The comparison of the Retained Gas in Shale (RGIS) between the Paleocene Ranikot Formation and the lower Cretaceous Sembar Formation, the Southern Indus Basin, Pakistan

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Abstract

In this study, mass balance approach was proposed and applied for volumetric calculations to compute the Retained Gas In Shale (RGIS) of the PaleoceneRanikot Formation and the Lower Cretaceous Sembar Formation in the Southern Indus Basin of Pakistan. The study was conducted based on the data from regional geological sections, base maps, and geochemical data. The volumetric calculations estimated that the Retained Gas In Shale (RGIS) of the Paleocene Ranikot Formation is 115.01 Trillion Cubic feet (Tcf), out of that 13.08 Trillion Cubic feet (Tcf) is risked RGIS while for the Lower Cretaceous Sembar Formation RGIS is 359.41 Trillion Cubic feet (Tcf), out of that 43.13 Trillion Cubic feet (Tcf) is risked RGIS. The results of this study concluded that the Sembar Formation has more shale gas potential in terms of Retained Gas In Shale (RGIS) in the Southern Indus Basin, than the Ranikot Formation. The approach employed in this study for RGIS calculation is pertinent to evaluate source rocks in other sedimentary basins.

Keywords - *Shale Gas, the Ranikot Formation, the Sembar Formation, the Southern Indus Basin, Retained Gas In Shale (RGIS).*

I. INTRODUCTION

(The IndusBasin is the largest onshore sedimentary basin in Pakistan, encompassing an area of about 138,000 square kilometers. The target area in this study is the Southern Indus Basin (see Fig. 1), a geologically complex area containing the Thar platform, Karachi trough, Sindh monocline, and Kirthar fold belt. The Southern Indus Basin is bounded to the north by the Jacobabad and Mari-Kandhkot highs (together called the Sukker Rift), which separate the Southern Indus Basin from the Central Indus Basin; to the west by Axial Belt; to the east by Indian shield; and to the south by the Arabian Sea. The Southern Indus Basin is interpreted as an extensional area, which has developed because of divergence of the Indian plate from Gondwana beginning in the Late Jurassic [11]

The main petroleum source rock for most of conventional oil and gas discoveries in the Southern Indus Basin is the Lower Cretaceous Sembar Formation, which is primarily shale but also contains sandstone, siltstone, and minor limestone ([1];[12]) while the shales in the Paleocene Ranikot Formation are primarily in the upper part of the carbonate unit which consists of fossiliferous limestone interbedded with dolomitic shale, calcareous sandstone and abundant bituminous material [3]. The thickness of the Sembar Formation ranges from 1,000 to 2,000 m with an organic rich interval of 1,000 ft, with a net shale thickness of 250 ft whereas the Ranikot Formation has thickness of 1,000 to 3,000 ft. with a net shale thickness of 200 ft [3]. A generalized stratigraphic column for the Southern Indus Basin is shown in Fig. 2.

In this study, mass balance approach was proposed and applied for volumetric calculations to compute the Retained Gas In Shale (RGIS) of the Paleocene Ranikot Formation and the Lower Cretaceous Sembar Formation in the Southern Indus Basin of Pakistan. The study was conducted based on the data from regional geological sections, base maps, and geochemical data.

