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A Workflow for Shale Play Exploration and Exploitation

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Abstract

This article aims to give an outline of an integrated geoscience approach that may apply in the initial identification of the shale play, address complex unconventional reservoirs, their associated challenges and finalise the pilot vertical wells to evaluate their potential.

Shale exploration depends on the proven source rock within the basin, so the availability of the required data, well data and seismic data in public domain for initial study and basin screening is usually easy. The investigation may start after knowing the well developed proven source rock in the basin. An extensive study of structure, tectono-stratigraphy, source rock and reservoir characterization, thermal maturity models and exploration strategy is required by using the regional tectonic history, drilled wells with multiple penerations in source rock, open-hole logs, mud samples and cores of the source rock to get the answers to the critical questions on the attributes that influence shale plays. Once these attribute questions have been satisfactorily confirmed to be in the required range or with an analog, that data can be utilized to locate possible sweet spots to drill pilot vertical wells with the goal of acquiring extensive coring, open hole logging and formation pressure testing data to identify the best candidates for further horizontal well evaluation.

This article highlights and demonstrates a possible step by step workflow for the selection of the shale play area, sweet spot and pilot vertical wells locations by using the schematic data maps, published material examples and building possible cut offs essential for exploration decision process.

Introduction

Evaluation of an unconventional shale play majorly depends on the source rock characterization. A number of analysis are required along with the prior well results showing oil/gas shows from the source rock, to investigate the source rock properties. The main contributors to mature the play area are analysis of core, well cuttings and electric logs. The Integration of these results required a good team and software.

Basin development and Source rock identification

End of well reports and shows

A good database of the area of interest is required mud logs and end of well reports with wells penetrated into the source rock stratigraphy. If there is any hydrocarbon shows found in the formation over the large area, it should be investigated. The presence of hydrocarbon shows and abnormal pressure is a key benchmark used to recognize the prospective unconventional play. The presence of hydrocarbon shows in tight formations where the poor-permeability characteristics indicate non-migration are indicative of self-sourcing hydrocarbon systems. So, the good porosity and poor permeability of the source rock is one indicator of a shale play. Figure-1 provides schematic data summary of hydrocarbon shows that may be reported in the mud logs, composite logs and end of wells reports for source rock stratigraphic interval.

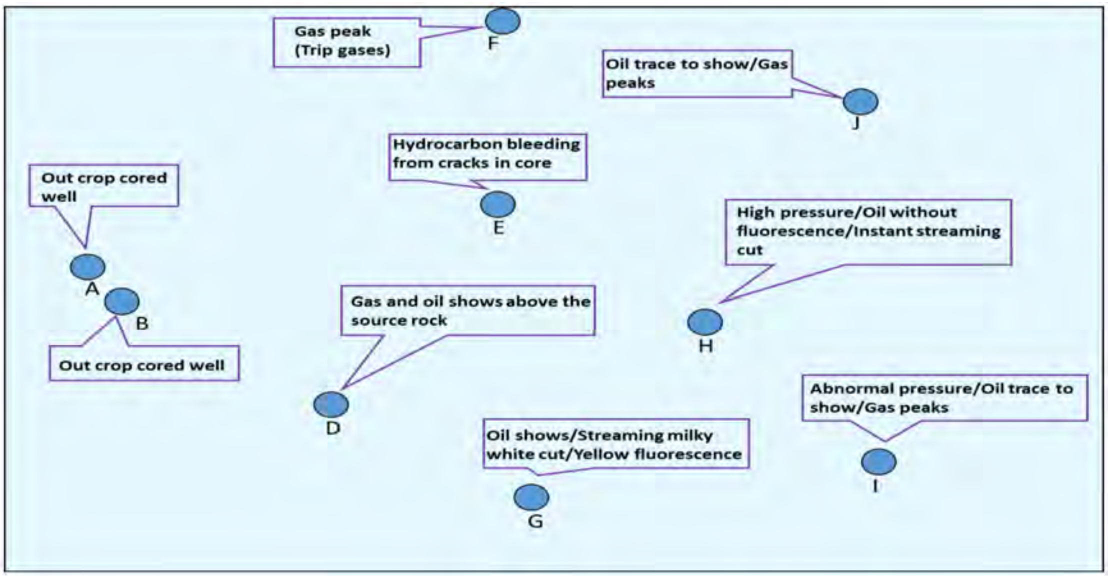


Figure 1—Schematic source rock hydrocarbon shows.

Tectono-Stratigraphy and structural analysis

Regional geodynamics and plate model re-construction helps to recognize the development of basin, and stratigraphy analysis helps to identify gross rock thickness, regional presence, organic rich intervals, depositional environment, lateral facies change, sea level changes, and sequence stratigraphy of the source rock. Therefore, to understand the stratigraphy, structure and depositional characteristics of the unconventional play, it is important to understand the tectonic and stratigraphic framework of the basin in regional context.

A study based on tectono-stratigraphy, regional basin analysis, petroleum system chart, available well data and well log correlations may helpful to understand the major tectonic events, stacking of sequences and their impact on the petroleum geology and the formations/members of interest of the basin. This study may help to understand the following:

1. Major and minor unconformities.
2. Understanding of paleo structural high and low areas.
3. Chrono and Litho stratigraphy and position of the main source rock.
4. The shelf/basin boundary.
5. Distribution of source rock.

In conclusion, following is a schematic case of the extensive regional presence of the source rock across the basin A of country X. Fig. 2 is showing shelf, slop and basin boundaries and Fig. 3 is a regional cross-section from wells A to K.

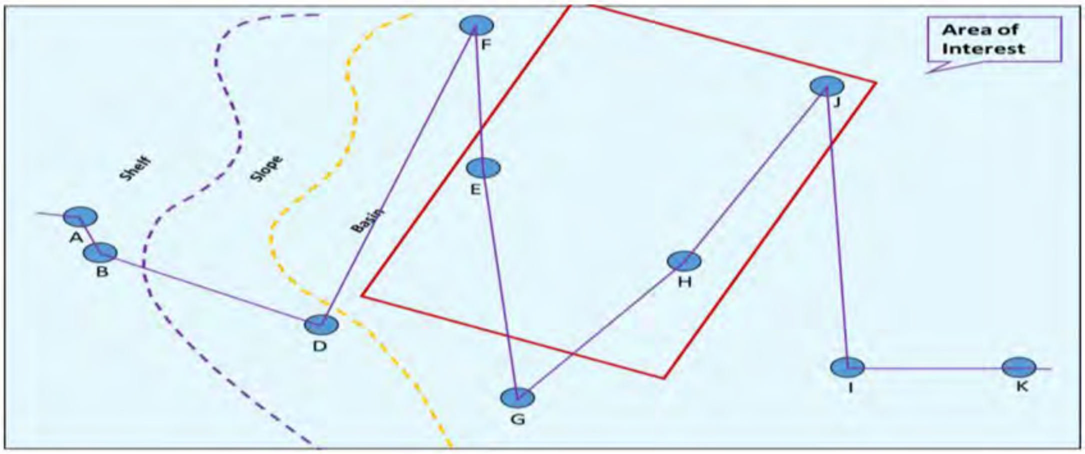


Figure 2—Schematic area of interest, shelf, slope and basin boundaries (regional scale map).

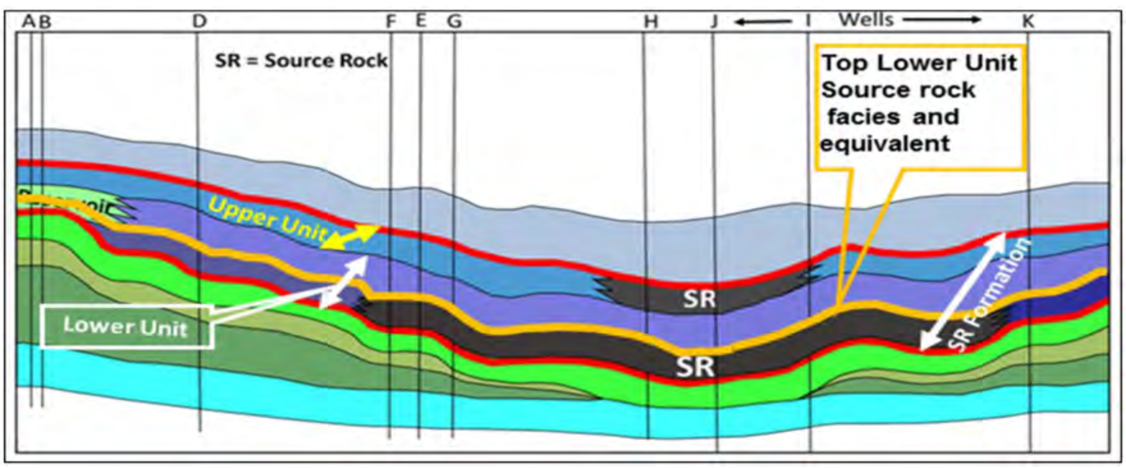


Figure 3—Schematic, regional cross section of Unconventional source rock facies. The well cross section shows the litho stratigraphic sub divisions within the source rock formation.

The eastern part of the basin having consistent thickness of the lower unit of the source rock in the large area, having the organic rich shales consists of dark grey to black shales (Fig. 3, Fig. 6, Fig. 7).

Identification of Source rock

The proven source rock may be identified by following the wells results (Fig. 1). Generally, it is difficult to have a good grid of the wells penetrated into the source rock. A total 10 wells are available in figure-2 example, with deep enough penetration into source rock and having well data, which includes end of well reports, electric logs, cuttings descriptions and cores. The Well site analysis of the cuttings convey that the shale is mostly black, greasy, very carboniferous and organic rich with the associated high TOC. The cuttings description also exhibits a vast amount of pyrite and gases while drilling.

The regionally correlatable source rock intervals may identify from well logs. The gross rock interval may be defined based on core/cuttings descriptions and well log responses (using especially, gamma ray, resistivity, sonic and bulk density logs). Regional well correlations may be carried-out by using wells in order to understand the presence of the source rock and their development/thickness across the basin. Well logs may also help to identify the sea level changes, sequences, para sequences and number of cycles within the source rock. The TOC measurements from wireline logs and gamma ray may also be used to estimate the gross rock thickness of the source rock intervals. Within source rock formation, two distinctive source rock intervals are delineated and are referred to upper unit and lower unit. Their gross thickness is variable in the wells. The thickest and most extensive source rock interval is the lower unit. An east-west cross-section showing the source rock subdivisions and correlation in the basin (Fig. 7). Isopack/paleo-topography maps for the source rock of different interval and for thickness variation may prepare from the well data and as well as seismic data (Fig. 4, Fig. 5, Fig. 6).

