Risk and Play Chance Analysis in Shale Oil Resource Assessment: A Case Study of Jambusar-Broach Block, Cambay Basin

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ABSTRACT

Shale oil or gas is a natural oil / gas contained within shale sequences. It is trapped in reservoirs mainly composed of shale with lesser amount of other fine grained rocks. Shale oil/gas generation within shale depends on amount and type of organic material it contains and degree of maturation it is subjected to. Discovery of oil & gas in organic rich shale in a number of basins in North America has given impetus for exploration of shale oil/gas in Indian sedimentary basins. A number of Indian sedimentary basins also have thick shale sections deposited with organic rich sediments over vast areas which may be prospective for shale gas and oil.

At this initial stage of exploration it has become very much imperative to assess the shale oil/ gas resource potential of the basin / block. Analysis of the risk & play chance and estimation of risked resource volume is the most important factor. This risked resources gives an idea about the critical factors to be taken care of during exploration period.

In this study, an attempt has been made to identify the risk elements, estimate the play chance and assess the unrisked and risked shale oil resources Assessment unit (AU)-wise and Layer-wise.

INTRODUCTION

India initiated shale gas and oil exploration activities in the basins namely, Damodar, Cambay, Krishna-Godavari, Cauvery and Assam & Assam Arakan Basins. ONGC began its shale gas/ oil exploration programme with a pilot shale gas well drilling in Damodar Basin. Out of the four wells drilled, gas flow to the surface was observed in one well in the Raniganj area from Barren Measures Formation. So far, in Cambay Basin, 8 shale gas/ oil assessment wells (5 exclusive pilot wells; A, B, C, D, E and 3 dual objective wells; G, H & I) have been drilled in Broach Low of this block. In addition, drilling of one exclusive shale gas/oil well, J (drilled in Gandhar area in Tankari low) has recently been completed. Two pilot wells E and B, in south Cambay basin, yielded shale oil on hydrofracturing from Paleocene-Early Eocene Cambay Shale Formation. Well F, another conventional well drilled through Cambay Shale, also shows presence of Shale oil in this block.

Shale oil/gas plays are generally characterised by low geologic risk and high commercial risk. Uncertainty exists in geologic and engineering data, and consequently in the results of calculations made with these data. The shale, characterized by low matrix permeability, requires hydrofracturing for shale gas and oil production. However, one of the most uncertain aspects of shale gas exploration/ development is the ability to accurately forecast oil/gas resources and shale oil/gas development economics. Probabilistic approaches are required to provide an assessment of uncertainty in resource estimates.

CASE STUDY

Cambay Basin is one of the major hydrocarbon producing onshore basins in India. Cambay Shale Formation is the regional source rock for oil/gas accumulations in Cambay Basin. The present study is focused in the Jambusar-Broach block (Fig.1 & 2), one of the major depocentres of the Cambay

Basin. Five exclusive shale oil/gas wells have already been drilled in this block with shale oil/gas find in wells E and B and in one conventional well F. Three wells have been drilled here with dual objectives of Shale oil and conventional oil and gas (Fig.2). Moreover, there are number of other deep wells, which have penetrated through Cambay Shale in the block.

Assessment unit-wise and Layer-wise Shale oil/gas Resource assessment has been taken up in this study. Jambusar-Broach block has been chosen for the study as Well-E, the pilot well for Shale oil/gas has produced 25 cubic meter of oil on hydro-fracturing from two zones of older Cambay Shale. Total five exclusive Shale oil/gas wells have been drilled so far in this block. Another conventional well,Well-F, also yielded Shale oil from Cambay Shale in this block (Fig.2). The VRo data (0.5-1.12) suggests that the Paleocene-Eocene sediments in Broach Depression are in Oil Window (Waldo, GCA, 2015) and envisaged to be having Shale oil prospectivity. The success well E also suggests presence of Shale oil in this block. Following this fact, Resource assessment of Shale oil has been attempted in this block. After studying all the geoscientific data, a suitable methodology has been adopted and the Shale oil resources have been assessed Assessment unit (AU) wise and layer wise of Cambay Shale Formation.