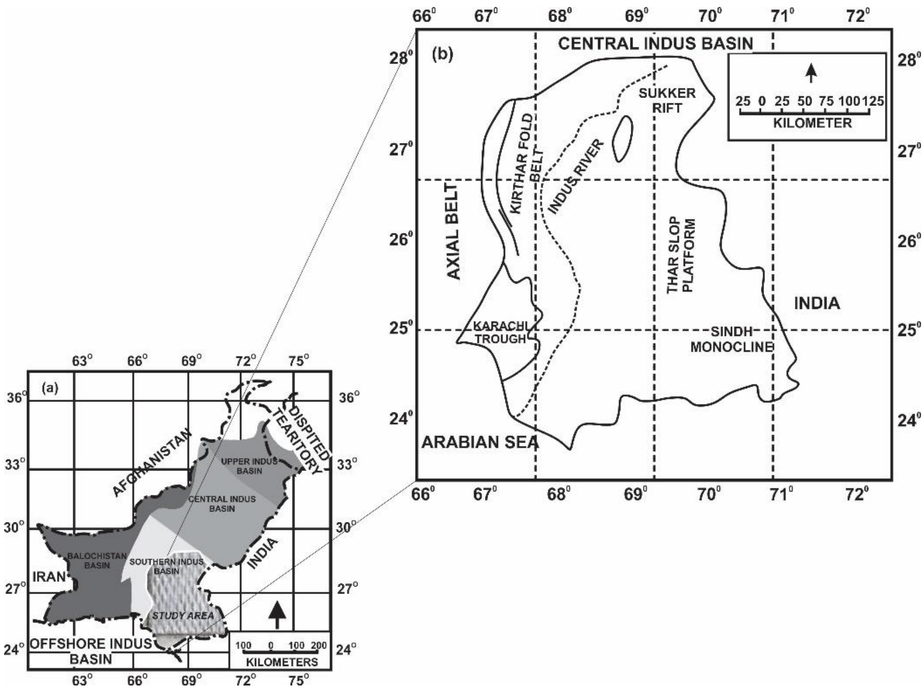

Fig 1: Study Area: (a) Sedimentary Basins of Pakistan; (b) the Southern IndusBasin

AGE			FORMATION	DISCRIPTION	LITHOLOGY
ERA	PERIOD	EPOCH			
CENOZOIC	QUATE-RNARY	RECENT	ALLUVIUM	CLAY, SHALE, SANDSTONE, CONGLOMERATE	
		PLIOCENE-PLEISTOCENE	SIWALIK	SANDSTONE, SHALE, CONGLOMERATE	
	TERTIARY	MIOCENE	GAJ	SHALE,LIMESTONE,SANDSTONE	
		OLIGOCENE	NARI		
		EOCENE LATE			
		EOCENE MIDDLE	KIRTHAR	SHALE,LIMESTONE	
		EOCENE EARLY	LAKI	LIMESTONE INTERBEDDED SHALE	
		PALEOCENE	RANIKOT	LIMESTONE, SANDSTONE, SHALE, BASALT	
MESOZOIC	CRETACEOUS	LATE	PAB	SANDSTONE,SHALE	
			MUGHAL KOT	LIMESTONE, SHALE WITH MINOR SANDSTONE	
			PARH	LIMESTONE	
		MIDDLE	GORU UPPER	MARLY SHALE	
			GORU LOWER	SANDY SHALE	
		EARLY	SEMBAR	OIL/GAS SHALE	
	JURASSIC	LATE			
		MIDDLE	CHILTAN	LIMESTONE	
		EARLY	SHIRINAB	LIMESTONE, SHALE, SANDSTONE	
	TRIASSIC	EARLY-LATE	WULGAI	SANDSTONE,SHALE	
	CAMBRIAN NOT ENCOUNTERED				

Fig 2: Generalized Stratigraphy of the Southern Indus Basin (after [10])

II. TECTONIC EVOLUTION OF THE SOUTHERN INDUS BASIN

The translation of the Indian plate is responsible for the structural and stratigraphic features of the Southern Indus Basin. After the Indian plate separated from the Australian and Antarctic plate, translated northward ([5]; [12]) and entered warmer latitudes in the Early Cretaceous, while at the same time, in the Southern Indus Basin, the regional erosion occurred and the erosive surface was overlain by the Sembar and Goru Formations towards the western shelf (Fig. 3). Throughout the Late Cretaceous the shelf environment was continued, resulting in the deposition of the regressive sandstones of the Pab Formation in the west [11]. The Indian plate persisted its drifting towards north in Late Cretaceous when flysch accumulated around the southern edge of the Indian plate and a transform fault became active along the Ninety-East Ridge during the Latest Cretaceous (Fig. 4). The western part of the Indian plate sheared southward which reactivated the extensional faulting [5]. An oblique collision happened just after the Tethyan Sea ended up and Sulaiman- Kirthar fold belt began to develop [4].