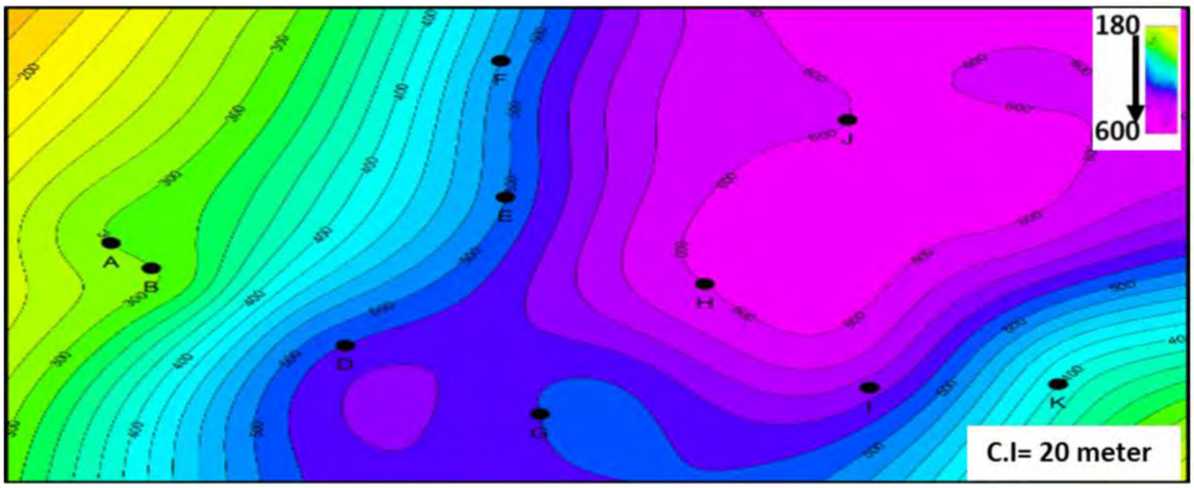


Figure 4—Schematic gross rock Isopack map of source rock Formation (Thickness in meters).

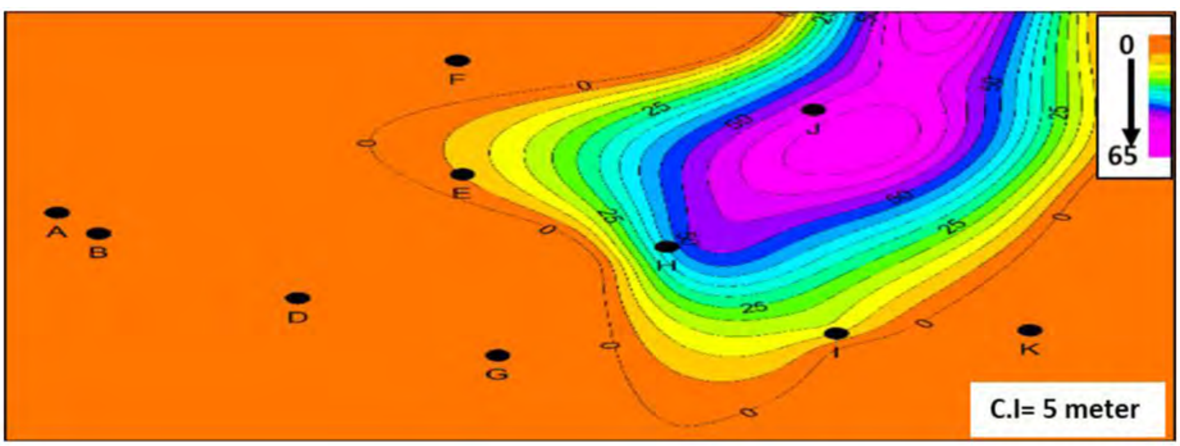


Figure 5—Schematic Upper unit Isopack map of source rock facies (Thickness in meters).

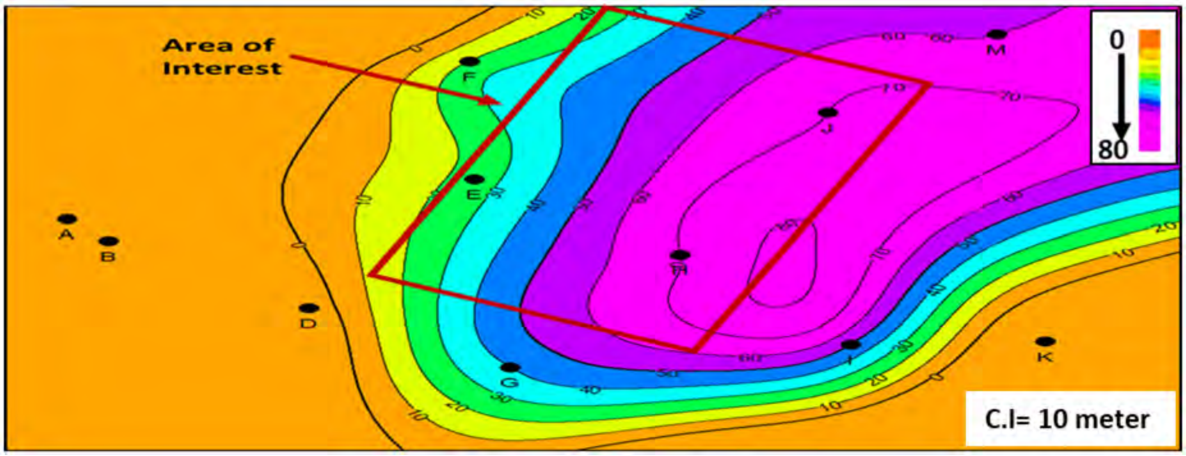


Figure 6—Schematic Lower unit Isopack map of source rock facies (Thickness in meters).

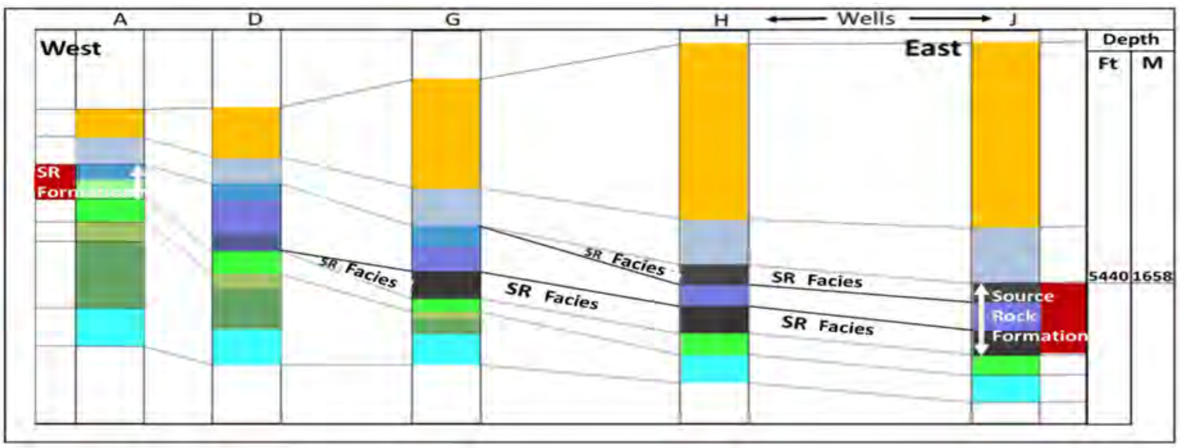


Figure 7—Schematic West to East well cross-section showing the internal litho-stratigraphy units of source rock.

Bio stratigraphy and chemo (chemical) stratigraphy

Developing of stratigraphic framework is the key to the exploration of any formation in a hydrocarbon basin. In shale plays, the traditional methods may use to define stratigraphic correlations are well log correlations, biostratigraphy and chemo-stratigraphy. A high-resolution stratigraphic application of inorganic geochemical data in shales can also be considered for stratigraphic analysis. Palynological biostratigraphy and chemo stratigraphic analysis may contribute to a better understandings of age control, correlatable events and information on the depositional environment for the sequence stratigraphic interpretation of the source rock interval. The distribution of palynomorphs and organic matter (palynofacies) can provide an indication of high productivity intervals that can be associated with the accumulation of organic-rich facies. Core samples from the wells can be selected for biostratigraphy and chemo stratigraphy analysis. Figure-8 is an example of palynomorphs of shale play from Ibrahim et al. Jan 2002.

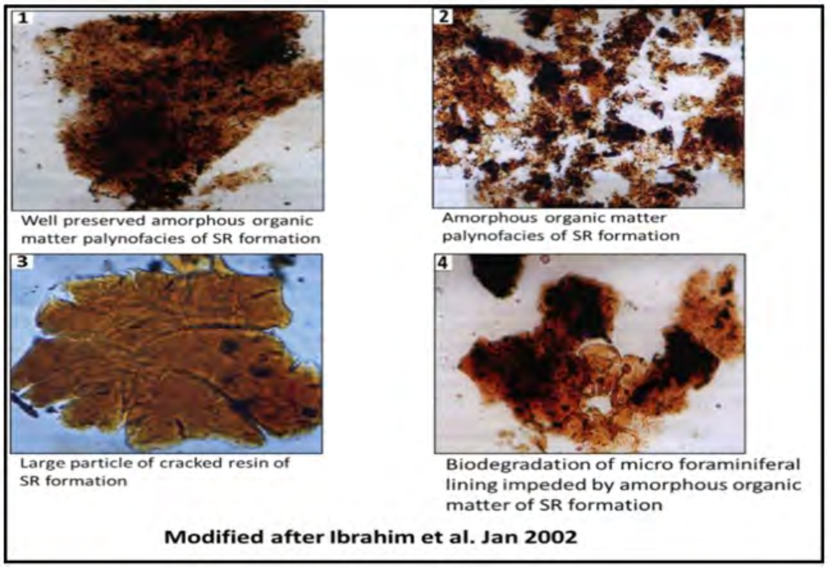


Figure 8—Example of palynomorphs of the source rock formation in transmitted light with magnification. Modified from (Ibrahim et al. Jan 2002)

The schematic result of chemo-stratigraphy is shown in Figure-9, which helps to identify the upper and lower unit of the source rock.

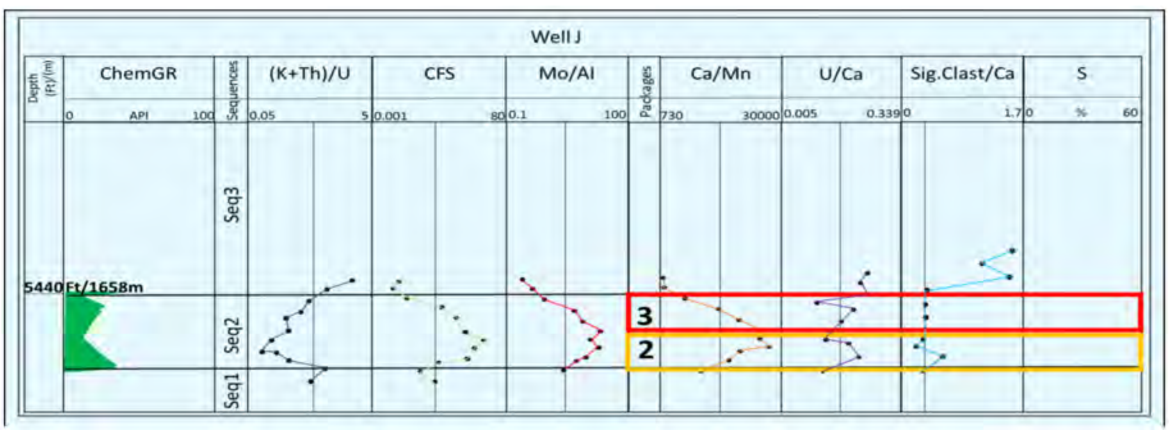


Figure 9—Schematic representative chemo-stratigraphic subdivision from well J.

From Figure-9, the regionally established chemo stratigraphic sequence Seq2 (source rock) is represented, and can be further broken down into the following chemo-stratigraphic packages: Seq2-Pack2 (SR upper unit), Seq2Pack3 (SR lower unit).

Figure-10 summarizes the relationship between litho-stratigraphy, source rock packages and chemo-stratigraphy/biostratigraphy zonation in source rock.

