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By A. El-Sakka, G.M. Hamada, E. Padmanabhan & A.M. Salim

University Teknologi PETRONAS, Malaysia

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Shale Gas Reserve Potential in the Sedimentary Basins of Malaysia and South-East Asia Region

A. El-Sakka^α, G.M. Hamada^σ, E. Padmanabhan^ρ & A.M. Salim^ω

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Keywords: *sedimentary basins, shale gas reserves, south asia region, global shale reserves.*

1. INTRODUCTION

In the last decade and more, shale gas resources have emerged as a viable energy source. The development of these shales changed the traditional approach geologists had been following—that of the sequence of gas first being generated in the source rock, followed by its migration into the reservoir rock in which it is trapped. The shale layer acts as both source and reservoir rock in gas reservoir, there is no need for migration and since the permeability is near zero, it forms its own seal. Large amount of gas is generated in shale layers by sedimentation of organic matter. It is

important for development of shale gas reservoirs to locate such layers where gas can be generated and accumulated in a sedimentary basin as well as the sweet spot with shale gas deposits. To accomplish this, the tectonics of shale sedimentary basins have to be analyzed, along with the sedimentary environment and sequence stratigraphy. As different shale gas reservoirs have different properties, it is imperative to study them before any exploration plan is put in place.

Shale gas consists of 70-90% methane, it is often called unconventional natural gas and is taken from different rock layers than traditional gas. shale gas exploration and exploitation is governed by many factors such as the areal extent of shale layer, thickness, total organic carbon content, kerogen type, maturity, mineralogy, brittleness versus ductility etc. integrated studies of geological, geochemical, geophysical, petrophysical, geo mechanical can help evaluating all these factors to identify the sweet spots for shale gas exploration and exploitation. The shale itself has very low permeability and, without employing fracturing technology, production well flow rates would be minimal, (Satinder et al, 2012 and Hamada, 2017).

The main method of shale gas production is hydraulic fracturing, which requires a tremendous amount of water. Every shale gas well needs millions of gallons of water. The hydraulic fracturing process shoots out a mixture of water and chemicals at high pressure to extract the gas, inevitably requiring large amounts of water. Thus, the most important issue in developing shale gas in SE ASIA developing the technology to minimize water usage. In summary, it can be stated that the potential for shale gas as a source of energy in Southeast Asia appears to be good. However, more work needs to be carried out to ascertain the exact capacity of this gas in each country mentioned earlier.

For a shale gas reservoir to become a successful shale gas play, the following characteristics need to be considered: organic richness (TOC), maturation, thickness, gas in place, permeability, mineralogy, brittleness and pore pressure. An optimum combination of these factors leads to favorable productivity. Geophysical methods can help in characterizing the shale gas resource plays. However, the methodology adopted is in general quite different from methodologies applied to conventional reservoirs. In addition, the characterization of each shale reservoir could require particular types of tools and approaches

Author α σ ρ ω: Faculty of Geosciences and Petroleum Engineering, University Teknologi PETRONAS, Malaysia.
e-mail: ghareb.mostafa@utp.edu.my

to well understand the sedimentation conditions and the petrophysical properties to meet the growing challenges and expectations of shale gas resources.

Exploration and production activity started in Southeast Asia in the beginning of the last century. Shale gas resources are widely spread across the globe, there is great interest in the economic potential for developing shale gas more widely. The main objective of this study is to discuss the potential of shale gas reserves in Malaysia and South-East Asia sedimentary basins. Shale can be a game changer in South East Asia and mainly for Malaysia, China, India, Pakistan, Indonesia and Thailand. All these countries are big importers of crude oil and shale has the potential to drastically reduce the huge import bills of these nations. However, Southeast Asia has strengthened its important role in the global energy market, due to the growing economies in the region.

II. MALAYSIA BASINS AND SHALE GAS POTENTIAL

Malaysia is in rapid economic growth while oil and gas is expected to play an important role in the economy towards the year 2020, when the country is expected to be fully industrialized.

Malaysia is the world's third-largest exporter of liquefied natural gas, and the second-largest oil and natural gas producer in the Southeast Asia. Malaysian sedimentary basins are major areas for potential oil and gas reservoirs as they contain many faults and natural traps, which collects and accumulate hydrocarbons under its impermeable layer. Six major Tertiary sedimentary basins are present in Malaysia: the Malay, Penyu, Sarawak, Sabah, Sandakan and a portion of Tarakan basins (Fig. 1) (EIA, 2013). Of these basins, only in Sarawak and Sabah basins have been proven to contain significant Shale gas accumulations that have been discovered. The six basins are grouped into three main regions: Peninsular basin, Sarawak & Sabah basin. Sarawak and Sabah basins area have been identified as a potential for unconventional play but in the early stage of exploration and no drilled wells to test the play. East Malaysia of Sabah and Sarawak is a huge area totaling almost 200,000 sq km making up approximately 60 % of the Malaysia land mass. Based on preliminary resource assessment, Malaysia has an estimated hydrocarbon initial in place of 8.8 Tcf shale gas resources. (PETRONAS, 2016). The development of unconventional gas resources especially shale gas is still under study.

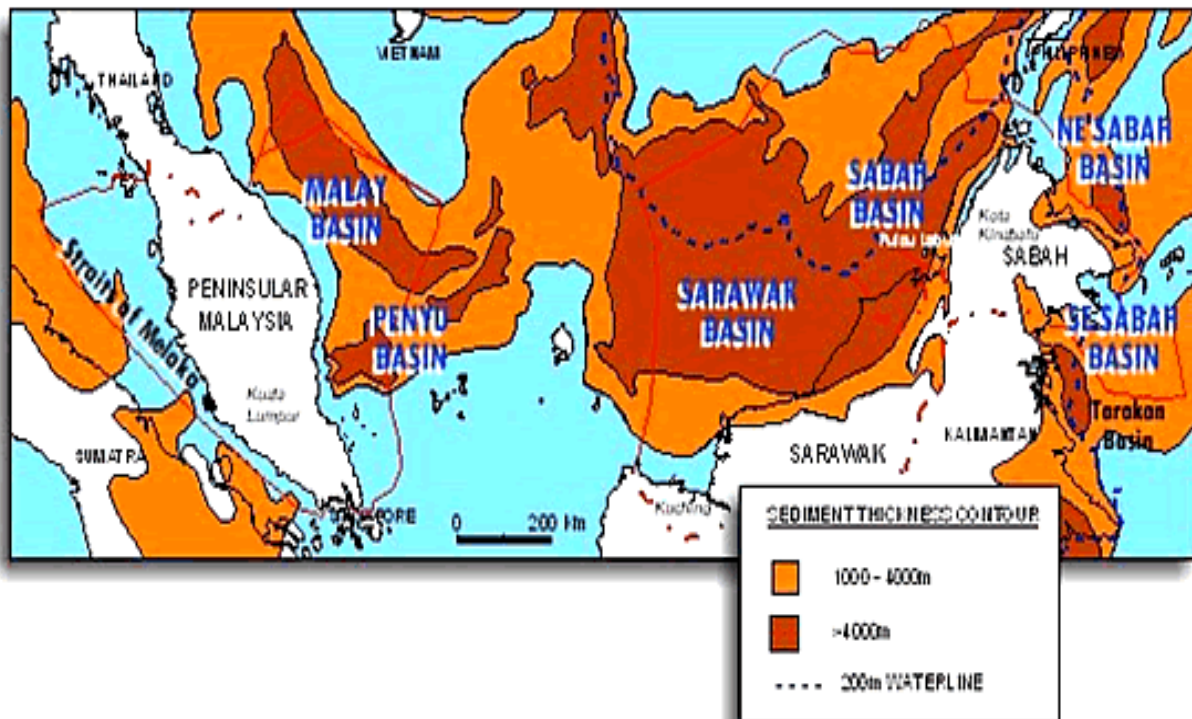


Figure 1: Sedimentary Basins in Malaysia (CCOP, 2010)

a) Sarawak

In Sarawak, the oldest formations date back to 300 million years. These ancient rocks form part of the West Borneo Basement which is the exposed part of

Sundaland in Southwest Borneo, thus related to continental South-East Asia. The Basement is built up of Paleozoic and Mesozoic rocks. Most of Sarawak is underlain by younger Tertiary sedimentary rocks

underlain by younger Tertiary sedimentary rocks especially the region northeast of the Lupar river. SETAP-SHALE Lithology Description (Inner neritic clay-shale & silty clay Occasionally interbedded with ss, calcareous ss & moderate thick limestone) with SR Potential (Poor-Fair Organic matter. NYALAU Lithology Description (Hard and semi to unconsolidated sandstone, massive, heterolithic coal seam, paleosol and thick mudstone (probably shelf and marginal marine mudstone) with TOC:78% Oil & gas. The

stratigraphic subdivision of the Tertiary sequence in Sarawak is based on sedimentary cycles, the cycles have been identified based on eight separate geological regions , namely the West Baram Delta, Balingian, Central Luconia, Tinjar, Tatau, West Luconia and SW Luconia and SW Sarawak Provinces as shown in (fig.2,3) (1994). The sedimentary succession on the Sarawak Basin shelf is more than 12 km thick. SIBUTI formation Lithology Description (shale, siltstone interbedded, limestone.)

