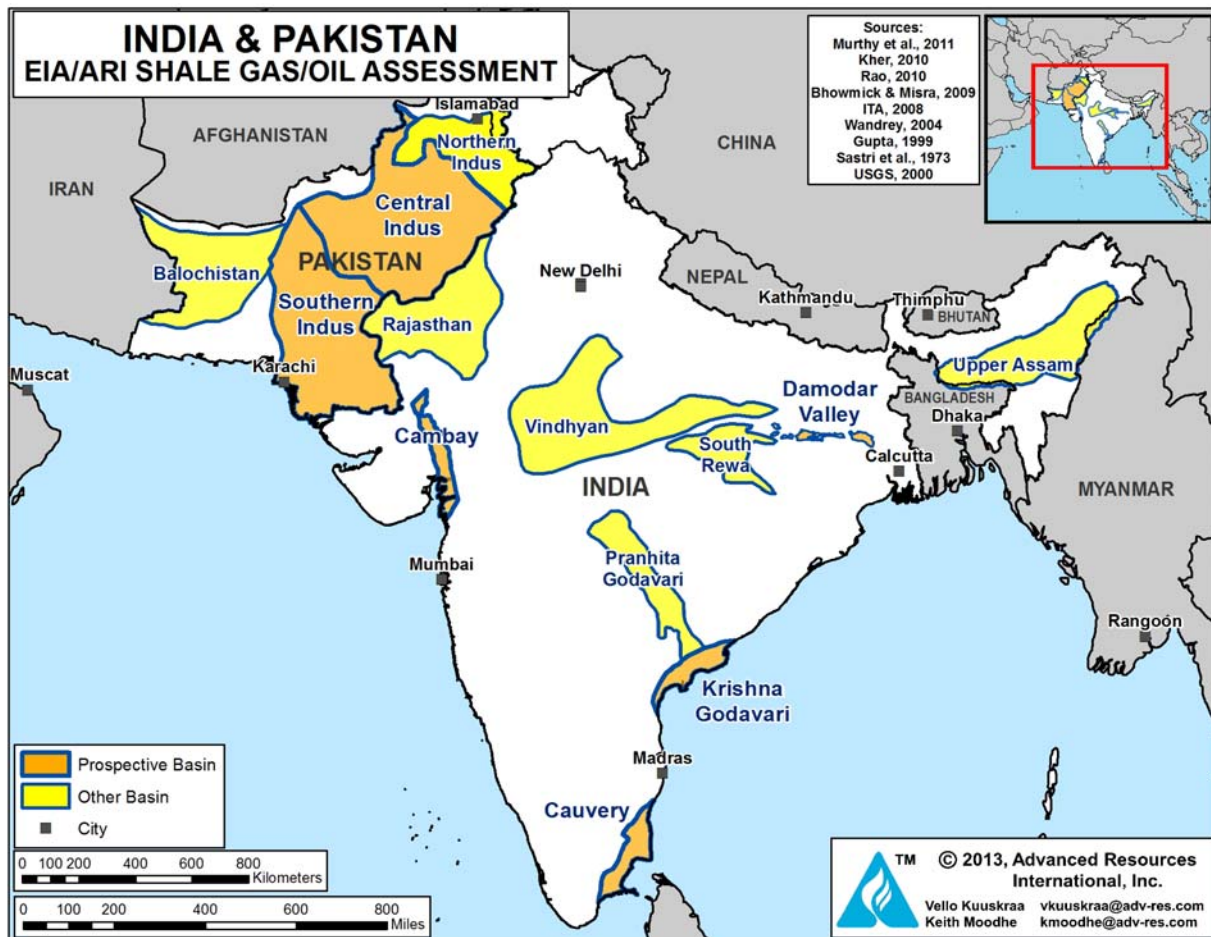


XXIV. INDIA/PAKISTAN

SUMMARY

India and Pakistan contain numerous basins with organic-rich shales. For India, the study assessed four priority basins: Cambay, Krishna-Godavari, Cauvery and Damodar Valley. The study also screened other basins in India, such as the Upper Assam, Vindhyan, Pranhita-Godavari, Rajasthan and South Rewa. However, in these basins the shales were thermally too immature or the data for conducting a rigorous resource assessment were not available. For Pakistan, the study addressed the areally extensive Indus Basin, Figure XXIV-1.

Figure XXIV-1. Shale Gas and Shale Oil Basins of India/Pakistan



Overall, ARI estimates a total of 1,170 Tcf of risked shale gas in-place for India/Pakistan, 584 Tcf in India and 586 Tcf in Pakistan. The risked, technically recoverable shale gas resource is estimated at 201 Tcf, with 96 Tcf in India and 105 Tcf in Pakistan, Tables XXIV-1A and XXIV-1B. In addition, we estimate risked shale oil in-place for India/Pakistan of 314 billion barrels, with 87 billion barrels in India and 227 billion barrels in Pakistan. The risked, technically recoverable shale oil resource is estimated at 12.9 billion barrels for these two countries, with 3.8 billion barrels for India and 9.1 billion barrels for Pakistan, Table XXIV-2A and XXIV-2B.

Table XXIV-1A. Shale Gas Reservoir Properties and Resources of India

Basic Data	Basin/Gross Area		Cambay (7,900 mi ²)			Krishna-Godavari (7,800 mi ²)			Cauvery (9,100 mi ²)	Damodar Valley (2,270 mi ²)
	Shale Formation		Cambay Shale			Permian-Triassic			Sattapadi-Andimadam	Barren Measure
	Geologic Age		U. Cretaceous-Tertiary			Permian-Triassic			Cretaceous	Permian-Triassic
	Depositional Environment		Marine			Marine			Marine	Marine
Physical Extent	Prospective Area (mi ²)		1,060	300	580	1,100	3,900	3,000	1,010	1,080
	Thickness (ft)	Organically Rich	1,500	1,500	1,500	330	500	1,300	1,000	1,000
		Net	500	500	500	100	150	390	500	250
	Depth (ft)	Interval	6,000 - 10,000	10,000 - 13,000	13,000 - 16,400	4,000 - 6,000	6,000 - 10,000	10,000 - 16,400	7,000 - 13,000	3,300 - 6,600
Average		8,000	11,500	14,500	5,000	8,000	13,000	10,000	5,000	
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Normal	Normal	Normal	Normal	Slightly Overpress.
	Average TOC (wt. %)		2.6%	2.6%	2.6%	6.0%	6.0%	6.0%	2.3%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.80%	0.85%	1.15%	1.50%	1.15%	1.20%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	High	High	High	High	High
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Wet Gas
	GIP Concentration (Bcf/mi ²)		55.9	170.5	228.0	6.9	57.8	204.7	119.6	62.9
	Risked GIP (Tcf)		35.5	30.7	79.4	3.4	101.4	276.4	30.2	27.2
	Risked Recoverable (Tcf)		3.6	6.1	19.8	0.2	15.2	41.5	4.5	5.4

Table XXIV-1B. Shale Gas Reservoir Properties and Resources of Pakistan

Basic Data	Basin/Gross Area		Lower Indus (169,000 mi ²)			
	Shale Formation		Sembar			Ranikot
	Geologic Age		L. Cretaceous			Paleocene
	Depositional Environment		Marine			Marine
Physical Extent	Prospective Area (mi ²)		26,700	25,560	31,320	26,780
	Thickness (ft)	Organically Rich	1,000	1,000	1,000	1,000
		Net	250	250	250	200
	Depth (ft)	Interval	4,000 - 6,000	6,000 - 10,000	10,000 - 16,400	6,000 - 13,000
Average		5,000	8,000	13,000	9,000	
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	0.85%
	Clay Content		Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi ²)		14.3	57.0	82.7	17.0
	Risked GIP (Tcf)		45.9	174.7	310.8	54.8
	Risked Recoverable (Tcf)		3.7	34.9	62.2	4.4

Table XXIV-2A. Shale Oil Reservoir Properties and Resources of India

Basic Data	Basin/Gross Area		Cambay (7,900 mi ²)		Krishna-Godavari (7,800 mi ²)		Cauvery (9,100 mi ²)	Damodar Valley (2,270 mi ²)
	Shale Formation		Cambay Shale		Permian-Triassic		Sattapadi-Andimadam	Barren Measure
	Geologic Age		U. Cretaceous-Tertiary		Permian-Triassic		Cretaceous	Permian-Triassic
	Depositional Environment		Marine		Marine		Marine	Marine
Physical Extent	Prospective Area (mi ²)		1,060	300	1,100	3,900	1,010	1,080
	Thickness (ft)	Organically Rich	1,500	1,500	330	500	1,000	1,000
		Net	500	500	100	150	500	250
	Depth (ft)	Interval	6,000 - 10,000	10,000 - 13,000	4,000 - 6,000	6,000 - 10,000	7,000 - 13,000	3,300 - 6,600
Average		8,000	11,500	5,000	8,000	10,000	5,000	
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Normal	Normal	Normal	Slightly Overpress.
	Average TOC (wt. %)		2.6%	2.6%	6.0%	6.0%	2.3%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	1.15%	1.20%
	Clay Content		Low/Medium	Low/Medium	High	High	High	High
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Condensate	Condensate
	OIP Concentration (MMbbl/mi ²)		79.8	19.2	17.5	6.5	30.2	12.1
	Risky OIP (B bbl)		50.8	3.5	8.7	11.5	7.6	5.2
	Risky Recoverable (B bbl)		2.54	0.17	0.26	0.34	0.23	0.21

Table XXIV-2B. Shale Oil Reservoir Properties and Resources of Pakistan

Basic Data	Basin/Gross Area		Lower Indus (169,000 mi ²)		
	Shale Formation		Sembar		Ranikot
	Geologic Age		L. Cretaceous		Paleocene
	Depositional Environment		Marine		Marine
Physical Extent	Prospective Area (mi ²)		26,700	25,560	26,780
	Thickness (ft)	Organically Rich	1,000	1,000	1,000
		Net	250	250	200
	Depth (ft)	Interval	4,000 - 6,000	6,000 - 10,000	6,000 - 13,000
Average		5,000	8,000	9,000	
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%
	Clay Content		Low	Low	Low
Resource	Oil Phase		Oil	Condensate	Oil
	OIP Concentration (MMbbl/mi ²)		36.6	9.1	25.4
	Risky OIP (B bbl)		117.4	27.9	81.7
	Risky Recoverable (B bbl)		4.70	1.12	3.27

INTRODUCTION

Evaluating the shale gas and oil resources of India and Pakistan posed a series of challenges. Only limited publically available data exist on the geologic setting and reservoir properties of the numerous shale formations in India and Pakistan. In addition, the shale basins in these two countries are geologically highly complex.

Many of the basins in India, such as the Cambay and the Cauvery, comprised a series of extensively faulted horst and graben structures. As such, the prospective areas for shale gas and oil in these basins are often restricted to a series of isolated basin depressions (sub-basins). While the shales in these basins are thick, considerable uncertainty exists on the areal extents of the prospective areas in these basins. To account for this uncertainty, we have applied prospective area risk factors to each basin. Figures XXIV-2 shows the stratigraphic column for the key basins of India.

Recently, ONGC drilled and completed India's first shale gas well, RNSG-1, northwest of Calcutta in West Bengal. The well was drilled to a depth of 2,000 meters and reportedly had gas shows at the base of the Permian-age Barren Measure Shale. Two vertical wells (Well D-A and D-B) were previously tested in the Cambay Basin and had modest shale gas and oil production from the Cambay Black Shale.¹

In Pakistan, the shale gas and oil assessment is restricted to the areally extensive Central and Southern Indus basins, together called the Lower Indus Basin. The shales in this basin have sourced the significant volumes of conventional oil and gas discovered and produced in Pakistan. However, to date, no shale specific exploration has been publically reported for Pakistan. Figure XXIV-3 provides the stratigraphic column for the key basins of Pakistan.

Fortunately, the technical literature on conventional oil and gas exploration in India and Pakistan often contains information on the nature of the source rocks that have charged the conventional gas and oil reservoirs, providing a valuable starting point for this resource assessment. As additional shale-directed geological and reservoir information is collected and distributed, a more rigorous assessment of India's and Pakistan's shale oil and gas resources will emerge.