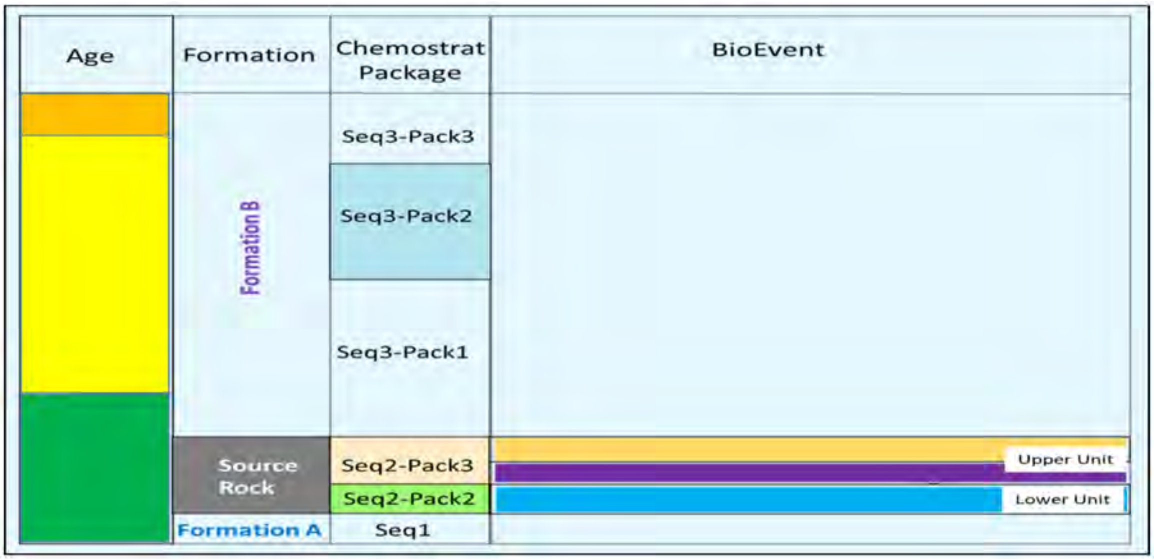


Figure 10—Schematic stratigraphic summary of the area of interest, showing age, litho-stratigraphy, chemo-stratigraphic package and bio-event.

Seismic data

The available 2D seismic data of different vintages may use to prepare time and depth maps at different levels to understand the structure style and source rock Isopack maps (Fig. 4, Fig.5, Fig. 6, Fig. 11) in combination with well data. Fig. 11 is showing the depth of the lower unit of the source rock of the basin.

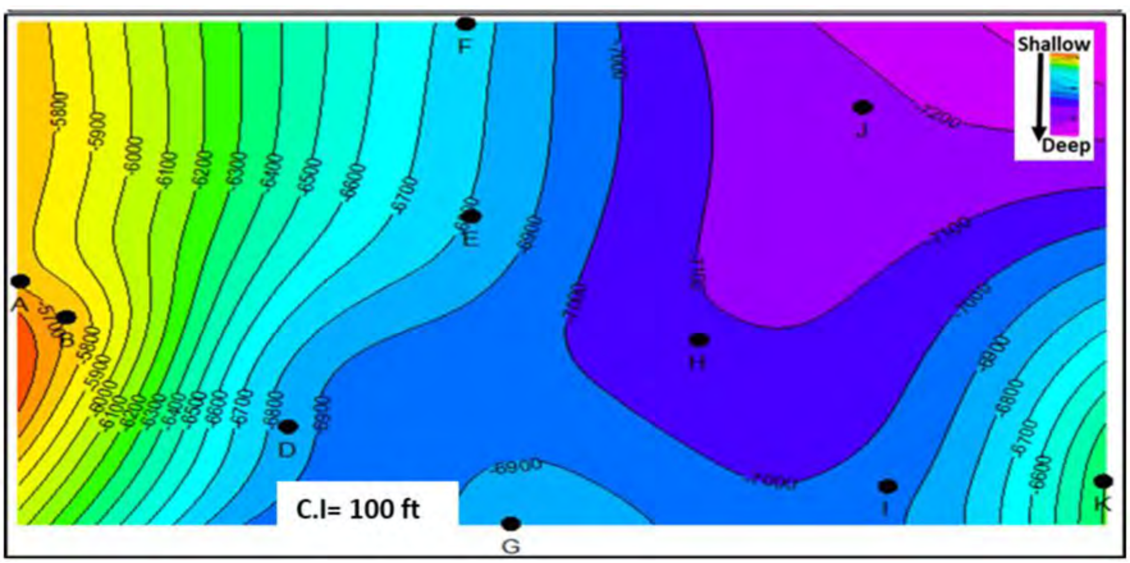


Figure 11—Schematic depth map of top lower unit source rock facies and equivalent (depth in feet).

Thickness of Source Rock

The shale thickness controls the hydrocarbon content and economic benefit of shale play. The vertical thickness of TOC has greatest importance instead of just the overall shale thickness. The source rock Formation should have at least one zone of high TOC with more than 100 feet continuous thickness. Thick beds are easier target for lateral wells and for hydraulic fracturing to produce. "The Eagle Ford Shale thickness range is 50ft to 300ft. At present, there is no unified understanding of the lower limit of shale reservoir thickness. In the U.S., the thickness of shale formation is defined as no less than 30 m, and the thickness of effective shale is no less than 9 m" (Wang et al., 2010). If the organic carbon content is higher, the lower limit can be smaller.

Reservoir and Source Rock Characterization

Reservoir Properties

Obtaining a precise and reproducible reservoir properties through standard techniques is difficult. A number of analysis program can be selected for the selected core and rock samples.

Routine Core Analysis (RCAL)

In order to know the rock capability to accumulate and transport reservoir fluids, it is necessary to determine the values of two key parameters porosity and permeability.

Porosity of shales

Porosity is the volume of pore spaces present in the rock sample (expressed as percentage) which may filled with oil, gas or water. Therefore, porosity controls the volume of fluids accumulated by the rock. Fig. 12 is showing the example of possible accumulation of hydrocarbon in the shale.

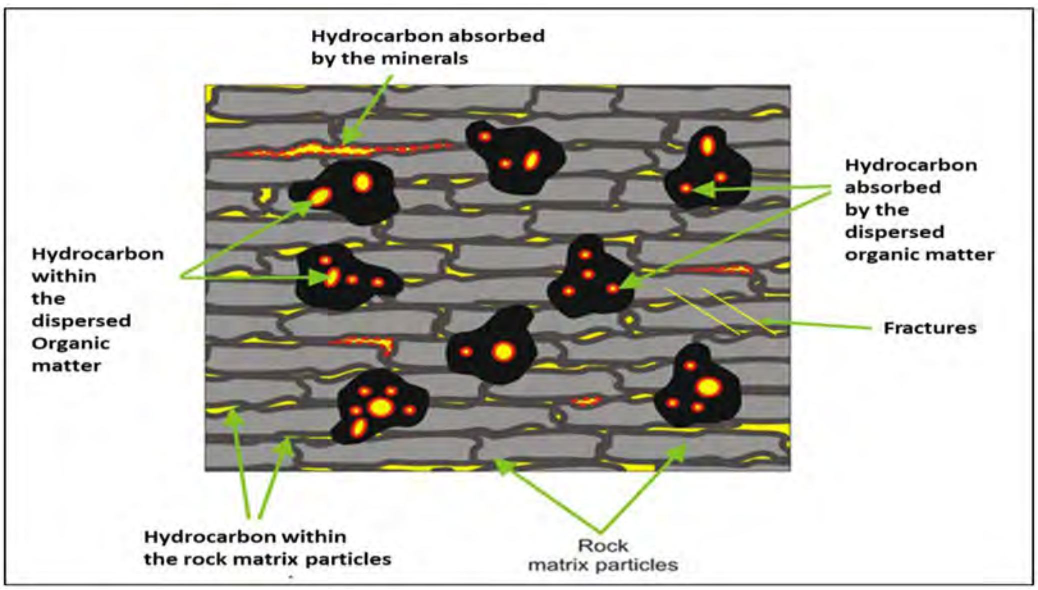


Figure 12—Accumulation spaces for hydrocarbon in the shale rock (modified after Ireneusz Dyrka)

The best shale play can have total porosities of greater than 4% and the higher is the better and minimum permeability. In shale play, the best way is to make an analogue with the proven play of the same kind of shale origin as discovered. The porosity is generally concentrated in laminated zones. The porosity of the shale can be divided into three parts: porosity within the natural fractures and micro-fractures, inter-granular porosity within the inorganic matrix and porosity inside the organic matter.

The TOC contents, organic matter maturity, the types and contents of clay minerals affect the development of shale pores: the development of organic matter pores is promoted by high TOC contents and appropriate organic matter maturity, whereas excessive maturity may reduce the number of organic matter pores (Nie et al., 2014; Tang et al., 2015; Guo et al., 2014; Curtis et al., 2012).

Permeability and fracture ability of shales

Permeability is a measurement of the ability of a porous rock to allow fluids to pass through it. Therefore, the permeability depends on the natural cracks/fractures in the rock which helps to flow the fluids between pore spaces.

"In shale play, Permeability is an important input parameter for forecasting production, planning the boreholes grid or designing of the hydraulic fracturing treatments. In the first stage of a shale play life, mainly the system of cracks and fractures that originate due to hydraulic fracturing, determine the inflow to the well but for long-term production and hence its profitability depends rock matrix permeability.

In shale rocks, both permeability and porosity are highly dependent on

- mineral composition
- organic matter distribution
- quantitative (%) content of organic matter
- thermal maturity of organic matter

Shale rocks characterized by low permeability it basically prevents any unrestrained flow of hydrocarbons" (*Ireneusz Dyrka*). The following Fig. 13 can be used as a reference to see the relationship between permeability and viscosity to understand that shale play is a shale oil or shale gas.

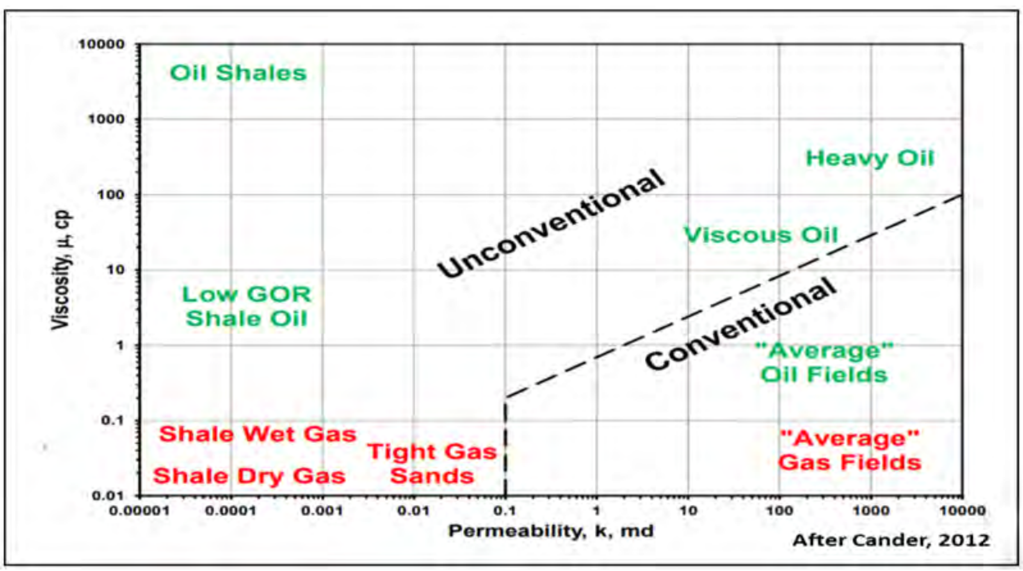


Figure 13—Showing Permeability diagram of conventional and unconventional reservoirs. (after Cander, 2012)

RCAL

There are number of methods available to calculate porosity and permeability in the laboratory using RACL, SEM, MICP analysis, traditional methods and well logs.