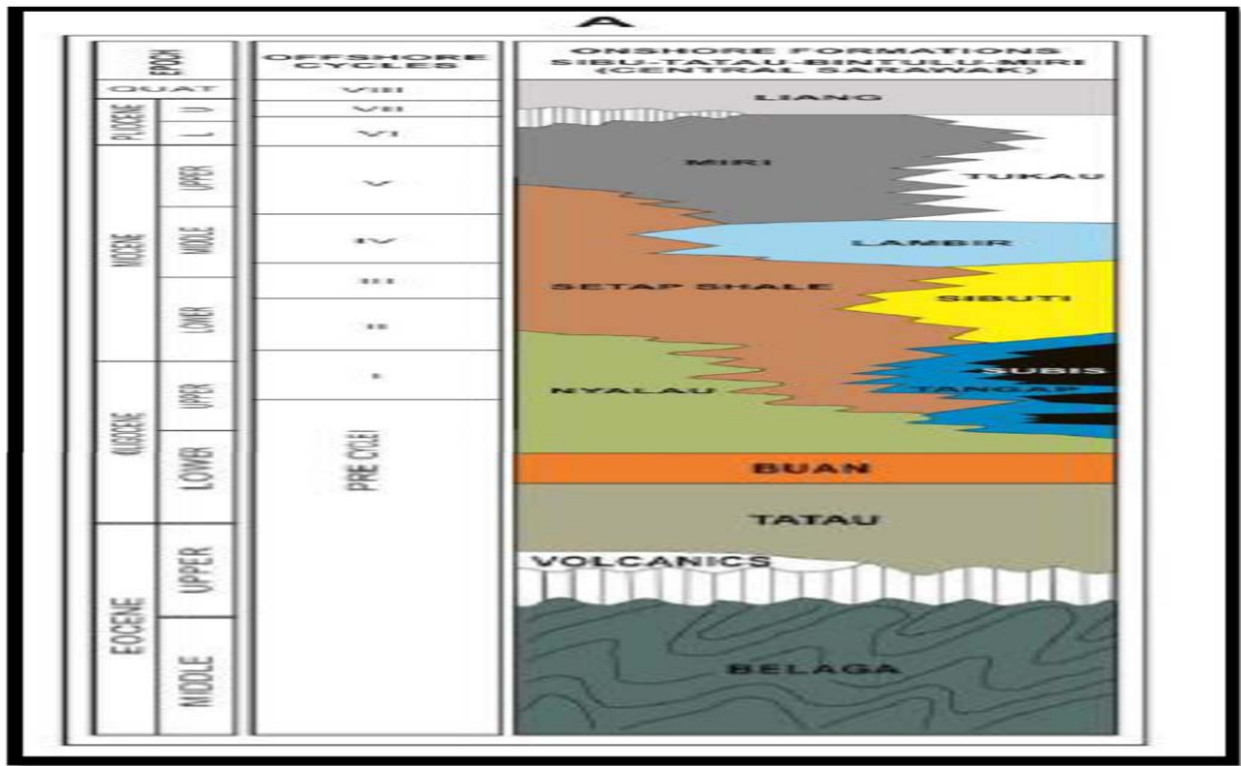


Figure 2: Onshore Formation central Sarawak, (Petronas,2015)

b) Sabah Basins

The Sabah Basin have three major basins, which located in NW Sabah, is mainly offshore while the other two basins cover some areas in the N.E. and S.E. of onshore Sabah. The Sabah Basin contains 12-km thick Neogene sediments that were deposited within the deep marine and progradational shelf slope environment.

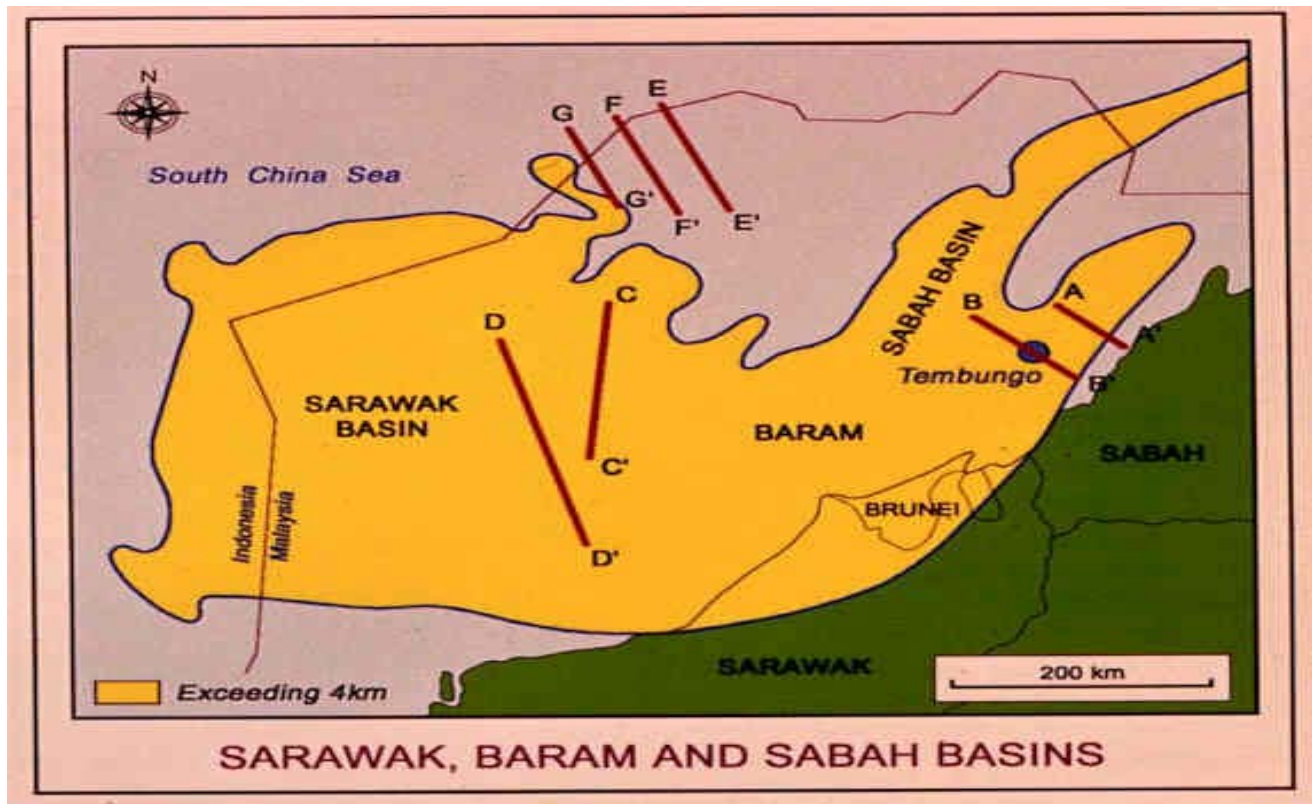


Figure 3: Location map of Sarawak and Sabah basins (IEA,1994)

c) Peninsular Basin

Peninsular Malaysia region have four main basins, The Malay Basin and the Penyu Basin are located offshore to the east of the peninsula. Other two basins, namely the Central Sumatra Basin and the North Sumatra Basin lie to the west of the peninsula and are mostly offshore with a small portion lying onshore. The Malay Basin contains about 12-km thick Neogene sediments that were deposited within the non-marine to shallow marine environment. In the Penyu Basin, oil has been discovered on horst blocks of Oligocene synrift play consisting of fluvial sandstones reservoirs.

III. CHINA POTENTIAL AND MAJOR SHALE GAS PROSPECTS

China is the third country gaining shale gas discovery in the world after the United States and Canada. China has a huge shale gas resources. According to some estimates, it is the world's largest reserve. China possesses 31.6 trillion cubic meters (1,115 trillion cubic feet) of technically recoverable shale gas resources(EIA, 2013).

For geographical distribution, target areas can be divided into four regions (Fig 4): South (Sichuan Basin, Jiangnan Basin and Chuxiong Basin), North (Ordos Basin, Bohai Bay Basin, Songliao Basin),

Northwest (Tarim Basin and Qaidam Basin), and Qinghai-Tibet (Qiangtang Basin).

Most of the shale gas is in the South (46.8 percent) and Northwest (43 percent) regions (Zhang, 2010a), primarily in Sichuan, Tarim, and Ordos basins. The North (8.9 percent) and Qinghai-Tibet (1.3 percent) regions only account for 10.2 percent of the total shale gas resources. Formations include marine shale, continental shale and transitional facies (Guan and Niu, 2005).

