Pakistan Journal of Hydrocarbon Research
Vol. 22 & 23, (June 2012 & 2013),p.51-62, 09 Figs.,01 Table.

Shale Gas Potential of Lower Cretaceous Sembar Formation in Middle and Lower Indus Basin, Pakistan.

Nazir Ahmad[1], Javed Mateen[1], Kashif Shehzad Ch[1]., Nasar Mehmood[1] and Fahad Arif[1]

ABSTRACT

Natural gas production from tight shale formations, known as "shale gas", has become an important source of natural gas in the world due to technological advances and rapid increases in natural gas prices as a result of significant supply and demand pressures. Pakistan is facing big challenges in meeting its ever growing energy needs due to expanding population and economic growth. It is necessary to exploit unconventional energy resources along with conventional ones to meet the country energy requirement.

Here, we investigate shale gas potential of Lower Cretaceous Sembar Formation within a large area of Middle and Lower Indus Sub-basins. The study includes the organic richness, hydrocarbon generative potential, shale thickness and distribution, subsurface depth of studied interval, maturity, volume of hydrocarbon generated and retained per section and reservoir characteristics of Sembar shales.

Geochemical data show that the TOC of the formation range from 0.55 wt. % to 9.48 wt. % with present day generation potential of 0.14 to 18.69 mg HC/g rock. The average TOC of immature samples is 1.0 wt.% with generation potential of 2.88 mg HC/g rock and hydrogen index (HI) of 240 mg HC/g TOC (type III and II/III).

Gross thickness of the formation ranges from less than 50 m to more than 1000 m with an average of 300 m in the study area. Subsurface depth (top of the formation) varies between 1000 m to 5000 m in platforms to foredeep areas. Overburden thickness, geothermal gradient, Tmax and Vitrinite Reflectance data place the formation in oil, wet and dry gas windows at the depths of 2500 m, 3200 m and 3400 m respectively.

Based on original generation potential and average source rock thickness, volume of generated hydrocarbon (gas equivalent) is 242 bcf/section. By taking expulsion (50% of the generated volume) into account and conversion of retained oil into gas through secondary cracking, the retained volume is 103 bcf/section.

Average porosity of the formation at reservoir level (3400 m to 4000 m) is 6.0%. Mineralogically, the formation is composed an average of 42% quartz, 47% clay, 10% calcite and 1% pyrite. Depth for shale gas exploitation in platform areas is about 3500 m, where as in foldbelt regions, it varies between 1000 m to 3000 m.

INTRODUCTION

Shale gas refers to in situ hydrocarbon gas present in organic rich, fine grained, sedimentary rocks (shale and associated lithofacies) (Suhas, 2008). Gas is generated and stored in situ in gas shales as both sorbed gas (on organic matter) and free gas (in fractures or pores). As such, gas shales are self-sourced reservoirs. This is a class of continuous petroleum system (Schmoker, 1995) in which shale that generated the gas also functions as low matrix permeability and low porosity reservoir rock. In terms of its chemical composition, shale gas is typically a dry gas composed primarily of methane (at least 90 percent methane), but some formations do produce wet gas (Daniel et al; 2008).

Gas is stored in shale source rocks in two principal ways(Daniel et al; 2008); (1) as gas adsorbed (chemical) and absorbed (physical) to or within the organic matrix and (2) as free gas in pore spaces or in fractures created either by organic matter decomposition or other diagenetic or tectonic processes. Key reservoir parameters for gas shale deposits include: (1) Total Organic Carbon (TOC), (2) Thermal maturity, (3) Reservoir thickness, (4) Reservoir characteristics (brittleness / mineralogy, porosity / permeability), (5) free gas fraction within pores and fractures, and adsorbed gas fraction within the organic matrix. Shales that host economic quantities of gas have a number of common properties. They are rich in organic material (0.5wt. % to 25wt. %), and are usually mature petroleum source rocks in the thermogenic gas window, where high heat and pressure have converted petroleum to natural gas. They are sufficiently brittle and rigid enough to maintain open fractures.

AIMS AND OBJECTIVES

The aims and objectives of this paper are to evaluate the shale gas potential and reservoir characteristics of Sembar Formation in Middle and Lower Indus Sub-basins to priorities the areas in term of shale thickness, its hydrocarbon generation potential, current depth and maturity for shale gas exploration. To evaluate the shale gas system, it is important to understand various geochemical processes and shale characteristics controlling generation, storage and access to this gas resource.

DATA SET AND METHDOLOGY

Total Organic Carbon (TOC) and Rock-Eval pyrolysis data of 11 wells comprising 135 data points were available for this study to evaluate the quantity, quality and type of organic matter. To assess the petroleum potential of the Sembar Formation, cross-plot of S2 vs. TOC has been prepared. Well summary sheets of OGDCL wells and other published data from the study area have been utilized to study the net thickness of shale sequence and its variations in the study area. Isopach and depth maps have been prepared by using well data. Geothermal gradient, overburden thickness, Rock-Eval Tmax, Vitrinite Reflectance and Thermal Alteration Index (TAI) data (where available) were used to establish the

[1]Oil & Gas Development Company Limited, Islamabad, Pakistan.

maturity level of the Sembar Formation. Volume percentages of minerals in the formation are computed from Spectrolith Quantitative lithology interpretation based on elemental concentrations by using ELan plus module of Geoframe. Neutron Porosity (NPHI), Density (RHOB) and Sonic (DT) logs combination were used to calculate porosity of the shale reservoir.

GEOLOGICAL SETTING

Pakistan lies along a Tertiary convergence zone of Indus Basin, between Greater India and Eurasia. The Indus Basin is represented by sedimentary fill of Precambrian to Recent age and on the base of sedimentation history and structural style, it is divided into three segments namely Upper, Middle and Lower Indus Sub-basins (Figure 1).

Middle Indus Sub-basin is separated from Upper Indus Sub-basin by the Sargodha High and Pizu uplift in the north. It is bounded by Indian Shield in the east, marginal zone of Indian Plate in the west, and Mari-Kandhkot High in the south. Structurally, it is divided into Punjab Platform in the east and Sulaiman Fold belt in the west. The Punjab Platform is a broad monocline gently dipping westward. Sulaiman Fold belt is a product of oblique collision between the Indian and Eurasian Plates during Paleocene to Mio-Pliocene.

The Lower Indus Sub-basin is located south of Mari-Kandhkot High, bounded by Indian Shield to the east, marginal zone of Indian Plate to the west. The southern border of the Lower Indus Basin is taken along the offshore Indus Sub-basin. Structurally, it is divided into Lower Indus Platform in the east and Kirthar Fold belt in the west.