Figure XXIV-2. Stratigraphic Column for India

			INDIA BASINS					
BASIN			CAMBAY	KRISHNA GODAVARI	CAUVERY	DAMODAR VALLEY	UPPER ASSAM	
ERA	PERIOD	EPOCH	F O R M A T I O N					
CENOZOIC	QUATERNARY	Holocene		Undifferentiated			Alluvium	
		Pleistocene	Gujarat Alluvium				Dhekiajuli Fm	
	TERTIARY	Pliocene	Jambusar Fm			Tillacheri Sandstone		
			Broach Fm					
			Jhagadia Fm					<i>Namsang Fm</i>
		Miocene	<i>Kand Fm</i>			Madanam Limestone		
			<i>Babaguru Fm</i>			Vanjiyur Sandstone		<i>Girujan Fm</i>
	Oligocene	<i>Tarkesvar Fm</i>			Shiyali		<i>Tipam Fm</i>	
		<i>Dadhar Fm/ Tarapur Shale</i>			Kovikalappal Fm		Surma Member	
		<i>Kalol Fm</i>			<i>Niravi Sandstone</i>		Barail Group	
Eocene	<i>Kadi Fm</i>	Younger Cambay Shale		Pandanallur Fm		Moran Fm		
						<i>Tinali Fm</i>		
				Karaikal Shale		Kopili Fm		
Paleocene		Older Cambay Shale				Sylhet Fm		
	<i>Olpad Fm</i>		Razole	<i>U. Kamalapuram Fm</i>		Prang Member Narpuh Member <i>Lakadong Member</i>		
MESOZOIC	CRETACEOUS	Upper	<i>Deccan Traps</i>	<i>Tirupati Sandstone</i>	Porlo-Novo Shale	Rajmahal Traps		
		Lower		Raghavapuram Shale	<i>Nannilam Fm</i>			
	JURASSIC	Upper		<i>Gollapalli Fm</i>	Kudavasal Shale			
				<i>Red Bed</i>	<i>Bhuvanagiri Fm</i>		Supra-Panchet Fm	
	TRIASSIC				Sattapadi Shale			
				<i>Mandapeta Fm</i>	<i>Andimadam Fm</i>		Dubrajpur Fm	
PALEOZOIC	PERMIAN			Kommugudem Fm		Raniganj Fm		
				Draksharama Fm		<i>Barren Measures</i>		
PROTEROZOIC	PRECAMBRIAN					Barakar Fm		
						Talchir		
			Basement			Basement		
						Basement		

Source Rock	Conventional Reservoir	Absent/Unknown
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Figure XXIV-3. Stratigraphic Column for Pakistan

			PAKISTAN BASINS				
BASIN			SOUTHERN INDUS	CENTRAL INDUS	NORTHERN INDUS	BALOCHISTAN	
ERA	PERIOD	EPOCH	F O R M A T I O N				
CENOZOIC	QUATERNARY	Pleistocene	Sivaliks	Sivaliks		Ormara Chatti	
		Pliocene				Talar/Hinglas	
	TERTIARY	Miocene	Gaj	Gaj	Kamlial Murree	Parkini Panjgur	
		Oligocene	Nari	Nari		Hoshab Siahn Amalaf	
		Eocene	Kirthar	Kirthar		Wakai	
			Ghazij/ Baska/Laki	Sakaser	Kohat	Saindak Kharan	
		Paleocene	Dunghan	Dunghan	Patala	Ispikan	
			Ranikot Khadro	Ranikot	Lockhart Hangu	Rakhshani	
	MESOZOIC	CRETACEOUS	Upper	Pab	Pab		Humai Sinjrani
				Mughal Kot	Mughal Kot	Kawagarh	
Parh				Parh			
Lower			Goru	Goru	Lumshiwai		
JURASSIC		Upper	Sembar	Sembar	Chichali		
			Takatu/Chiltan	Samana Suk			
		Middke	Lorolai/Datta		Samana Suk		
		Lower	Shirinab	Shinawari Data	Shinawari Data		
TRIASSIC		Upper	Wulgai/Alozai	Kingriali	Kingriali		
		Middke		Tredian	Tredian		
	Lower	Mianwali		Mianwali Chidru			
PALEOZOIC	PERMIAN		Zaluch	Wargal Sardhai			
			Nilawhan	Warcha Dandot Tobra			
	CAMBRIAN		Baghanwala	Baghanwala			
			Juttana	Juttana	Juttana		
PROTEROZOIC	PRECAMBRIAN	Kussak	Kussak	Khewra			
		Khewra	Khewra	Khewra			
		Salt Range	Salt Range	Salt Range			
		Jodhpur	Jodhpur				
		Basement	Basement	Basement			

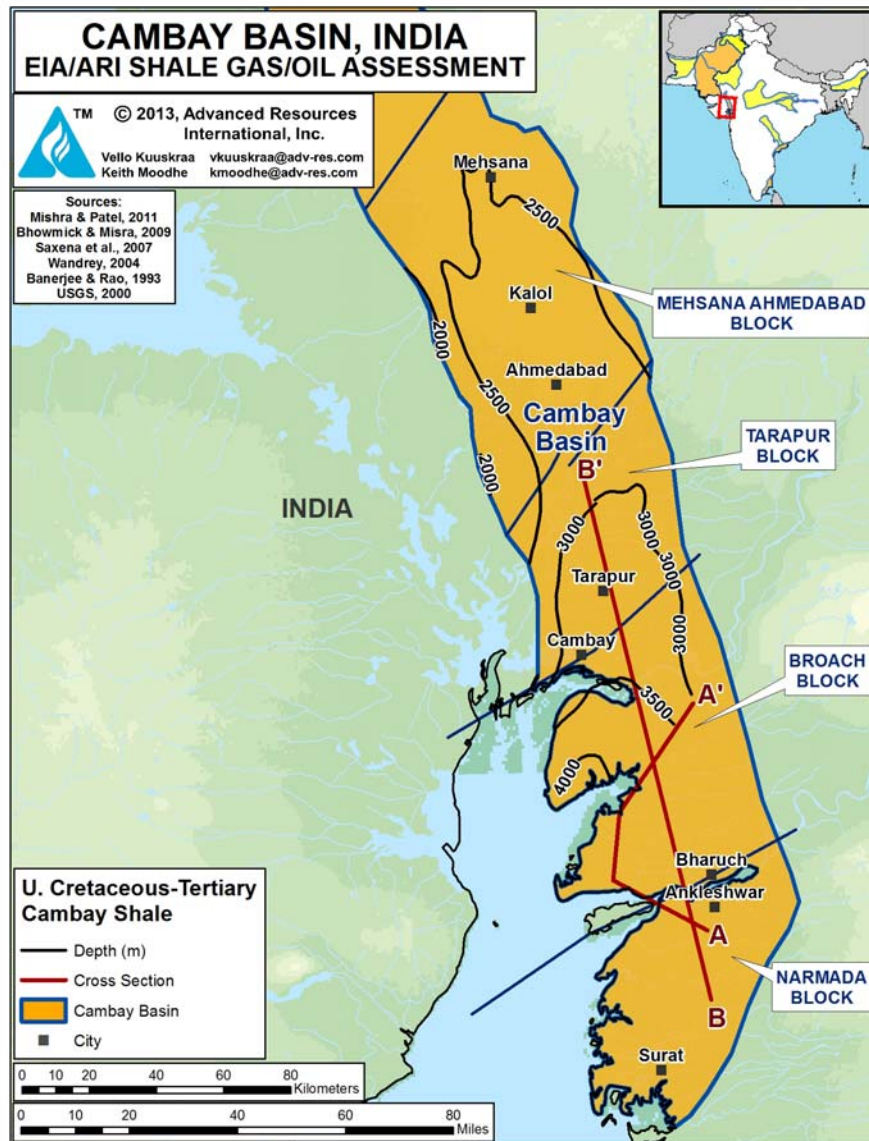
Source Rock	Conventional Reservoir	Absent/Unknown
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1. CAMBAY BASIN, INDIA

1.1 Introduction and Geologic Setting

The Cambay Basin is an elongated, intra-cratonic Late Cretaceous to Tertiary rift basin, located in the State of Gujarat in northwest India. The basin includes four assessed fault blocks: Mehsana-Ahmedabad, Tarapur, Broach and Narmada, Figure XXIV-4.

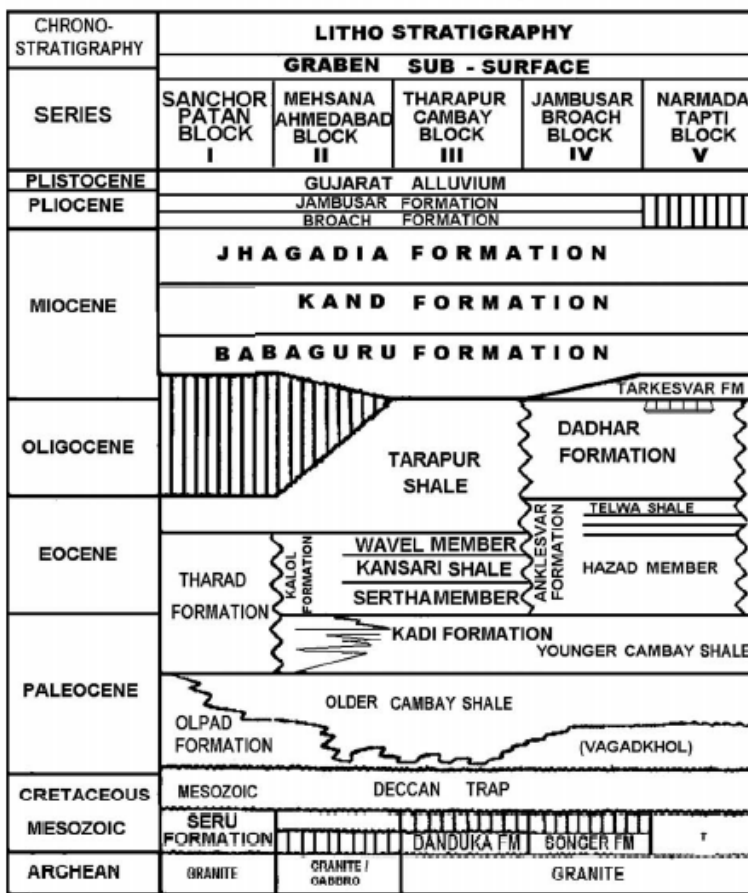
Figure XXIV-4. Depth of Cambay Black Shale, Cambay Basin



The Cambay Basin is bounded on its eastern and western sides by basin-margin faults and extends south into the offshore Gulf of Cambay, limiting its onshore area to 7,900 mi².²

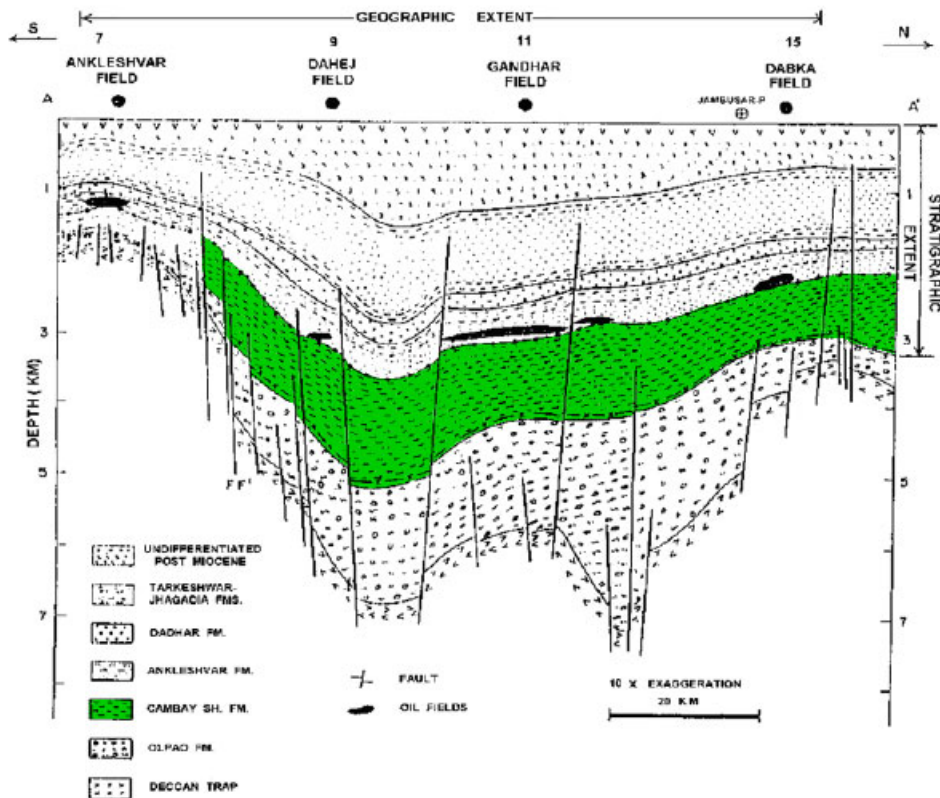
The Deccan Trap, composed of horizontal lava flows, forms the basement of the Cambay Basin. Above the Deccan Trap, separated by the Olpad Formation, is the Late Paleocene and Early Eocene Cambay Black Shale, Figure XXIV-5.³ The Cambay Black Shale represents the marine transgressive episode in the basin. With a thermal maturity ranging from about 0.7% to 2%, the shale is in the oil, wet gas and dry gas windows.⁴ For purposes of this study, we have assumed that the oil window starts at 6,000 feet of depth, that the wet gas window starts at 11,000 feet, and that the dry gas window is below 13,000 feet of depth, Figures XXIV-6 and XXIV-7.

Figure XXIV-5. Generalized Stratigraphic Column of the Cambay Basin.



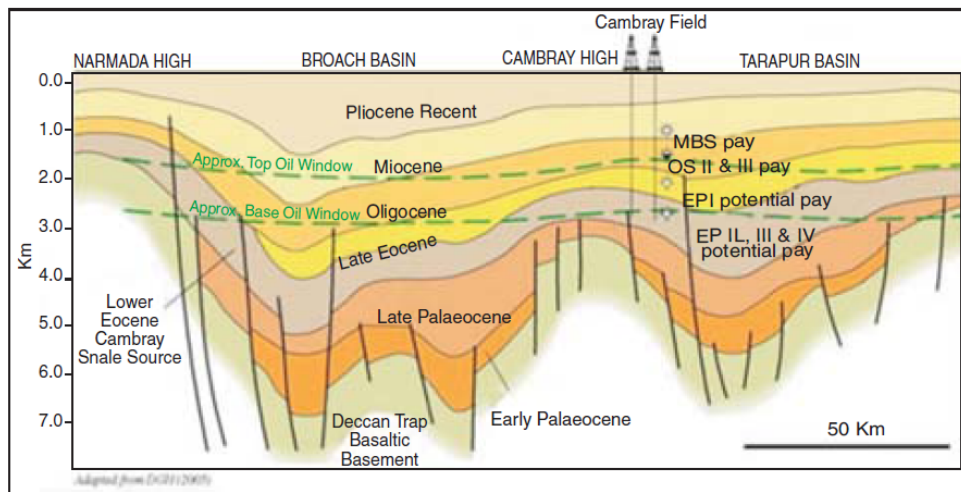
Source: Silvan, 2008

Figure XXIV-6. Cross Section of Cambay Black Shale System



Source: Shishir Kant Saxena, 2007

Figure XXIV-7. N-S Geological Cross-Section Across Cambay Basin



Source: P.K. Bhowmick and Ravi Misra, Indian Oil and Gas Potential, Glimpses of Geoscience Research in India.

