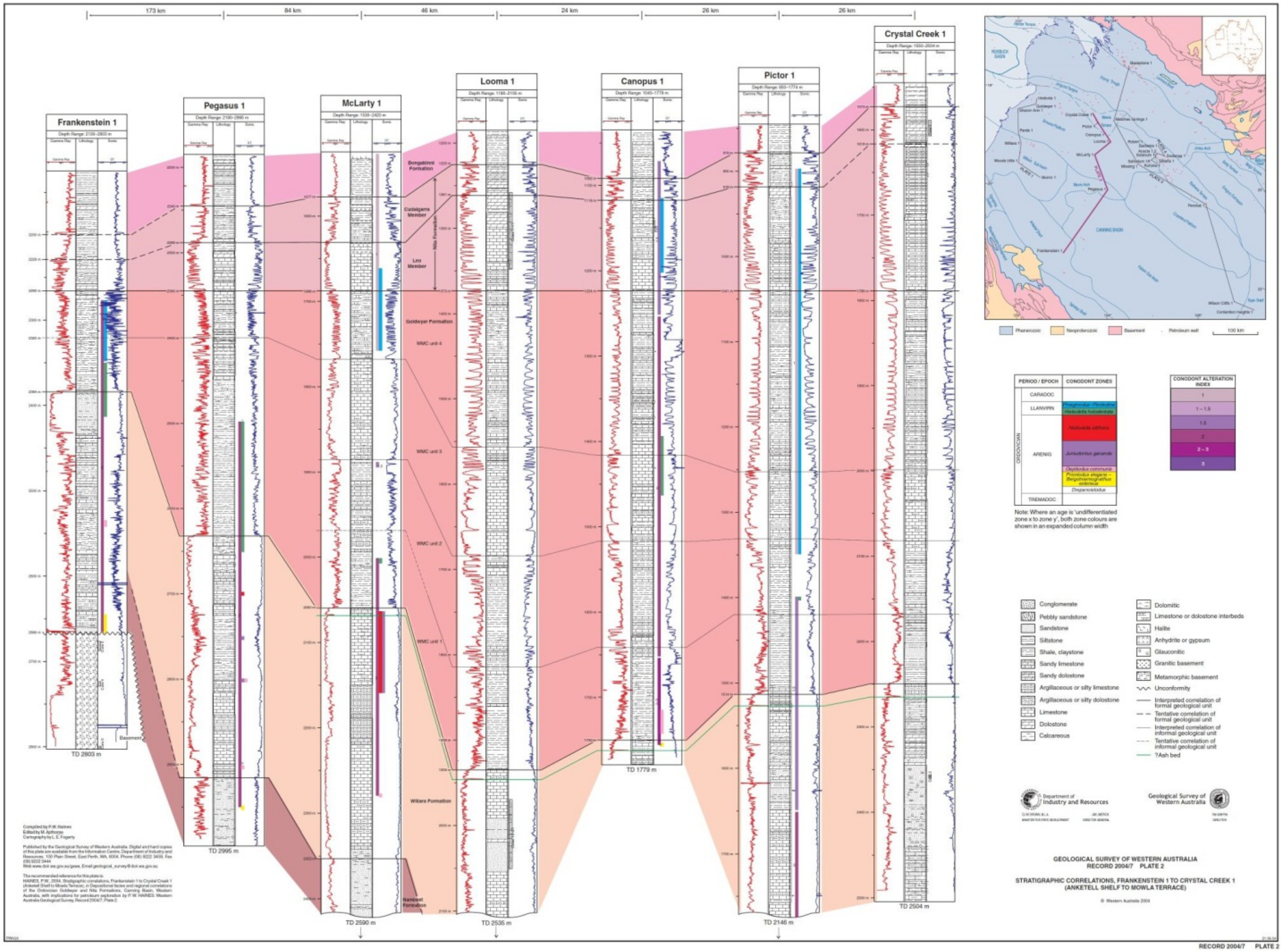
TOC in the Goldwyer Shale generally ranges from 1% to 5% (mean 3%), with some values in excess of 10%, Figure III-17.[27] The upper member of the Goldwyer Shale is particularly rich, with TOC up to 6.40%. Rock-Eval pyrolysis indicates this source rock is within the oil window over much of the southern 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 (Ro > 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-mi^2 area may be prospective for dry gas development with a second 19,620-mi^2 area prospective for wet gas and condensate. A smaller 14,900-mi^2 area appears prospective for shale oil. The boundaries and depth contours for the undrilled deep trough areas were extrapolated from information at adjoining uplifts.