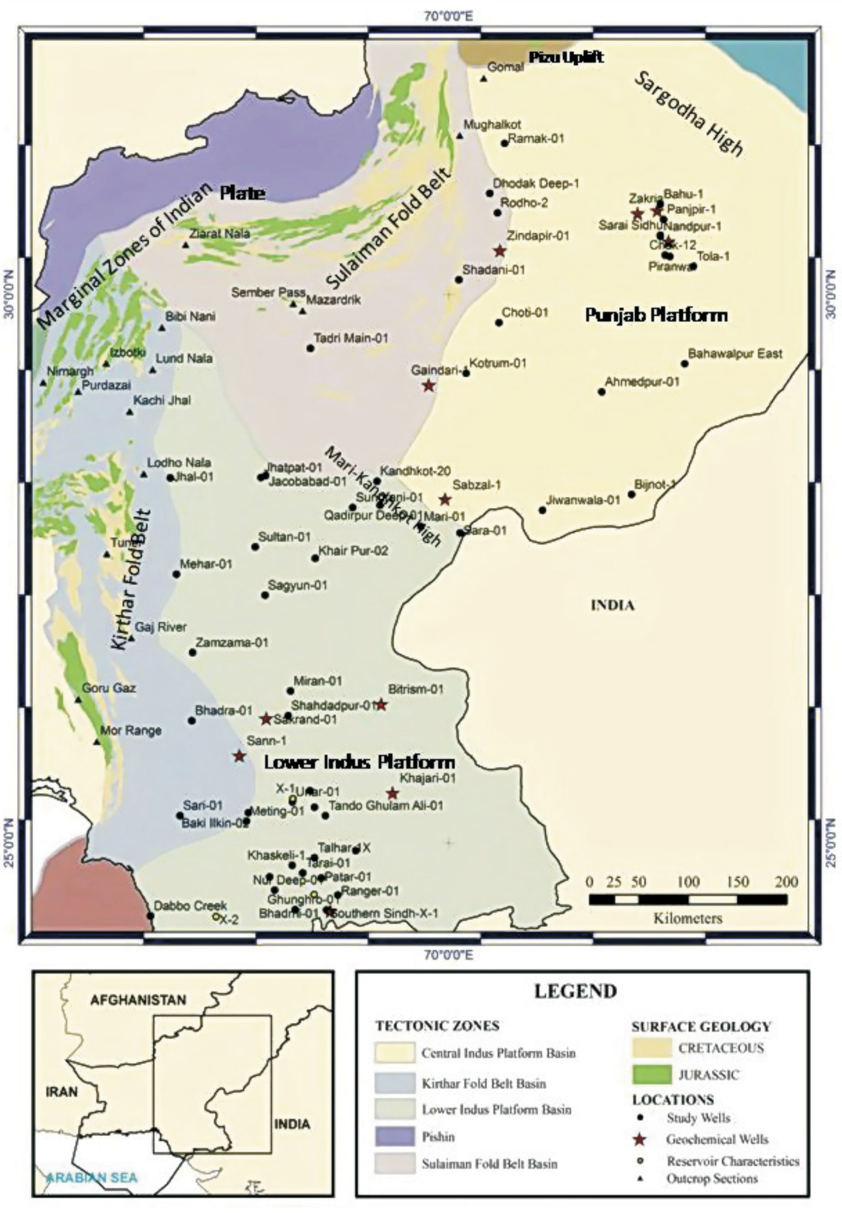

Figure 1 - Base map showing study area with tectonic domains and study wells.

STRATIGRAPHY OF THE STUDY AREA

Stratigraphy of the study area ranges from Infra-Cambrian to Recent with non-deposition and erosion at various stratigraphic levels (Figure 2). Cambrian to Cretaceous strata truncate against Tertiary unconformity eastward in the Punjab Platform (OGDCL, 1988) while Tertiary sequence has direct contact with the Jurassic sequence in eastern part of the Lower Indus Platform. In general, the thickness of the sediments increases westward. The known stratigraphy in Sulaiman and Kirthar Fold belts ranges from Permian to Recent age. Erosion in some parts of the fold belts is so deep that it has exposed the Jurassic rocks at or near the surface.

GEOLOGY OF THE SEMBAR FORMATION

Sembar Formation was deposited in a passive margin setting with sediments derived from the uplifted and emergent Indian continent to the southeast (Hedley et al, 2001). Present day distribution of the formation shows that it was deposited in a broad sedimentary basin which probably extended from the Indian Shield in the east up to Bela-Ornach fault System in the west (Raza et al, 1990). The term Sembar Formation was introduced by Williams (1959), after Sembar Pass in the Mari hills (29º 55´ 05´ N and 68º 34´ 48´ E). Sembar Formation is present over most of the study area with the exception of Khairpur horst, some parts of western Sulaiman and northern Kirthar Ranges (Figure 3). The formation is composed entirely

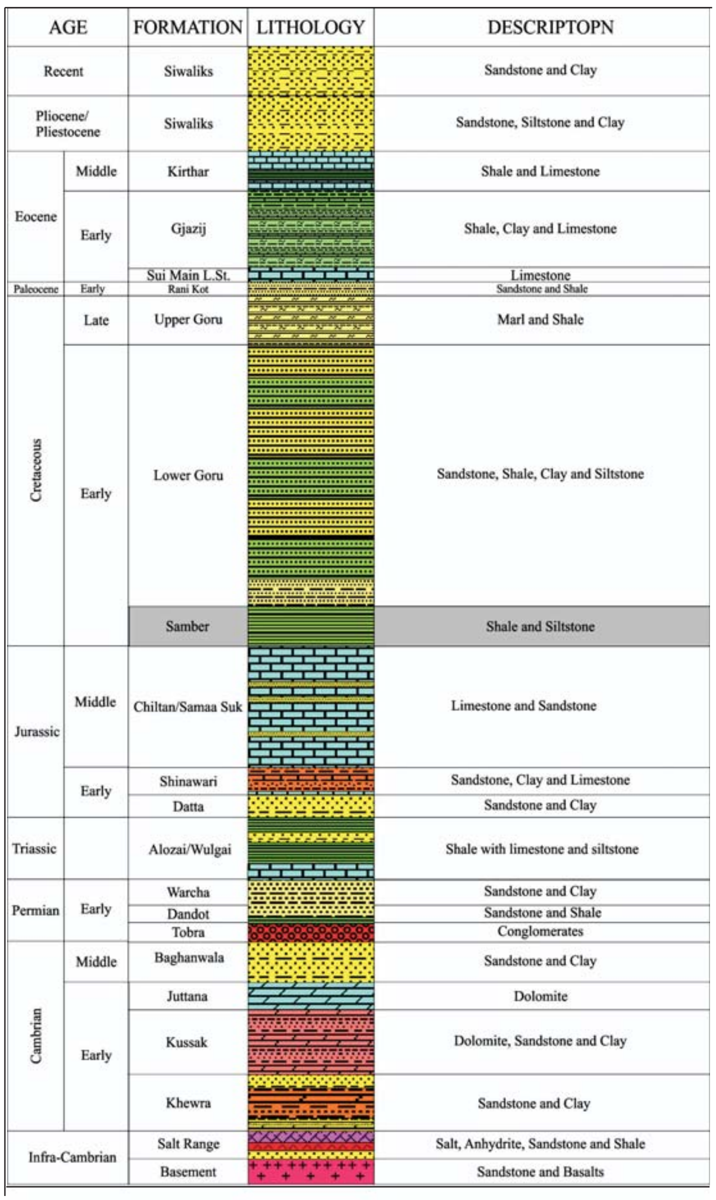

Figure 2 -Generalized Stratigraphic column of Middle and Lower Indus Basin.

of clastic rocks, mostly shale with lesser quantities of sandstone and siltstone in the Lower Indus Platform. The sand content increases in the southeastern part of the platform. The Karachi depression, Kirthar Range, Kirthar depression and northern part of Sind monocline received only the finer clastics as being away from the source (Raza et al, 1990). In the Sulaiman Fold belt, Sembar Formation consists of dark grey to black siltstone and shales. In eastern part of the fold belt, the formation becomes sandy within the lower part (OGDC-IFP, 1988).Glauconite is commonly present in the formation. In the basal part, pyritic and phosphatic nodules and sandy shales are developed locally (Shah, 2009). Shale is light to dark grey, soft to medium hard, moderately indurated, pyritic, silty and slightly calcareous in the study area (Raza et al,1990; OGDC-IFP, 1988; and Gakhar, 2010). Gross thickness of the formation ranges from less than 50 m to more than 1000 m. The thickness in the type section is 133 m but the formation thickens to 262 m in the Mughal Kot section of the Sulaiman Range (Shah, 2009). In Middle Indus Sub-basin, the formation thickens from east and west towards the depo-centers and has attained thickness of more than 800 m in NW-SE trending trough from Gaindari-1 well in the northwest to Sara-1 well in the southeast. In Lower Indus Platform, thickness ranges from 50 m to more than 600 m. The thickness reduced to 0 m on Jacobabad and Sagyun Highs. In Kirthar Fold belt, the formation has variable thickness. In northern partof the fold belt (Kalat Plateau), thickness is reduced to a few meters, and the formation is absent in some parts (Iftikhar and Haneef, 2002). The formation is 200 m thick