SHALE OIL/GAS RESOURCE ASSESSMENT

Methodology

Adoption of methodology for Resource Assessment based on data availability in a basin/block is the most important part of Resource estimation. A number of Resource assessment methods, with probabilistic approach, are available viz., Analogy, Volumetric method, Material Balance, production decline curve analysis and reservoir simulation etc. (Dong et al., 2015). Depending on the data availability in Jambusar-Broach block, volumetric method of resource estimation has been adopted. The assessment has been carried out layer-wise and assessment unit wise. The process involves synthesis of geological, geochemical and reservoir data, assessment unit (prospective area) demarcation, identification of vertical layers within shale formations, risk assessment of various parameters and play chance estimation, unrisked and risked resource estimation.

Geologic and Reservoir Characterization of Shale Basins and Formation(s)

The resource assessment begins with the compilation of data from multiple sources to define the shale gas and shale oil basins and to select the major shale gas and shale oil formations to be assessed. The stratigraphic columns and well logs, showing the geologic age, the source rocks and other data, are used to select the major shale formations for further study. Preliminary geological and reservoir data are studied for each major shale basin and formation, including the following key items:

- Depositional environment of shale (marine vs non-marine)
- Depth (top and base of shale interval)
- Structure, including major faults
- Gross shale interval
- Organically-rich shale gross and net thicknesses
- Total organic content (TOC, by wt.)
- Thermal maturity (Ro)

These geologic and reservoir properties are used to examine a first order overview of the geologic characteristics of the major shale gas and shale oil formations and to help select the shale gas and shale oil basins and formations deemed worthy of intensive assessment.

Areal Extent of Major Shale Oil / Gas formations

Assessment unit demarcation

The area of Jambusar-Broach block has been divided into Nine Assessment units (AUs) on the basis of tectonic elements, depth of occurrence and thickness of Cambay Shale Formation, total organic content (TOC), source rock maturity or VRo values, mineralogical content/ brittleness etc. The tectonic