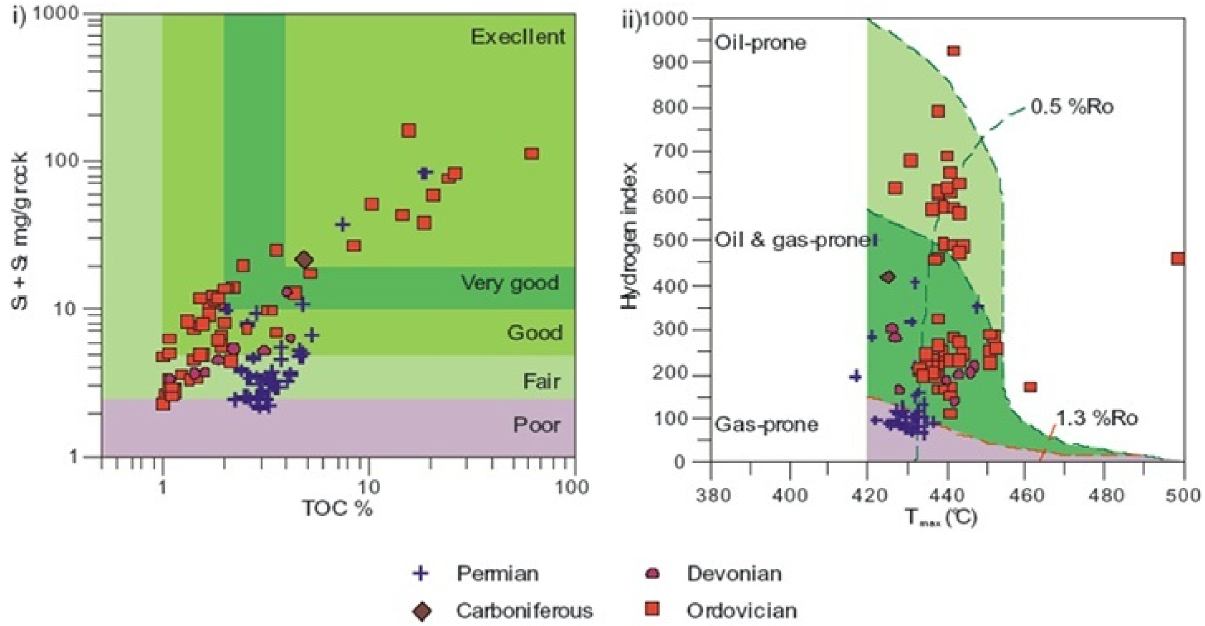
In the dry and wet gas prospective areas, the Goldwyer Shale has resource concentrations of 109 Bcf/mi^2 and 67 Bcf/mi^2, respectively. Including associated gas, the Goldwyer Shale in the Canning Basin has a risked shale gas in-place of 1,227 Tcf, with risked, technically recoverable shale gas of 235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

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



Source: Haines, 2004

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



Source: Ghori and Haines, 2007

4.5 Recent Activity

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

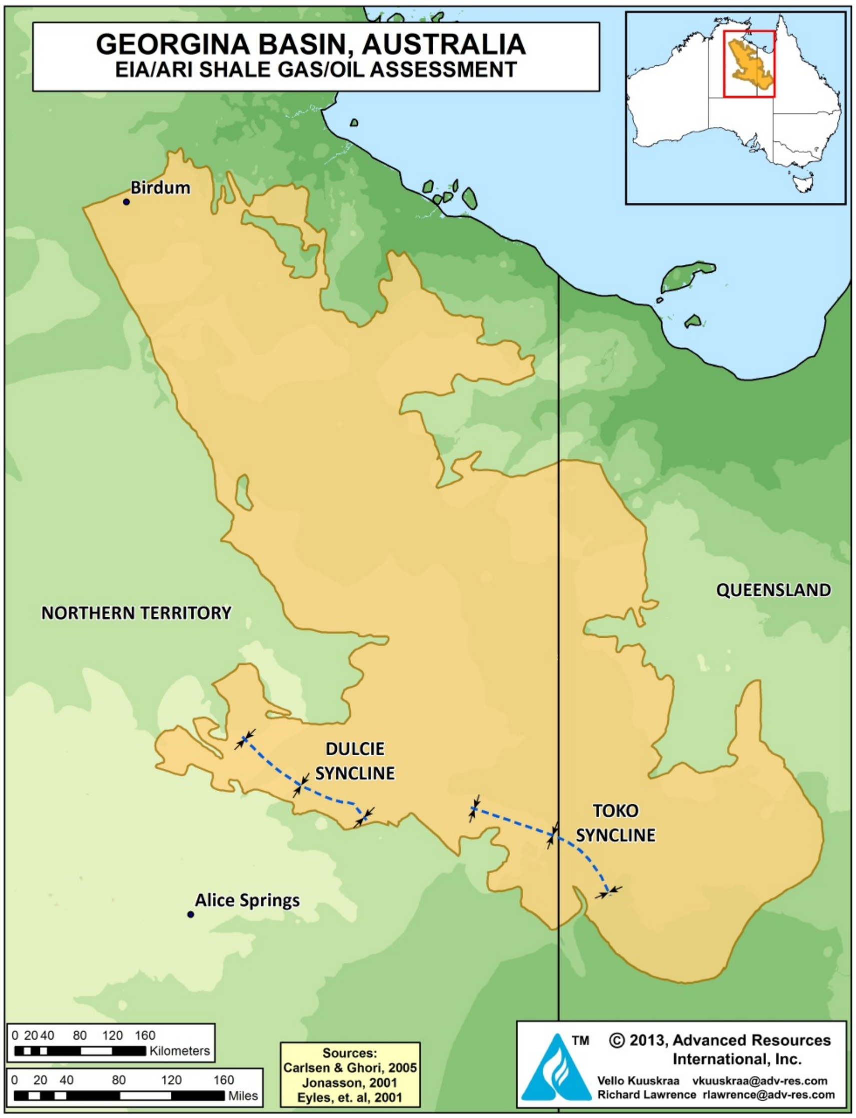
New Standard Energy (NSE), the other principal operator in the Canning Basin, holds exploration licenses covering 17,300 mi^2 in the northern edge of the Kidson sub-basin. In September 2011, NSE formed a joint venture with ConocoPhillips to accelerate exploration of the Goldwyer Shale. ConocoPhillips 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-mi^2 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