The Cambay Basin contains four primary fault blocks, from north to south: (1) Mehsana-Ahmedabad; (2) Tarapur; (3) Broach; and (4) Narmada (Sivan et al., 2008).³ Three of these blocks appear to have sufficient thermal maturity to be prospective for shale gas and oil, Table XXIV-3.⁵

Table XXIV-3. Major Fault Blocks and Shale Prospectivity of Cambay Basin

Fault Blocks		Comments
1.	Mehsana-Ahmedabad	Prospective for Shale Oil
2.	Tarapur	Prospective for Shale Oil and Wet Gas
3.	Broach	Prospective for Shale Oil and Wet/Dry Gas
4.	Narmada	Insufficient Data, Likely Immature

- Mehsana-Ahmedabad Block.** Three major deep gas areas (depressions) exist in the Mehsana-Ahmedabad Block - - the Patan, Worosan and Wamaj. A deep well, Well-A, was drilled in the eastern flank of the Wamaj Low to a depth of nearly 15,000 ft, terminating below the Cambay Black Shale. In addition, a few wells were recently drilled to the Cambay Black Shale in the axial part of the graben low. A high-pressure gas zone was encountered in the Upper Olpad section next to the Cambay Shale, with methane shows increasing with depth. Geochemical modeling for this fault block indicates an oil window at 6,600 ft, a wet gas window at 11,400 ft, and a dry gas window at 13,400 ft.⁶
- Broach and Tarapur Blocks.** The deeper Tankari Low in the Broach Block and the depocenter of the Tarapur Block appear to have similar thermal histories as the Mehsana-Ahmedabad Block. As such, we assumed these two areas have generally similar shale gas and oil properties as the Cambay Black Shale in the Mehsana-Ahmedabad Block.

1.2 Reservoir Properties (Prospective Area)

The depth of the prospective area of the Cambay Black Shale ranges from about 6,000 ft in the north to 16,400 ft in the lows of the southern fault blocks, averaging 8,000 ft in the oil prospective area, 11,500 ft in the wet gas and condensate prospective area, and 14,500 ft in the dry gas prospective area. Thermal gradients are high, estimated at 3°F per 100 feet, contributing to accelerated thermal maturity of the organics.⁷ The Cambay Black Shale interval ranges from 1,500 to more than 5,000 ft thick in the various fault blocks.⁸ In the northern

Mehsana-Ahmedabad Block, the Kadi Formation forms an intervening 1,000-ft thick non-marine clastic wedge within the Cambay Black Shale interval. In this block, the shale thickness varies from 300 to 3,000 ft, with the organic-rich shale thickness, located in the lower portion of the Cambay Black Shale interval, averaging 500 net ft, Figure XXIV-8.

The organic matter in the shale is primarily Type II and Type III (terrestrial) with a TOC that ranges from 2% to 4%, averaging 2.6%, Figure XXIV-9. The shale formation is moderately over-pressured and has low to medium clay content.

Within the overall 1,940-mi² Cambay Black Shale prospective area in the Cambay Basin, we estimate: a 580-mi² area prospective for dry gas; a 300-mi² area prospective for wet gas and condensate; and a 1,060-mi² area prospective for oil, Figure XXIV-10.

1.3 Resource Assessment

The Cambay Black Shale has resource concentrations of: 228 Bcf/mi² of shale gas in its 580-mi² dry gas prospective area; 170 Bcf/mi² of wet gas and 19 million barrels/mi² of condensate in the 300-mi² wet gas/condensate prospective area; and 80 million barrels/mi² of shale oil (plus associated gas) in the 1,060-mi² oil prospective area.

Within the overall 1,940-mi² prospective area for the Cambay Black Shale in the Cambay Basin, we estimate a risked resource in-place of 146 Tcf for shale gas and 54 billion barrels for shale oil. Based on moderate to favorable reservoir properties, we estimate that the Cambay Black Shale has 30 Tcf of risked, technically recoverable shale gas and 2.7 billion barrels of risked, technically recoverable shale oil, Tables XXIV-1A and XXIV-2A.

1.4 Recent Activity

Although the shales in the Cambay Basin have been identified as a priority by India, no plans for exploring these shales have yet been publically announced. However, two shallower conventional exploration wells (targeting the oil-bearing intervals in the basin) penetrated and tested the Cambay Black Shale. Well D-A, a vertical well, had gas shows in a 90-ft section of the Cambay Basin at a depth of about 4,300 ft. After hydraulic stimulation, Well D-A produced 13 bbl/day of oil and 11 Mcfd of gas. Well D-B, an older vertical well drilled in 1989 to a depth of 6,030 ft, also encountered the Cambay Shale at about 4,300 ft. The well was subsequently hydrofractured and produced 13 bbl/day of oil and 21 Mcfd of gas.

Figure XXIV-8. Gross Thickness of Cambay Black Shale, Cambay Basin

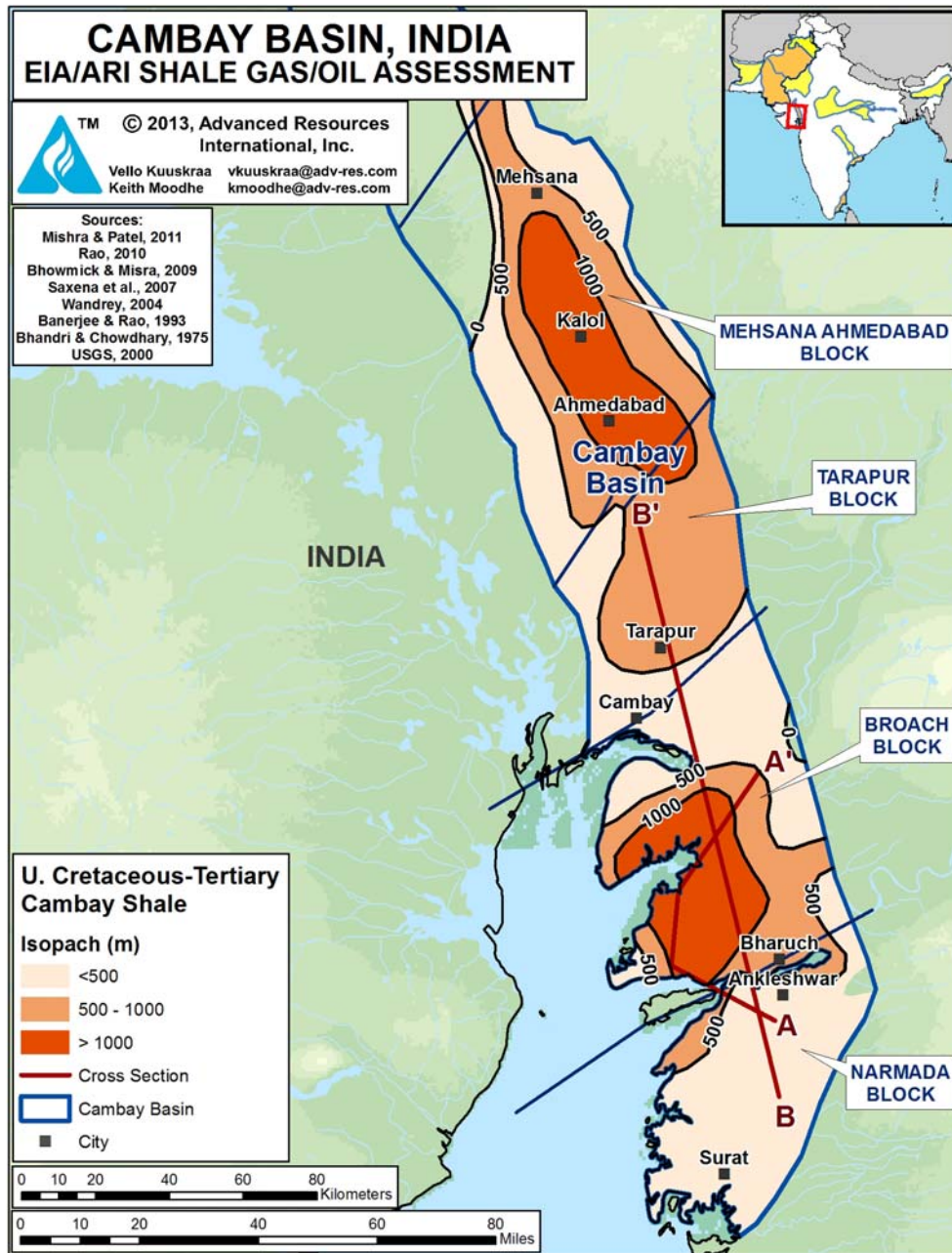


Figure XXIV-9. Organic Content of Cambay "Black Shale", Cambay Basin

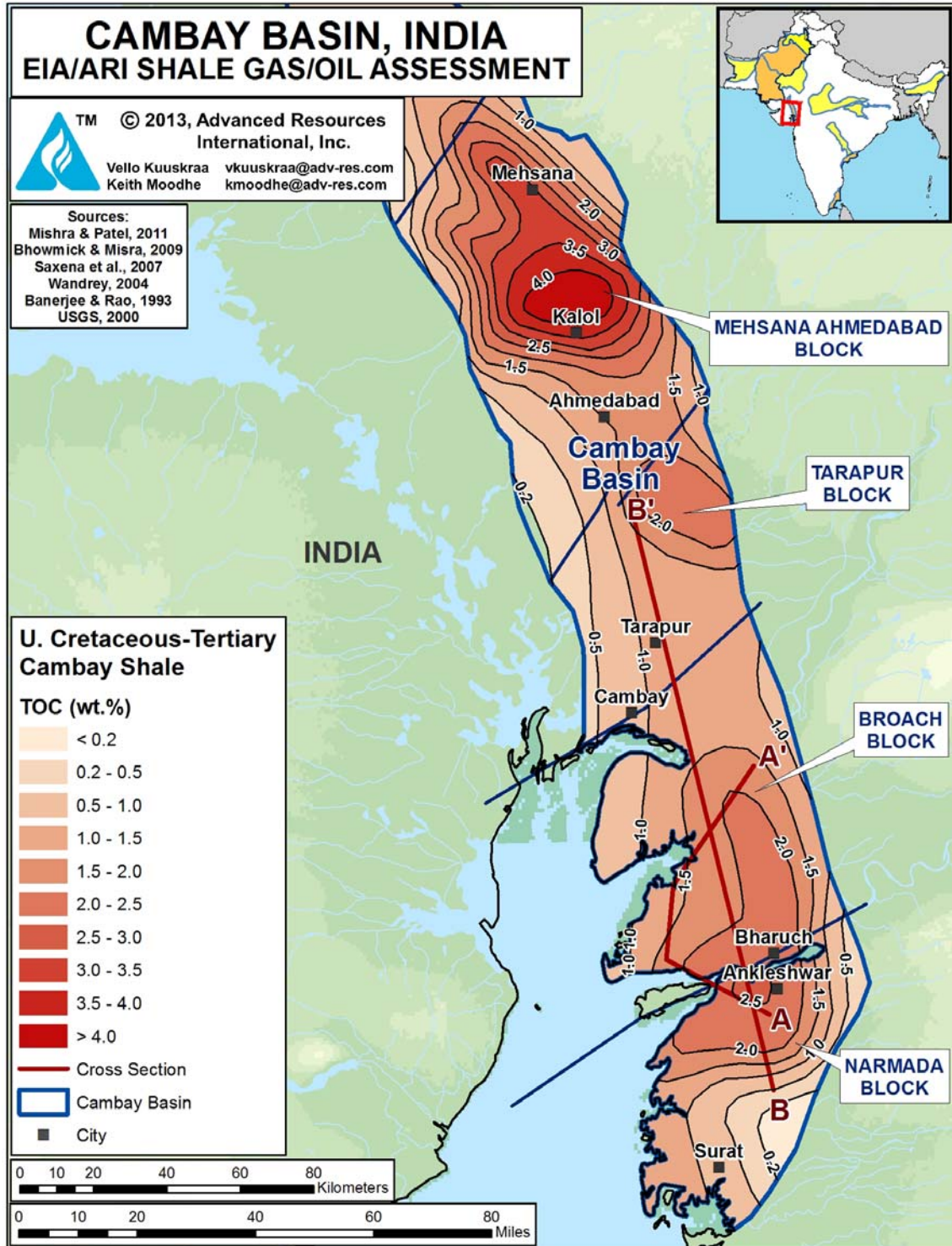
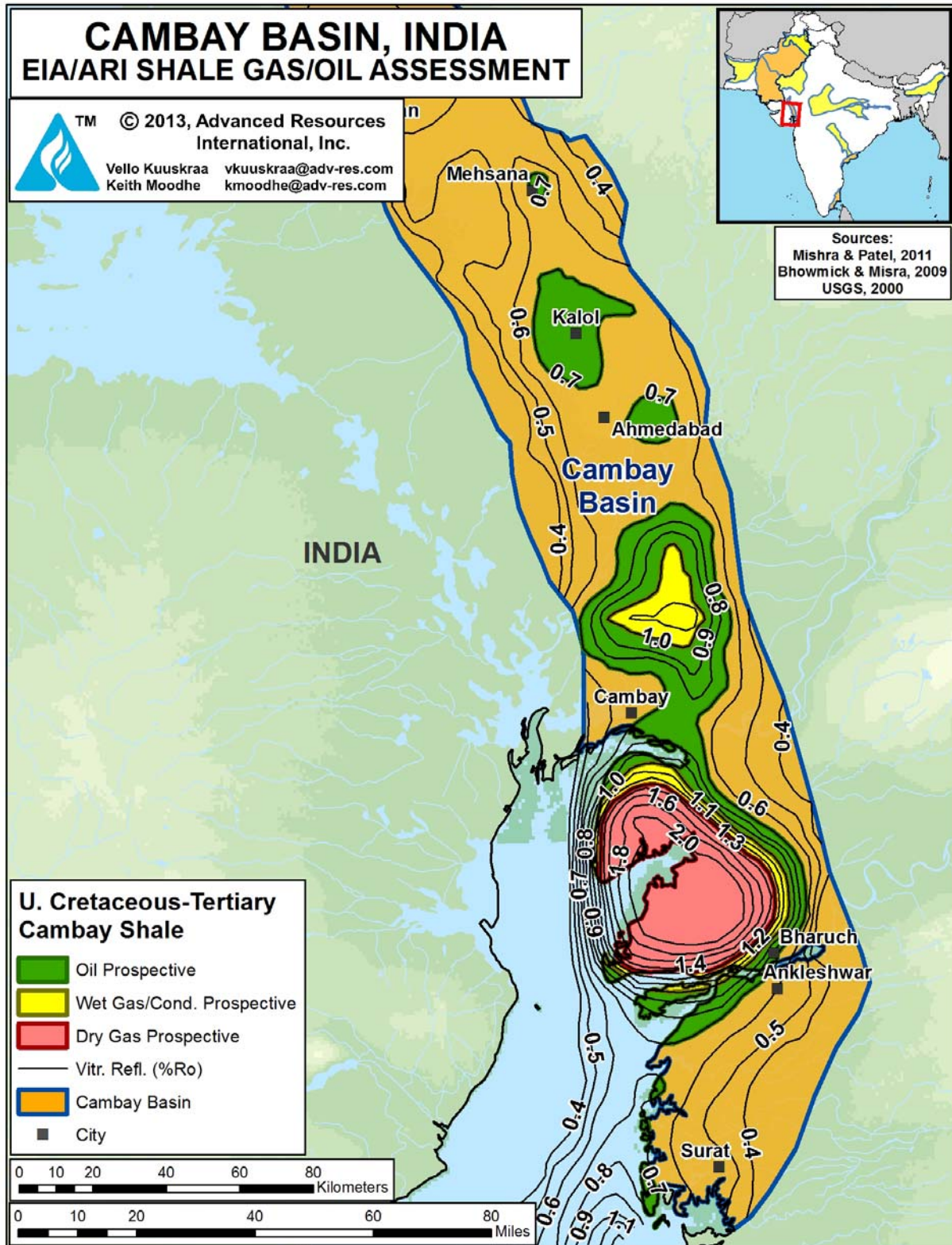