Routine core analysis gives only the very basic properties of unpreserved core. The core porosity, grain density and permeability can be calculated. Fig. 14 is an example, showing the thin section of porosity, permeability and grain density. Table-1 is showing the shematic value of the porosity, permeability and grain density of the well H and Fig. 15 is showing the comparison of the porosity and permeability of the well H with the Eagle ford.

Table- 1—Schematic representative RCAL result of five samples from well H of the area of interest from high TOC layer in the lower part of the SR lower unit.

Well Name	Depth (ft)	Porosity %	Permeability (nD)	Grain density (g/cm3)
H	7240	14	800	2.4
H	7250	9.5	500	2.2
H	7260	8	600	2.3
H	7270	6.4	400	2.3
H	7280	6.2	200	2.0
H	7290	6.2	500	2.3

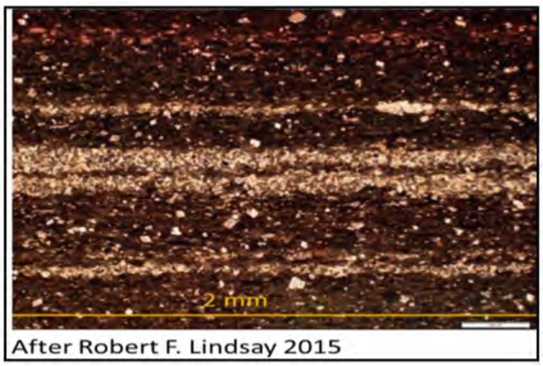


Figure 14—Thin section example of porosity, permeability and grain density of the source rock (modified from Robert F. Lindsay 2015).

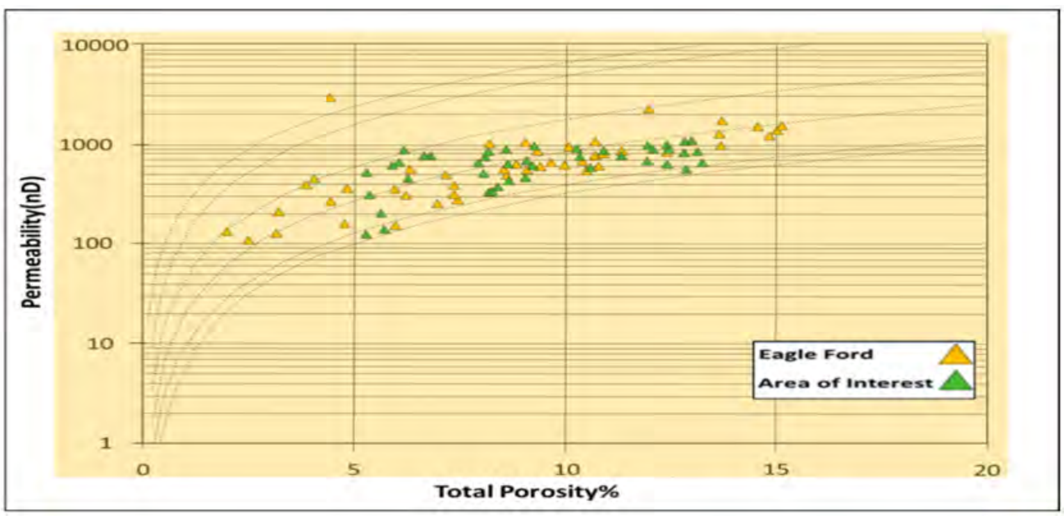


Figure 15—Schematic, Area of interest and Eagle ford porosity and permeability comparison.

Inorganic petrographic analysis

The main inorganic petrographic analysis techniques are thin section petrography, Scanning Electron Microscope (SEM) and X-Ray Diffraction (XRD).

Thin Section Petrography

Thin sections petrography can be done from core plugs to investigate the optical properties of the minerals in the rock. This work is a part of petrology and supports to disclose the origin and evolution of the parent rock. Thin section petrography technique provides information about Mineralogy, texture, cementation, pore geometry and pore classification which helps to find out the general depositional trend.

Figure-16 is showing the example of the petrographic analysis and confirming the general depositional (Hanifa shale play Saudi Arabia) trend, shelf, slop and basinal areas from high energy deposition at the shelf margin (Well D, Fig. 1) to the low energy following organic-rich deposits in the basin centre (Well K, Fig. 1).

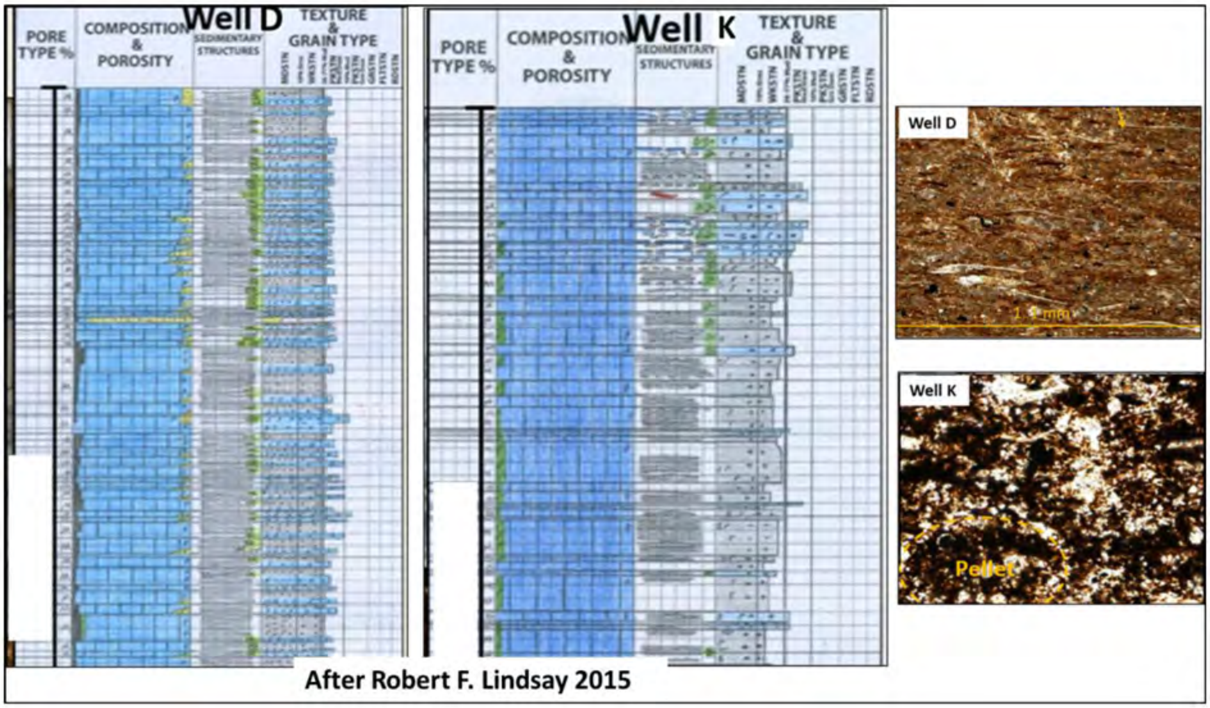


Figure 16—Showing example of pore type, composition, porosity, mineralogy, texture, grain type and general depositional trend Hanifa shale play Saudi Arabia (modified after Robert F. Lindsay 2015).

The petrographic descriptions may integrate with the RCAL results in order to better understanding with the pore systems. In area of interest the porosity and permeability ranges are 6 to 14 % and 100 to 1000 nD respectively and having analogue with the Eagle ford shale play. These porosity ranges may be correlated with the neutron-porosity logs and the porosity ranges should be consistent.

X-Ray Diffraction (XRD)

The composition of shale is of critical importance with reference of type and origin of the clay minerals. Generally, clays of the smectite group from mafic rock types (Ca plagioclase feldspars) and of volcanic origin have swelling problems during drilling and hydraulic fracturing. The kaolinite and illite groups of granitic origin (K orthoclase feldspars) have minimal negative reaction to drilling and slick water fracture fluid. The XRD techniques (XRD Clay size minerals and XRD whole rock (Clay size mineral particles)) and wireline logs can easily define the minerals of the rock. XRD techniques provides information about bulk mineral composition, identification of fluid-sensitive clays, grain density correlations. It is the most widely used technique for identifying crystalline minerals and is especially useful for fine dispersed clay mineral and its inner structure analyses.

Total Clay (illite, kaolinite and smectite) and Quartz content, Pyrite and total carbonate may be calculated which helps to decide that shale can be fractured through hydraulic fracturing or not and also the reservoir quality. It is recommended that the content of brittle minerals in high-quality shale reservoir should be greater than 50%, while the content of clay mineral should be less than 40% (Z. Jiang et al, 2016).

Table-2 is showing XRD result for well H.

Table -2—Schematic representative summary of the XRD results from well H of the area of interest.

X-Ray Diffraction Analysis (Combined Whole Rock and Clay)			
Whole rock XRD analysis			
well name	quartz	55.3	
H	k feldspar	1	
H	plagioclase	0	
H	anhydrite	0	
H	calcite	36.5	
H	dolomite	0.7	
H	gypsum	3.3	
H	pyrite	2.2	
H	Fe calcite	1	
Clay fraction XRD analysis			
well name	illite/smectite	35	Most of the clay fraction is quartz
H	chlorite	8	
H	kaolinite	30	
H	illite-smectite I-rich	27	

Scanning Electron Microscope (SEM)

The SEM imaging technique provides information about Mineral morphology, pore geometry, micro fabric texture, energy-dispersive spectra (EDS) mineral mapping and 3D volume modeling. The type of sensitivity and the degree of damage are closely related to the composition, content, and occurrence distributions of sensitive minerals. The above-mentioned XRD is particularly suitable for identifying the composition and content of sensitive minerals, whereas SEM is especially applicable to visually identifying mineral grain size and occurrence, pore configuration, throat size, and grain surface and pore throat wall configuration fast and effectively. Fig. 17 is a ternary plot used to see the shale clay and quartz content and to compare with the proven shale play.

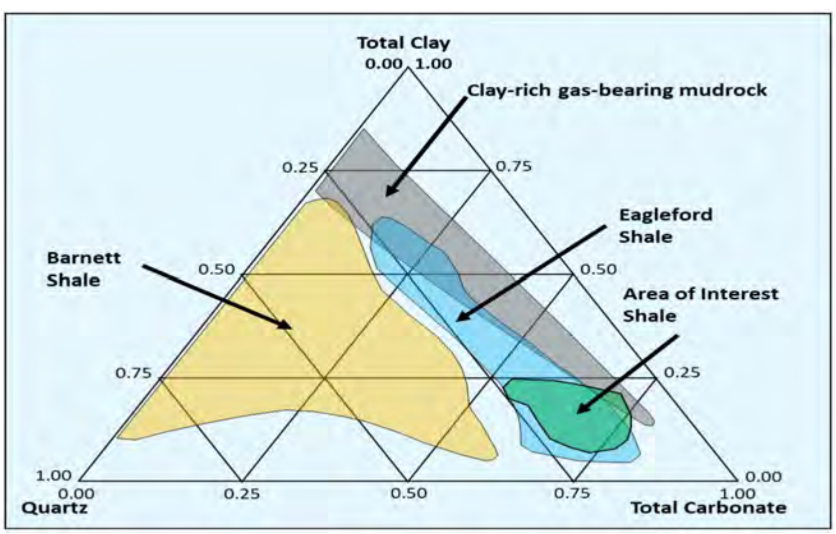


Figure 17—Schematic ternary plot showing the mineralogy of source rock intervals (area of interest) compared to Eagle Ford and Barnett shale play. Source rock has carbonate mineralogy with lower clay content (modified after Passey, 2010).