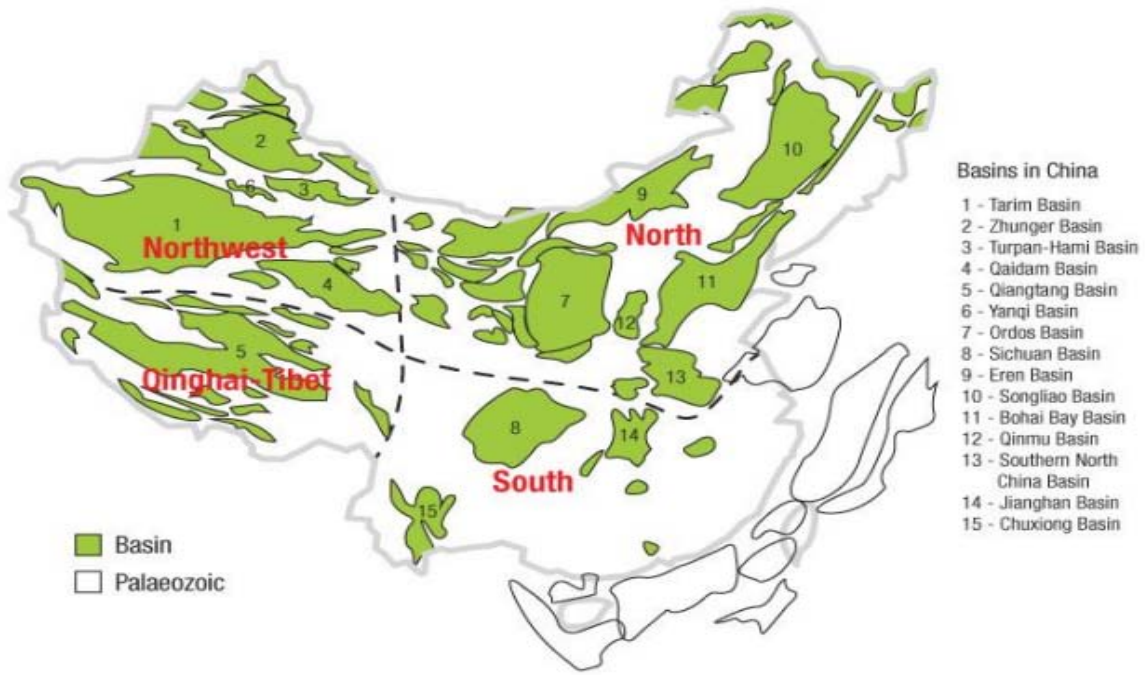


Figure 4: Basins in China (Wang and Wang, 2011)

The estimated amount of technically recoverable gas in two China shale basins shown in Fig. 5, Tarim and Sichuan, rank the country among the world's richest. The EIA study estimated that the Sichuan and Tarim basins hold 1,275 Tcf of technically recoverable gas, assuming that about 25% of the gas can be produced.

basins are the Songliao, Bohai, Ordos, Tuha and Jungar Basins. The Sichuan Basin is considered as the most promising basin to develop shale gas in short term, because of its well-developed gas pipeline network and mature gas market.

The Sichuan and Tarim Basins are two large organic rich shale plays, and other five less prospective

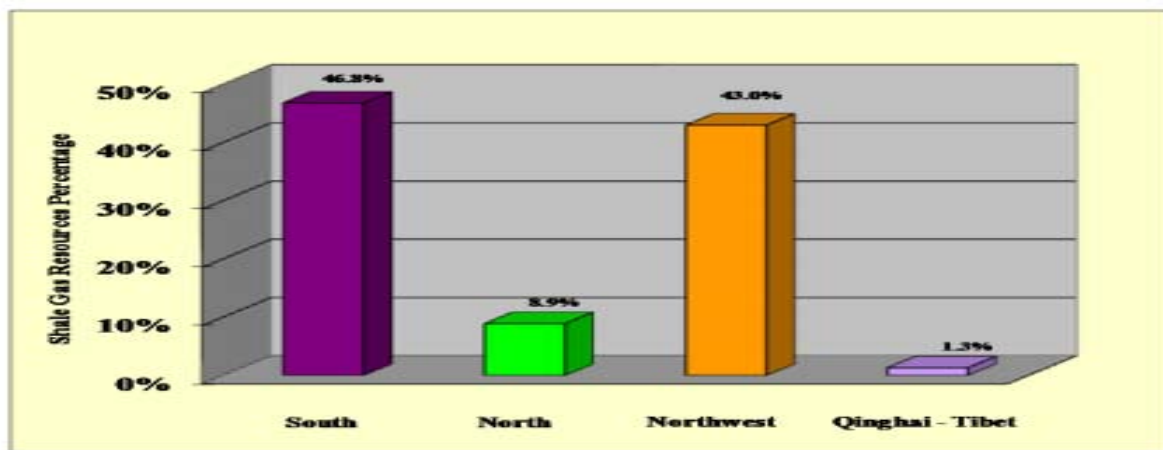


Figure 5: Shale Geographic Distribution in China (Zhang, 2010)

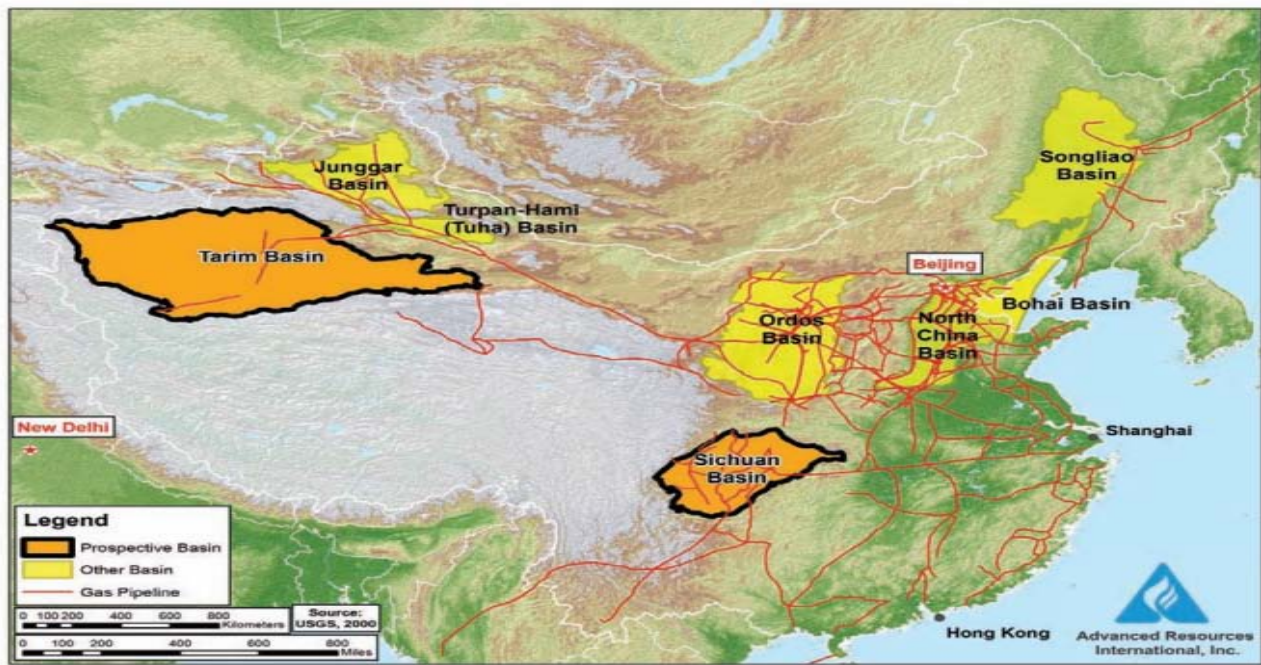


Figure 6: China shale gas Prospective basins, Tarim and Sichuan & gas pipeline (ARI, 2013)

China is facing with many challenges in shale gas exploration and development. Firstly, shale formations are not homogenous. The depth of shale reservoirs in China is normally from 3000 to 4000 meters, which is deeper than in the USA. Second, China has more complicated reservoir characteristics and Limited water resource makes shale gas development more difficult. The major Chinese petroleum companies have shown great interest in shale gas development. The geologic features of large gas fields in China, including forming conditions, distribution regularity, main controlling factors, reservoir lithology and geologic ages, gas geneses and sources, traps and gas accumulation. China has an estimated 1,115 Tcf of risked, technically recoverable shale gas, mainly in marine- and lacustrine-deposited source rock shales of the Sichuan (626 Tcf), Tarim (216 Tcf).

a) Sichuan Basin

Sichuan Basin is one of the richest shale gas basins in China. Shale exploration activity in China has been focused on the Sichuan Basin, which contains marine-deposited, dry-gas mature source rock shales that resemble commercially productive shales. The Sichuan Basin covers a large 190,000-km² area in south central China. The basin currently produces about 1.5 Bcf/d of natural gas from conventional and low-permeability sandstones and carbonates within the Triassic Xujiahe and Feixianguan formations, from complex structural-stratigraphic traps (mainly faulted anticlines) that are distributed across the basin. Sichuan Basin is the Changning-Weiyuan area, which is found to be high in thermal evolution degree (Ro: 2.0%-

4.0%), porosity (3.0%–4.8%), gas concentration (2.82–3.28 m³/t) and the burial depth is relatively moderate (1500–4500 m). (Zou C. D., 2010) The EIA shale report assessment said the shale formations in the Sichuan shale are, on average, around 11,000 ft. deep. Sichuan basins technically recoverable resources which are 17.716 trillion of cubic meters. (Xin-gang, 2015). Some available data on this basin are summarized in Table1.