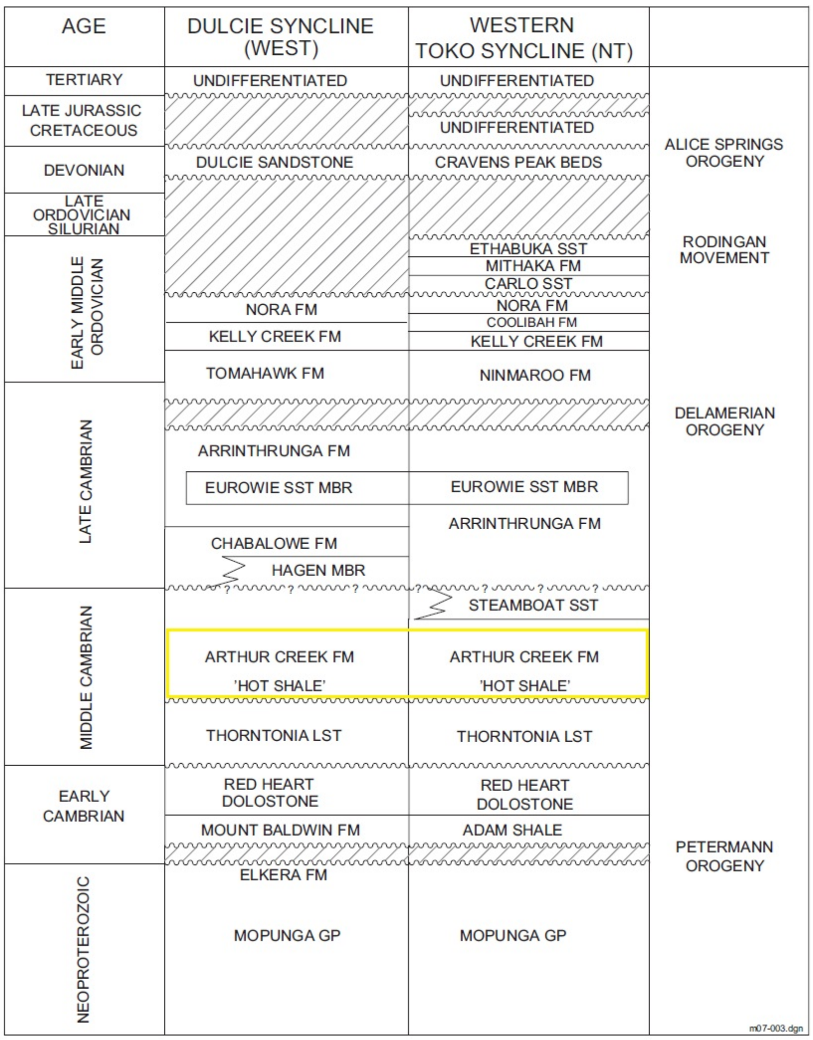


Source: ARI, 2013.

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



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

Advanced Resources International, Inc.

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.

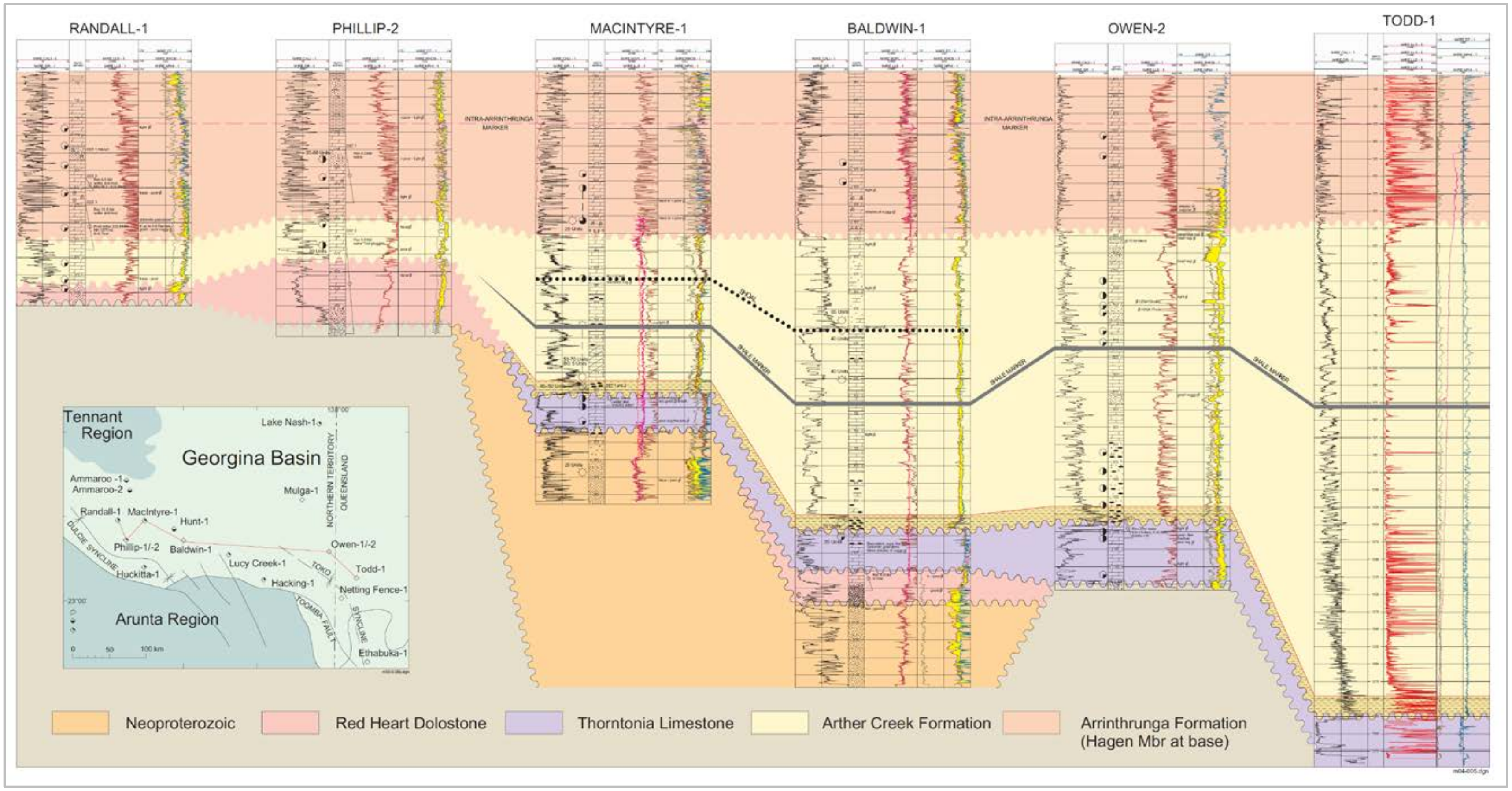
Geoscience Australia studied thirteen samples of core from four wells in the Georgina Basin, mainly from the Lower Arthur Creek Shale. The TOC of these samples ranged from 2% to 16%, with an average TOC of 5.5%.[34] The organic matter is composed of oil and wet gas prone Type I and II kerogen.