As shown in Fig. 2, rocks of Early Paleozoic to Late Permian age have not been encountered in most of the wells, and only a few wells have encountered Triassic and Jurassic rocks. The Lower Cretaceous formations are Sembar and Goru, while the Late Cretaceous formations are Parh, Mughal Kot, and Pab. The outcrops of the Paleocene Ranikot Formation and Eocene Laki and Kirthar Formations are mostly present onshore, whereas the Oligocene Nari Formation and the Miocene Gaj Formation are present offshore.

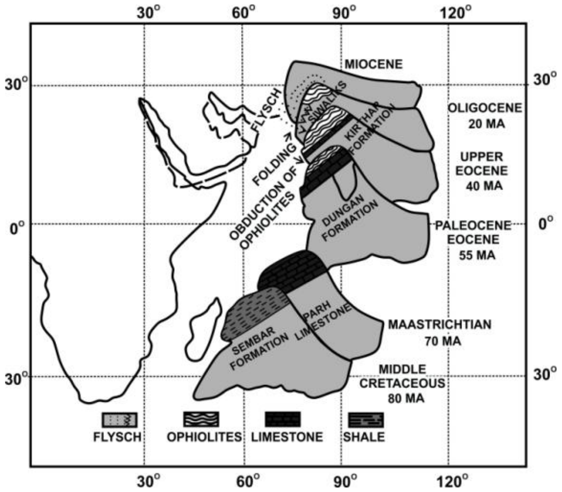

Fig 3:Sediment during Middle Cretaceous through Miocene (Modified after [2])

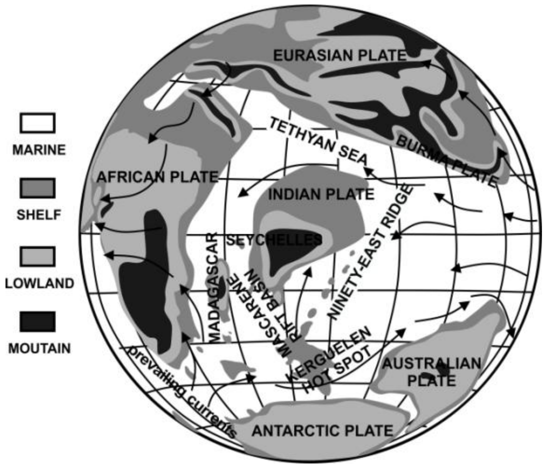

Fig 4: Paleogeography of Late Cretaceous when Indian subcontinent was moving (Modified after [6] and [11])

In the Southern Indus Basin, the Ranikot and the Sembar Formations are thins out towards the south east and it indicates that the prospective area of hydrocarbon is towards west of the basin (Figs. 5 and 6).

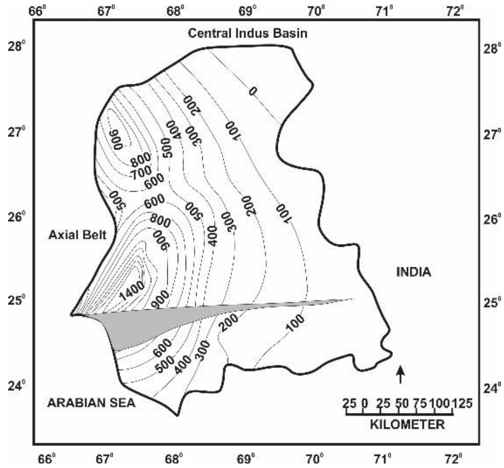

Fig 5: Isopach Map of the Ranikot Formation (modified after [8])