Table 1: Identified Shale Gas Formation in Sichuan Basin

System	Series	Formation	Depth	Formation thickness (m)	Shale Thickness (m)	Area (10 ³ km ²)	Shale Gas Resource (10 ¹² m ³)
Triassic	upper	Xujiahe	1,870-5,000	1,800-5,100	500-1,860	14-16.5	8.4-33.5
Silurian	lower	Longmaxi	2,300-4,100	200-800	50-500	128.2	4-12.4
Ordovician	upper	Wufengzu	2,300-4,500		2-40	147.3	0.52
Cambria	lower	Qiongzhusi	2,700-3,600	50-500	74-400	184.5	7.14-14.6
Sinian	upper	Doushantuo		25-70	10-40		

The Sichuan Basin, primary focus for shale gas, has multiple shale targets but also significant geologic challenges, such as numerous faults, often steep dips, high tectonic stress, slow drilling in hard formations, and high H₂S and CO₂ in places. Table-1 data provides good control of shale thickness, depth, structural geology, thermal maturity, and organic content.

The Sichuan basin has four tectonic zones: the Northwest Depression, Central Uplift, and the East and South Fold Belts. The Central Uplift, characterized by relatively simple structure and comparatively few faults, appears to be the most attractive region for shale gas development. In contrast, the East and South Fold Belts are structurally more complex, with numerous closely spaced folds and faults.

The four-main organic-rich shale targets in the Sichuan Basin are the Lower Cambrian Qiongzhusi,

Lower Silurian Longmaxi, Lower Permian Qixia, and the Upper Permian Longtan formations. (Figure 3). Most important is the Lower Silurian Longmaxi Formation, which contains an average 300 m of organically rich, black, graptolitic-bearing, siliceous to cherty shale. TOC is mostly low to moderate, reaching 4% and consisting mainly of Type II kerogen (Liu et al., 2011). Thermal maturity is high and increases with depth, ranging from dry gas prone to over mature (Ro 2.4% to 3.6%).

Another shale gas target in the Sichuan Basin is the Cambrian Qiongzhusi Formation. Even though deeper than the Longmaxi and mostly screened out by the 5-km depth, the Qiongzhusi contains high-quality source rocks that provide stacked shale resource potential. The formation was deposited under shallow marine continental shelf conditions and has an overall thickness of 250 to 600m.

Table 2: Stratigraphy of Source Rock Shale Targets in the Sichuan Basin

SICHUAN BASIN						
ERA	PERIOD	EPOCH	FORMATION	AGE (Ma)	THICKNESS (m)	
CEANOZOIC	QUATERNARY			0 - 3	0 - 380	
	TERTIARY	Upper		3 - 25	0 - 300	
		Lower		25 - 80	0 - 800	
MESOZOIC	CRETACEOUS			80 - 140	0 - 2000	
	JURASSIC	Upper	Fenglaizhen	140 - 195	650 - 1400	
		Middle	Suning		340 - 500	
		Middle-Low er	Shaximiao		600 - 2800	
	TRIASSIC	Upper		Xujiahe	195 - 205	250 - 3000
		Middle		Leikoupo	205 - 230	900 - 1700
		Lower		Jialingjiang		
			Feixianguan			
PALEOZOIC	PERMIAN	Upper	Changxing	230 - 270	200 - 500	
		Lower	Longtan			
			Maokou		200 - 500	
	CARBONIFEROUS	Mississippian	Huanglong	270 - 320	0 - 500	
	SILURIAN	Upper		320 - 570	0 - 1500	
		Lower	Longmaxi			
	ORDOVICIAN				0 - 600	
Upper			Xixiangchi			
Middle			Yuxiansi			
CAMBRIAN	Lower		Qiongzhusi	0 - 2500		
PROTEROZOIC	SINIAN	Upper	Dengying	570 - 850	200 - 1100	
		Lower	Doushantuo			
	PRE-SINIAN			850	0 - 400	

b) Tarim Basin

The Tarim Basin, located in the Xinjiang Autonomous Region, is China's largest onshore sedimentary basin (600,000 km², the Tarim Basin produces 260,000 B/D of oil and 1.6 Bcf/d of natural gas from conventional reservoirs, which were sourced mainly by organic-rich Cambrian and Ordovician shales. Figure 7 shows the structural elements of the Tarim Basin, and Prospective of shale gas.

The Tarim Basin is sub-divided by fault and fold systems into a series of seven distinct structural zones, comprising three uplifts and four depressions. (Xiao et al., 2000) Petroleum source rocks are found in the Cambrian, Ordovician, Carboniferous Triassic, Cretaceous, and Tertiary, Figure 8 shows which the

marine deposited black shales of Cambrian and particularly Ordovician age are considered the most important source rocks in the basin. (Cai et al., 2009) Tarim and the Northern China area are marine deposits often have high organic matter content and Ro value of 1.1%–2.5%. the organic matter is mostly II–III type kerogen. while those in the Tarim average 13,500 ft. deep. (Rassenfoss, Jul 2012).

By 2020, China's annual shale gas production will be expected to reach 300×10^8 m³. No shale leasing or drilling have been reported, probably because of this basin's remoteness and extreme depth of the shale. (Zou C., 2010).

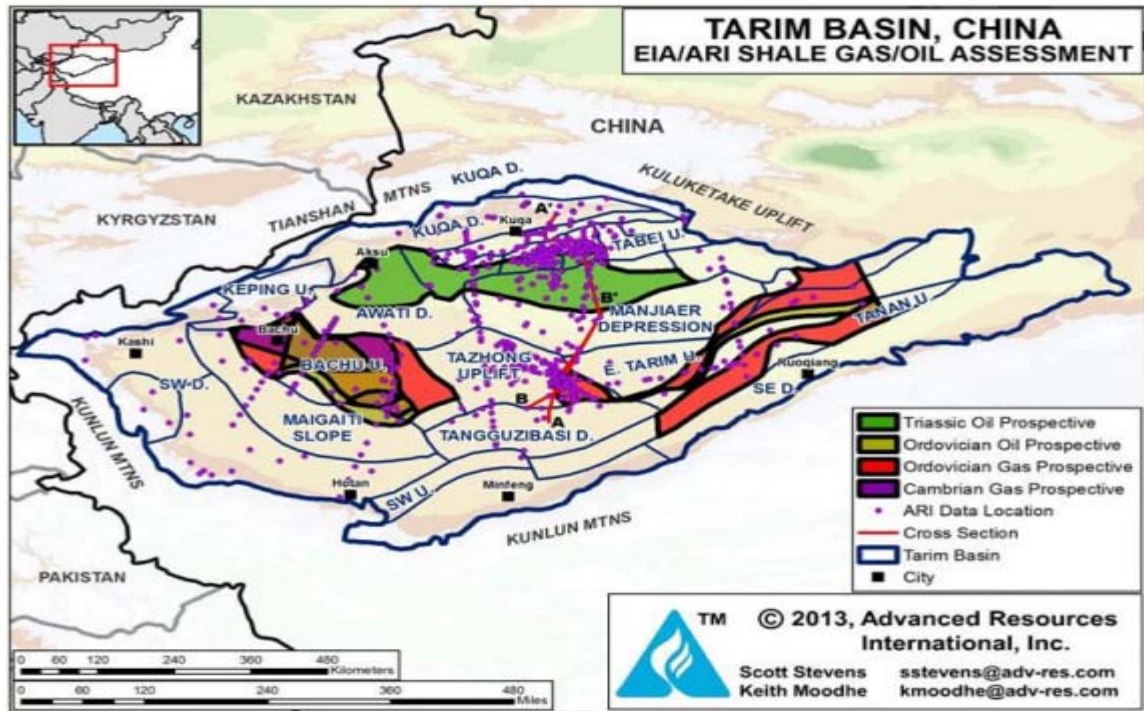


Figure 7: Shale Prospective Areas in the Tarim Basin (ARI, 2013)