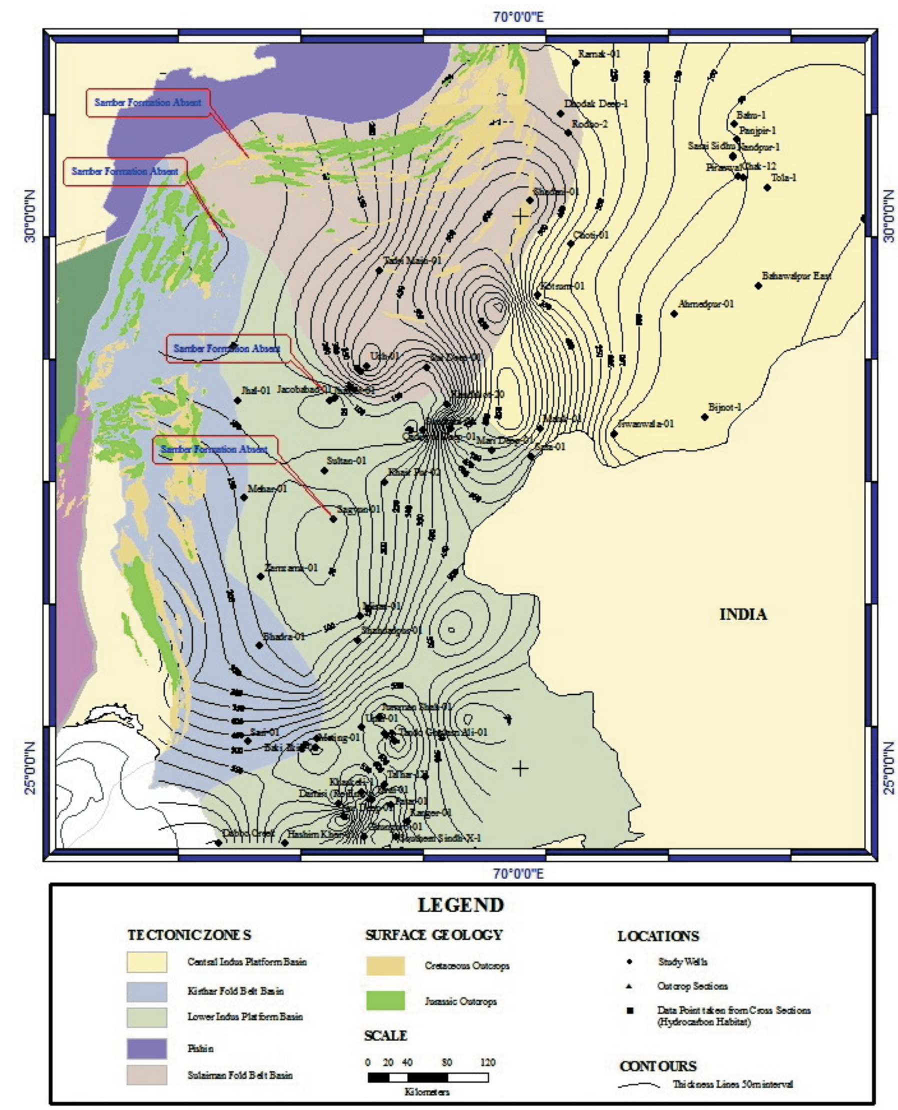

Figure 3 - Isopach map, showing the distribution and thickness variation of the Sembar Formation in study area.

in the southern central Kirthar Range, where it composed of dark greenish grey, olive green Belemnitic shales with siltstones (Khan et al, 2002). In the Mor Range of Kirthar fold belt, thickness of the formation ranges from 300 m to 500 m (Smewing et al, 2002; and Shah, 1977). The formation seems to have deposited under open marine environmental condition (Qadri et al, 1986) that deepens west and northwestward (OGDCL, 1988). Its lower contact with various Jurassic formations such as Mazar Drik Formation, Chiltan Limestone and Shirinab Formation is disconformable while upper contact is generally gradational with the Goru Formation (Shah, 2009). The age of the formation is mainly Neocomian.

GEOCHEMICAL PARAMETER OF SEMBAR FORMATION

Source Rock Potential

The total amount of petroleum that can be generated from a unit mass of source rock is called the source rock potential (Beicip-FanLAB). It depends on the initial amount of organic matter in the source rock, quantified by the Total Organic Carbon (TOC), and on the petroleum potential of that organic matter (Initial Hydrogen Index).

Hydrocarbon potential of Sembar Formation has been assessed by using the geochemical data of 11 wells in the study area (Figure 1). The data comprises Total Organic Carbon (TOC) and Rock-Eval data. The source rock database includes over 135 TOC data points and same number of Rock-Eval data points.

To assess the quantity and quality of organic matter from Sembar Formation, cross-plot of S2 vs. TOC has been prepared by utilizing Rock-Eval pyrolysis S2 and TOC data (Figure 4). The slope of the lines radiating from origin in the figure are directly related to hydrogen index (100 * S2/TOC, mg HC/ g TOC) (Peters et al, 2006). Hydrogen index values of greater than 600, 300-600, 200-300, 50-200, and less than 50 mg HC/g TOC distinguish organic matter types I (very oil prone), II (Oil prone), II/III (oil and gas), III (gas prone), and IV (inert), respectively.

In the northernmost part of the Lower Indus Platform, geochemical data show that TOC contents are variable but reach 2.74% with present day generation potential of 0.88 1.01 mg HC/g rock (Ejaz, 1997). This low potential is due to high maturity (>1.4 % VRo) as any original potential to generate hydrocarbon is likely to have been spent. In Sakrand-1 well, located in the central part of the Lower Indus Platform, TOC values ranges from 1.88 wt. % to 4.34 wt. % with present day generation potential of 0.14 5.54 mg HC/g rock, having mainly gas generation potential (HI < 150 mg HC/g TOC)(Ahmed,1994). Geochemical data from southeastern part of the Lower Indus Sub-basin have fair to very good organic matter (0.60 2.53 wt. %), with present day generation potential of 0.55 5.13 mg HC/g rock (Abbas, 2009; Ali et al, 1998;). TOC values in Sembar Formation from Sann-1, located in the western part of Lower Indus Platform, ranges from 1.86 wt. % to 9.48 wt. % with average of 4.15 wt. % (Robinson et al, 1999). The formation has excellent source potential (18.69 mg HC/g rock) with oil and gas prone organic matter.