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.

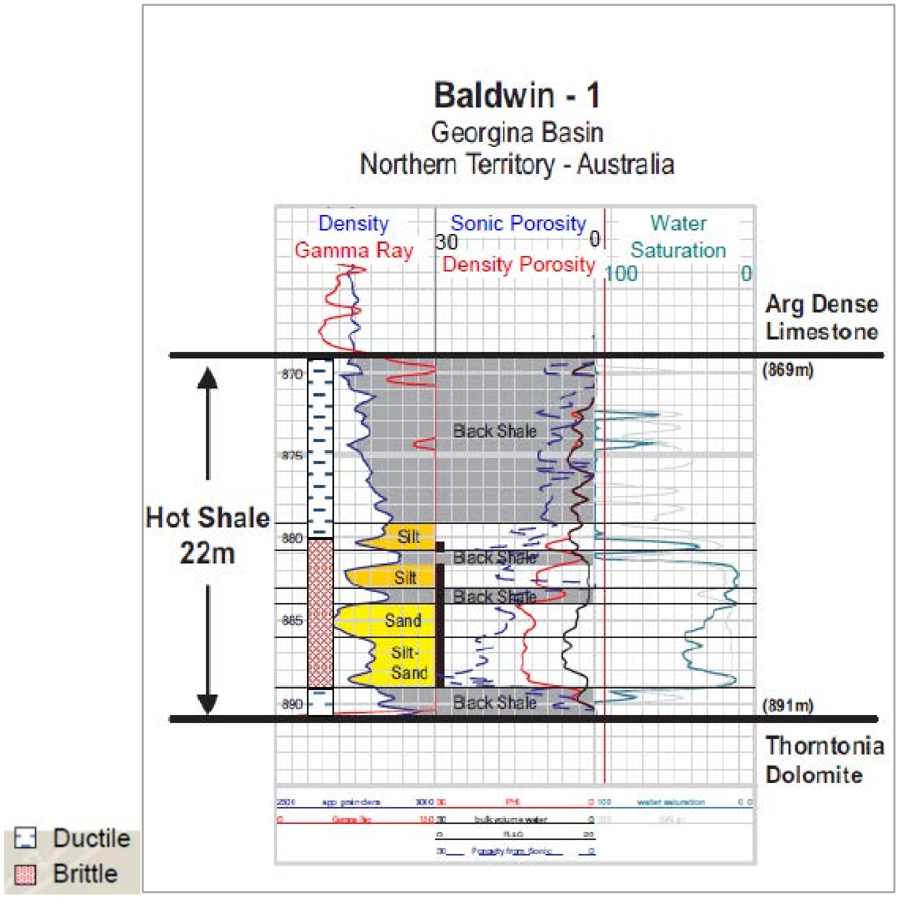
Oil and gas resources were estimated for two prospective areas: an eastern region covering the Dulcie Syncline and surrounding area, and a western region covering the Toko Syncline and surrounding area. Total risked wet and dry shale gas in-place (in both synclines and including associated gas) is estimated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