ERA	PERIOD	EPOCH	FORMATION	AGE (Ma)	THICKNESS (m)
CENOZOIC	QUATERNARY	Q			
	TERTIARY	N _{2a}			
		N _{1w}			
		Eh			
MESOZOIC	CRETACEOUS	K _{2y}			
	JURASSIC	K _{1x}			
		J _{2a}			
		J _{2t}			
		J _{2y}			
	J _{1k}				
	TRIASSIC				
PALEOZOIC	PERMIAN	Upper	Shazijing Aqiaqun	290	0 - 780
		Middle-Lower	Aqiaqun		
		Upper-Middle	Xiaohaizi		
	CARBONIFEROUS	Lower	Kalashayi	290 - 355	0 - 691
			Bachu		
	DEVONIAN			355 - 405	0 - 241
	SILURIAN	Upper		405 - 439	0 - 517
		Middle			
		Lower			
	ORDOVICIAN	Upper	Hetuoao (O ₁₋₂)	439 - 459	0 - 300 org-rich
		Middle	Yijianfan (O ₂)	459 - 478	0 - 150 org-rich
		Lower	Lianglitage (O ₃)	478 - 505	0 - 50 org-rich
	CAMBRIAN	Upper	Qiulitage	505 - 600	2918
Middle		Awatage	125		
Lower		Xiaoerbulake	74		
PROTEROZOIC	SINIAN			600+	200 - 1100

Figure 8: Stratigraphy of the Tarim Basin, Highlighting Prospective Cambrian, Ordovician, Carboniferous, Triassic, Cretaceous, and Tertiary Source Rocks

IV. INDIA SHALE GAS POTENTIAL

Natural gas is rapidly substituting fuel to suffice the growing energy requirement of today's world. As the consumption of natural gas is increasing rapidly, it is essential to identify and develop the available energy resources. India has the huge prospects of unconventional shale gas resources. Commercial exploration of these shale gas resources can effectively make the global natural gas curve more elastic.

There is a sizeable deposit of shale formations in several sedimentary basins of India with different total organic (TOC) content and maturity history. The Cambay, Krishna-Godavari, Cauvery and Damodar valley are the four major basins of shale gas reservoirs as indicated by considerable thickness of shales; sufficient TOC (2 to 6 wt%) content; and good thermal maturity with vitrinite reflectance of more than 1.0. (Ind., 2014). The reservoir properties and resource potential (290 TCF) of shale gas, estimated by ARI, are shown in Table-3.

According to ARI (American Research Institute), shale gas reserves would be anywhere between 600 Tcf to 2000 Tcf and technically recoverable shale gas resource is estimated as 63 Tcf in spread over many

sedimentary basins India. Most of Indian basins especially the Cambay, Krishna-Godavari, Cauvery and Damodar Valley have good prospects of shale gas (Fig.9). Several other basins such as the Vindhyan, Upper Assam, Pranhita-Godavari and Rajasthan, though show thermal immaturity, contain measurable thickness of shale with good TOC content.

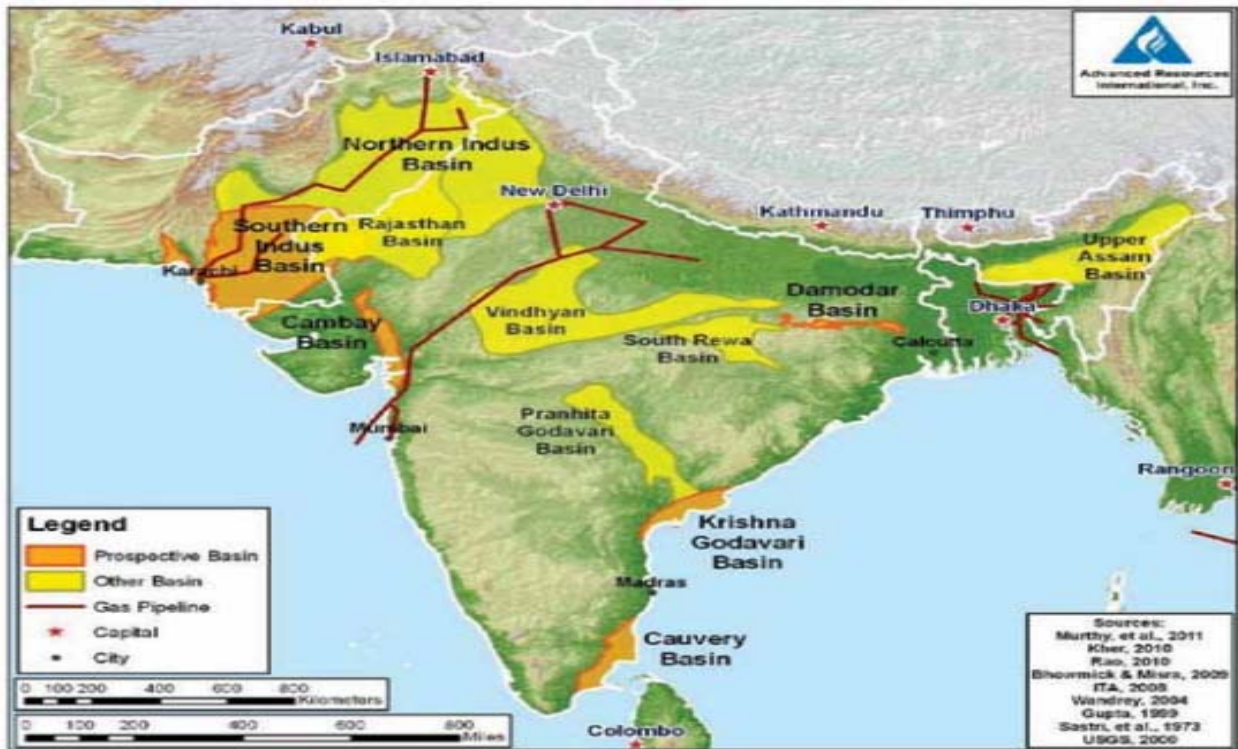


Figure 9: Shale gas basins of India (US EIA 2011)

a) *Cambay Basin*

Thick Cambay Shale has been the main hydrocarbon source rock in the Cambay basin. The basin covers total area of about 53,500 sq. km. It is bounded on its eastern and western sides by basin-margin faults. The Cambay basin contains five distinct fault blocks (Fig.10) from north to south: (1) Sanchor Patan; (2) Mehsana-Ahmedabad; (3) Tarapur; (4) Broach; and (5) Narmada. These blocks are characterized by local lows, some of which appear to have sufficient thermal maturity for shale gas. ARI estimates a risked gas in-place for the Cambay Black Shale of approximately 20 Tcf of which may be technically recoverable.

b) *Krishna Godavari Basin*

It is located on the east coast of India; land part covers an area of 15000 sq. km and the offshore part covers an area of 25,000 sq. km. Shale in the Krishna Godavari Basin is limited to the four grabens (sub-basins) where the thermal maturity is sufficiently high for wet to dry gas generation. (Mahto, 2014) Estimated risked shale gas in place is of 136 Tcf, with a risked technically recoverable resource of 27 Tcf.

c) *Cauvery Basin*

The Cauvery basin covers an area (25,000 sq.km) and shallow offshore areas (30,000 sq. km). The basin contains a thick interval of organic rich source rocks in Lower Cretaceous Andimadam and Sattapadi shale formations. The oldest rocks in the Cauvery Basin

are the shallow marine, late Jurassic sediments and early Cretaceous deposits. Average resource around 43 Tcf of risked shale gas in-place is estimated of which 9 Tcf is considered technically recoverable.

d) *Damodar Valley Basin*

The Damodar Valley Basin is part of a group of basins collectively named as Gondwanas. (Pradhan, 2015) The Gondwanas, comprising the Satpura, Pranhita-Godavari, Son-Mahanadi and Damodar Basins. In this basin around 33 Tcf of risked shale gas in-place is estimated of which 7 Tcf is considered technically recoverable.

e) *Southern Indus Basin*

The Southern Indus Basin is in southern Pakistan adjacent to the border with India. Southern Indus Basin has five commercial oil discoveries and one gas discovery in the conventional Cretaceous-age and three gas discoveries and one gas condensate discovery in shallower formations. Moreover, with the help of this technology the well can drain shale gas resources from a geographical area that is much larger than a single vertical well within the same shale formation.