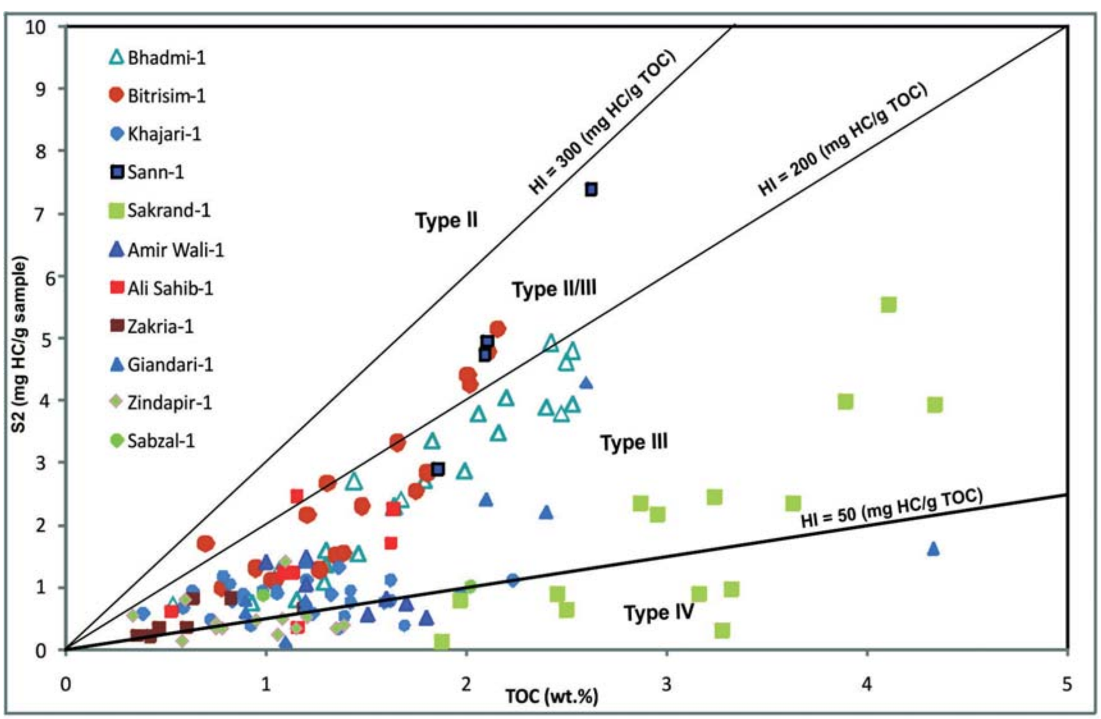

Figure 4 - Cross-plot of Total Organic Carbon (TOC) and Rock-Eval pyrolysis S2 (mg HC/g rock) of 135 samples, shows the quantity and quality of organic matter in the Sembar Formation from study area (modified after Peters et at, 2006).

Geochemical studies of the Sembar Formation conducted in Kirthar Sub-basin, rated it as a good source rock. TOC of the formation ranges from 0.83 wt. % to 3.0 wt. % in the area (Raza et al,1990).

In the Punjab Platform, Sembar/Chichali Formation has fair potential to generate oil and gas. TOC values ranges from 0.5 wt. % to 1.64 wt. % with hydrogen index up to 212 mg HC/g TOC (Gakhar, 2010).

In the Sulaiman Fold belt, the Sembar Formation comprises predominantly of black, often glauconitic, silty shale. The geochemical data from Giandari-1 and Zindapir-1 show that total organic carbon (TOC) of shale ranges from 0.56 wt.% to 4.33wt.% with poor present day genetic potential (0.12 mg HC/g sample). In southern and southwestern part of the fold belt, the geochemical data show that the formation has poor hydrocarbon potential in term of quantity and quality of organic matter (TOC < 1.0 wt.%). This poor present day hydrocarbon potential is due to high maturity (VRo >1.5%) (OGDC-IFP, 1988).

Maturity

Overburden thickness, geothermal gradient, vitrinite reflectance (VRo), thermal alteration index (TAI), Rock-Eval pyrolysis oven temperature (Tmax), where available were used to establish the maturity level of the Sembar Formation in the study area.

Subsurface depth of Sembar Formation ranges from less than 1000 m to more than 5000 m in the study area (Figure 5). The subsurface depth increases from east to west. In Lower Indus and Punjab Platforms, depth at the top of the Sembar Formation ranges from 1000 m to 4000 m. In Sulaiman and Kirthar Foredeeps and in Sibi Trough, subsurface depth is more than 5000 m. In Kirthar and Sulaiman Fold belts due to tectonic disturbance and unavailability of wells data, depth contouring was not possible, however on the basis of geological cross-sections (OGDCL, 1988; and OGDC-IFP, 1988) subsurface depth is less than 3000 m.

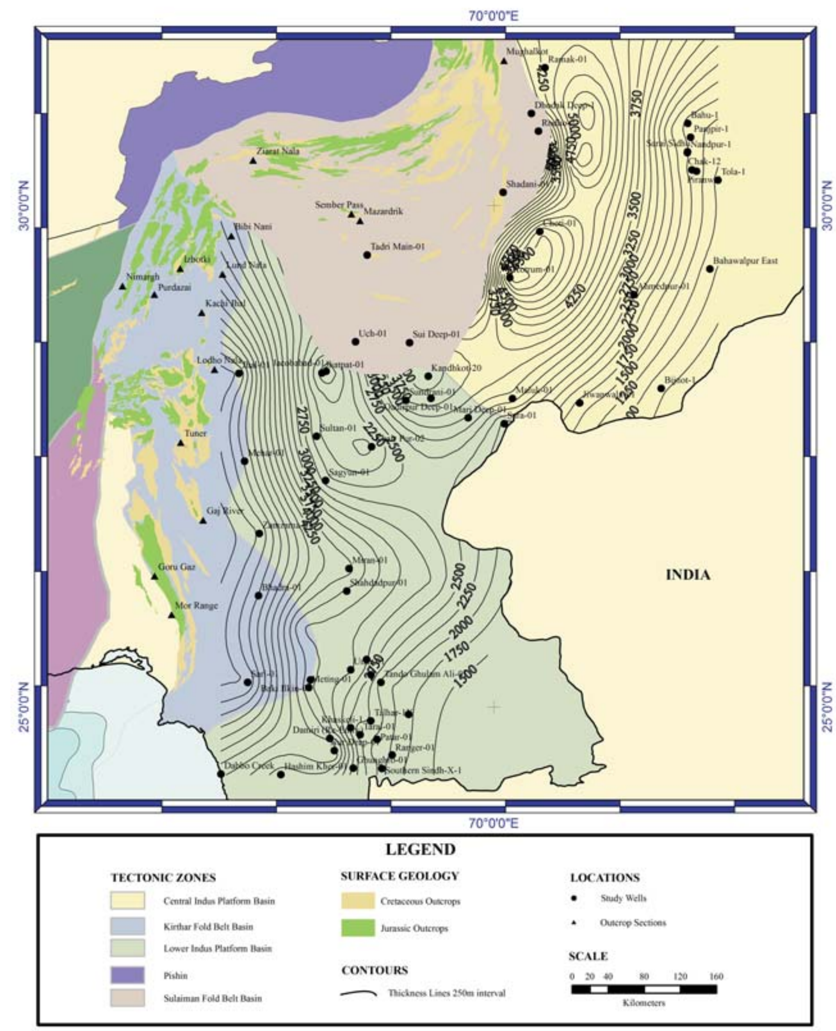

Figure 5 - Depth map at the Top of Sembar Formation.

In the study area, geothermal gradient ranges from <20°C to approximately 45°C/km (OGDCL, 1988). Geothermal gradient increases from east to west. In Punjab Platform, geothermal gradient ranges from 15°C to 27.5°C/km while in Sulaiman Fold belt, the average geothermal gradient is 30°C/km. Sibi Trough and its extension in Lower Indus Basin, has geothermal gradient in the range of 15°C to 20°C/km. In Lower Indus Sub-basin, geothermal gradient ranges from 20°C to 35°C/km with anomalous geothermal gradients (>40°C/km) in some parts of the sub-basin.