Geomechanics

Understanding of geomechanical properties of shale are important for drilling, fracturing and production of hydrocarbons. The mechanical behavior of the source rock depends on the shale type (carbonate origin or clastic origin), mineralogy, coring direction, confining pressures and burial depth. The geomechanics study helps to understand the brittleness, maximum and minimum horizontal stress, pore pressure, overburden stress and natural fracturing of the source rock by using core and logs. Brittleness is used to define the best hydraulic fracturing candidate and knowledge of stresses helps to know the wellbore stability.

Young's Modulus and Poisson's Ratio measures rock strength and deformation to calculate relative brittleness or ductility of the shale play (Fig. 18). Young's modulus measures the amount of deformation (strain) of the rock through applied force (stress) (Fig. 18, B & C). Poisson's Ratio measures the change in shape (degree of deformation) of the rock through applied stress (Fig. 18, B & C). A brittle rock deforms elastically as stress is applied, and then breaks without being plastically deformed. A ductile rock undergoes plastic deformation before rupture at a given stress (Fig. 18, A).

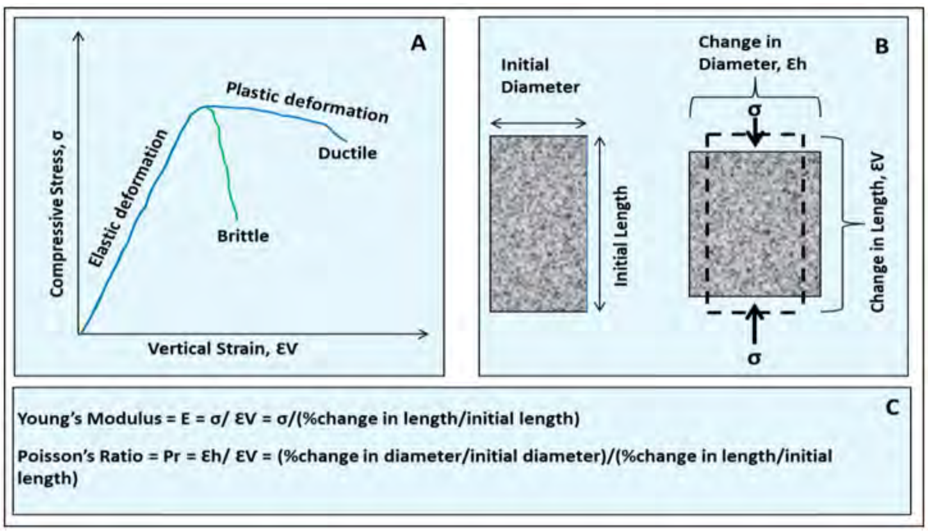
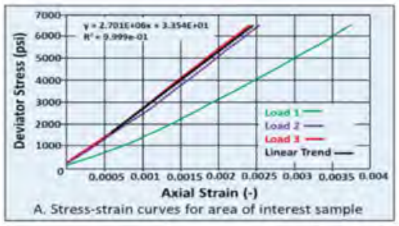
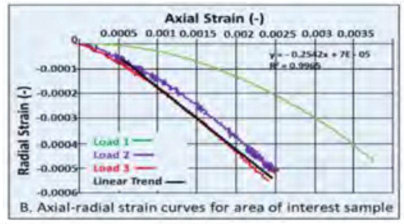


Figure 18A—Showing the Stress-stain diagram. B. Showing change in length of a rock due to applying the stress. C. Equation of Young's modulus (E) Equation of Poisson's ratio (Pr). (modified, Jiang et al).

"As a rule of thumb, the larger the Young's modulus is, the higher the degree of natural fracture development is. The lower the Poisson's ratio is, the higher the brittle mineral content is, and the lower the clay content is. As a result, the fracturing availability of shales will be greater. It is proposed by Jiang et al. that a good shale reservoir should satisfy the following conditions: a Poisson's ratio < 0.25, a Young's modulus value > 20 GPa (gigapascals), a brittle mineral content > 40% and a clay mineral content < 30% (Jiang et al., 2010). The horizontal and vertical core plugs may select for geomechanical analysis. The triaxial compression tests may performed on core samples. Figure-19(A) showing the triaxial compression test stress-strain curves for determining Young's Modulus. Figure-19(B) showing the associated axial-radial strain curves for determining Poisson's Ratio. Figure-19(C) showing the summary of the mechanical properties of the lower unit of the source rock.



A. Stress-strain curves for area of interest sample



B. Axial-radial strain curves for area of interest sample

Summary of the Mechanical Properties			
Sample No.	No. of Test	Average Young's Modulus (GPa)	Average Poisson's Ratio(-)
1	2	21.58	0.22
2	2	23.31	0.211
3	2	19.1	0.206
4	2	22.31	0.199
5	2	24.58	0.198
6	2	20.03	0.201
7	2	21.62	0.199
8	2	22.69	0.204

Figure 19—Schematic representative summary of the mechanical properties of the selected samples from wells E, F, G, H, I, J. (modified, Jiang et al).

Geochemistry (Geochemical Methods)

Geochemistry helps to determine the source rock potential by calculating the quantity (organic richness, TOC), quality (Kerogen type) and thermal maturity of the source rock. These three features characterize the source rock.

Organic Richness (TOC)

"This is the percentage or quantity of organic carbon (TOC) in a rock, which includes both kerogen (insoluble) and bitumen (soluble)" (Peters and Cassa, 1994). "TOC represents the amount of carbon, oxygen and hydrogen atoms are available for hydrocarbon generation" (Kennedy et al., 2012). The concentration of organic material in a source rock, is characterised by the weight percent of organic carbon. The minimum TOC value by weight percent for an effective source rock is about 0.5% and greater than 2-3% is considered as a minimum value for unconventional shale play. "TOC can be obtained from Rock-Eval pyrolysis or similar experiments in a laboratory, from well logging techniques, such as gamma-ray logs." (Shuxian Jiang et al, 2018). The TOC analysis of the whole core, core slices and cuttings samples of the source rock interval determines the organic rich zones, Quality and hydrocarbon generative potential when combined with kerogen type and maturity. The results may be used to select samples for further Rock Eval and organic petrography analysis.

Table-3 is showing guidelines for accessing TOC.

Table-3—Guide line for accessing TOC and hydrocarbon generation.

Average TOC values for all source rocks (Chin, 1991)		
Rock Type		TOC Value, %
Average for all shales		0.8
Average for shale source rocks		2.2
Average for calcareous shales source rocks		1.8
Average for carbonate source rocks		0.7
Average for all source rocks		1.8
Guideline for Assessing Organic Richness of Source Rocks (Law, 1999)		
chances for hydrocarbon	wt.% TOC, Sha les	wt.% TOC, Carbonates
Poor	0.0 − 0.5	0.0 − 0.2

Average TOC values for all source rocks (Chin, 1991)		
Fair	0.5 – 1.0	0.2 – 0.5
Good	1.0 – 2.0	0.5 – 1.0
Very Good	2.0 – 5.0	1.0 – 2.0
Excellent	>5.0	>2.0

Figure-20 Showing the TOC vs source rock capacity to be a source rock or Non source rock for shale play.

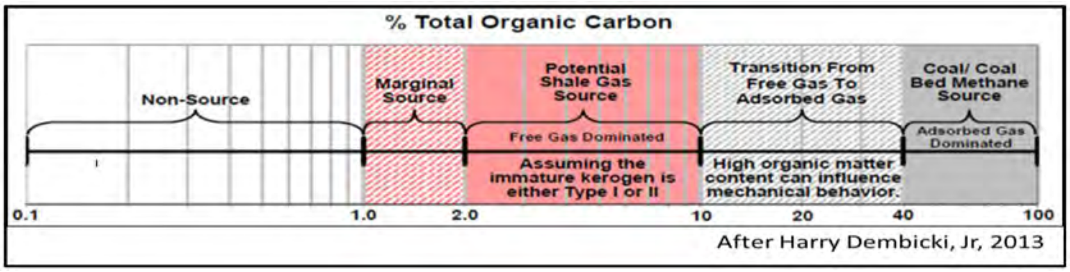


Figure 20—Showing the windows of opportunity of the source rock for shale play.

Rock Evaluation pyrolysis, S1, S2, S3 and Tmax analysis

Rock evaluation pyrolysis analysis is a tool which measures the petroleum potential of a source rock in kg/tonne of rock by heating the sample to evolve hydrocarbons. Pyrolysis is the decomposition of organic matter by heating in the absence of oxygen.

Rock Evaluation pyrolysis analysis measure S1, S2, S3 and Tmax. Samples with TOC values more than 2% may prioritized and selection may also make at regular intervals with in the wells to better constrain the maturity profiles of the source rock from Tmax values and to determine the following:

1. To evaluate source rock facies and hydrocarbon generative potential.
2. Kerogen type (Type I, Type II, Type III) may determine to access the source rock capability of generating oil and gas or gas only.
3. The level of thermal maturity.

"From Figure-21, Rock samples may have heated in two stages. The S1 peak represents the amount of hydrocarbon thermally extracted from the rock by heating to about 300 degrees C. The S2 peak records hydrocarbons generated by thermal cracking of kerogen during heating to about 550 degrees C. The S3 peak represents CO_2 production. Tmax represents the temperature at which cracking of kerogen releases the maximum amount of hydrocarbons" (Schlumberger, Oilfield Glossary).

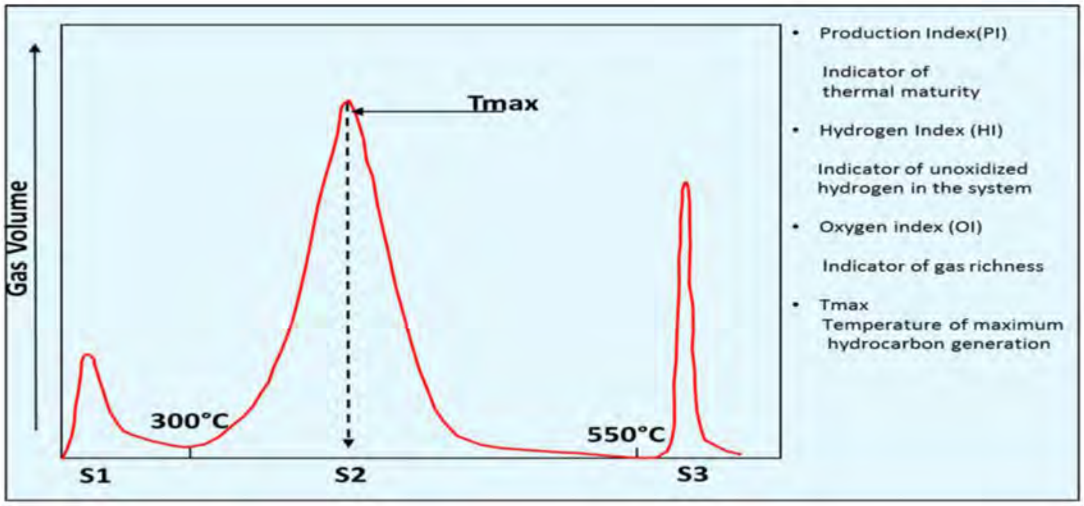


Figure 21—Thermochemical breakdown (Gas peaks versus temperature) of organic matter by heating in the absence of oxygen (Schlumberger, Oilfield Glossary).