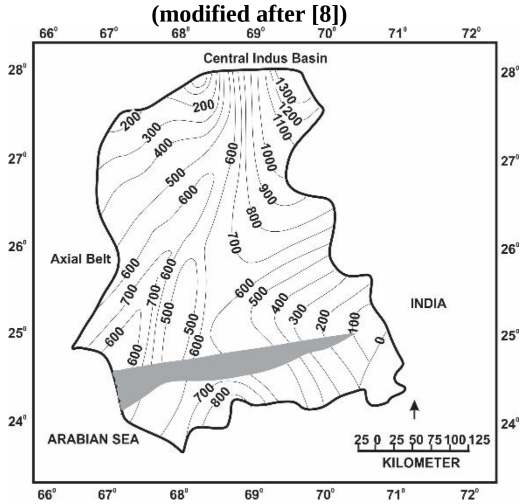

Fig 6: Isopach Map of the Sembar Formation (modified after [8])

In the Southern Indus Basin, the exploration started in 1939 when Drigh Road GIB-01 well was drilled to 511 m deep (1,676 ft) near Karachi. In May of 1948 another well was drilled on Lakhara structure and after 1955 the exploration activities have been accelerated. The drilling conditions in the Southern Indus Basin are quite favorable because most of the discoveries are shallow and did not encounter high pressure problems [8]. A summary of the source and reservoir rocks in the Southern Indus Basin is shown in Table 1.

Table 1
Source and Reservoir Rocks in the Southern Indus Basin (after [8])

Source Rocks			
Age	Formation	Deposition	Rock Type
Eocene	Laki	Basin	Shale
Paleocene	Korara	Basin	Shale
	Ranikot	Outer Shelf	Shale
Cretaceous	Mughal Kot	Shelf	Shale
	Parh	Shelf	Shale
	Goru	Slope Turbidites	Shale and Mudstone
	Sembar	Basinal Mud	Shale
Jurassic	Chiltan	Outer Shelf	Limestone
Triassic	Wulgai	Outer Shelf	Shale and Limestone
Reservoir Rocks			
Age	Formation	Porosity	Rock Type
Miocene	Gaj	Intragranular	Sandstone
Oligocene	Nari	Intragranular	Sandstone
Eocene	Laki	Fracture	Limestone
Paleocene	Ranikot	Fracture	Limestone
	Ranikot	Intragranular	Sandstone
Cretaceous	Pab	Intragranular	Sandstone
	Goru	Intragranular	Sandstone
Jurassic	Chiltan	Fracture	Limestone
	Shirinab	Intragranular	Sandstone
Triassic	Wulgai	Intragranular	Sandstone

III.METHODOLOGY

All A mass balance equation was used in this study to calculate the potential volume of hydrocarbons retained (HC_{ret}) in the Sembar shales. The equations were derived based on similar approaches by [9] and Claypool, 2002 (as cited in [7]). The amount of the hydrocarbon retained in a shale source rock, termed as "Retained Gas In Shale" (RGIS), can be calculated by subtracting the estimated amount of hydrocarbon expelled from the estimated amount of hydrocarbon generated:

$$RGIS = HC_{ret} = HC_{gen} - HC_{exp}. \quad (1)$$

$$HC_{gen} = R \times M_{OC} \times C_1. \quad (2)$$

$$R = HI^0 - HI \quad (3)$$

$$M_{OC} = TOC \times M_{rock} \quad (4)$$

By substituting R and M_{OC} into Eq. 2 one gets:

$$HC_{gen} = \left(HI^0 - HI\right) \times TOC \times M_{rock} \times C_1 \quad (5)$$

On the other hand:

$$HC_{exp} = SI_{exp} \times M_{rock} \times C_1 \quad (6)$$

$$SI_{exp} = 1{,}000 \times \frac{(TOC^0 - TOC)}{(0.8333 - TOC)} \quad (7)$$

By substituting SI_{exp} from Eq. 7 into Eq. 6 one obtains:

$$HC_{exp} = 1{,}000 \times \frac{(TOC^0 - TOC)}{(0.8333 - TOC)} \times M_{rock} \times C_1 \quad (8)$$

Finally, by combining Eq. (1), Eq. (5) and Eq. (8) one gets the following equation with TOC in fraction.