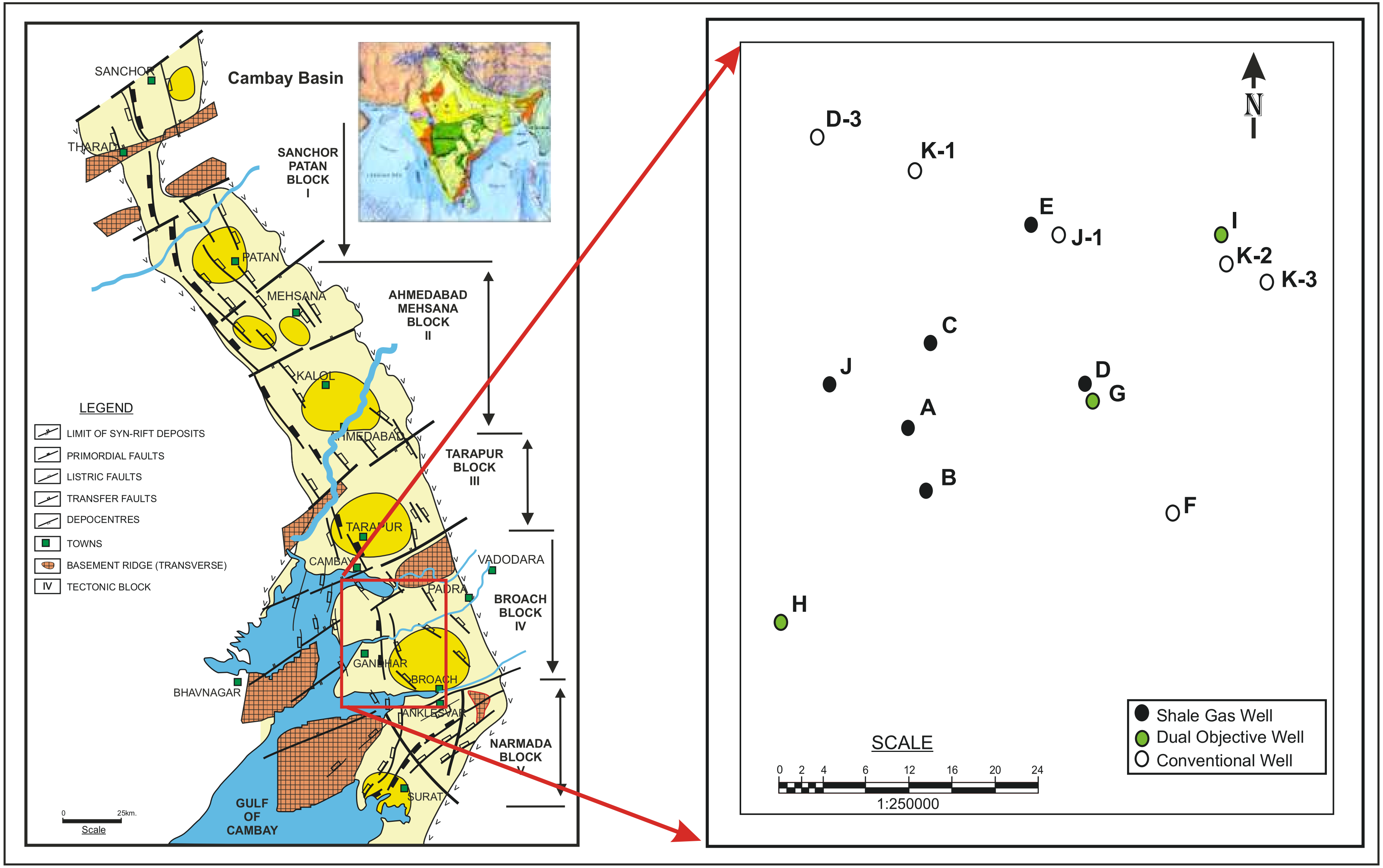

Fig. 1: Tectonic Map of Study area (Kundu et al., 1993)

Fig. 2: Well Loction Map of Study area

elements like fault, depth of occurrence of Cambay Shale Formation have been taken from structure contour map on top of Cambay Shale (Mondal et al., 2012) (Fig. 3), thickness of Cambay Shale Formation taken from Isopach map of Cambay Shale (Chandra et al., 2017) (Fig. 4). The demarcated nine Assessment units are also shown in Fig. 4.