Table 3: Shale gas reservoir properties and resource potential of India. (ARI and US EIA 2011)

Basic data	Basin/Gross Area	Cambay basin (20,000 mi ²)	Damodar Valley basin (1,410 mi ²)	Krishna- Godavari basin (7,800mi ²)	Cauvery basin (9,100 mi ²)	
	Shale Formation	Cambay Shale	Barren Measure	Kommugudem Shale	Andimadam Formation	
	Geological Age	Upper Cretaceous/ Tertiary	Permian-Triassic	Permian	Cretaceous	
Physical Extent	Prospective Area(mi ²)	940	1,080	4,340	1,005	
	Thickness (ft)	Interval	1,600-4,900	0-2,100	3,100-3,500	600-1,200
		Organic Rich	1,500	1,050	1,000	800
		Net	500	368	300	400
	Depth (ft)	Interval	11,500-16,400	3,280-6,560	6,200-13,900	7,000-13,000
Average		13,000	4,920	11,500	10,000	
Reservoir properties	Reservoir Pressure	Moderately Overpressured	Moderately Overpressured	Normal	Normal	
	Average TOC (wt. %)	3.0%	4.5%	6.0%	2.0%	
	Clay Content	Medium	High	High	High	
Resource	GIP Concentration(BCF/mi ²)	231	123	156	143	
	Risked GIP (TCF)	78	33	136	43	
	Risked recoverable(TCF)	20	7	27	9	

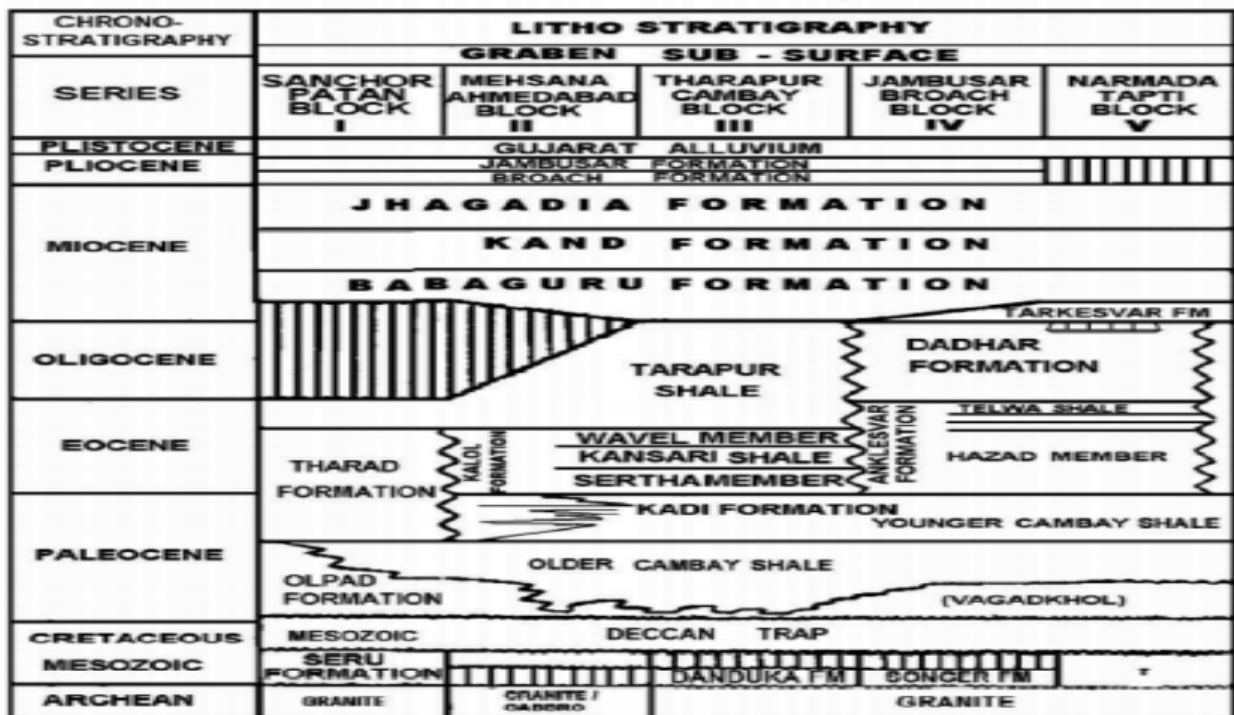


Figure 10: General stratigraphic column of the Cambay Basin (Sivan et al., 2008)

India has vast resources of shale gas and it is mainly untapped due to strict government policies, lack of new technologies & technical expertise and lack of interest from the industry. But, it is essential to explore and exploit the shale gas due to growing energy needs in the country. The Cambay, Krishna Godavari, Cauvery and the Damodar Valley are the most prospective

sedimentary basins for carrying out shale gas activities in the country.

V. PAKISTAN

Pakistan has world's 9th largest shale gas and oil reserves which are far greater than the total resources available in Central Asian states. Three

Sedimentary basins of Pakistan; Indus, Balochistan, and Pasheen. The geological history of Indus basin comes from the Precambrian Age. The Indus Basin consists of the Upper Indus Basin, Kohat sub-Basin, Potwar sub-Basin, Lower Indus Basin, Central Indus Basin, Southern Indus Basin. Total area around 271, 700 km², which is 33 percent of total sedimentary area of the country. Figure 12 provides the stratigraphic column for the key basins of Pakistan.

Pakistan has more than 827,365 Km² sedimentary basin area, Indus sedimentary area is

enriched with thick sequence of shale formations as a source and has a proven petroleum system. The recent estimates by EIA Assessment have shown that the total Shale Gas reserves in Pakistan are estimated around 586 Tcf. However, the technically recoverable shale gas resources are close to 100-105 Tcf as shown in Figure 11. (Mahto, 2014). Not much work has been done for shale gas assessment in the upper Indus basin, Balochistan, and Pasheen.

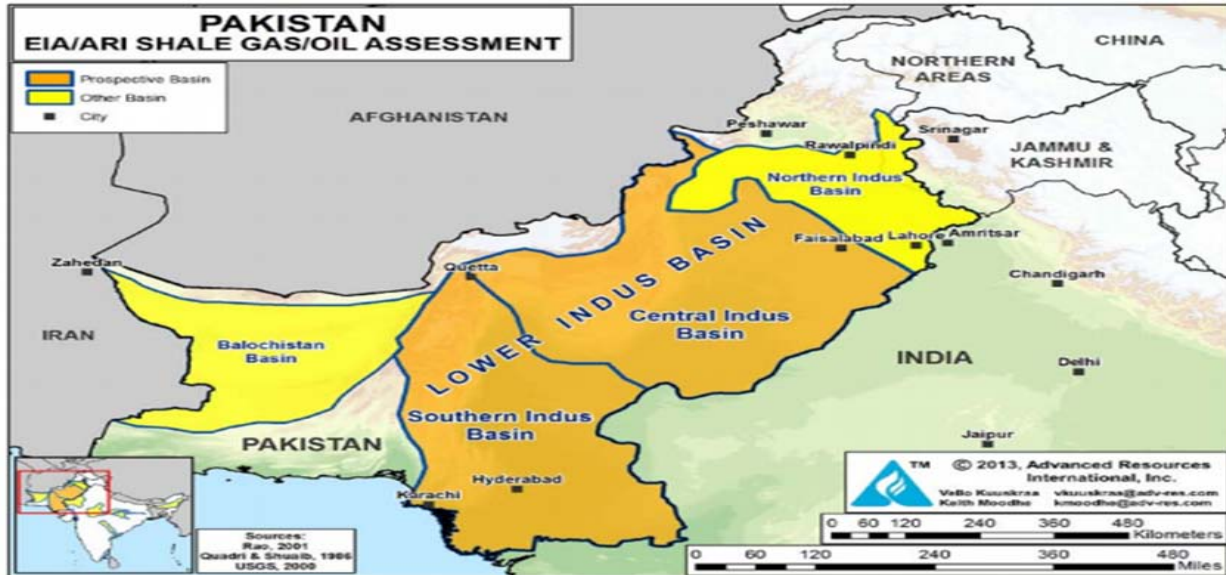


Figure 11: Shale gas Potential in Pakistan (ARI, 2013)

Shale gas and oil assessment is restricted to the extensive in Central and Southern Indus basins, together called the Lower Indus Basin. (Kuuskraa V. S., 2013) The shales in this basin have sourced the significant volumes of conventional oil and gas discovered and produced in Pakistan. However, no shale specific exploration has been publicly reported for Pakistan.

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

Figure 12: Stratigraphic Column for Pakistan (EIA, 2013)

a) Lower Indus Basin

The Lower Indus basin has two types of shale formations, which are Sembar and Ranikot formation. 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, 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.

i. Sembar Formation

- It mainly consists of clastic rocks, typically shale with lesser quantities of siltstone and sandstone in the Lower Indus. The sand content increases towards the Southeast in the Lower Indus Basin. However, in the Middle Indus Basin, the formation is composed of siltstone with few marl and shales.