Available vitrinite reflectance (VRo) data from wells and outcrop sections, place the Sembar Formation in oil and gas window below the depth of 2400 m. Sembar Formation in Sulaiman and Kirthar Fold belts, is over-mature (OGDC-IFP, 1988) with vitrinite reflectance data ranging from 1.0% to 3.9%. In Jandran-1 well, Sembar Formation is at peak gas generation stage (OGDCL, 1988). In Tarai-1 well, located in the Lower Indus Sub-basin, Sembar Formation at a depth of 2360 m - 3000 m, has thermal maturity equivalent to 1.0% Ro (OGDCL, 1988). In Kirthar Trough, vitrinite reflectance (1.09% Ro) and thermal alteration index (TAI ~ 2.9) from Sann-1 well, place the Sembar Formation in gas window at the depth of 3530 m (Robinson et al, 1999).

Figure 6 Shows the depths of maturities of Sembar Formation based on plot of Tmax data versus depth. The value of Tmax increases in response of increasing maturation of organic matter. For type II, the beginning of oil genesis corresponds to Tmax of 435ºC. Most of the kerogen transformed up to Tmax of 455°C. The gas and condensate zones correspond to a range of Tmax of 455-470°C. For type III, the beginning of oil genesis corresponds to Tmax higher than 435ºC. The transition to condensate zone corresponds to the Tmax of 470°C. Dry gas is produced for Tmax higher than 500°C.

Oil-window depth ranges from 2500 m to 3200 m (Figure 6) while condensate window depth ranges from 3200 m to 3400 m and dry gas maturity starts from the depth of 3400 m. These maturity depths were plotted on the depth map (at the base of Sembar Formation) (Figure 7) to priories the areas regarding source maturity. Discoveries (oil-condensate-gas) coincide with the depths of maturities interpreted on Tmax-depth trend.

VOLUME OF HYDROCARBON GENERATED, EXPELLED AND RETAINED

Estimates of the volume of petroleum originating from a source rock require the information on the distribution, thickness, richness, and thermal maturity of the source rock (Peters et al, 2006). Figure 8 represents the plot of Rock-Eval pyrolysis S2 verses TOC of immature to early oil-mature samples from three wells located in the southeastern part of the Lower Indus Sub-basin. This is an effective tool to assess the source potential and type of kerogen (Langford et

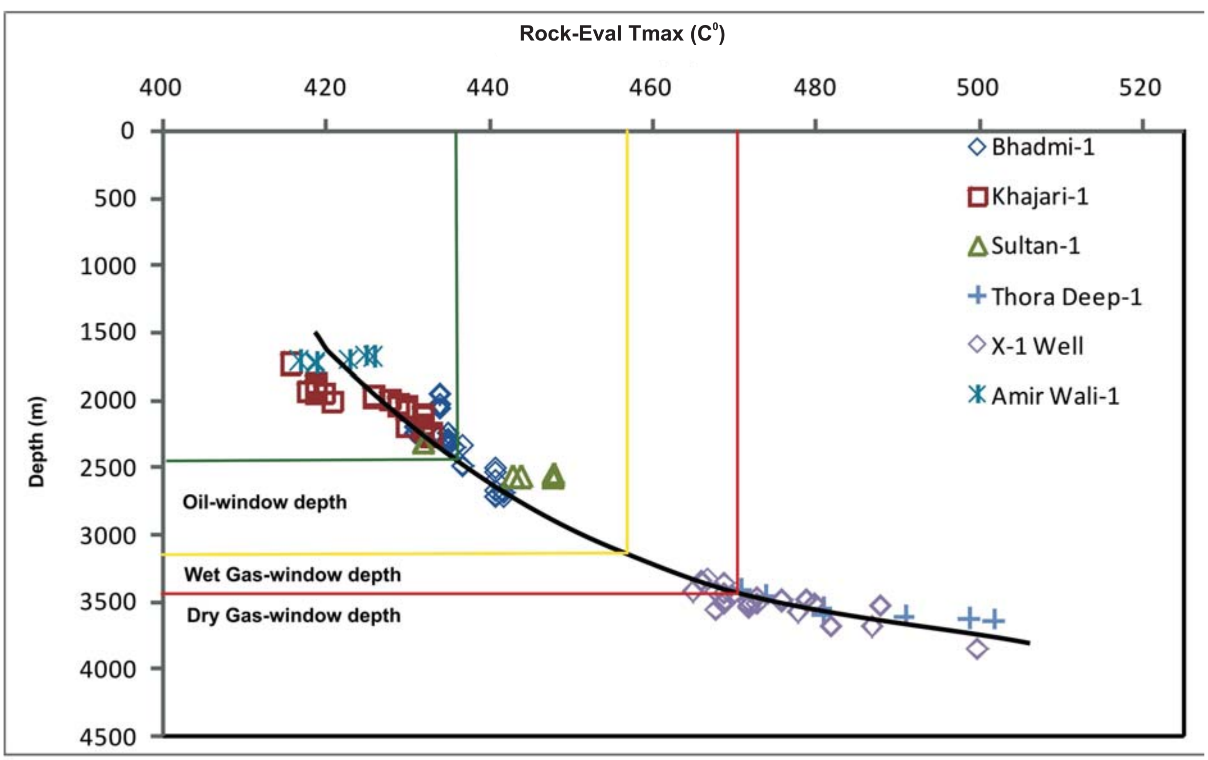

Figure 6 - Plot of Rock-Eval Tmax vs. Depth, shows the depth of oil and wet and dry gas windows for the Sembar Formation in the study area.

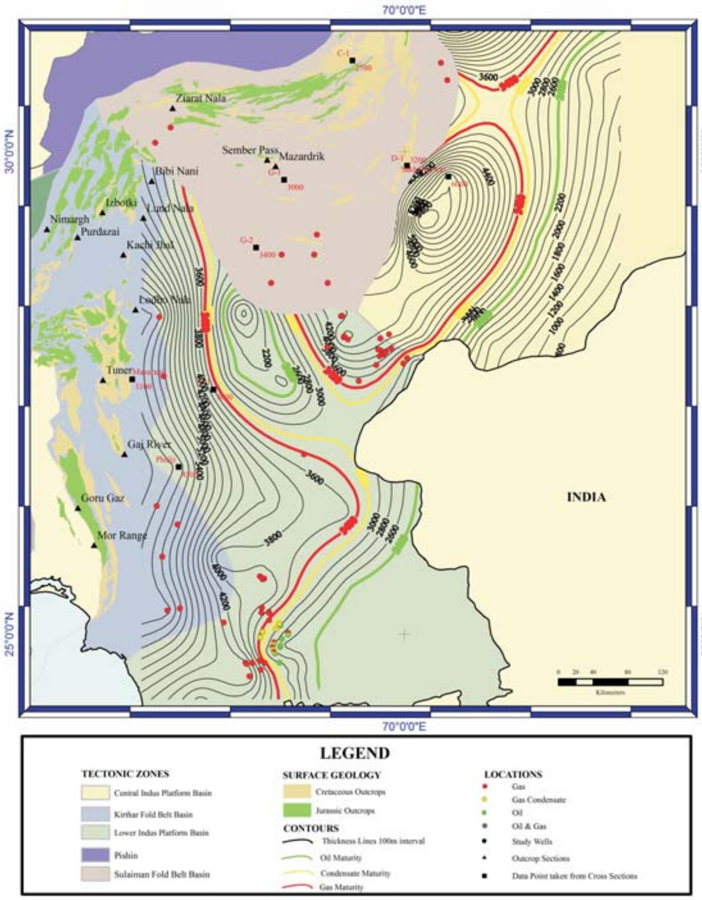

Figure 7 - Depth map at the base of Sembar Formation, showing the depth of oil, condensate and dry gas windowswith oil, oil and gas, condensate and dry gas wells.