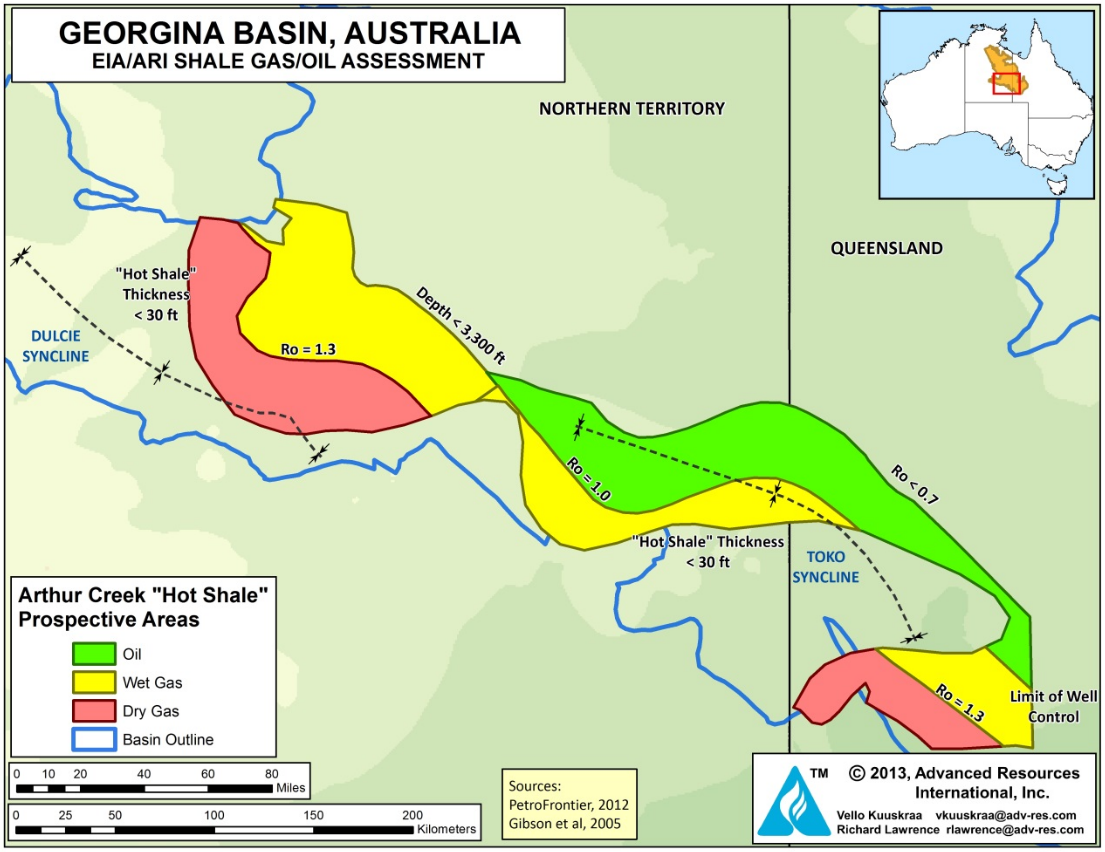
Figure III-21. Log Response of Lower Arthur "Hot Shale"



Source: ARI 2012

Advanced Resources International, Inc.

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



Source: ARI, 2013.

5.5 Recent Activity

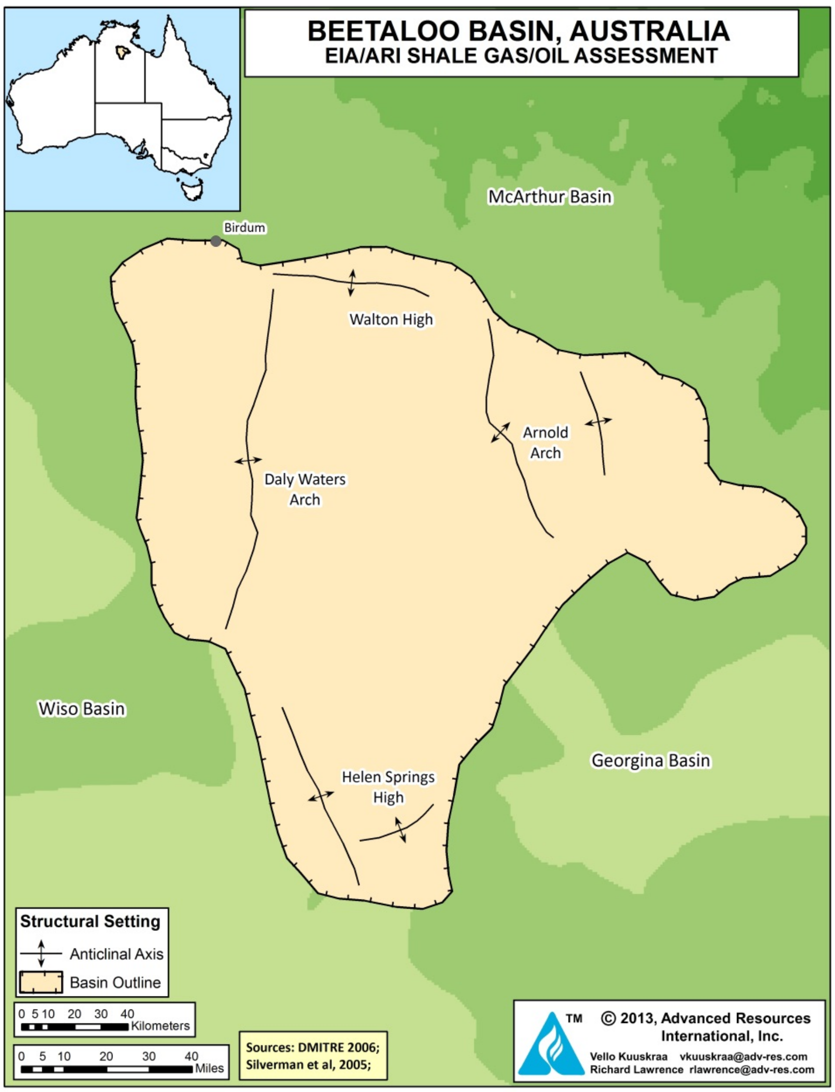
PetroFrontier Corporation, a Canadian company, holds several exploration permits in the southern portion of the Georgina Basin. A farm-in with Statoil Australia was established in 2012 with both companies committing to spending $25 million on an exploration program. Two horizontal exploration wells testing 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 Thorntonia Carbonate section. The core seeped oil on retrieval and had extensive florescence 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-mi^2 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]