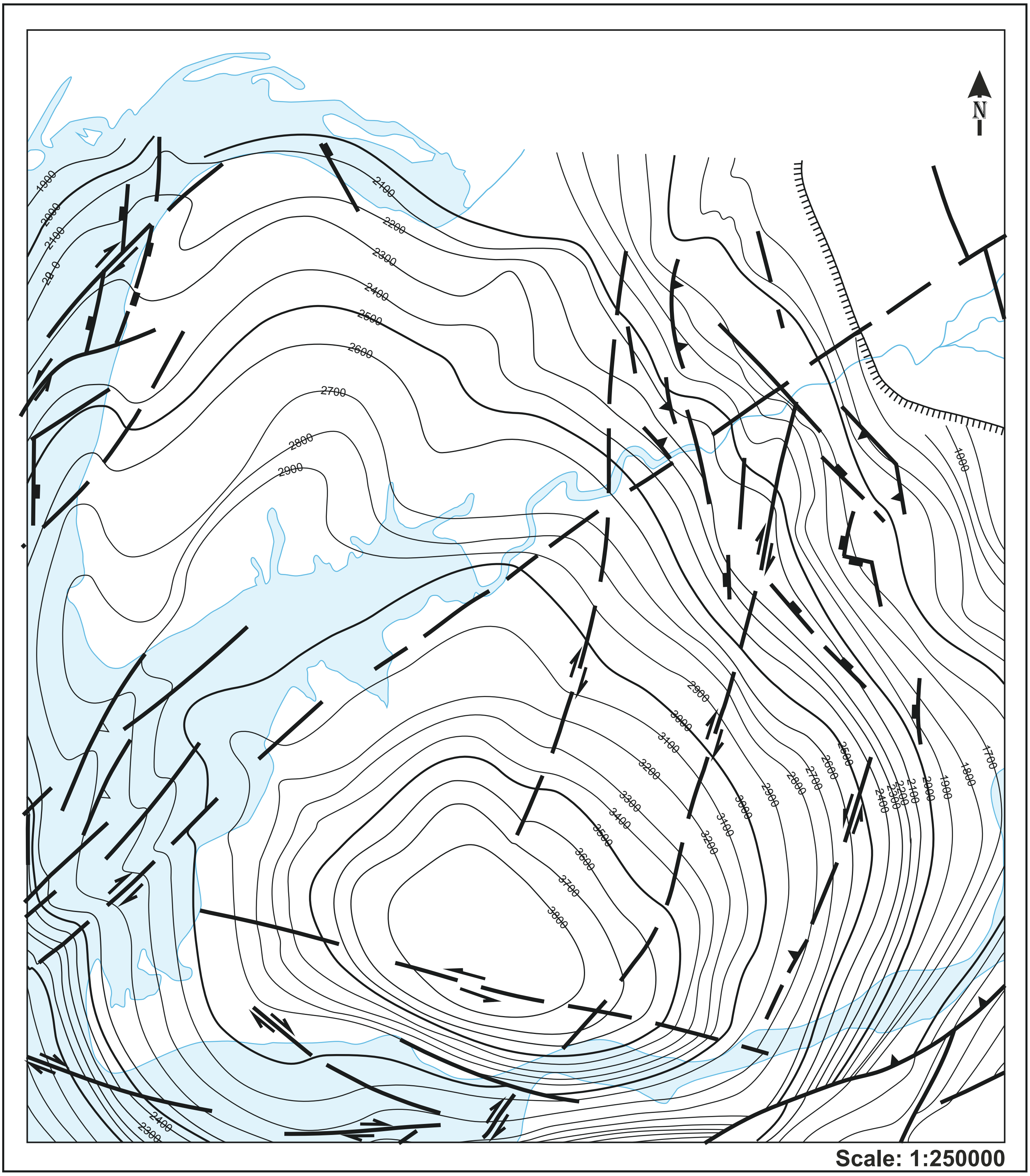

Fig. 3: Structure Contour Map on top Cambay shale (Mondal et al., 2012)