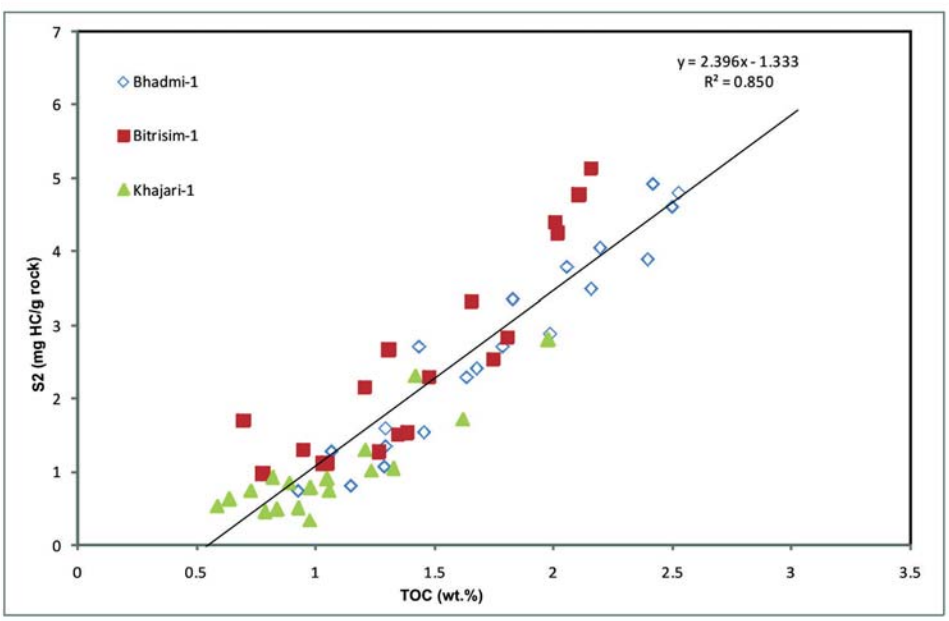

Figure 8 - Cross-plot of TOC and Rock-Eval pyrolysis S2 (mg HC/g sample) of 57 immature to early oil-mature samples show the quality of organic matter.

al, 1990).The slope of the regression line gives an average hydrogen index (HI) and percentage of pyrolyzable hydrocarbon in TOC in the suit of samples (Langford et al, 1990). Twenty four percent of the organic matter is convertible in to hydrocarbons and average hydrogen index (HI) is 240 mg HC/g TOC (type II/III). The x-axis intercept is the amount of dead carbon that does not yield any hydrocarbons which is 0.55 wt. %. By discounting the effect of this dead organic matter, the average TOC is 1.0 wt. %. Method of Jarvie et.al, (2007) was used to estimate hydrocarbon generation, expulsion and retained potential of Sembar shale (Table-1). Based on convertible organic matter, original generation potential of the shale is 2.88 mg HC/g rock. It can be converted to barrels of oil equivalent per acre-foot, and using an average thickness of 1000 ft, results in a yield of 12.0 MMBO equivalent per section (where a section is 640 ac (2.59 km2) or, in gas equivalent, 72.6 bcf/section. By taking expulsion factor as 0.5, the primary retained oil is 9.5 bbl/ac.ft and gas 132.5 mcf/ac.ft. The cracking of oil to gas is limited by the amount of available hydrogen in the system needed to form wet and dry gas (Javie et.al, 2007). The atomic H/C ratio for oil is about 1.8 H/C depending on composition, whereas the formation of methane requires 4.0 hydrogens per carbon.

Thus, there is about 55% hydrogen shortage in oil when it is cracked to methane. Gases originated from Sembar shale are less than 100% methane and a reasonable average is about 85% methane across the entire gas-condensate productive area. Even at 85% methane, the H/C requirement for condensate wet-gas formation is about 3.7, so hydrogen deficiency is still approximately 51%. Taking hydrogen deficiencies into account, total retained gas in the Sembar shale is about 103 bcf/section. These are the minimum estimate of hydrocarbons generated, expelled and retained in the system.

RESERVOIR CHARACTERSITICS

Key reservoir parameters for gas shale deposits include: (1) Total Organic Carbon (TOC), (2) Thermal maturity, (3) Reservoir thickness, (4) Reservoir characteristics (brittleness/mineralogy, porosity/permeability), (5) free gas fraction within pores and fractures, and adsorbed gas fraction within the organic matrix. TOC, thermal maturity and thickness of Sembar shale have already been discussed in the previous sections. In this section we will discuss the brittleness/mineralogy, porosity/permeability and will show how these parameters are important for the exploitation of shale gas resource.

Mineralogy/Brittleness

Brittleness (related to mineralogy), is an important factor in gas production from tight shale systems that require stimulation (Jarvie et.al, 2007). During stimulation, a fracture network is created which provides linkage between the well-bore and the micro-porosity. Fracture gradients in shale depend on the percentages of clay, quartz and carbonate contents. Although a shale by name and particle size, has clay contents range from more than 40 to less than 5%.

Thin section, X-ray diffraction, and backscatter SEM analyses of 2 shale samples of Sembar Formation show that the rock is composed of silty shale which consists of scattered silt sized grains of quartz. They are surrounded by a continuous depositional matrix. On average, it is composed of 59% quartz, 28% clay, 3% calcite, 8% pyrite and 2% plagioclase minerals (David, 1992).

Volume percentages of clay, quartz and carbonate contents were calculated to analyze the mineral composition of Sembar from well X-1 (Figure 1) in the Lower Indus Basin. These volume percentages are computed from Spectrolith

Table 1 - Hydrocarbon generation, expulsion and retained potential of Sembar shale with optimum maturity level.

Description	Average estimates
Average TOC (wt. %) *	1.0
Generation Potential (mg HC/g rock) **	2.88
Estimate of amount of oil generated from kerogen (30% of total hydrocarbons) (bbl oil/ac-ft) †	19
Estimate of amount of gas generated from kerogen (70% of total hydrocarbons) (mcf/ac-ft) ‡	265
Source rock average thickness (ft)	1000
Primary oil generated from kerogen from shale with above thickness (mmbo/section)‡‡	12
Primary oil generated from kerogen from shale with above thickness converted to gas equivalent (bcf/section)	73
Primary gas generated from kerogen from shale with above thickness (bcf/section)	169
Total hydrocarbons (oil + gas) generated from primary cracking of kerogen (gas equivalent, bcf/section)	242
Expulsion factor	0.5
Oil expelled (bbl oil/ac-ft)	9.5
Gas expelled (mcf/ac-ft)	132.5
Retained hydrocarbons	
Primary oil retained in shale (bbl oil/ac-ft)	9.5
Primary gas retained in shale (mcf/ac-ft)	132.5
Correction factor for insufficient hydrogen in oil	0.49
Gas yield from secondary cracking of oil (mcf/ac-ft)	28
Total retained gas (primary gas + secondary gas from oil cracking) (mcf/ac-ft)	160
Total retained gas under these assumptions (bcf/section)	103

* See figure 4b and related text

** Conversion of wt. % organic carbon to mg HC/g rock, divide by 0.08333

† Conversion of Rock-Eval S2 in mg HC/g rock to bbl oil/ac-ft, multiply by 21.89.