Figure XXIV-10. Prospective Areas of the Cambay Black Shale, Cambay Shale Basin

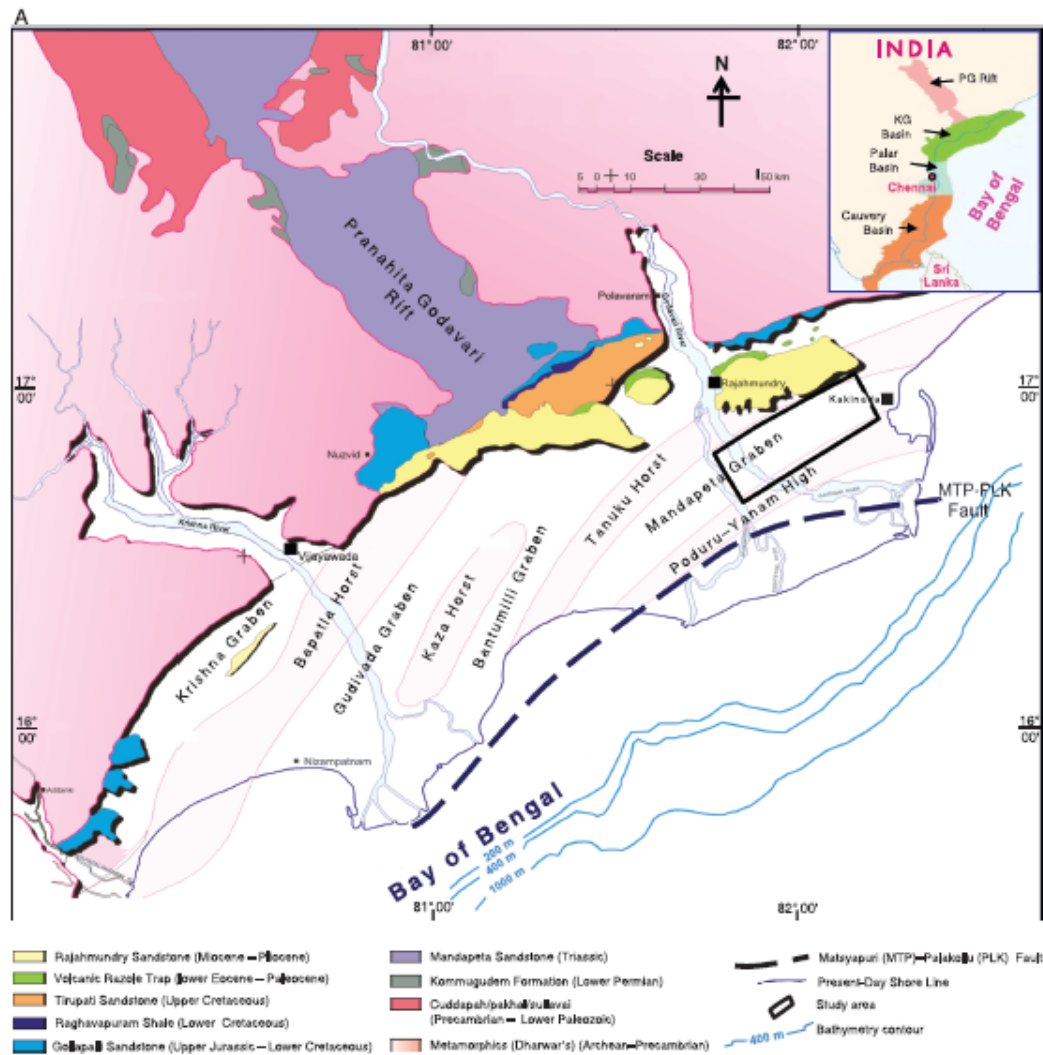


2. KRISHNA-GODAVARI BASIN, INDIA

2.1 Introduction and Geologic Setting

The Krishna-Godavari Basin covers a 7,800-mi² onshore area of eastern India, Figure XXIV-11.⁹ The basin contains a series of organic-rich shales, including the Permian-age Kommugudem Shale and the Triassic-age Mandapeta Shale. For purposes of this assessment, these two shales have been combined into the Permian-Triassic Shale. With thermal maturities ranging from 0.7% to 2% R_o, these shales are in the oil to dry gas windows. The Upper Cretaceous Raghavapuram Shale may also have potential but was not assessed by this study.

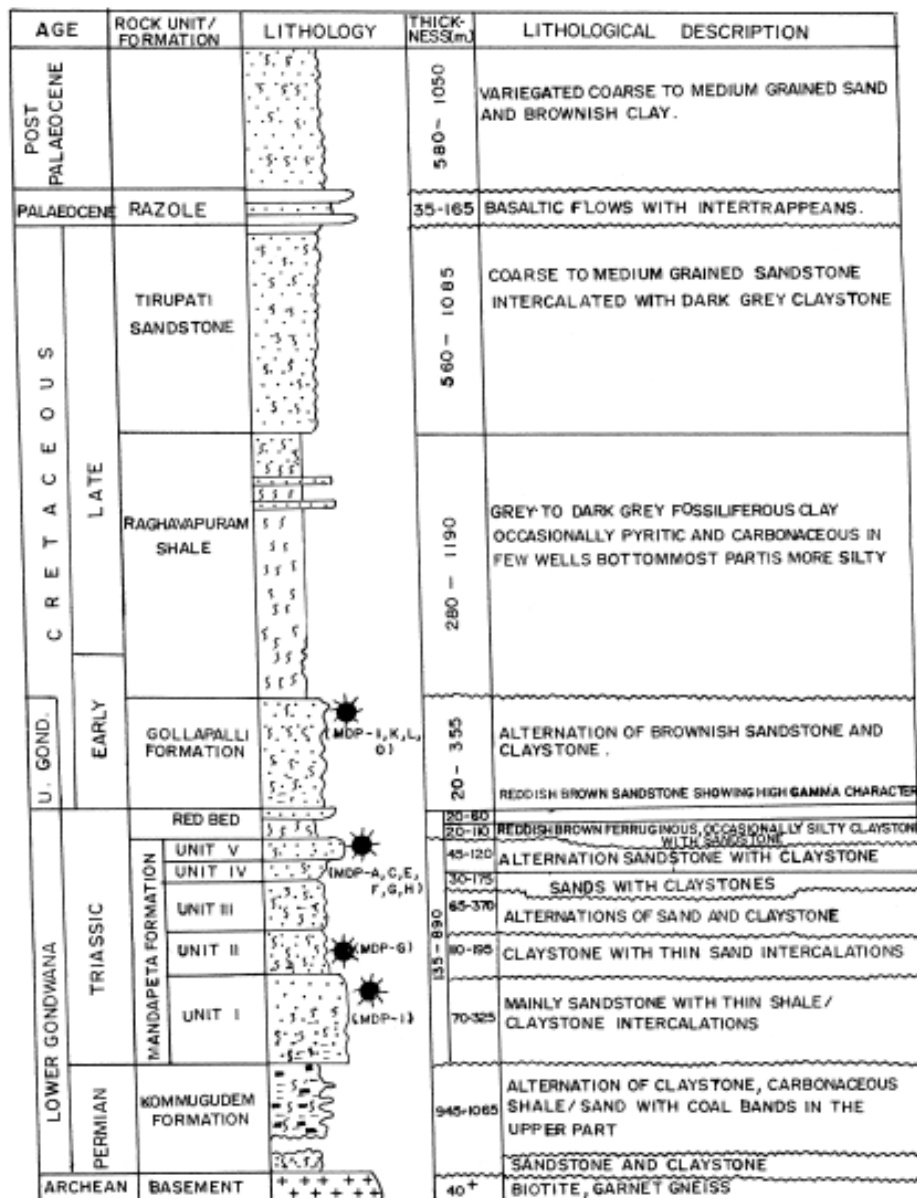
Figure XXI-11. Krishna-Godavari Basin's Onshore Horsts and Grabens



Source: Murthy, 2011.

Permian-Triassic Shale. The Kommugudem Shale, the lower unit of the Permian-Triassic Shale, is a thick Permian-age rock interval containing alternating sequences of carbonaceous shale, claystone, sand and coal, Figure XXIV-12. The Mandapeta Graben, the most extensively explored portion of the Krishna-Godavari Basin, provides much of the geologic and reservoir characterization data for this basin.¹⁰

Figure XXIV-12. Stratigraphic Column, Mandapeta Area, Krishna Godavari Basin



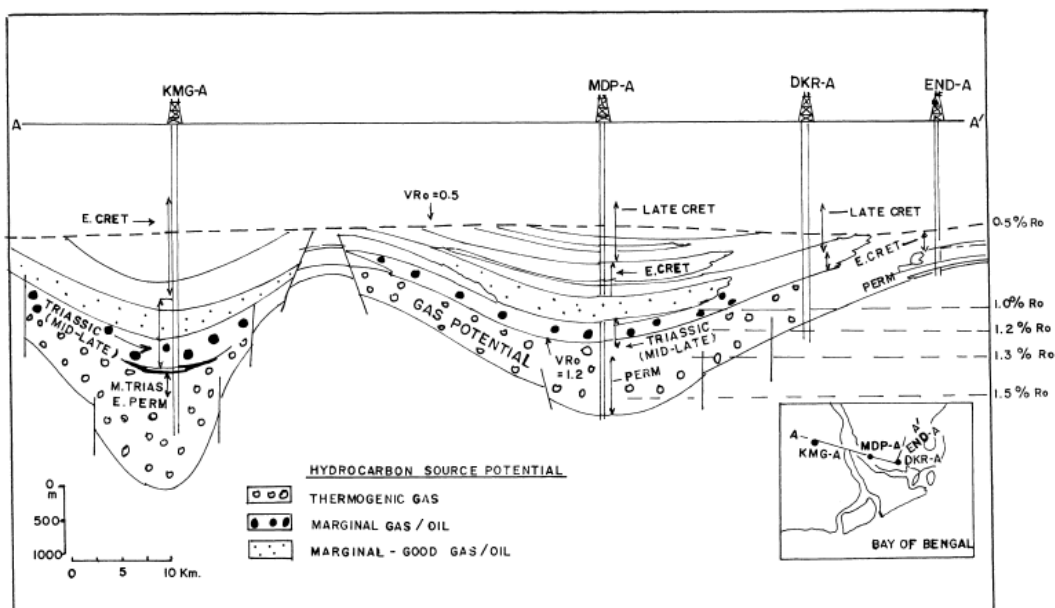
Source: Kahn, 2000.

The Kommugudem Shale was deposited in fluvial, lower deltaic, and lacustrine environments. While an effective source rock with excellent organic richness, analysis of the shale indicates hydrogen-deficient organic matter (based on low S_2 values from pyrolysis) and high levels of primary inertinite.

The basal shale in the Mandapeta Formation, the upper unit of the Permian-Triassic Shale, is a localized, thermally mature (R_o of 0.8% to 1.1%) Triassic-age shale that is considered the source rock for the oil produced from the overlying Early Cretaceous Golapalli Sandstone. The Mandapeta Formation and its basal shale are present in the Mandapeta and Bantumilli grabens but are absent in the Poduru-Yanam High (Draksharama and Endamuru areas) to the east. While the TOC of the Mandapeta Shale is generally low, 0.4% to 1.6%, we have included this Triassic shale unit into the overall Permian-Triassic sequence.

Vitrinite reflectance of the Permian-Triassic Shale in the deep graben structures ranges from 0.7% to 2% R_o , placing the shale in the oil to dry gas windows. Figure XXIV-13 illustrates the relationship of shale depth and geologic age in the Krishna-Godavari Basin to the thermal maturity (R_o) in two of the graben structures, Kommugudem (KMG) and Mandapeta (MDP).

Figure XXIV-13. Cross Section for Permian-Triassic Shale, Krishna Godavari Basin



Source: Kahn, 2000.

2.2 Reservoir Properties (Prospective Area)

In the prospective area of the Krishna-Godavari Basin, the depth of the Permian-Triassic Shale ranges from 4,000 to 16,400 ft, averaging 5,000 ft in the oil prospective area, 8,000 ft in the wet gas and condensate prospective area, and 13,000 ft in the dry gas prospective area.

To better understand the source rock quality of the Permian-Triassic Shale, 140 m of shale was tested in 10 wells. The data showed the TOC of the shale ranges up to 11%, averaging 6%, for ten rock samples taken at various depths, Table XXIV-4.