$$RGIS = HC_{ret} = \left[\left(HI^0 - HI\right) \times TOC - 1{,}000 \times \frac{(TOC^0 - TOC)}{(0.8333 - TOC)}\right] \times M_{rock} \times C_1 \quad (9)$$

Where:

- RGIS = HC_{ret} (kg) is the amount of hydrocarbon retained within the shale
- HC_{gen} (kg) is the amount of hydrocarbon generated within shale
- HC_{expl} (kg) is the amount of the hydrocarbon expelled from the shale
- HI^0 (mgHC/gTOC) is the original hydrogen index
- HI (mgHC/gTOC) is the average hydrogen index
- R is the difference between HI^0 and HI
- TOC^0 (fraction) is the initial total organic carbon content
- TOC (fraction) is the average total organic carbon content
- M_{rock} (g) is the mass of the source (shale)
- M_{OC} (gTOC) is the mass of the organic carbon in gTOC
- SI_{exp} (mgHC/gRock) is the amount of the hydrocarbon expelled from shale
- C_1 is the unit conversion coefficient; $C_1 = 10^{-6}$ kg/mg
- 0.8333 is the carbon fraction in generated petroleum (Peter et al., 2005)

The original total organic content TOC^0 (before maturation) is calculated as follows (Peter et al., 2005):

$$TOC^0 = \frac{0.8333 \times HI \times TOC}{\left[HI^0 \times (1 - f) \times (0.8333 - TOC) + HI \times TOC\right]} \quad (10)$$

And the fractional conversion (f) of source rock organic matter to petroleum is calculated by the following equation (Peter et al., 2005):

$$f = 1 - \frac{HI \times \left[1{,}200 - \left\{HI^0 / \left(1 - PI^0\right)\right\}\right]}{HI^0 \times \left[1{,}200 - \left\{HI / \left(1 - PI\right)\right\}\right]} \quad (11)$$

Where PI^0 is assumed to be 0.02 for the thermally immature part of the Sembar shale and PI^x is the measured Rock Eval® Pyrolysis Index.

The expulsion efficiency (ExEf) can be calculated by the following equation (Peter et al., 2005):

$$ExEf = 1 - \frac{(1 - f) \times \{PI / (1 - PI)\}}{f + \{PI^{0} / (1 - PI^{0})\}} \qquad (12)$$

Where:

- f is fractional conversion factor (dimensionless)
- ExEf is the expulsion efficiency of the source rock (dimensionless)
- PI^0 is the original production index (fraction)
- PI is the average measured Rock Eval production index (fraction).

IV. RESULTS AND DISCUSSION

Volumetric calculation is performed for dry and wet gas zone with in the study area (Perspective area = 247 x 200 km). The input and out put for the Ranikot and the Sembar Formation are shown in Tables 2 and 3 respectively. The calculation results for the Ranikot Formation show that 64% is the amount of hydrocarbon retained (RGIS) and 36% is the expelled hydrocarbon (Fig.7) where as for the Sembar Formation has 52% hydrocarbon retained (RGIS) and 48% expelled hydrocarbon (Fig.8).

Input Data			
Parameters	Symbol	Value	Unit
Prospective Area	A	19,073	mi^2
Net thickness	h	0.061	km
Bulk density	ρ_b	2.4	g/cm^3
Average Total Organic Carbon content	TOC	0.02	fraction
Original Total Organic Carbon content	TOC^0	0.021	fraction
Average Hydrogen Index	HI	77	mgHC/gTOC
Original Hydrogen Index	HI^0	118	mgHC/gTOC
Average Production Index	PI	0.28	fraction
Original Production Index	PI^0	0.02	fraction
Cumulative Success Factor		12	percent
Conversion Factor from kg to ft^3	-	30.42	ft^3/kg
Results			
Generated Hydrocarbon	HC_{gen}	181.09	Tcf
Expelled Hydrocarbon	HC_{exp}	66.08	Tcf
Retained Gas In Shale	RGIS	115.01	Tcf
Risked Retained Gas In Shale	$RGIS_{risked}$	13.80	Tcf