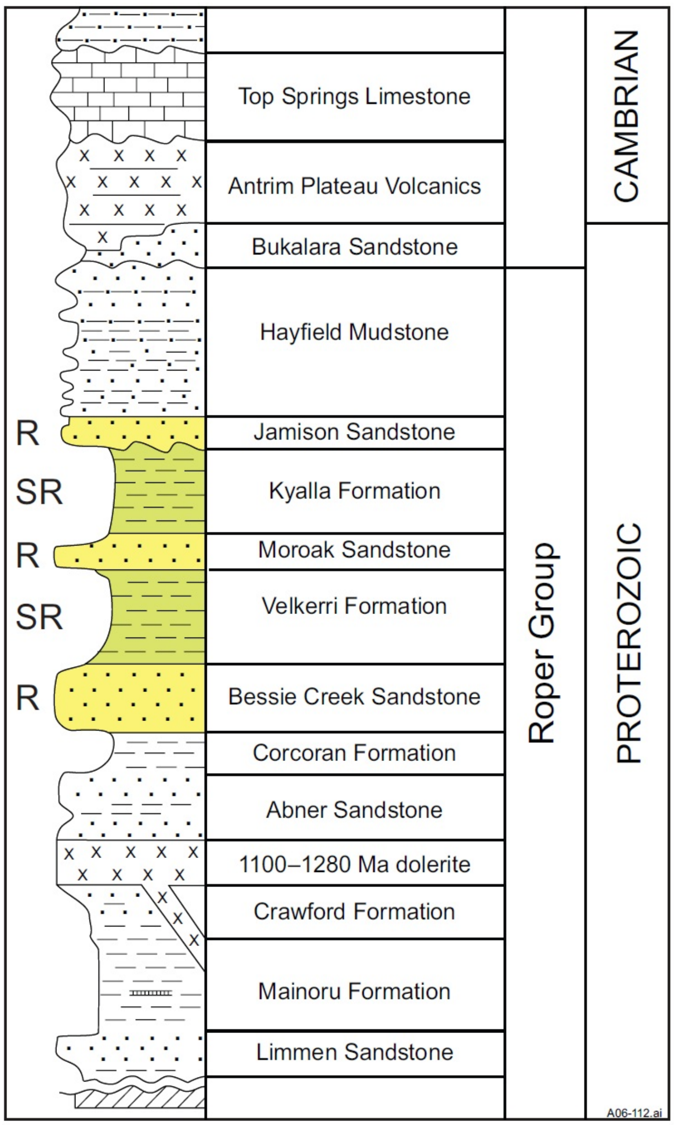
Figure III-23. Beetaloo Basin Location Map



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

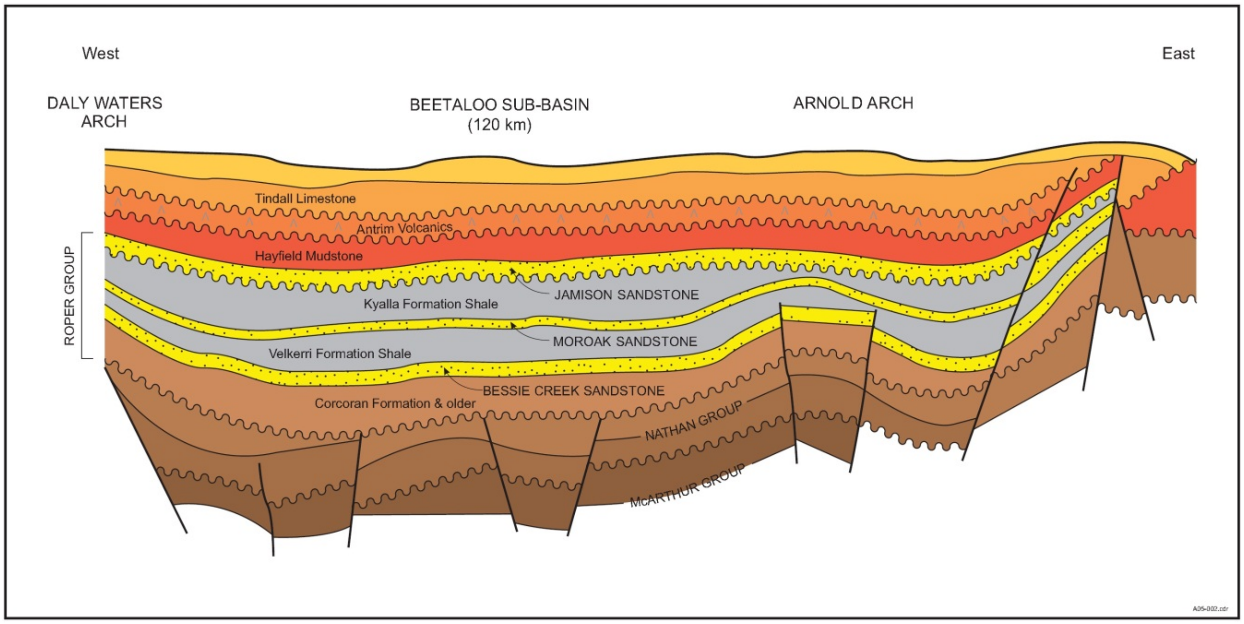


Source: Silverman et al, 2005

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 basin[37], formed during the late Pre-Cambrian and unconformably overlying the western portion of the McArthur Basin. North-south trending faults, observed in the McArthur Basin, are thought to extend into the Beetaloo Basin Figure III-25. A 110 mile long regional gravity high bounding the west side of the basin, the Daly Waters Arch, is a thrust belt with over 3,000 feet of relief.