- Shale in Sembar Formation is basically medium hard, pyritic, moderately indurated and slightly calcareous in the area. The gross thickness varies from >50m to 800 m.
- The TOC and thermal maturity (Ro) of Sembar formation as per exploration targets is around 2% and 1%-1.6% respectively.
- ii. Ranikot Formation
 - The shale in Paleocene Ranikot Formations is primarily upper carbonate unit, which is tailored with fossiliferous limestone inter-bedded with dolomitic shale, calcareous sandstone and abundant bituminous material.
 - The prospective area of the Ranikot formation has a thickness of around 1,000-3,000ft with net shale thickness of 200 ft.

- Ranikot Shale are estimated around 4 Tcf of wet Shale Gas.

VI. THAILAND

This large Southeast Asian country has significant prospective shale gas potential. Nearly 90% of its current petroleum output comes from offshore fields in the Gulf of Thailand, with only limited production from small onshore fields. Approximately 40% of Thailand's primary energy consumption is supplied by natural gas.

Thailand's greatest potential appears to be shale gas deposits contained in Permian and Triassic shale source rocks in the Khorat, the country's largest

onshore sedimentary basin. (Jeenagool, 2015) These shales can be locally thick, organic-rich, dry gas prone, deeply buried, and overpressure.

Thailand has three main onshore sedimentary basins which may have unconventional oil and gas potential, Figure-13. These include the large Khorat Basin in the northeast; a series of smaller, isolated pull-apart basins in the Northern Intermontane Basin, where shale oil deposits are being mined; and the similarly complex Central Plains Basin.

The Khorat Basin in northeast Thailand has an estimated 5 Tcf of risked technically recoverable shale gas resources. While no shale gas/oil exploration activity has been reported to date.

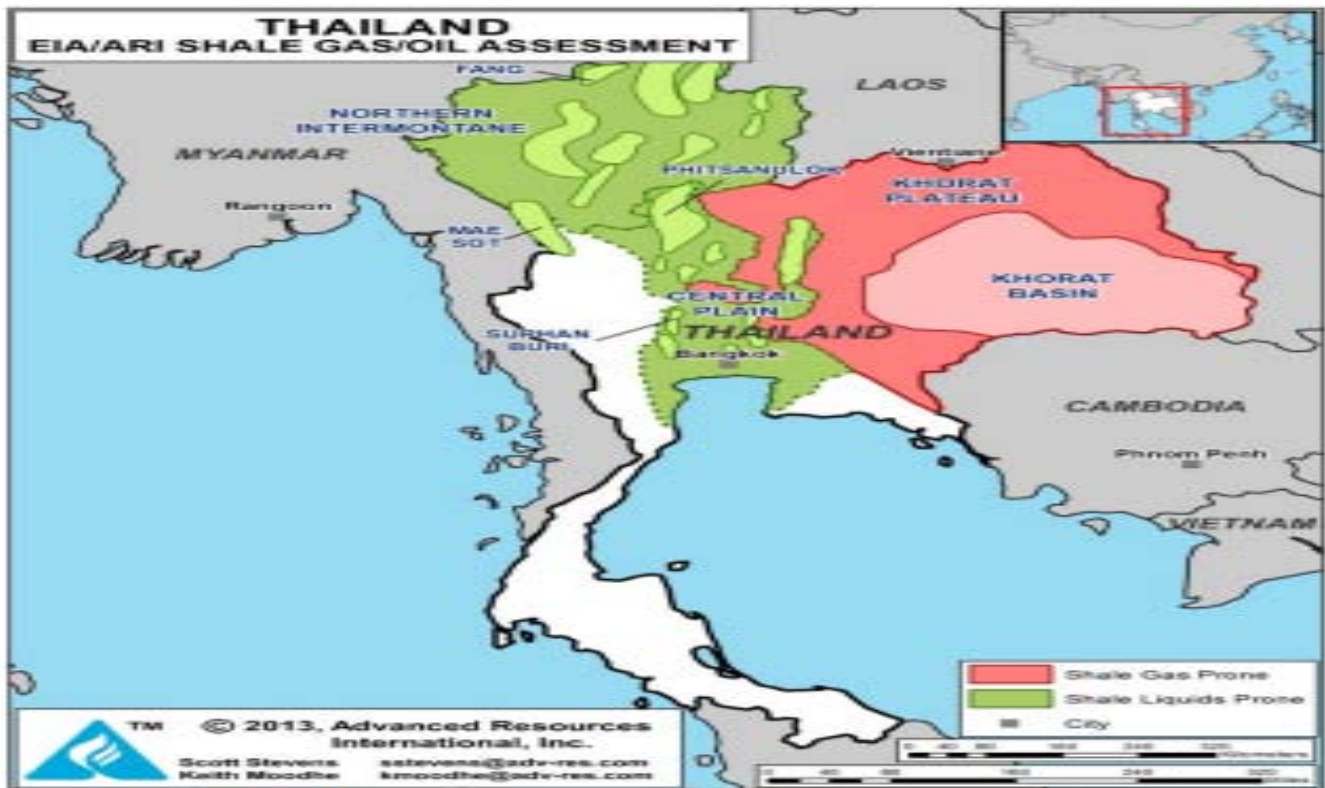


Figure 13: Thailand sedimentary basin (EIA, 2013)

a) Khorat Basin

Thailand's largest onshore sedimentary basin, the 35,000-mi². The Khorat Basin in northeast Thailand appears to have the country's best shale gas potential. As shown in the Table-4 the prospective of shale gas in the Khorat, Northern Intermontane and Central Plains basins.

The structural Khorat Basin depression was initiated during the Middle Paleozoic, with widespread deposition of clastic and carbonate sedimentary rocks, beginning with the Carboniferous Si That Formation. (Kuuskraa V. , 2013)

Fluvial and lacustrine deposits of the Triassic Kuchinarai Group also have been identified as petroleum source rocks in the Khorat Basin, with high-TOC intervals. The Kuchinarai Group reportedly averages a prospective 6,500 to 7,000 feet deep within the basin. Thermal maturity modeling suggests it reaches the dry gas window, with no liquids potential ($R_o > 2.0\%$).

Table 4: Khorat basin properties

Basic Data	Basin/Gross Area		Khorat (32,400 mi ²)
	Shale Formation		Nam Duk Fm
	Geologic Age		Permian
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi ²)		1,750
	Thickness (ft)	Organically Rich	400
		Net	200
	Depth (ft)	Interval	6,000 - 12,000
Average		9,000	
Reservoir Properties	Reservoir Pressure		Mod. Overpress.
	Average TOC (wt. %)		3.0%
	Thermal Maturity (% Ro)		2.50%
	Clay Content		Low
Resource	Gas Phase		Dry Gas
	GIP Concentration (Bcf/mi ²)		83.0
	Risky GIP (Tcf)		21.8
	Risky Recoverable (Tcf)		5.4

Figure 14 illustrates the stratigraphy and petroleum systems of the Khorat Basin. The shallow marine to basinal Permian Saraburi Group is considered the primary source rock, while the fluvial to lacustrine

Triassic Kuchinarai and HuaiHinLat Groups offer additional source rock potential. Permian dolomite and karstedlimestones form the main conventional petroleum reservoirs.