Table XXIV-4. Analysis of Ten Rock Samples, Kommugudem Shale¹¹

Well	Depth (m)	TOC (%)	S ₂ *	Shale Interval Tested (m)
AA-1	3,320-3,880	10.4	7.0	110
AA-2	3,585-3,630	4.2	2.9	45
AA-9	3,330-3,360	7.1	6.4	30
AA-10	3,880-3,920	3.1	0.6	40
AA-11	2,890-3,150	7.0	7.9	260
BW-1A	3,915-4,250	5.6	0.8	335
BW-2	2,970-3,085	8.8	5.5	115
BW-2	3,100-3,175	7.8	6.0	75
BW-9	2,800-3,040	11.2	6.9	315
DE-1	1,900-2,040	8.9	13.9	120

*Volume of hydrocarbon cracked from kerogen by heating to 550°C, measured in terms of mg hydrocarbon/g rock.

The thickness of the shale ranges from 330 to 1,300 ft, with 100 to 390 ft of net organic-rich shale, depending on prospective area. The pressure gradient of the Permian-Triassic Shale is normal. The reservoir is inferred to have moderate to high clay content based on its lacustrine deposition. We mapped an 8,000-mi² prospective area for the Permian-Triassic Shale in the Krishna-Godavari Basin which encompasses the oil, wet gas/condensate and dry gas windows.

Raghavapuram Shale. The Cretaceous-age Raghavapuram Shale offers an additional potential shale resource in the Krishna-Godavari Basin. The TOC of this shale unit ranges from 0.8% to 6.4%, with the lower HG-HR Shale interval of the Raghavapuram Formation having the higher TOC values, Figures XXIV-14¹² and XXIV-15.¹² The shale becomes thermally mature for oil (Tmax 440 to 475° C) at depth below 10,600 ft.²¹

However, the great bulk of the Cretaceous Raghavapuram Shale is shallower than 10,600 ft and thus has a thermal maturity (R_o) value less than the 0.7% minimum threshold used by this study. In addition, the data on the area and vertical distribution of the Raghavapuram Shale is limited. Thus, this shale has not been included in the quantitative portion of our shale resource assessment.

2.3 Resource Assessment

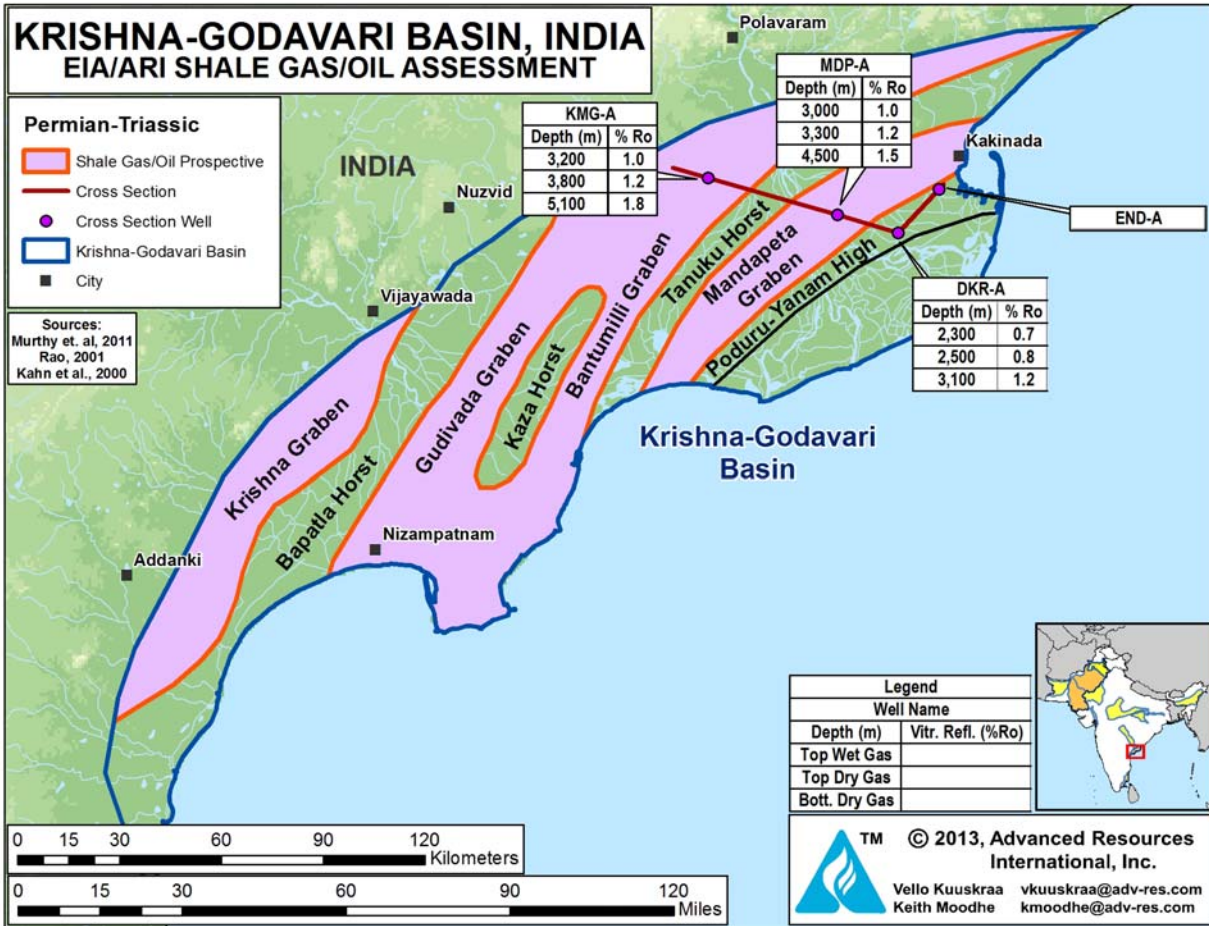
The 8,000-mi² prospective area of the Permian (Kommugudem) and Triassic (Mandapeta) Shale in the Krishna-Godavari Basin is limited to the four grabens (sub-basins) shown in Figure XXIV-16. The Permian-Triassic Shale has resource concentrations of: 205 Bcf/mi² in the 3,000-mi² dry gas prospective area; 58 Bcf/mi² of wet gas and 6 million barrels/mi² of condensate in the 3,900-mi² wet gas/condensate prospective area; and 18 million/mi² barrels of oil (plus associated gas) in the 1,100-mi² oil prospective area.

Within the overall prospective area, the Permian-Triassic Shale of the Krishna-Godavari Basin has risked shale gas in-place of 381 Tcf, with 57 Tcf as the risked, technically recoverable shale gas resource. In addition, we estimate a risked shale oil in-place for this basin of 20 billion barrels, with 0.6 billion barrels as the risked, technically recoverable shale oil resource, Tables XXIV-1A and XXIV-2A.

2.4 Recent Activity

The technical literature discusses 16 wells that have been drilled at the Mandapeta Graben into or through the Permian-Triassic Shale in search for hydrocarbons in conventional Mandapeta and Gollapalli sandstone reservoirs. The information from these 16 wells has provided valuable data for the key cross-sections and other reservoir properties essential for the shale resource assessment study of the Krishna-Godavari Basin.

Figure XXIV-16. Prospective Areas for Shale Gas and Shale Oil, Krishna-Godavari Basin

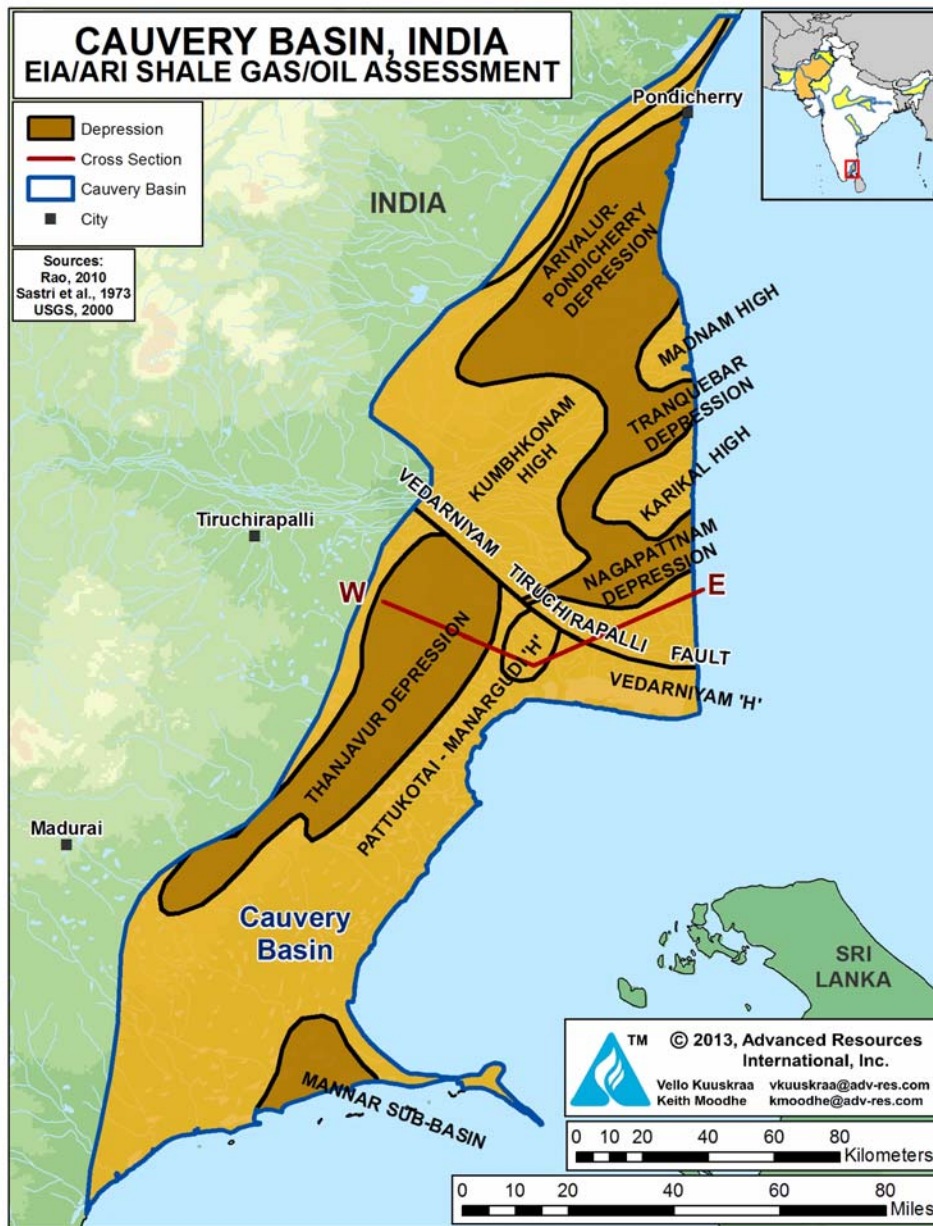


3. CAUVERY BASIN, INDIA

3.1 Introduction and Geologic Setting

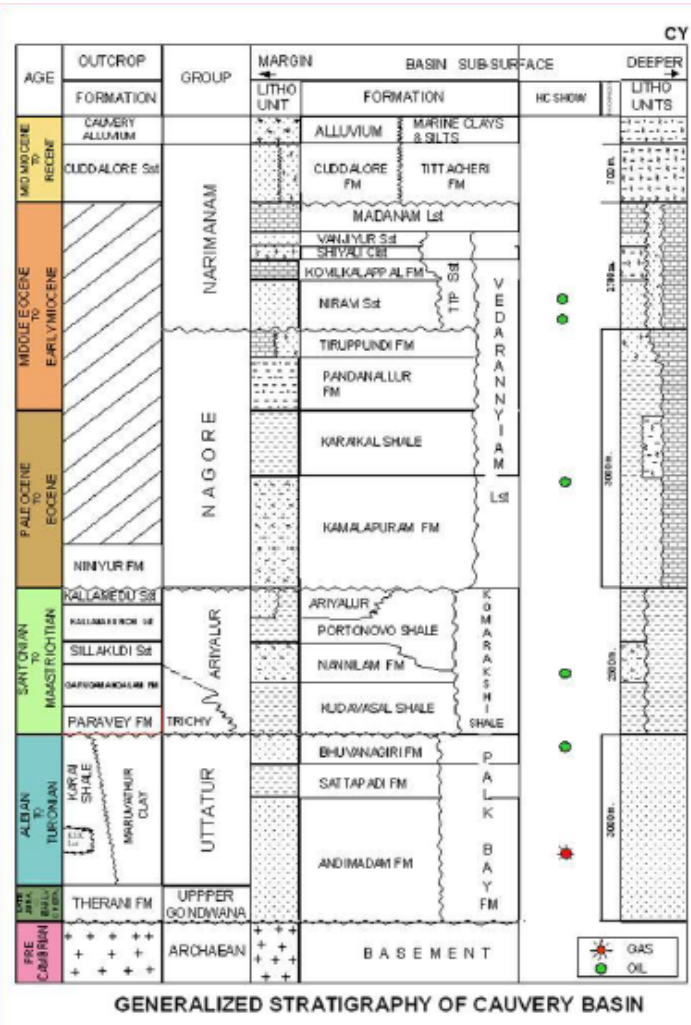
The Cauvery Basin covers an onshore area of about 9,100 mi² on the east coast of India, Figure XXIV-17. The basin comprises numerous horsts and grabens, with thick organic-rich source rocks in the Lower Cretaceous Andimadam Formation and Sattapadi Shale.

Figure XXIV-17. Cauvery Basin Horsts and Grabens



The gas- and oil-prone shale source rocks in the Cauvery Basin are the Lower Cretaceous Andimadam Formation and the Sattapadi Shale, Figure XXIV-18. The shale resource prospective area of the Cauvery Basin is limited to four depressions (troughs) - - Nagapattnam, Tranquebar, Ariyalur-Pondicherry and Thanjavur - - and the Mannar Sub-basin. The source rocks are generally shallow marine Type III with some Type II kerogen. The thermally mature source rocks in the shallower Sattapadi Shale and the deeper Andimadam Formation contain thermogenic wet gas and condensate.¹³

Figure XXIV-18. Generalized Stratigraphy, Cauvery Basin¹⁵



Source: Rao, 2010.