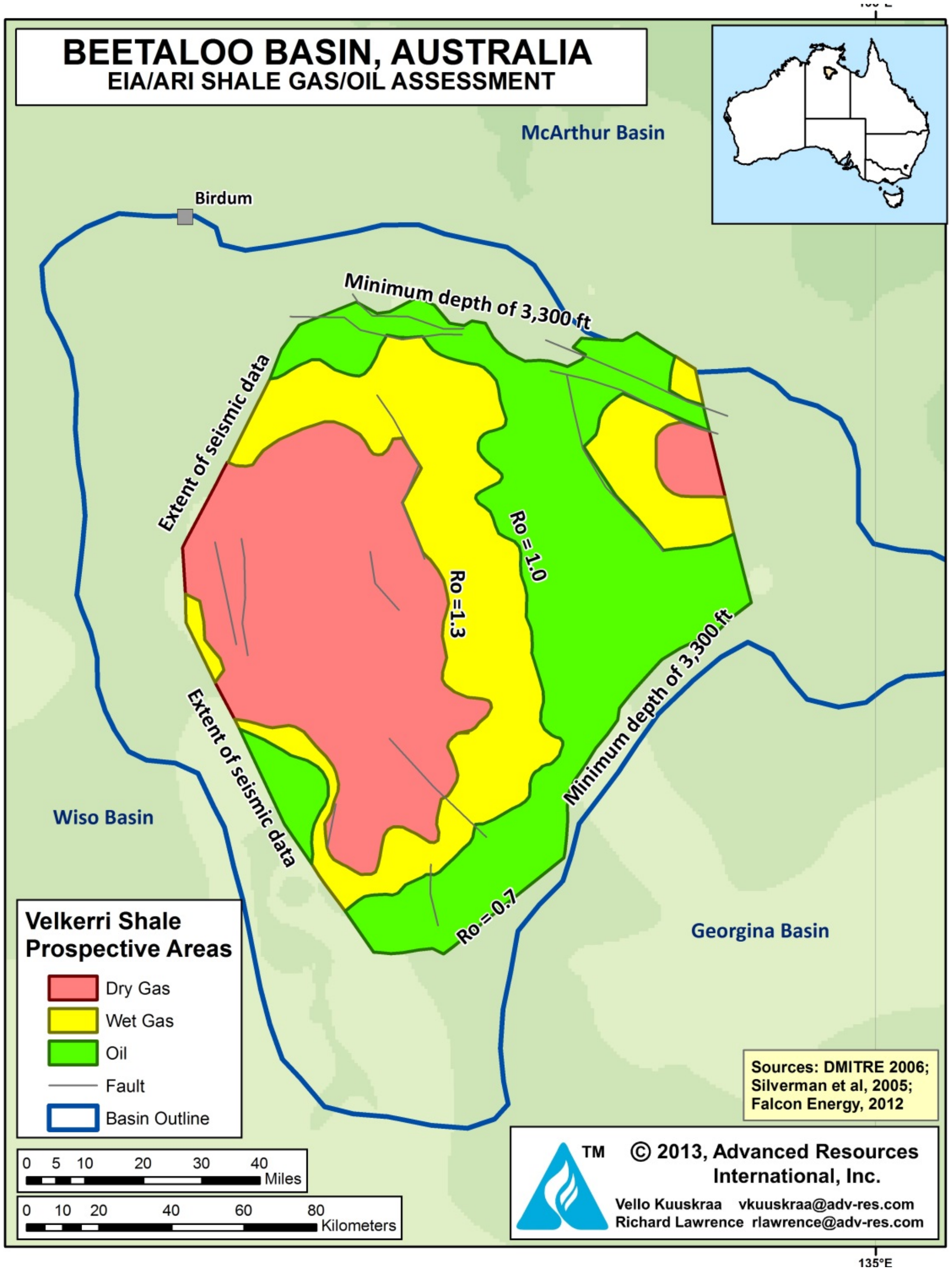
Figure III-25. East-West Cross-Section of the Beetaloo Basin



Source: Ambrose and Silverman, 2006[38]