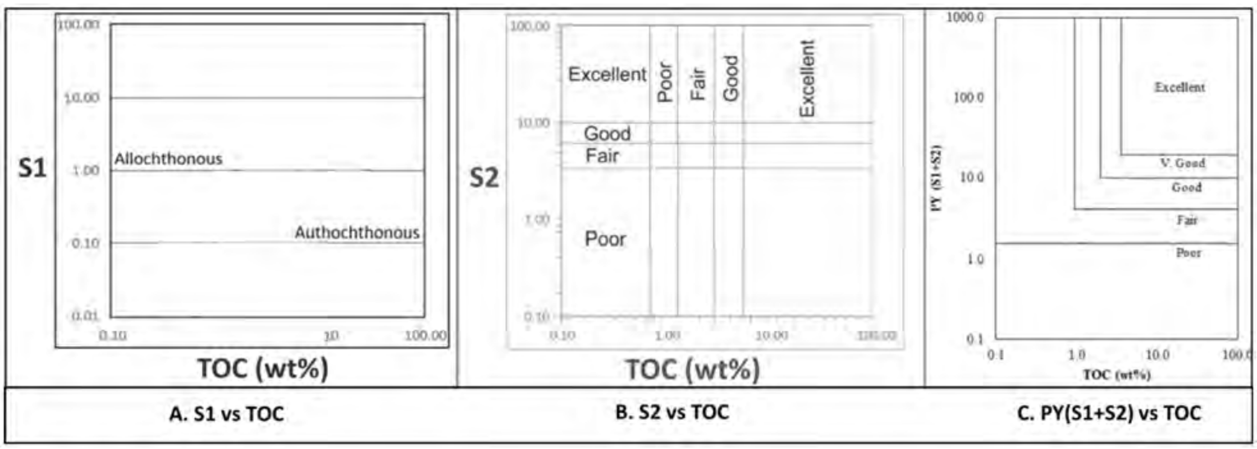


Figure 21A—Guideline for the assessment of source rocks potentiality, based on the TOC% and Rock–Eval pyrolysis data, such as S1 and S2 by Tissot and Welte, Peters and Cassa and Peters.

Following Table-4a shows the schematic results of the rock evaluation pyrolysis analysis.

Table-4a—Schematic results of the rock evaluation.

Well Name	Depth (ft)	TOC (%)	toc	S1	S2	S3	PY	PI	TMAX	HI	OI
							(S1+S2)	(S1/(S1+S2))		(S2/TOC)*100	S3/TOC*100
H	7420	3.3	3.3	0.17	9.46	0.61	9.63	0.02	430	287	18.48
H	7250	4.1	5.1	0.40	16.62	1.06	17.02	0.02	431	326	20.78
H	7260	5.8	5.8	0.60	16.96	0.95	17.56	0.03	425	292	16.38
H	7270	4.8	4.8	0.88	14.99	3.2	15.87	0.06	428	312	66.67
H	7280	4.1	4.5	1.04	8.84	4.1	9.88	0.11	422	196	91.11
H	7290	5.9	6	0.17	13.08	2	13.25	0.01	431	218	33.33

Table-4b is showing the guidelines for accessing organic matter of source rock.

Table-4b—Guidelines for accessing organic matter vs TOC of source rock.

Petroleum Potential	Organic Matter		
	TOC (wt. %)	Rock-Eval Pyrolysis	
		S1[a]	S2[b]
Poor	0.0 –0.5	0.0–0.5	0.0 – 2.5
Fair	0.5 – 1.0	0.5 – 1.0	2.5 – 5.0
Good	1.0 – 2.0	1.0 – 2.0	5.0– IO
Very Good	2.0 –4.0	2.0 – 4.0	10 – 20
Excellent	>4	>4	>20
Bitumin		Hydrocarbons	
(wt. %)	(ppm)	(ppm)	
0.0 – 0.05	0.0 – 500	0.0 – 300	
0.05 – 0.10	500 – 1OOO	300 – 600	
0.10 – 0.20	1OOO – 2000	600 – 1200	
0.20 – 0.40	2000 – 4000	1200 – 2400	
>0.40	>4000	>2400	
Peters and Cassa (1994)			

Figure-21 is showing the process used to determine the quality of shale as a source rock.
Table-5 is showing the guidelines for accessing Kerogen analysis via HI.

A. This relation shows that if the majority of the studied rock samples of the source rocks characterized by autochthonous hydrocarbons indicating that the oil produced in the source rock itself.
B. This relation may use to see the quality of SR samples.
C. This relation may use to identify the generation potential by processing the data from the geochemical pyrolysis of the source rock.

Table-5—Guidelines for Kerogen analysis and hydrogen index.

	Oil	Oil and Gas	Gas and Oil	Gas
HI Value	>600	400 – 600	200 – 400	<200
HI = S2 (mg/g) / %TOC Î 100				

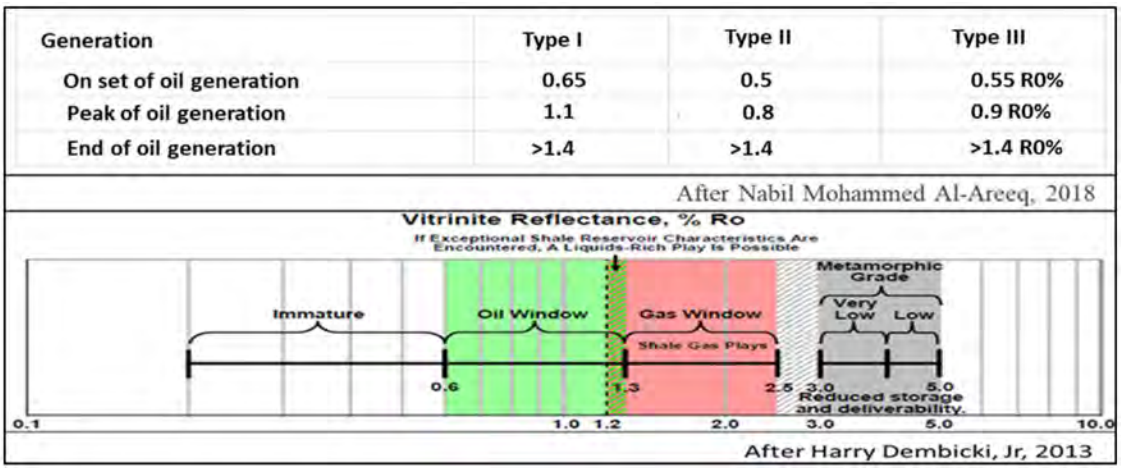
The sum of S1 and S2 determines pyrolysis Yield (PY) in source rock. According to Hunt (1996), source rock which has PY values 10 (very good) is the potential of its generation. (after A Millayanti et al 2019).

Organic Petrography

Organic Petrography analysis can be done on core slice or whole core or cutting samples to determine the maturity of the source rocks in terms of Vitrinite Reflectance Equivalent % (%VRE). This will help to tie-in maturity data derived from Tmax and refine the understanding of regional maturity of the source rock. Samples may select from the highest TOC content (more than 2% TOC) and at a regular interval to establish the most representative maturity profile per well to determine the following:

1. Visual examination (visual kerogen analysis) of macerals microscopically to determine the organic matter type. This can be use as further evidence to determine the oil and gas or gas only generating capability of the rocks following rock evaluation analysis.
2. Capture these results in the form of photomicrograph.
3. To establish a relationship between the distributions of oil prone macerals in the inorganic (calcite) matrix and the amount of hydrocarbons that can be expelled from a source rock (indication from TOC levels).
4. Estimate the reflectance of macerals to delineate the maturity of source rocks. This will be used in conjunction with maturity data obtained from rock evaluation to refine the SR maturity model in the basin modelling.

Figure-22 Showing the source rock maturity windows.



Generation	Type I	Type II	Type III
On set of oil generation	0.65	0.5	0.55 R0%
Peak of oil generation	1.1	0.8	0.9 R0%
End of oil generation	>1.4	>1.4	>1.4 R0%

After Nabil Mohammed Al-Areeq, 2018

Figure 22—Showing the Ro vs source rock maturity windows.

Figure-23 Guidelines for accessing organic matter.

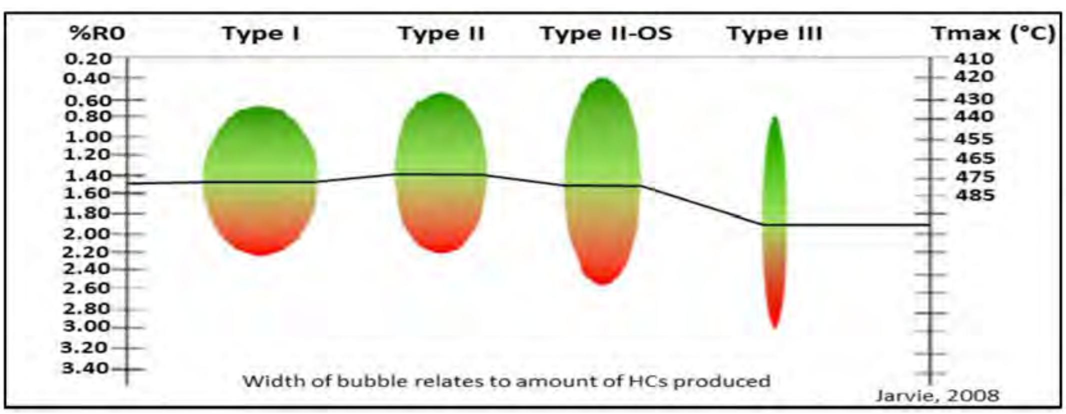


Figure 23—%Ro, kerogen type and Tmax relationship (Devon et al, 2009 & Jarvie, 2008)

Geochemical Analysis results

Organic richness/TOC

The two zones of source rock identified from the TOC analysis described as upper unit and lower unit. The lower unit is consistent in a large area and having TOC 1% to 6% (Fig. 24) and average TOC > 2% which is considered a good layer for unconventional play.

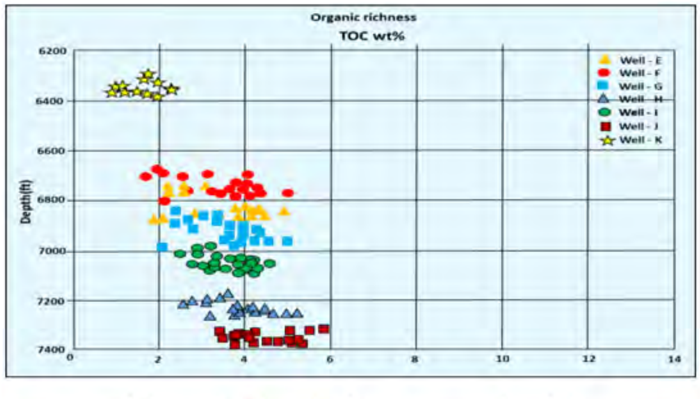


Figure 24—Schematic summary of the TOC levels for lower unit of the source rock.