3.2 Reservoir Properties (Prospective Area)

We have identified a 1,010-mi² wet gas and condensate prospective area for the shales in the Cauvery Basin. The thickness of the Lower Cretaceous interval is 3,000 to 5,000 ft, with the Andimadam Formation and the Sattapadi Shale accounting for the bulk of the gross interval, Figure XXIV-19. The TOC of the combined Andimadam/Sattapadi Shale is estimated at 2% to 2.5%, averaging 2.3%. The organic shales are distributed irregularly over the Cauvery Basin, Figure XXIV-20.

Figure XXIV-19. Formation Thickness, Cauvery Basin

AGE	FORMATION		THICKNESS in m	
Recent to Mid. Miocene	Tittacheri Sandstone		300-500	
Lower Miocene	Madanam Limestone		600-1200	
	Vanjiyur Sandstone			
	Shiyali Clay stone	CAP		
Oligocene	Kovilkalappal Fm.		500-800	
	Niravi Sandstone	PLAY		
Eocene	Pandanallur Fm.		200-400	
	Karaikal Shale	CAP		
	Up.Kamalapuram Fm.	PLAY		
Paleocene	Lr.Kamalapuram Fm.	PLAY	200-800	
Cretaceous	Upper	Porto-Novo Shale	CAP	600-1500
		Nannilam Fm.	PLAY	
		Kudavasal Shale	CAP	
	Lower	Bhuvanagiri Fm.	PLAY	
		Sattapadi Shale	SOURCE+CAP	
Andimadam Fm.	SOURCE+PLAY			
Archaean	Basement	PLAY		

Source: P.K. Bhowmick and Ravi Misra, Indian Oil and Gas Potential, Glimpses of Geoscience Research in India

The Cauvery Basin contains a series of depressions (sub-basins) that hold potential for shale gas. Two of these - - Ariyalur-Pondicherry and Thanjavur - - contain thick, thermally mature shales.

- **Ariyalur-Pondicherry Sub-Basin.** The Ariyalur-Pondicherry Depression (Sub-basin) is in the northern portion of the Cauvery Basin. The Lower Cretaceous Andimadam and Sattapadi Shale encompasses a thick interval at a depth of 7,000 to 13,000 ft, averaging 10,000 ft. Organic-rich gross pay thickness is 1,000 ft with net pay of about 500 ft. The thermal maturity of 1.0% to 1.3% R_o places the shale in the wet gas and condensate window. The onshore prospective area of this sub-basin is estimated at 620 mi², Figure XXIV-21.
- **Thanjavur Sub-Basin.** The Thanjavur Depression (Sub-basin), in the center of the Cauvery Basin, has a thick section of Andimadam and Sattapadi Shale at a depth of 7,000 ft (top of Sattapadi Shale) to 13,000 ft (base of Andimadam Fm), averaging 9,500 ft deep, Figure XXIV-22. The organic-rich average net pay thickness is 500 ft.¹⁵ Given limited data, we assume the TOC and thermal maturity for the shale in this sub-basin is the same as in the Ariyalur-Pondicherry Sub-basin. The onshore prospective area with thick organic-rich shale is small, estimated at 390 mi², Figure XXIV-21.

3.3 Resource Assessment

In the 1,010-mi² prospective area of the Cauvery Basin, the combined Andimadam Formation and Sattapadi Shale have an average wet shale gas resource concentration of 120 Bcf/mi² and a shale condensate resource concentration of 30 million barrels/mi².

For the combined Andimadam Formation and Sattapadi Shale in the Cauvery Basin, we estimate risked shale gas in-place of 30 Tcf and risked shale oil in-place of 8 billion barrels. Of this, 5 Tcf of shale gas and 0.2 billion barrels of shale oil are the risked, technically recoverable shale resources.

3.4 Recent Activity

We are not aware of any shale gas or oil development in the Cauvery Basin.

Figure XXIV-21. Prospective Areas for Shale Gas and Shale Oil, Cauvery Basin

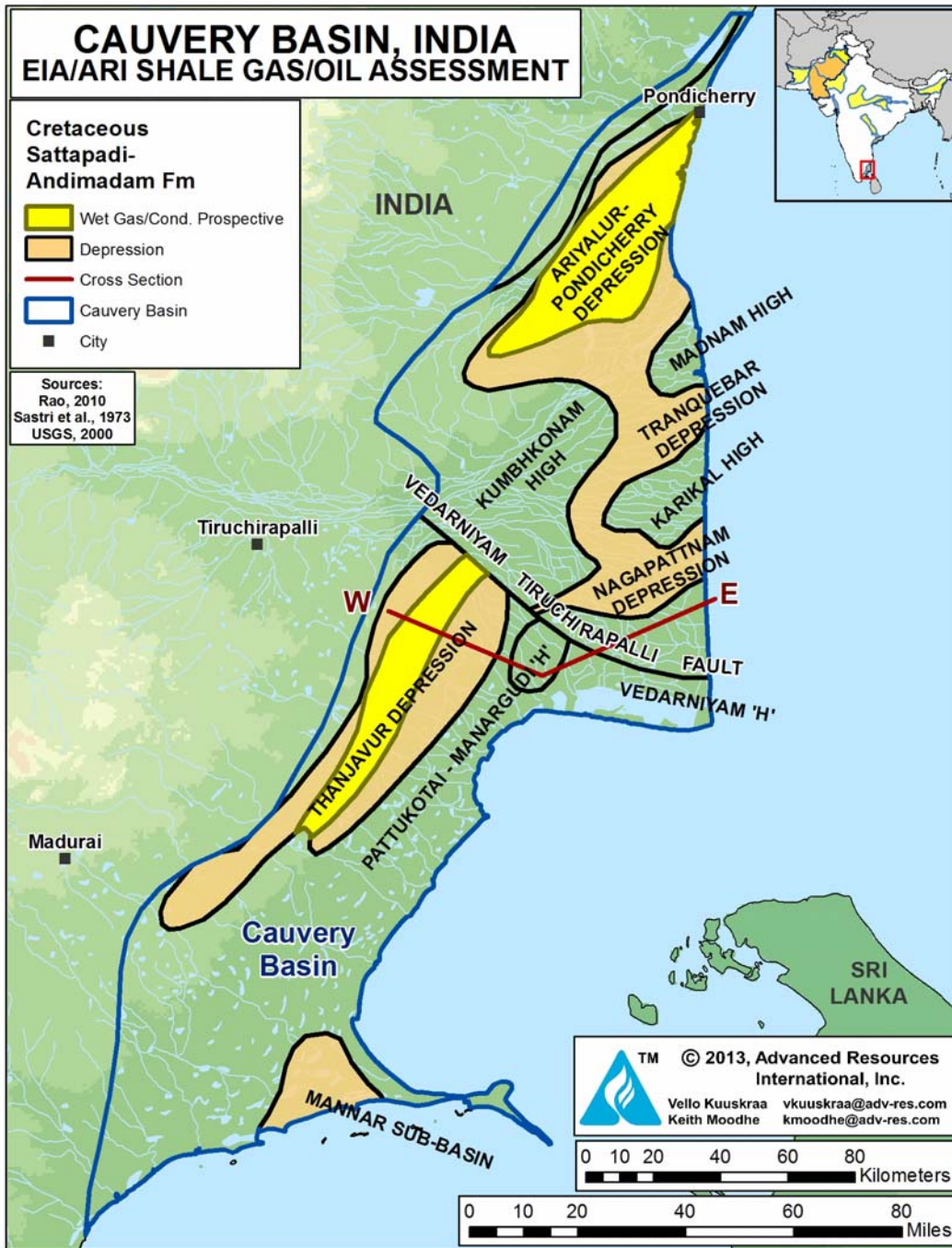
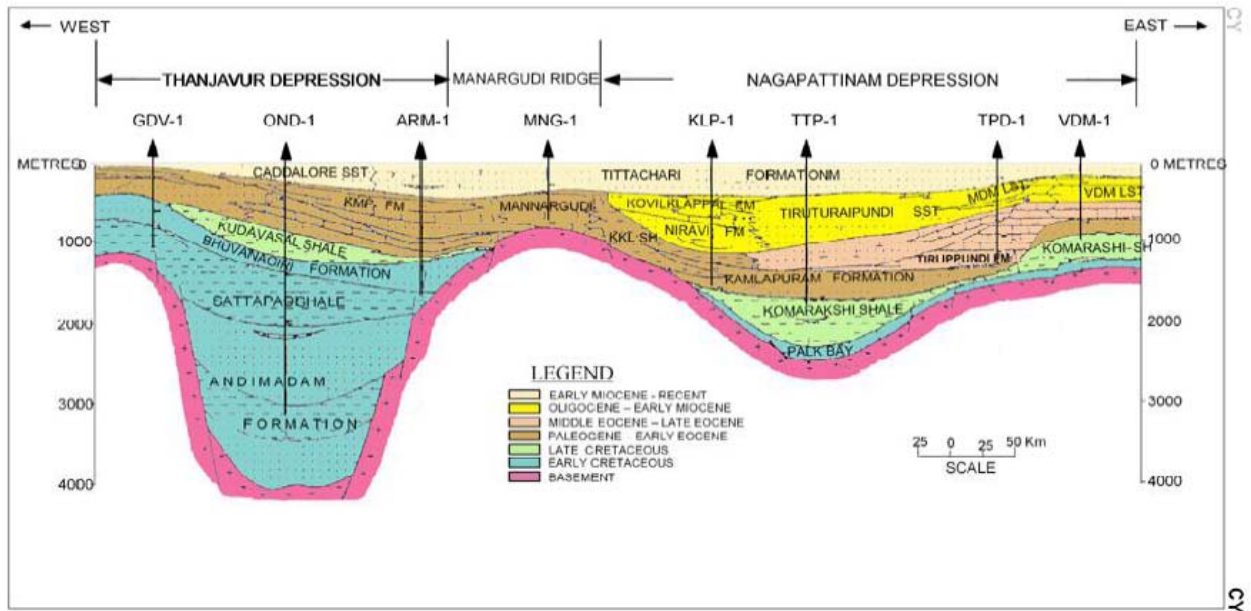


Figure XXIV-22. East to West Cross-Section Across Cauvery Basin.¹⁵



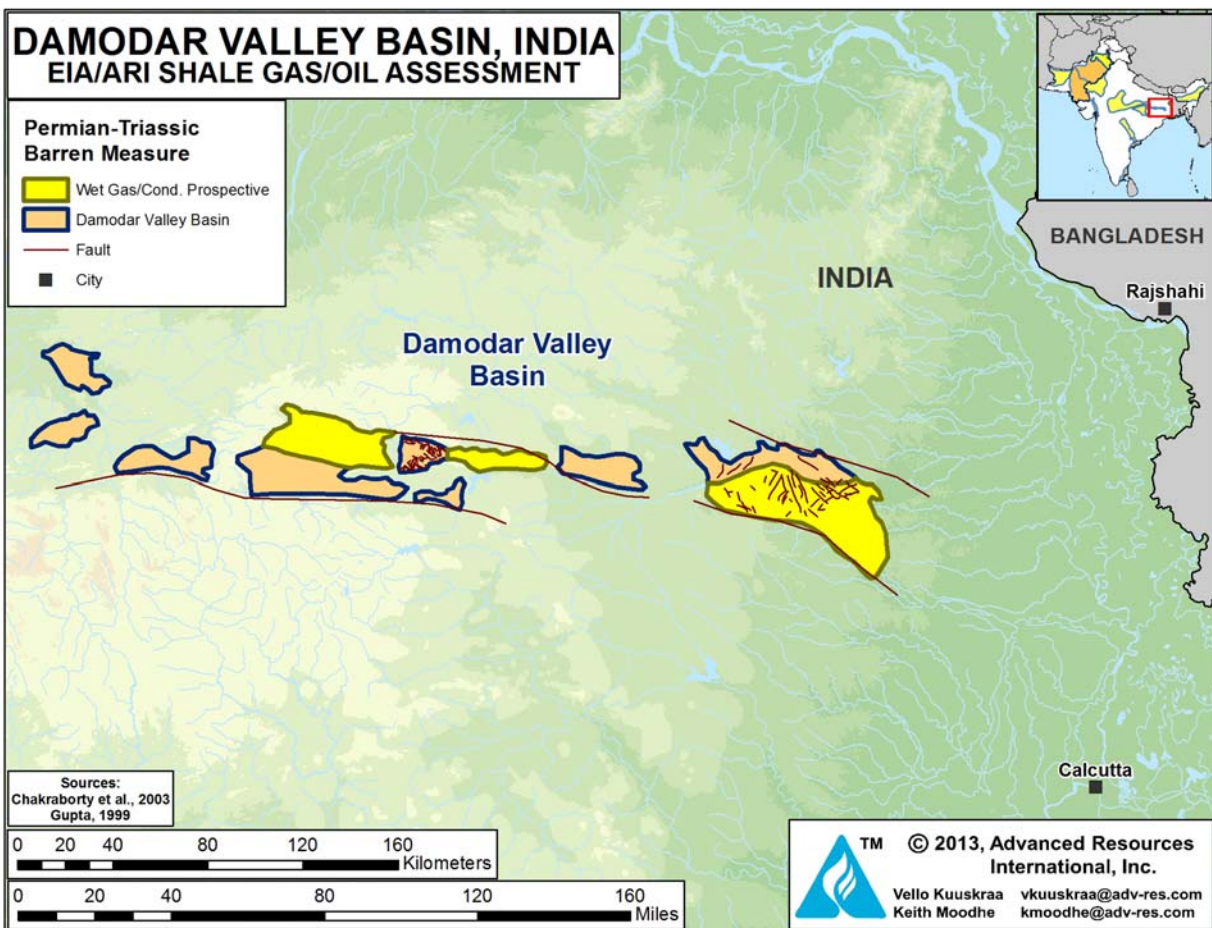
Source: Rao, 2010.