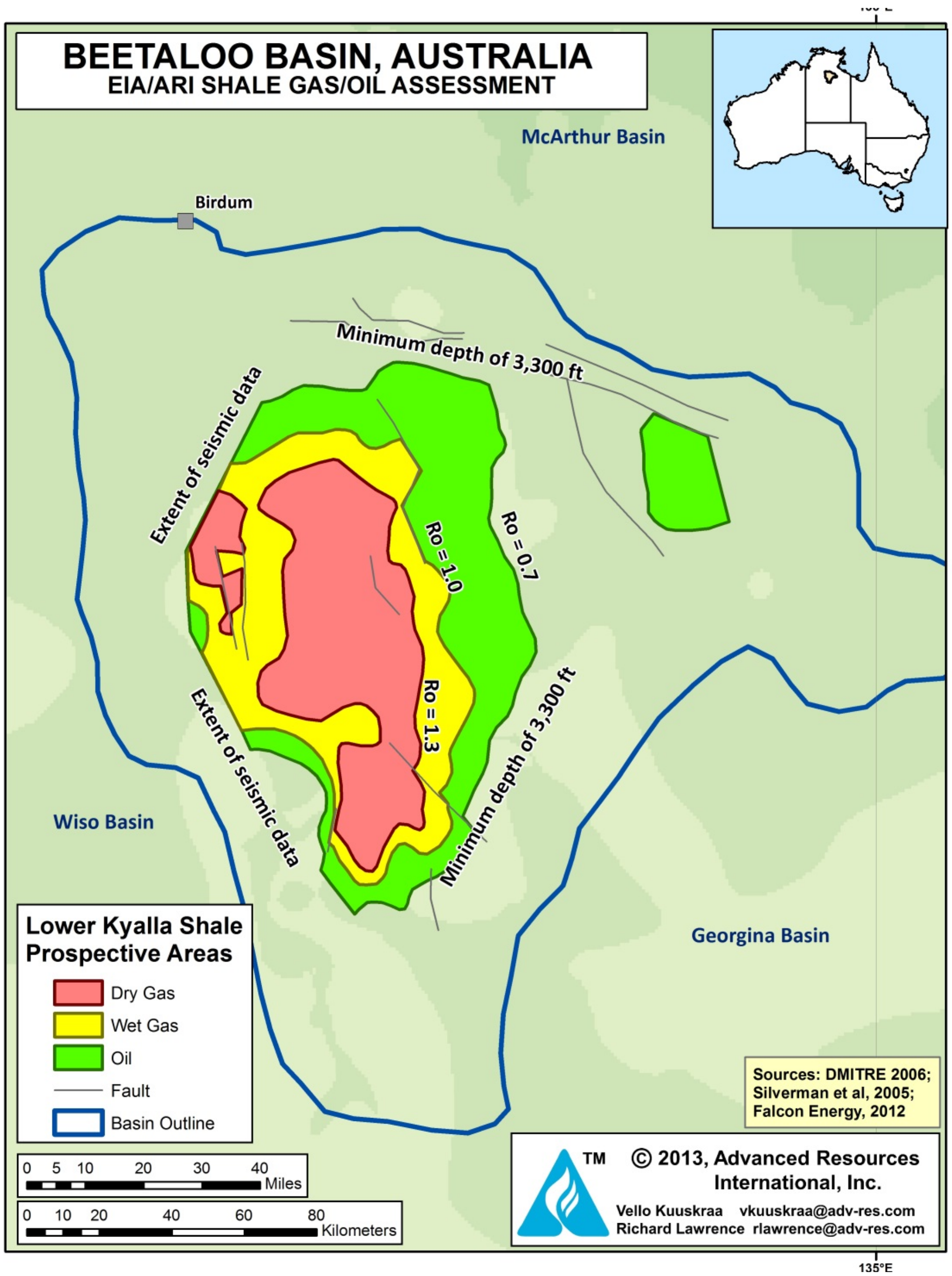
The Velkerri and the Kyalla shales have dry gas, wet gas/condensate and oil windows, based primarily on formation depth. The dry gas prospective area is 2,480 mi^2 for the Velkerri Shale and 1,310 mi^2 for the Kyalla Shale. The wet gas/condensate prospective area covers 2,130 mi^2 for the Velkerri Shale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

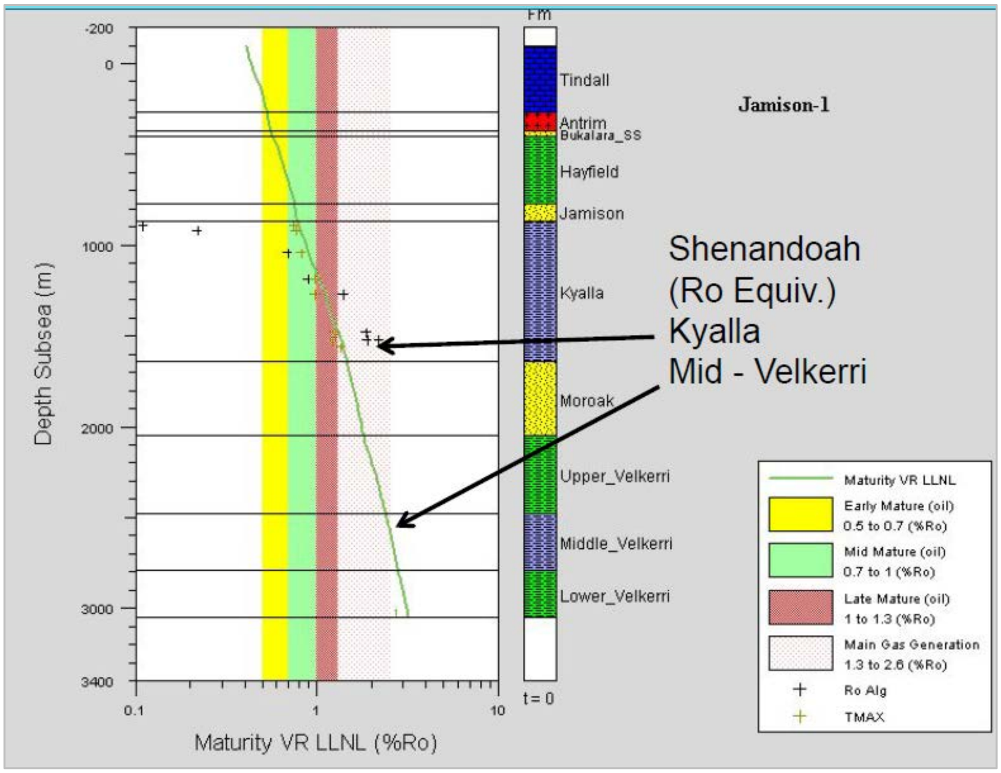
The Middle Velkerri has a maximum total organic carbon (TOC) content of 12%, averaging 4%. The organic matter is composed of oil prone Type I and II kerogens. The Upper and Lower Velkerri shales, with TOC contents of less than 2%, have not been included in the resource assessment.

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 Ro 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.

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