Source rock quality/kerogen typing

A cross plot of HI vs %VRE (Fig. 25) is showing the source rock quality/kerogen typing. The source rock samples having values less than 0.6%VRE are immature.

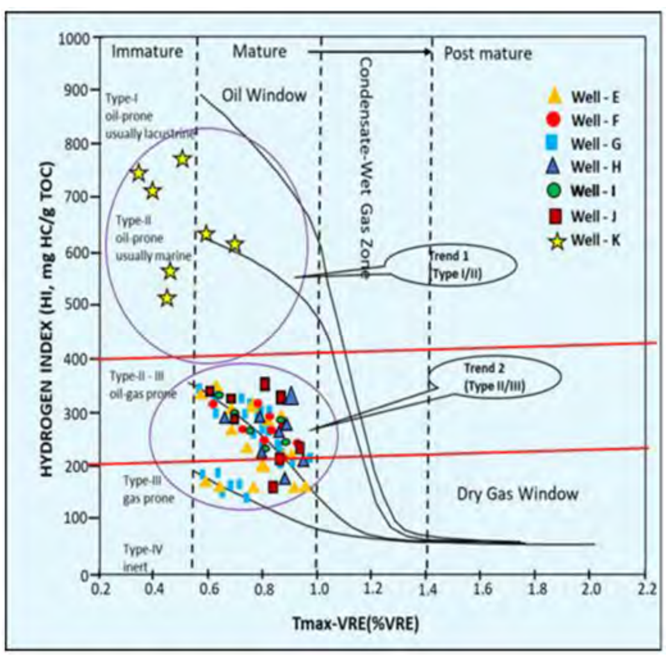


Figure 25—Schematic summary of the HI vs. Tmax-VRE plot of the source rock samples. The trend 1 indicates an oil-prone, Type I/II source rock and The trend 2 indicates an oil to gas-prone, Type II/III source rock.

A high HI is an indicator of a good oil-prone source rock. However, it is also important to correlate these high HI samples to TOC values as an organic-rich source rock coupled with sufficient maturity is required to generate hydrocarbons.

The plot in figure-26 illustrates a linear relationship between the hydrocarbon potential (S2) and organic richness (TOC) of source rocks. The gradients of the lines within the graph represent the hydrogen content of the source rock (HI). These varying trends can represent either a change in facies of the source rock or a reduction of hydrogen content due to the effects of maturation.

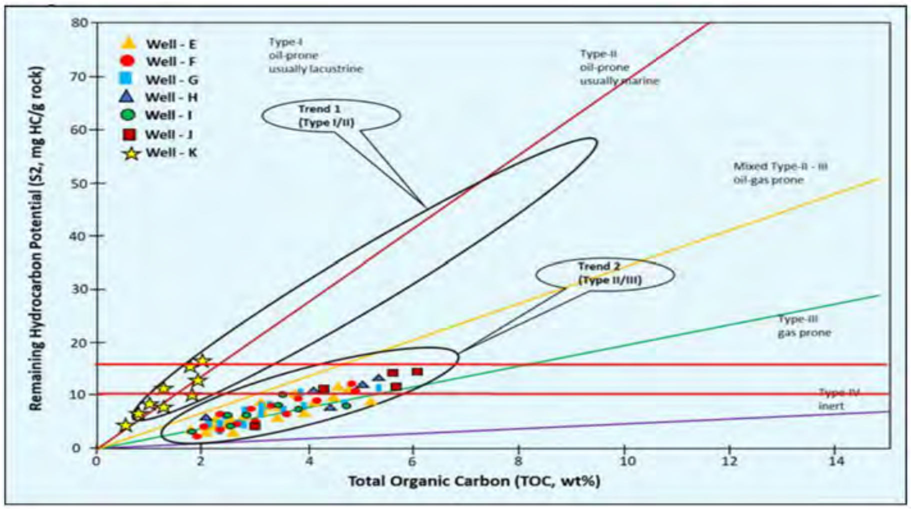


Figure 26—Schematic plot of the S2 vs. TOC. The average values of the SR Formation are between 2 − 6 wt% indicating fair to good source rocks.

Well K data in which the samples are immature as observed from figure-24–25 have a range of TOC 0.5 −2.2 wt% for the source formation which does not meet minimum commonly applied TOC threshold of >2% for an unconventional play to work. Generally, the average TOC for the source rock of area of interest is 2− 6% as observed in the wells. The TOC levels show a fair to good source rock, however it is important to calibrate the net thickness of the effective source rock for an unconventional play to work.

Source Rock Maturity (thermal maturity, VRE, VR0, R0)

Tmax data

Vitrinite Reflectance Equivalent (Tmax-VRE) values can be calculated from Tmax data calibration based on a Type II source rock. This can help to understand the maturity profiles of the source rock formation and also can use to correlate with the maturity of the source rock obtained through basin modelling. An additional maturity data Solid hydrocarbon reflectance (SHC-VRE) can measure during organic petrography analysis to crosscheck the VRE measurements. Fig. 27 is showing the average maturity data of the study area of the each well.

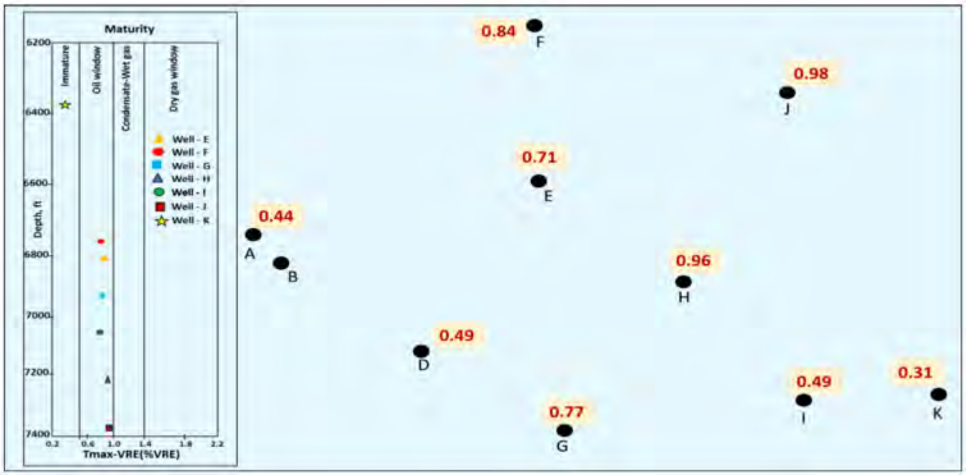


Figure 27—Schematic average maturity data in the wells.

Maturity Data Uncertainty

Oxygen index (OI) decreases as organic carbon content (TOC) increases (Katz, 1983). Figure-28 is showing the OI vs. TOC graph, well H cutting samples indicate high levels of OI exceeding 100. High OI levels can be a result of higher levels of oxygen in the source rock depositional environment or facies change, resulting in poorer preservation of organic matter. On the other hand, it could also be an indicator of sample contamination by mud additives.

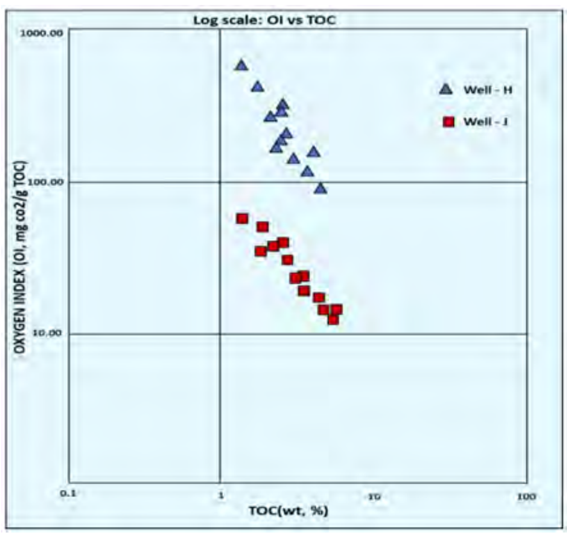


Figure 28—Schematic example of organic carbon content (TOC) on the oxygen index (OI) of source rock formation.

There is no evidence of a change in source rock depositional environment for the source rock based on algal SOM and pyrite being observed in organic petrography photomicrographs from all wells. This clearly indicates that the source rock formation was deposited under marine, anoxic conditions. In addition, cuttings samples from the H well have TOC levels of 2 – 5.6% and S2 of 4 – 9 indicating that the source rock potential is no poorer than the samples taken from J well, where both wells having the almost same level of thermal maturity.

Thermal Maturity Models

A 3D basin model covering the whole area of interest may construct. The stratigraphy may use from the drilled wells. Depth estimates for relevant horizons may base on the seismic interpretation. The reconstruction of the thermal histories in sedimentary basins may calibrate against maturity profiles such as vitrinite reflectance. The software having ability to define a crustal model that obeys the structural evaluation of the basin and may apply to define the heat flow evolution through time. The crustal model may use to define heat flow through time which reflects the tectonic evolution of the area. The computed results of the model may then compared to the available temperature and maturity data from wells.

Data Calibration

a. Temperature data from available wells (Fig. 1) may use to calibrate the present-day thermal regime in the study area.
b. The maturity information from (RockEval, Tmax, SHC) may use to QC the basin model results.

Source Rock maturity model from basin modelling

Estimated/modelled maturity for the source rock is shown in Figure-29. The maturity model shows a good agreement with the VRE data from Tmax as well as VRE from SHC from all wells. These maps may use for the play mapping and selection of possible exploration target areas.

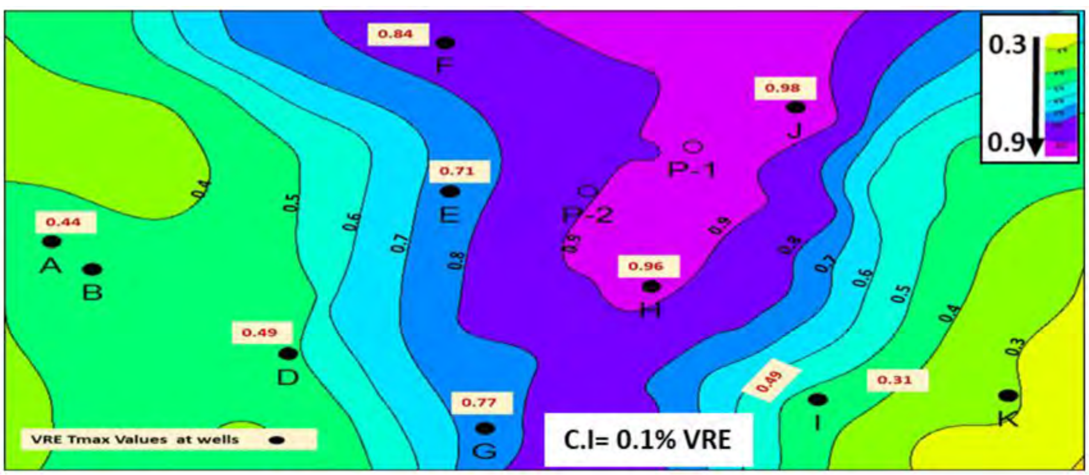


Figure 29—Schematic Modelled/calculated maturity map (from basin modelling) for the source rock formation. For model checks and consistency, modelled maturity may compare to VRE data from Tmax and SHC. Contour interval = 0.1 % VRE.