4. DAMODAR VALLEY BASIN, INDIA

4.1 Introduction and Geologic Setting

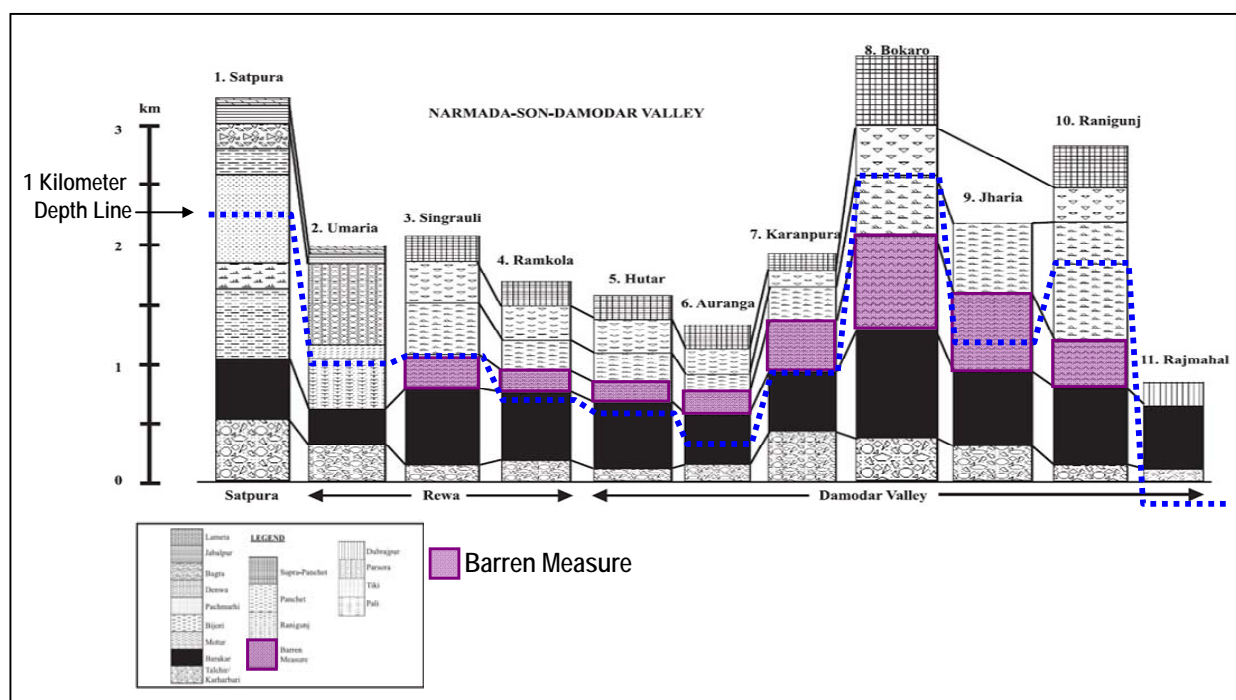
The Damodar Valley Basin is part of a group of basins collectively named the “Gondwanas”, owing to their similar dispositional environment and Permo-Carboniferous through Triassic deposition. The “Gondwanas,” comprising the Satpura, Pranhita-Godavari, Son-Mahanadi and Damodar Valley basins, were part of a system of rift channels in the northeast of the Gondwana super continent. Subsequent tectonic activity formed the major structural boundaries of the Gondwana basins, notably the Damodar Valley Basin, Figure XXIV-23.

Figure XXIV-23. Damodar Valley Basin and Prospectivity for Shale Gas and Shale Oil



Sedimentation in the Early Permian was primarily glacial-fluvial and lacustrine, resulting in significant deposits of coal. As such, the majority of exploration in the Damodar Valley has focused on the coal resources of the basin, which account for much of India's coal reserves. However, a marine incursion deposited a layer of early Permian Shale, called the Barren Measure Shale in this basin, Figure XXIV-24¹⁴. This shale formation was the target of India's first shale gas exploration well in the eastern portion of the Damodar Valley. Though present in other Gondwana basins, such as the Rewa Basin, in central India, data suggest that the Barren Measure Shale is only thermally mature in the Damodar Valley Basin.¹⁵

Figure XXIV-24. Regional Stratigraphic Column of the Damodar Valley Basin, India¹⁶.



Source: Chakraborty, Chandan, 2003.

The Damodar Valley Basin comprises a series of sub-basins (from west to east) - - the Hutar, Daltonganj, Auranga, Karanpura, Ramgarh, Bokaro, Jharia and Raniganj. Though these sub-basins share a similar geologic history, tectonic events and erosion since the early Triassic have caused extensive variability in the depth and thickness of the Barren Measure Shale in these basins.

Because exploration has focused on the coal deposits within the Damodar Valley Basin, relatively little geologic data is available on the Barren Measure Shale. Thermal maturity data on coals adjoining the Barren Measure Shale suggest that the shale is within the wet gas/condensate (R_o of 1.0% to 1.3%) window, and regional studies have shown favorable TOC, with average values of 3.5%.

Present-day burial depth and lower pressures are the main limitations for the shale gas and condensate prospectively of the Barren Measure Shale in the Damodar Valley Basin. In some sub-basins, regional erosion has removed up to 3 kilometers of overlying sediments.

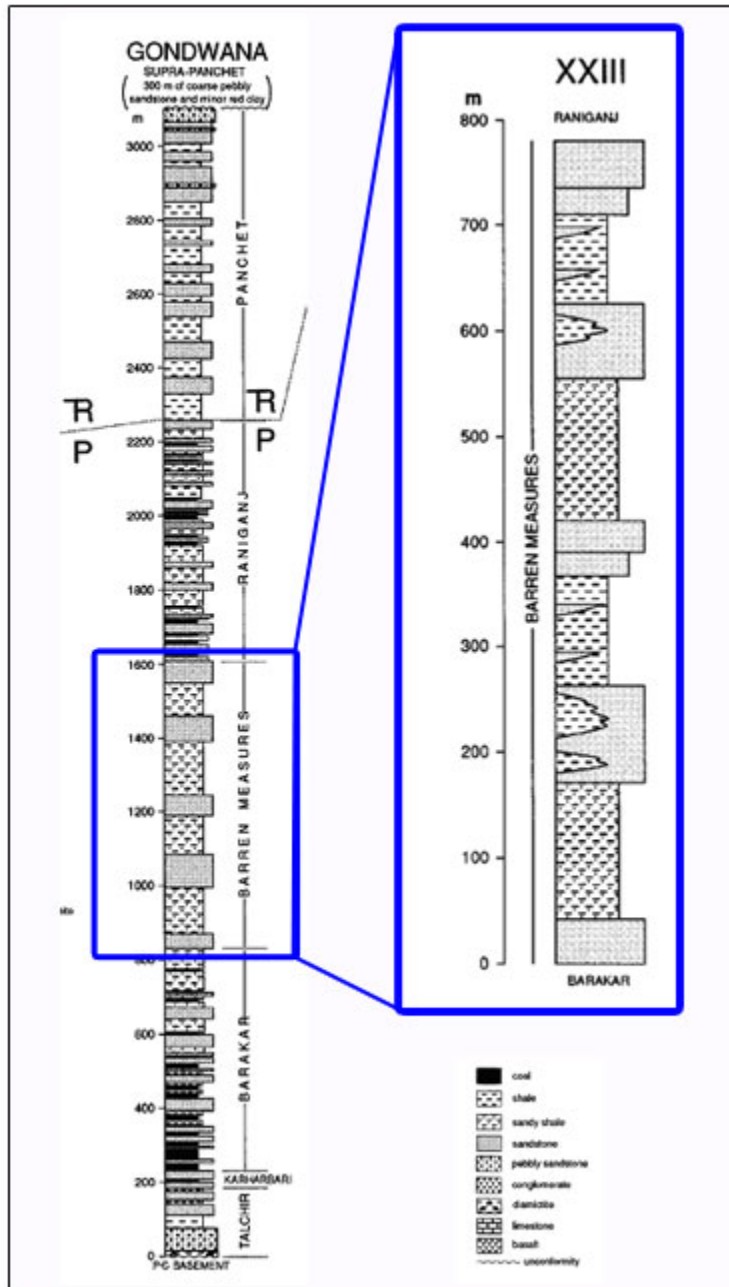
Based on the regional stratigraphic column, Figure XXIV-25,¹⁷ and operator data, the overall 1,080-mi² prospective area for the Barren Measure Shale in the Damodar Valley is limited to the Bokaro, Karanpura and Raniganj sub-basins.

The prospective areas within the Bokaro (110 mi²) and Raniganj (650 mi²) sub-basins are limited by surface outcrops of formations of the Barren Measure Shale to the west and north, respectively. We have estimated a 320-mi² prospective area for the northern half of the Karanpura Basin, based on statements by Schlumberger and ONGC.¹⁸

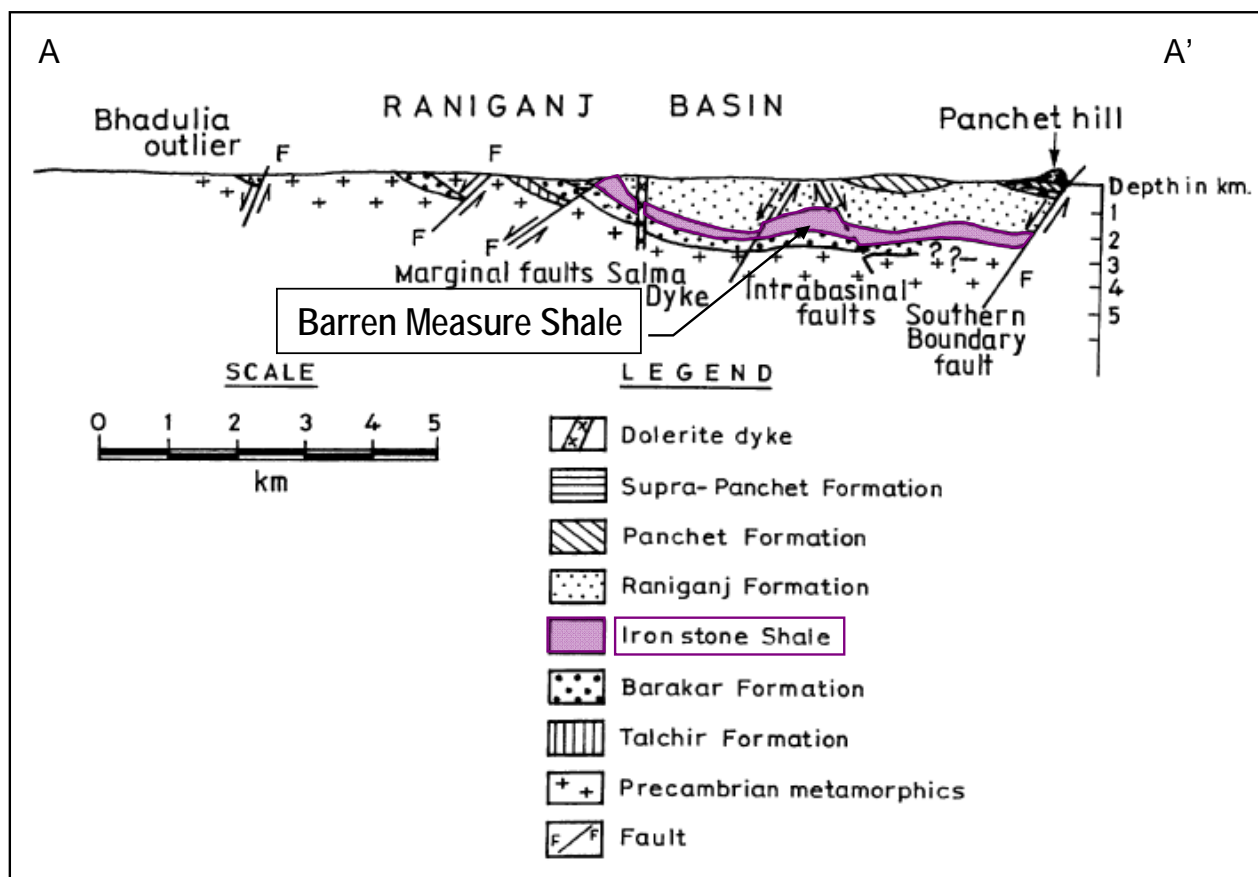
4.2 Reservoir Properties (Prospective Area)

Absent data on thermal maturity and organic content specific to each of the three sub-basins, we assigned average published reservoir property values to these three sub-basins. TOC is assumed to range between 3% and 6% averaging 3.5%, based on information from INOC and ESSAR.^{19,20} Thermal maturity was estimated from the coal formations surrounding the Barren Measure Shale, indicating values of 1.1% to 1.3% R_o , placing the shale within the wet gas/condensate window.²¹ Depth to the Barren Measure Shale averages about 5,000 ft, based on reports from the shale gas well drilled into the Raniganj sub-basin and from regional cross sections, Figure XXIV-26. We estimate a weighted average gross interval thickness in the three prospective sub-basins of about 2,000 ft, of which about 1,000 ft is organic-rich and 250 ft is net shale.¹⁷

Figure XXIV-25. Generalized Stratigraphic Column of the Gondwana Basin.



Source: Veevers, J., 1995

Figure XXIV-26. Raniganj Sub-Basin Cross Section.²²

Source: Ghosh, S. C., 2002.

4.4 Resource Assessment

Using the geologic characteristics discussed above, we estimate that the Barren Measure Shale in the Damodar Valley Basin has a wet shale gas resource concentration of 63 Bcf/mi² and a shale condensate resource concentration of 12 million barrels/mi².

Risked shale gas in-place is estimated at 27 Tcf, with the prospect area risk factor recognizing the significant faulting present in the basin. We estimate 5 Tcf of risked shale gas may be technically recoverable from the Barren Measure Shale in the Damodar Valley Basins. In addition, we estimate risked shale oil in-place of 5 billion barrels, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

4.4 Recent Activity

Along with the Cambay Basin, the Damodar Valley Basin has been set as a priority basin for shale gas exploration by the Indian government. In late September 2010, Indian National Oil and Gas Company (ONGC) spudded the country's first shale gas well, RNSG-1, in the Raniganj sub-basin of the Damodar Valley. The well was completed mid-January 2011, having reportedly encountered gas flows from the Barren Measure Shale at approximately 5,600 ft. Detailed well test and production results are not publicly available. This well was the first of a proposed four-well R&D program in the basin. The plan calls for an additional well to be drilled in the Raniganj sub-basin and for two wells to be drilled in the Karanpura sub-basin.