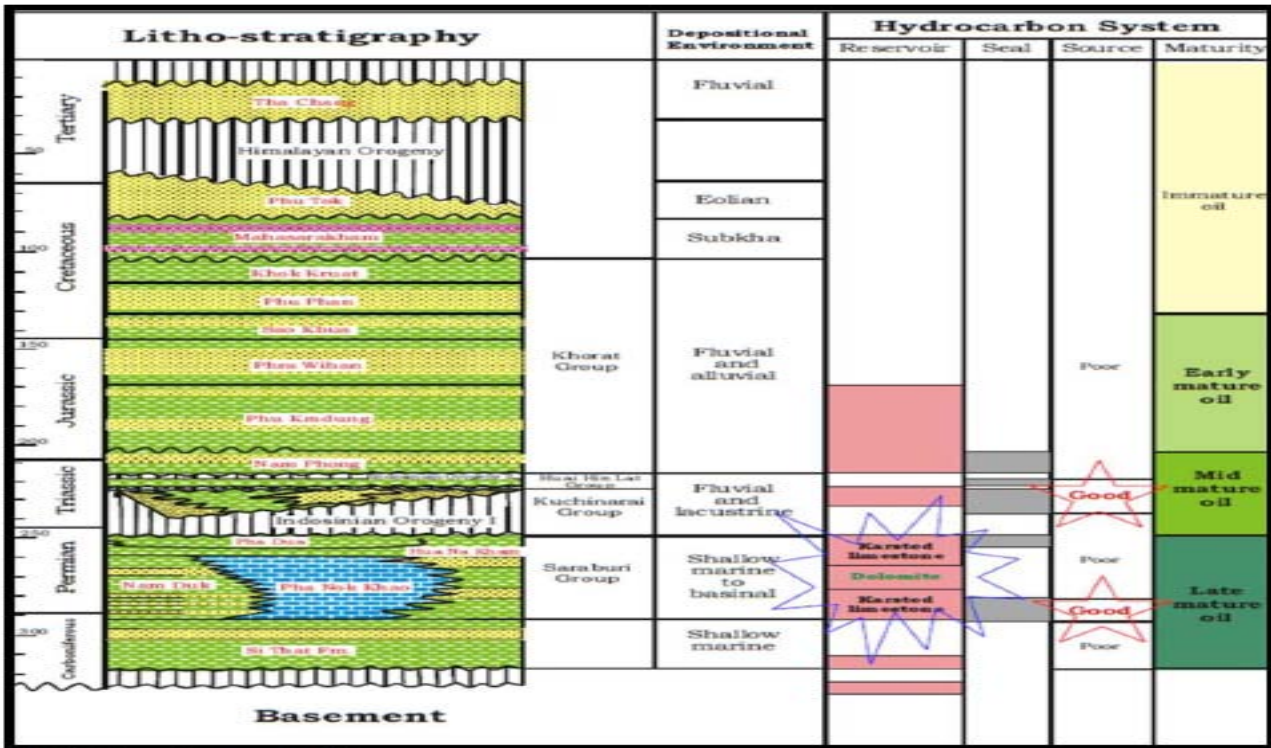


Figure 14: Stratigraphy and Petroleum Systems of the Khorat Basin. Shallow Marine Permian Saraburi Group is the Primary Source Rock

VII. INDONESIA SHALE GAS POTENTIAL

Indonesia is the world's fourth most populous country (250 million) and a major producer of coal, oil, and natural gas. Indonesia has shale gas and shale oil

potential within selected marine-deposited formations, as well as more extensive shale resources within non-marine and often coaly shale deposits, Estimated 46 Tcf technically recoverable shale gas resources out of 303 Tcf of risky shale gas in-place.

Indonesia has shale gas within selected marine-deposited formations, more extensive shale resources. The petroleum source rocks in onshore Indonesian basins are relatively young, mostly Eocene to Pliocene. (Rahmalia, 2012) Indonesia have many onshore sedimentary basins (Figure 15) which may have shale gas potential, these include the Central and South Sumatra basins on Sumatra Island; the Kutei and Tarakan basins in Kalimantan; most reserve of shale gas in the eastern part (Salawati, Bintuni, Tomori) but it

structurally complex basins. Other basins in Indonesia appear to be less prospective due to low TOC, high clay and CO₂ contents Many of Indonesia's organic-rich shales are non-marine coaly deposits that may not be brittle enough for shale development. Their depositional setting ranges from deepwater marine in eastern Indonesia to mostly lacustrine and deltaic environments in central and western Indonesia. (Fig.15 shows Stratigraphy of Source Rocks)

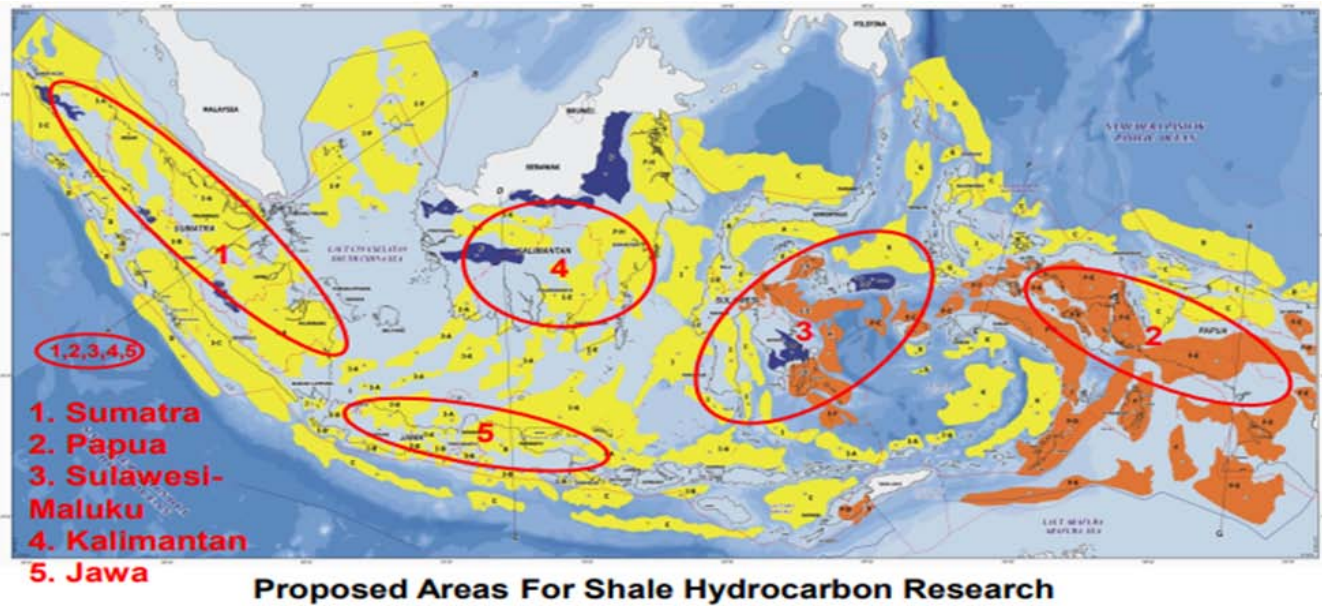


Figure 15: Shale gas Potential in Indonesia (EIA 2013)

Indonesia has two main shale gas potentials, which are Bintuni basin and Sumatra Basin.

a) *Bintuni Basin*

The Bintuni Basin, located in the eastern side of the Bird's Head region, appears to have the simplest structural conditions and best shale prospectively in the eastern Indonesia region. The stratigraphic section resembles that of the Salawati Basin, with preserved Paleozoic, Mesozoic, and Tertiary units. The prospective areas of the Permian Aifam formation have an estimated 29 TCF of technically recoverable shale gas resources out of 114 Tcf of gas in-place. (Kuuskraa V. S., 2013) This marine-deposited unit could be the best shale gas target in Indonesia. To date No shale gas/oil leasing or exploration activity has been reported in eastern Indonesia.

b) *Sumatra Basin*

Sumatra has shale oil and gas potential in three deep basin complexes: The North, Central, and South Sumatra basins. The North Sumatra Basin produces mainly conventional gas both onshore and offshore. Central Sumatra Basin one of main resources in Shale gas with technically recoverable resources from the

Brown Shale are estimated at 3.3 Tcf out of 42 Tcf shale gas.

South Sumatra Basin, this basin is a significant conventional oil and gas producing area as well as a focus of Shale gas & coalbed methane exploration. The basin contains late Eocene to early Oligocene deposits of clastic sediments in transgressional pull-apart depressions. The Eocene to Oligocene TalangAkar Formation is prospective within a large 15,490-mi² area and estimated to have a 367-ft thick high-graded zone with average 5% TOC and 0.7% Ro. The pressure gradient is normal and the clay content is considered high. The TalangAkar Formation has an estimated 4.1 of technically recoverable shale gas resources, out of 68 Tcf.

VIII. CONCLUSION

- Shale gas refers to natural gas in organic rich fine grained rocks (shale and/or mud rock). Gas stored in shale as: 1) adsorbed gas attached to organic matter, 2) free gas in matrix pores, micro pores and natural fractures and 3) solution gas in liquids such as bitumen and oil. For shale gas, hydraulic

fracturing of a reservoir is the preferred stimulation method.

- Shale gas reservoir to become a successful shale gas play, the following characteristics need to be considered: organic richness (TOC), maturation, thickness, gas in place, permeability, mineralogy, brittleness and pore pressure. An optimum combination of these factors leads to favorable productivity. Geophysical methods can help in characterizing the shale gas resource plays
- The economic feasibility of shale gas as unconventional resources is highly dependent on the price of conventional resources, and the assumption that the price will remain at a certain level for some time to come. Available technology

and development plans have great impact on the forecasting of unconventional resources either as complement or replacement of the conventional resources.

- It can be stated that the potential for shale gas as a source of energy in Southeast Asia appears to be moral. However, more work needs to be carried out to establish the exact capacity of this gas in each country mentioned. The below table summarizes all shale gas reserve potential Basins of Malaysia and South-East Asia Region, where china has the largest share of 1115 TCF, followed by India presenting 584 TCF and Malaysia represents the lowest potential of 8.8TCF.

Country	Basin	Risked Gas in place TCF
Malaysia	Sarawak & Sabah	8.8
China	Sichuan	1,115
	Tarim	
	Ordos	
India	Cambay	146
	Godavari	381
	Cauvery	30
	Damodar	27
Pakistan	Indus, Balochistan & Pasheen	105
Thailand	Khorat	22
Indonesia	Sumatra	68
	Bintumi	114

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