Hydrocarbon generative capacity and supercharge factor

A key element in assessing unconventional plays is to determine whether the source rock has generated enough hydrocarbons to saturate all the available pore space in the rock and the source rock is super charge. The workflow for the calculation of this supercharge factor is summarised below:

a. Take cumulative hydrocarbon generated by the source rock from the basin model Fogure-30.
b. Convert to HC column using an average in-situ density of 850 Kg/m3 (API gravity of about 35)
c. Convert to saturated rock column (in meter) using an effective porosity (from petrophysical evaluation)
d. Divide by net reservoir thickness to calculate a supercharge factor figure-31.

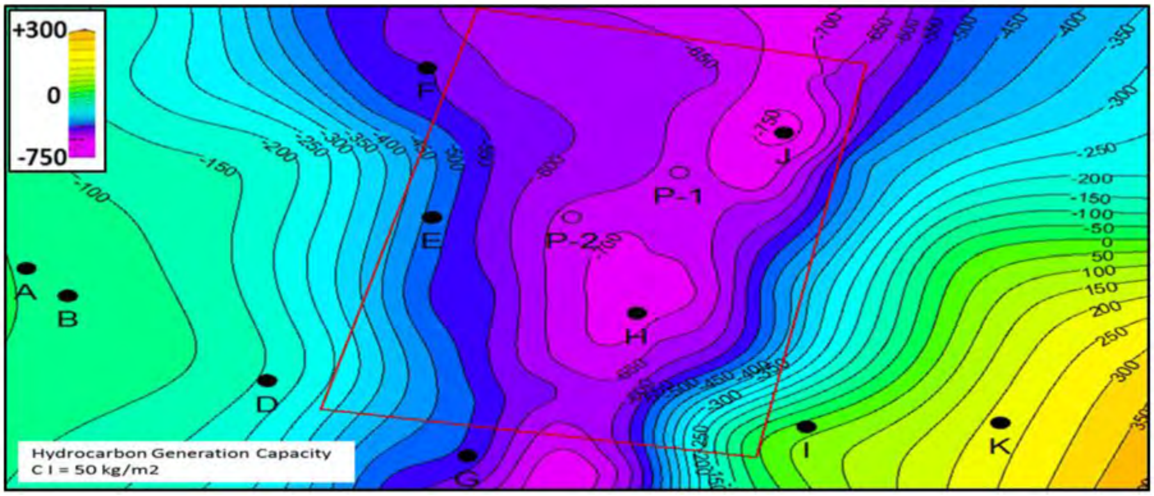


Figure 30—Schematic Modelled cumulative hydrocarbon generated by source rock.

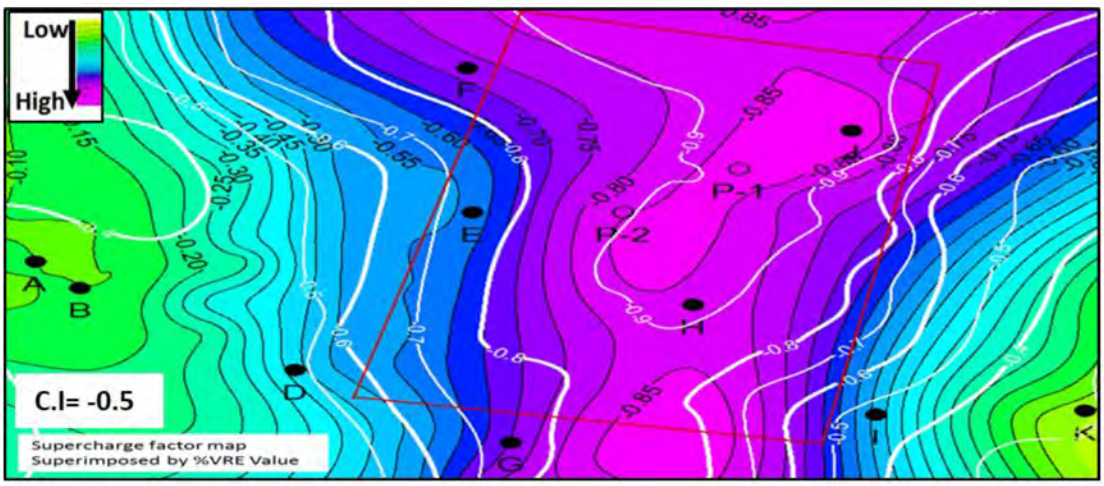


Figure 31—Schematic supercharge factor map translated from Modelled cumulative hydrocarbon generated by source rock Figure-30. Note also that current assumption is that all HC generated are expelled out of the Kerogen into the source rock matrix.

The net reservoir thickness may define by the petrophysical evaluation. Based on the assumptions for net source rock thickness, TOC and maturity, the supercharge factor is < 1 (between 0.85 and 0.98 in eastern part of area of interest) thereby indicating that enough hydrocarbons have been generated to fully saturate the source rock.

Identification of exploration focus area

Schematic evaluation of the exploration potential of source rock intervals in area of interest was undertaken. Table-6 is showing integrated analysis of key unconventional play criteria.

Table-6—Key elements for unconventional plays – Summary of evaluation of area of interest.

HC Shows	Avg TOC	Thickness	Maturity	Total Porosity	Mineralogy	Depth	Pressure Gradient
Proven SR, High mud gas readings measured in many wells	Lower unit: 4% Avg TOC (1 to 6% range), type 1 l/l 11 oil-gas prone	25m – 70m	Oil window: R0 = 0.65 − 0.98%	Avg 6 − 14 %, of the lower unit	Quartz 0.75, Clay 0.25, Mostly CaCo3(Carbonate origin shale)	1800 to 2800 m	0.70 psi/ ft (base case): over pressured

Key Findings

Figure-32, 33 shows the play map and play area sweet-spot map. VRE values associated with the SR formation range from 0.44 in the west and 0.98 in the east (basin centre area). The Oil generation from organically rich shale units is considered to commence at R0=0.65, with peak oil generation occurring at R0>0.9. The eastern area (centre of the basin) is the high-graded area with respect to depositional setting, maturity, hydrocarbon generation capacity, supercharge factor, depth and thickness. This high graded area is marked as a sweet-spot having an aerial extent of approximately 800sq.km.

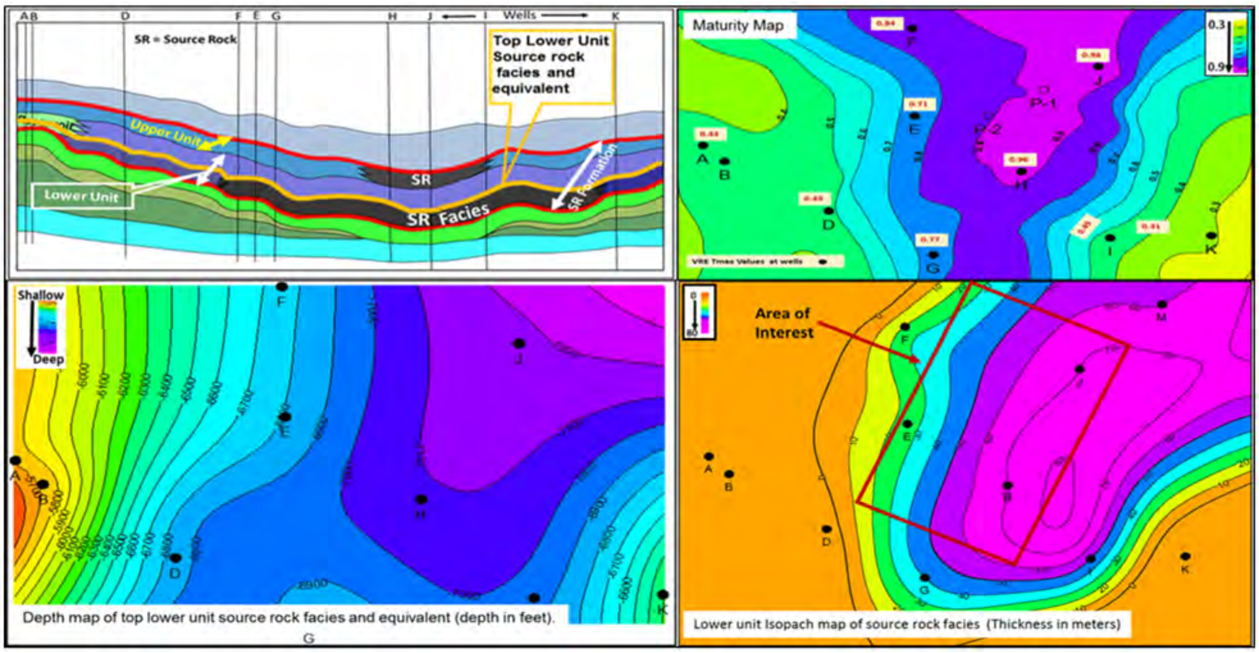


Figure 32—Schematic play map displaying regional cross section highlighted with top lower unit source rock facies and equivalent, depth map (feet), Maturity (%VRE) and Lower unit Isopack map.

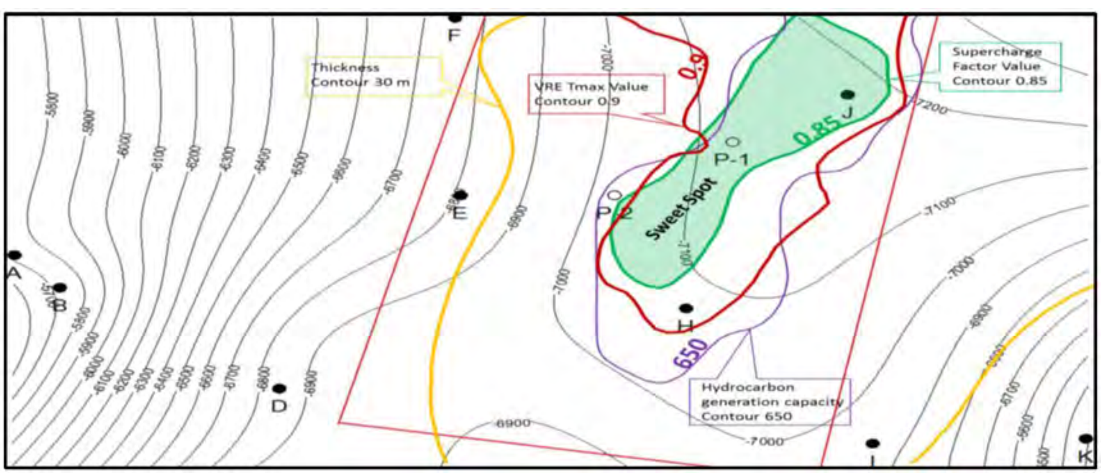


Figure 33—Schematic source rock play area sweet-spot map, based on Maturity model.

The work so far is done is on the basis of the regional data and on regional scale. To validate the identified play area sweet-spot in the area of interest (local scale, exploration block scale) two pilot vertical wells P-1 and P-2 may select to drill with the goal of acquiring extensive coring, open hole logging and formation pressure testing data to identify the best candidates for further horizontal well evaluation. P-1 well is in the sweet-spot and P-2 well is out side of the sweetspot figure- 33.

Conclusion

Based on the above suggested work flow screening of the basin can be done for shale play. The given maps, guide lines and cut offs can be used to calculate the key elements of the shale play.

As mentioned in the workflow, it is recommended to compare the calculated key elements with the proven shale play of the same type of the source rock (clastic orign or carbonate origin).

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