5. OTHER BASINS, INDIA

5.1 Upper Assam Basin

The Upper Assam Basin is an important onshore petroleum province in northeast India. The basin has produced oil and some associated gas, mainly from the Upper Eocene-Oligocene Barail Group of coals and shales. In general, the TOC in the lower source rocks ranges from 1% to 2% but reaches 10% in the Barail Group. These source rocks are in the early thermal maturity stage (beginning of the oil window) in the bulk of the Upper Assam Basin.²³ Although the shales may reach thermal maturity for oil and gas generation in the deeper parts of the basin, toward the south and southwest, no data confirming this assumption exists in the public domain. The reported thermal maturity of the Barail Group Shale ranges from R_o of 0.5% to 0.7%, placing these shales as immature for oil.²⁴ While the shale may reach the oil and wet gas window in the very deepest portion of the basin, the measured vitrinite reflectance is reported at only 0.7% at a depth of 14,800 ft.²⁵

5.2 Pranhita-Godavari Basin

The Pranhita-Godavari Basin, located in eastern India, contains thick, organic-rich shales in Permian-age Jai Puram and Khanapur formations. While the kerogen is Type III (humic) and thus favorable for gas generation, the 0.67% R_o indicates that the shales are thermally immature.

5.3 Vindhyan Basin

The Vindhyan Basin, located in north-central India, contains a series of Proterozoic-age shales. While certain of these shales, such as the Hinota and Pulkovar, appear to have sufficient organic richness, no public data exists on their thermal maturity.

5.4 Rajasthan Basin

The Rajasthan Basin covers a large onshore area in northwest India. The basin is structurally complex and characterized by numerous small fault blocks. The Permian-age Karampur Formation is the primary source rock in this basin. While the source rock is Type III and classified as mature, only limited data are available on the reservoir properties of this shale.

Sembar Shale. The Lower Cretaceous Sembar Formation is the main source rock in the Lower Indus Basin. The Sembar contains shale, silty shale and marl in the western and northwestern portion of the basin and becomes sandy in the eastern part of the basin. The kerogen within the Sembar Formation is mostly Type II with some Type III.

The Lower Indus Basin covers a massive 91,000-mi² area of western Pakistan. Within this large basin area, for the Sembar Shale, we have identified a 31,320-mi² prospective area for dry gas ($R_o > 1.3\%$), a 25,560-mi² prospective area for wet gas and condensate (R_o between 1.0% and 1.3%), and a 26,700-mi² prospective area for oil (R_o between 0.7% and 1.0%). To account for the limited data on the Sembar Shale in this large basin area, we have highly risked the prospective areas and the likelihood of development success.

The eastern boundary of the prospective area of the Sembar Shale in the Lower Indus Basin is the minimum thermal maturity criterion of R_o 0.7%. The northern and western boundaries of the prospective area are set by the limits of Sembar Formation deposition and depth. The southern boundary of the prospective area is the offshore.

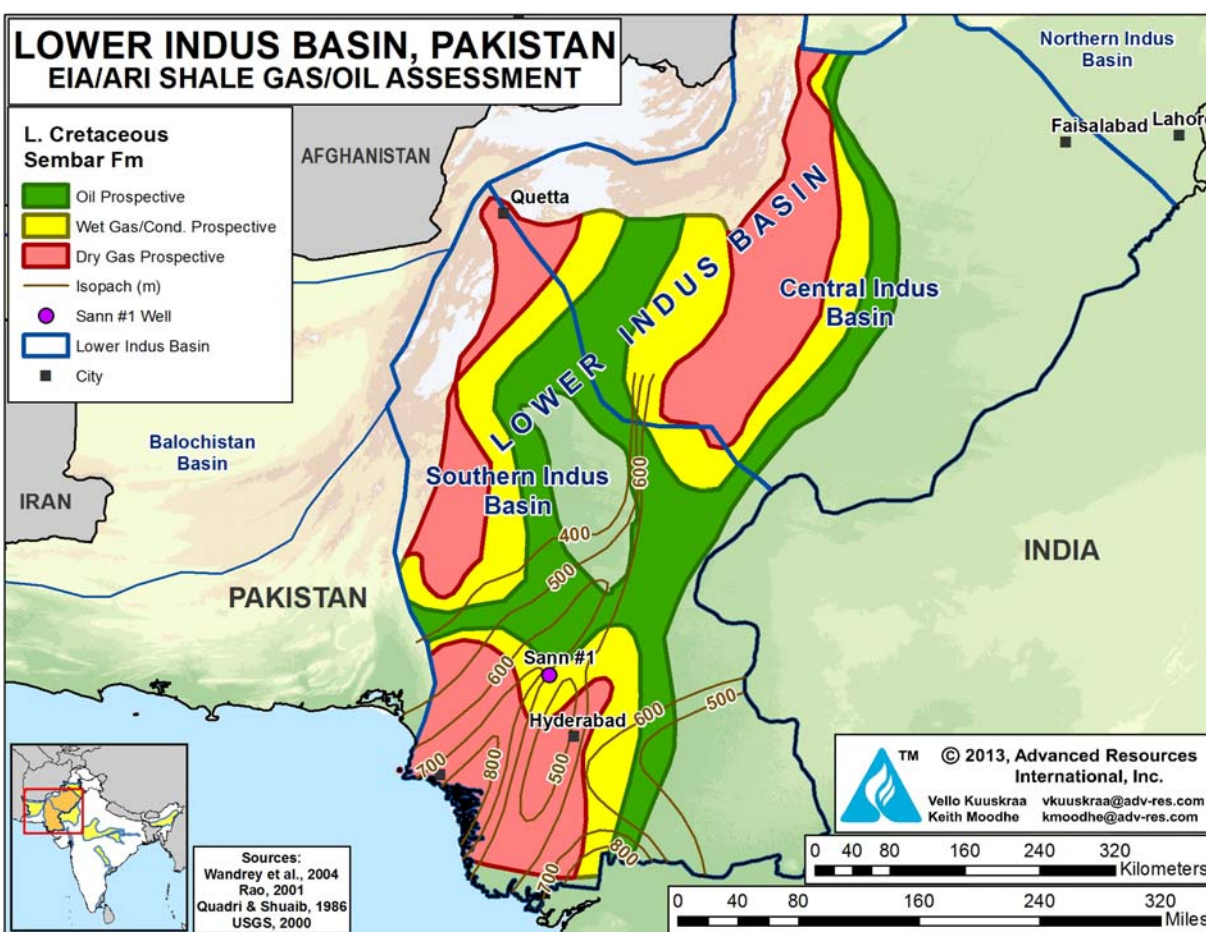
Ranikot Formation. The shales in the Paleocene Ranikot Formation are primarily in the upper carbonate unit which consists of fossiliferous limestone interbedded with dolomitic shale, calcareous sandstone and “abundant” bituminous material. The upper unit was deposited in a restricted marine environment. West of the Karachi Trough axis, the Ranikot Formation becomes dominantly shale (Korara Shale) with deep marine deposition.

Within the southern portion of the Lower Indus Basin, we have identified 26,780-mi² for the Ranikot Shale that appears to be prospective for oil (R_o of 0.7% to 1.0%). The eastern, northern and western boundaries of the Ranikot Shale prospective area are set by the 300 m isopach contour; the southern boundary of the prospective area is the offshore.

6.2 Reservoir Properties (Prospective Area)

Sembar Shale. The Sembar Formation was deposited under open-marine conditions.²⁷ In the prospective area of the Lower Indus Basin, the thickness of the Sembar Shale ranges from 1,000 to over 2,000 ft, Figure XXIV-28. We identified an organic-rich interval 1,000 ft thick with a net shale thickness of 250 ft. We estimate TOC of approximately 2% and an R_o of 1.0% to 1.6%. The Sembar Shale, in the shallower portions of the Lower Indus Basin, is in the oil and wet gas windows, with the lower limit of the oil window at about 4,000 ft and the wet gas/condensate window at 6,000 to 10,000 ft.²⁷ In the deeper portions of the basin below 10,000 ft, the Sembar Shale enters the dry gas window.

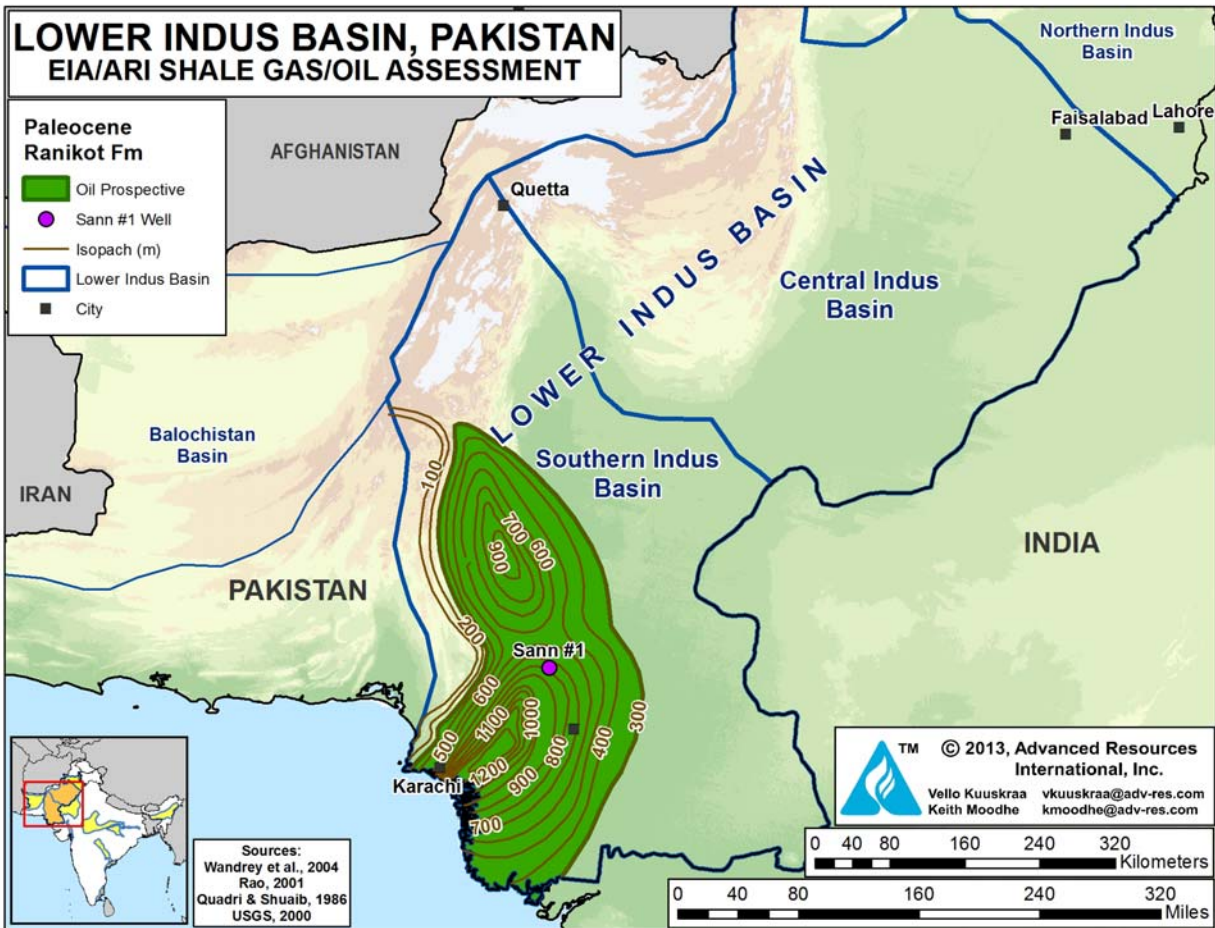
Figure XXIV-28. Isopach of Sembar Shale, Lower Indus Basin, Pakistan²⁶



The thermal gradients in the basin increase from east to west, from 1.31°F/100 ft on the Thar Slope in the east to 2.39°F/100 ft in the Karachi offshore in the west. The average thermal gradient in the basin is 2.1°F/100 ft. The Sembar Shale appears to have low clay content.

Ranikot Formation. The prospective area of the Ranikot Formation has a thickness of 1,000 to 3,000 ft, with a net shale thickness of 200 ft, Figure XXIV-29. We assume 2% TOC and a thermal maturity of 0.7% to 1.0% R_o , placing the Ranikot Shale in the oil window.

Figure XXIV-29. Isopach of Ranikot Formation, Southern Indus Basin, Pakistan²⁶



6.3 Resource Assessment

Within the 31,320-mi² dry gas prospective area, the Sembar Shale in the Lower Indus Basin has a resource concentration of 83 Bcf/mi². Within the 25,560-mi² wet gas and condensate prospective area, the Sembar Shale has resource concentrations of 57 Bcf/mi² of wet gas and 9 million barrels/mi² of condensate. Within the 26,700-mi² oil prospective area, the Sembar Shale has a resource concentration of 37 million barrels/mi².

Within the overall prospective area of the Lower Indus Basin, the Sembar Shale has risked shale gas in-place of 531 Tcf, with 101 Tcf as the risked, technically recoverable shale gas resource. In addition, the Sembar Shale has 145 billion barrels of shale oil in-place, with 5.8 billion barrels as the risked, technically recoverable shale oil resource.

Within its 26,780-mi² wet gas and condensate prospective area, the Ranikot Shale has resource concentrations of 17 Bcf/mi² of wet gas and 25 million barrels/mi² of shale oil/condensate. Within this prospective area of the Lower Indus Basin, the Ranikot Shale has 55 Tcf of risked shale gas in-place and 82 billion barrels of risked shale oil in-place. The risked, technically recoverable shale resources of the Ranikot Shale are 4 Tcf of wet shale gas and 3.3 billion barrels of shale oil/condensate.

6.4 Recent Activity

No publically available data has been reported on shale gas exploration or development for the Lower Indus Basin of Pakistan.

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