Table 2
Volumetric Calculation for Ranikot Formation

Input Data			
Parameters	Symbol	Value	Unit
Prospective Area	A	19,073	mi^2
Net thickness	h	0.076	km
Bulk density	ρ_b	2.4	g/cm^3
Average Total Organic Carbon content	TOC	0.02	fraction
Original Total Organic Carbon content	TOC^0	0.021	fraction
Average Hydrogen Index	HI	295	mgHC/gTOC
Original Hydrogen Index	HI^0	422	mgHC/gTOC
Average Production Index	PI	0.25	fraction
Original Production Index	PI^0	0.02	fraction
Cumulative Success Factor		12	percent
Conversion Factor from kg to ft^3	-	30.42	ft^3/kg
Results			
Generated Hydrocarbon	HC_{gen}	696.64	Tcf
Expelled Hydrocarbon	HC_{exp}	337.23	Tcf
Retained Gas In Shale	RGIS	359.41	Tcf
Risked Retained Gas In Shale	$RGIS_{risked}$	43.13	Tcf

Table 3
Volumetric Calculation for Sembar Formation

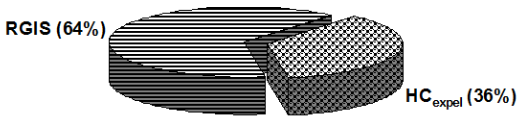

Fig 7: Gas Expelled and Retained in the Ranikot Shale for the Southern Indus Basin

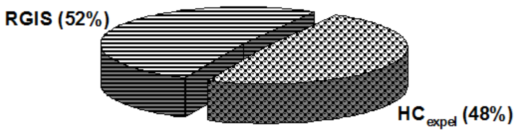

Fig 8: Gas Expelled and Retained in the Sembar Shale for the Southern Indus Basin

The calculations suggest that the minimum gas generated in shale of the Ranikot Formation is 9.49 Bcf/mi^2 (Eq. 5); the gas expelled is 3.64 Bcf/mi^2 (Eq. 8); and the retained gas is 6.03 Bcf/mi^2 (Eq. 9) and risked retained gas is 13.80 Tcf. The extent of the fractional conversion of HI^0 to petroleum is 0.36 (Eq. 11) which means that 36% of the petroleum generation process has been completed while 64% process is remaining and the expulsion efficiency (ExEf) of the Sembar shale is 33% (Eq. 12). On the hand the calculations suggest that the minimum gas generated in shale of the Sembar Formation is 36.52 Bcf/mi^2 (Eq. 5); the gas expelled is 17.68 Bcf/mi^2 (Eq. 8); and the retained gas is 18.84 Bcf/mi^2 (Eq. 9) and risked retained gas is 43.13 Tcf. The extent of the fractional conversion of HI^0 to petroleum is 0.33 (Eq. 11) which means that 33% of the petroleum generation process has been completed while 67%

process is remaining and the expulsion efficiency (ExEf) of the Sembar shale is 37% (Eq. 12)

V. CONCLUSIONS

The Retained Gas In Shale (RGIS) is calculated to be 115 Tcf for the Ranikot Formation and risked RGIS is 13.80 Tcf while RGIS is 359.41 Tcf for the Sembar Formation and risked RGIS is 43.13 Tcf.

The derived Eq. (9), for the calculation of hydrocarbon potentially retained in shale, is applicable to Type II and III kerogen but it cannot be applied to extremely thermally mature source rock where average HI is zero.

The results of this study concluded that the Sembar Formation has more shale gas potential in terms of Retained Gas In Shale (RGIS) in the Southern Indus Basin, than the Ranikot Formation. The approach employed in this study for RGIS calculation is pertinent to evaluate source rocks in other sedimentary basins.

A detailed pressure analysis is recommended to be performed with laboratory kinetic scheme and isotherm analysis to elaborate the hydro fracturing with in the formation.

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