‡ Conversion of Rock-Eval S2 in mg HC/g rock to mcf/ac-ft, multiply by 131.34 (btu basis)

‡‡ section is 640 acre (2.59 km^2)

Quatitative lithology interpretation based on elemental concentrations. This model uses as inputs the relative yields of Silicon (Si), Calcium (Ca), Iron (Fe), Sulphur (S), Titanium (Ti), Gadolinium (Gd), Potassium (K), Uranium (U), Thorium (Th) acquired from single sonde, induced neutron gamma ray spectrometers (Herron and Herron, 1996 a&b) Absolute elemental concentrations were estimated using a processing technique based on a modified geochemical oxides closure model (Grau and Schweitzer, 1989). These elemental concentration logs were then used to derive lithologic fractions through a processing method described as spectral analysis of lithology, or spectrolith. Conventional logs were loaded into Geoframe. ELanplus module of Geoframe was used to analyze formation components. The logs i.e. GR, NPHI, RHOB, PEF and DT that are used in ELanplus as tool response equation, are in fact linear functions of volumetric fractions of constituents. Several Z-plots and X-plots were prepared over the Sembar Formation which was used with the ELan analysis for the detection of different mineral components in the formation. Mineral volumes from Spectrolith, Elan analysis and sample description from well cuttings were taken into consideration in order to build an optimum lithological model for the studied formation. Total rock volume of Sembar Formation is divided into five lithological fractions: clay, carbonate, pyrite, siderite, and Quartz+feldspar+mica. Fractional volumes of these minerals were plotted against depth to see the variations in percentage volumes of these mineral volumes (Figure 9). Volume of quartz ranges from 30% to 50%, volume of clay contents range from 35% to 60% and volume of calcite is up to 12%.

Porosity

The hydrocarbon generative potential of shales and the presence of porosity and permeability to store and transmit hydrocarbons, determine the potential for shale gas production from a formation or unit of interest (Vaibhav, 2008)

Estimates of porosity from logs suggest that normally pressured sediments exhibit an exponential relationship of the form $\varphi = \varphi o$*e-cy, where φ is the porosity at any depth y, φo is the surface porosity and c is a coefficient that dependent on lithology. The porosity-depth relationship curves established by various authors (Dore et al, 1993) show that shales at surface have porosities in the range of 46% to 65%, which decay exponentially and reduced to 3% at the depth of 6 km (Figure 10).

We have calculated the porosity of Sembar shale from well X-1 by using porosity logs. Once formation components were described, porosity was calculated by using neutron (NPHI), density (RHOB) and sonic (DT) combination. End points were selected using several cross plots and mineral volumes as defined earlier. Grain density curve derived from induced neutron gamma ray spectrometers was used to compute porosity from density log. These porosity values were plotted against depth to compare them with established porosity-depth plots (Figure 10). Reduction in porosity of shale almost fallows these plots. Porosity of the Sembar shales range from 5% to 8% in the studied well.

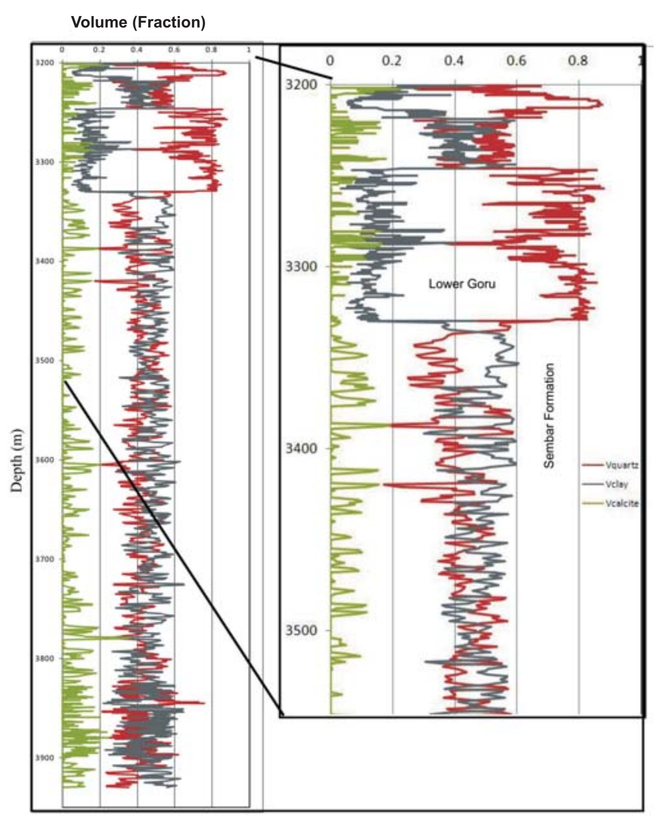

Figure 9 - Volume (in fraction) of Quartz, Clay and Calcite minerals in Sembar shales.

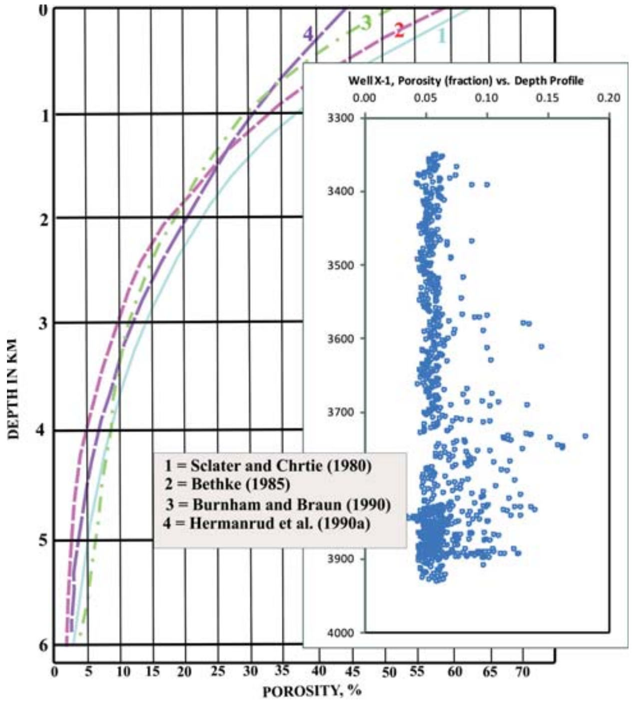

Figure 10 - Suggested porosity vs. Depth relationships for shales(After Dore et al 1993). Inset shows the calculated porosity vs. Depth profile of well X-1

RESULTS AND CONCLUSIONS

Sembar Formation is evaluated for gas shale play in the Middle and Lower Indus Sub-basins. It has been tried to understand various geochemical processes and shale characteristics, which controls the hydrocarbons generation, expulsion, storage and access to this gas resource.

1. Sembar Formation of Lower Cretaceous age is widely distributed formation in the Middle and Lower Indus Sub-basins. Lithologically, it is composed of black silty shale with interbeds of black siltstone. The shale is pyritic, glauconitic and moderately indurated. Thickness of the formation ranges from less than 50 m in the east to more than 900 m in the central part of the basin. Subsurface depth of the formation ranges from less than 1000 m in the east (platforms) to more than 5000 m in the west (foredeeps).
2. It has good organic richness with mixed (type III, II/III) organic matter. An average TOC is 1.0 wt.% with generation potential of 2.88 mg HC/g rock and hydrogen index of 240 mg HC/g TOC.
3. The computation of original generation potential yields about 63 bbl of oil equivalent/ac-ft (30% oil and 70% gas). Expulsion is assumed to be about 50% of the total generation potential of the formation. The total retained gas is 103 bcf/section which is the sum of already retained gas in pore spaces and the one formed as a result of secondary cracking of oil at higher temperature.
4. Based on vitrinite reflectance and Tmax data, the formation is gas mature below the depth of 3500 m.
5. Mineralogically, the formation is composed of an average of 42.0 % quartz, 47.0 % clay, 10.0 % calcite and 1.0 % pyrite.
6. In platform areas, the depth to exploit shale gas is about 3500 m while in fold belts; depth varies between 1000 m and 3000 m due to tectonic disturbance.

The geochemical parameters, physical characteristics and chemical composition make it potential candidate for gas shale play in the area.

REFERENCES

Abbas,S., 2009; Geochemical Investigation on Flush cuttings of Bitrism Well # 01, District Sanghar, Sindh Province. G & R Lab note no.575, OGDCL, unpublished.

Ahmed, R., 1994; Geochemical Investigation of Sakrand-1. G & R Lab note no.280, OGDCL, unpublished.

Ali, Z., Graham, E., and Ahmed, R., 1998; Recent Mediterranean Sea Sediments- An Analogue to Lower Cretaceous Petroleum Source Rocks in Lower Indus Basin, Pakistan.Pakistan Journal of Hydrocarbon Research, Vol.10, P. 55-70.

Beicip-FanLAB; Genex Single Well User's Guide Version 2.1. IFP Basin Modeling Software, Petroleum Software Division (France).

David K. Davies and Associates, Inc, 1992; Shale Study, Upper Goru to Sembar Formations, Badin Concession, Sindh, Pakistan. Report prepared for UTP Pakistan Inc.

Dore A.G. 1993. Basin modelling: advances and applications: proceedings of the Norwegian Petroleum Society Conference, 13-15 March 1991, Stavanger, Norway, Edited by A.G. Dore, J.H. Augustson, C.

Hermanrud, D.J. Stewart, and O. Sylta.
Beicip-Franlab; Genex-Single Well, User Guide
Arthur J.D., Langhus B., Alleman D., 2008. AN Overview Of Modern Shale Gas Development In The United states, http://www.allllc.com/publicdownloads/ALLShaleOverviewFINAL.pdf
Ejaz, M., 1997;Geochemical Investigation on Core and Flush Cutting Samples of Sabzal Well # 1, District Rahim Yar Khan, Punjab Province. G & R Lab note no.340, OGDCL, unpublished.
Gakkhar R. A., 2010; Sedimentology and organic geochemistry of Cretaceous and Jurassic rocks of Punjab Platform, Pakistan. Phd. Thesis, Un-published, University of Leoben,Austria.
Grau, J. A., and Schweitzer, J. S., 1989; Elemental concentrations from thermal neutron capture gamma ray spectra in geological formations; Nuclear Geophysics, Vol. 3, No, 1, pp. 1-9.
Hedley, R., Warburton, J. and Smewing, J., 2001. Sequence Stratigraphy and Tectonics in the Kirthar Foldbelt, Pakistan. ATC-2001, Islamabad, p. 61-72.
Herron, S.l., and Herron, M. M., 1996a; Quantitative lithology; an application for open and cased hole spectroscopy; transactions of the 32nd Annual SPWLA logging symposium, Jun 16- 19.
Herron, S.l., and Herron, M. M., 1996b; Quantitative lithology; open and cased hole applications derived from integrated core chemistry and mineralogy database; geological Soceity Special volume on core Log Integration, Geological Society of London Meeting on Core Log Interpretation, 17-18 September, 1996, Burlington House, Piccadilly, London.
Iftikhar, A. A., and Haneef, M., 2002. Stratigraphy of Kalat Block. University of Peshawar, April 2002.
Jarvie, D. M., R. J. Hill, Tim E. Ruble, and R. M. Pollastro, 2007; Unconventional shale-gas systems: The Mississippian Barnett Shale of north-central Texas as one model for thermogenic shale-gas assessment. AAPG Bulletin, v. 91, no. 4 (April 2007), pp. 475499.
Khan, A. S., Kelling. G., Umar, M., and Kassi, A. M., 2002. Depositional Environments and Reservoir Assessment of Late Cretaceous Sandstones in the South Central Kirthar Foldbelt, Pakistan. Journal of Petroleum Geology, vol.25, P. 373-406.
Langford, F. F., and M.-M. Blanc-Valleron, 1990, Interpreting Rock- Eval pyrolysis data using graphs of pyrolizable hydrocarbons vs. total organic carbon: AAPG Bulletin, v. 74, No. 6, p. 799804.
OGDCL, 1988; Pakistan Hydrocarbon Habitat: Exploration Promotion Package. Min. Petrol. and Nat. Res., OGDCL, Islamabad, Unpubl. Internal Rept.
OGDC-IFP, 1988; Petroleum Potential and Sulaiman and Kirther Fold belts, Oil and gas Development Company limited Internal Report.
Peters, K. E., L.B. Magoon, K. J. Bird, Z.C. Valin, and M. A. Keller, 2006; North Slope, Alaska: Source rock distribution, richness, thermal maturity, and petroleum charge. AAPG Bulltin, V. 90, No. 2 (Feb.2006), P. 261-292.
Qadri, V. N. and S.M. Shuaib, 1986; Hydrocarbon Prospect of Southern Indus Basin, Pakistan. AAPG V. 70, No. 6, P. 730-747.
Raza H.A, S.M. Ali,R. Ahmed, and J. Ahmed, 1990; Petroleum Geology of Kirthar Sub-basin and Part of Kutch Basin. Pakistan Journal of Hydrocarbon Research, Vol.2, No.1 (January 1990), P. 29-73.
Robinson, C.R; Smith, M.A; Royle, R.A. 1999; Organic Facies in Cretaceous and Jurassic hydrocarbon source rocks, Southern Indus Basin, Pakistan. International Journal of Coal Geology V. 39, P. 205-225.
Schmoker, J. W., 1995; Method for assessing continuous-type (unconventional) hydrocarbon accumulations, in Daniel M. Jarvie, Ronald J. Hill, Tim E. Ruble, and Richard M.Pollastro, 2007, Unconventional shale-gas systems: The Mississippian Barnett Shale of north-central Texas as one model for thermogenic shale-gas assessment. AAPG Bulletin, v. 91, no. 4 (April 2007), pp. 475499.
Shah S.M. I, 2009, Stratigraphy of Pakistan. GSP Memoirs, V. 22, P. 6-10, P. 187.
Shah, S.M. I., 1977. Stratigraphy of Pakistan. GSP Memoirs, V. 12, Fig.06.
Smewing, J.D., Warburton, J., Daley, T., Ul-Haq, N., 2002. Sequence Stratigraphy of the Southern Kirthar Foldbelt and Middle Indus Basin, Pakistan. Geological Society of London, Special Publications, 195, P. 273-299.
Suhas .C. Talukdar, 2008; Application of Geochemistry for Shale Gas Assessment. www.fwgs.org/cTalukdarASSESSMENT.pdf.
Vaibhav, P. D. 2008; General screening criteria for shale gas reservoirs and production data analysis of Barnett shale. repository.tamu.edu/.../1969.../ DESHPANDETHESIS .pdf.
William, M.D., 1959; Stratigraphy of the Lower Indus Basin, West Pakistan, in Shah S.M. I, 2009, Stratigraphy of Pakistan. GSP Memoirs, V. 22, P. 186-187

PJHR

Received Feb. 1, 2012, revised June 5, 2012 and accepted October 28, 2012. First the paper was presented in Annual Technical Conference of PAPG - SPE held in Islamabad, Pakistan, Nov. 22-23, 2011 and published in its proceedings. Now the paper is being published after subjecting it to refereeing process outlined by Higher Education Commission , Islamabad, Pakistan.