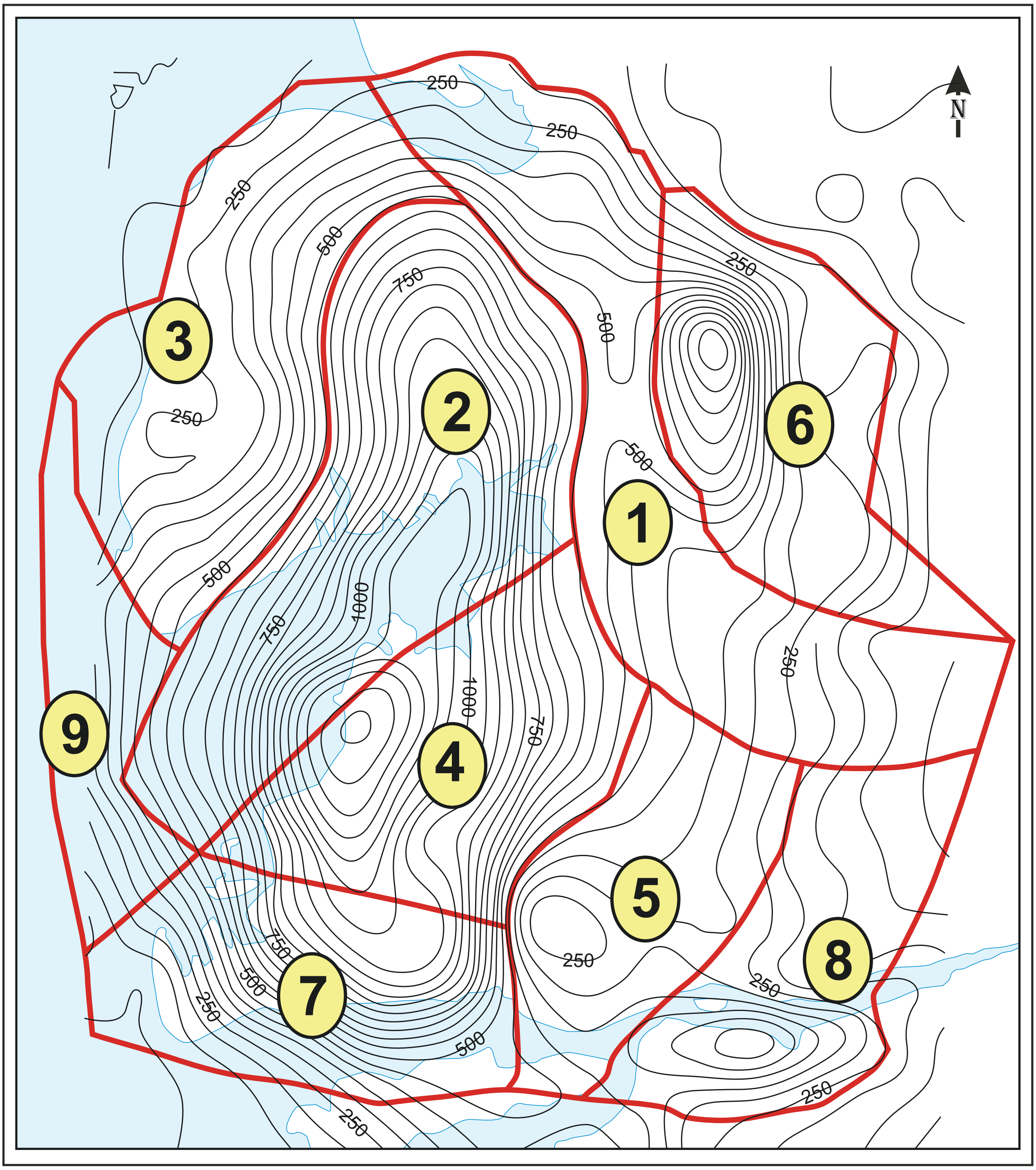

Fig. 4: Demarcated nine Assessment Units in Study area (Chandra et al., 2017)

The TOC, source maturity, VRo data is taken from geochemical studies of drilled wells of Cambay Shale section. The brittleness depends on mineralogical content like quartz, siderite and clay contents of the shale formation. The range of depth, thickness, geochemical properties and reservoir properties like porosity, brittleness etc., Assessment unit-wise and Layer-wise have been furnished in Fig. 5.

Prospective Area for Each Shale Oil/Gas Formation

The prospective area should have adequate thickness of shale formation/layer, TOC, VRo of source sediments and also have good porosity. The criteria used for establishing the prospective area include depositional environment, depth, total organic content (TOC), thermal maturity (VRo) etc.

Layers of Cambay Shale Formation

The Cambay Shale Formation in Jambusar–Broach Block is pervasive throughout the Block but thins out considerably towards the Eastern (K-2 & K-3 wells) & Western (D-3 well) margins of the Broach Depression. The central part of the low is expected to have more than 1300m thick Cambay Shale. Altogether 22 drilled well logs have been studied and Cambay shale have been correlated in this area (Fig. 6). Based on correlation, which was mainly focused on the third order TR cycles, Gamma (Gamma response has been stretched for better resolution and demarcation of TR cycles) & Resistivity response on logs, the Cambay Shale Formation has been divided into nine 3rd order sequence stratigraphic sections (Transgressive-Regressive cycles) (Padhy et al., 2013). With the help of these TR cycles the Cambay shale section has been divided broadly into four different depositional sequences or Layers (Fig. 6).

ESTIMATION OF THE UNRISKED AND RISKED SHALE OIL / GAS IN-PLACE (OIP/GIP)

Detailed geologic and reservoir data are assembled to establish the oil and gas in-place (OIP/GIP) for the prospective area.

The calculation of oil in-place for a given areal extent (sq.km) is governed, to a large extent, by some key characteristics of the shale formations; net organic-rich shale thickness and oil-filled porosity, saturation. In addition, pressure and temperature govern the volume of gas in solution with the reservoir oil, defined by the reservoir's formation volume factor.

OIP =A*h* φ*So*(1/FVF or 1/Boi)*Sp.gr

Net Organic-Rich Shale Thickness: The gross organically-rich thickness of the shale interval in an area is established from geochemical study of well cuttings and core samples drilled, well log data and cross-sections, wherever available. A net to gross ratio is used to account for the organic-barren rock within the gross organic-rich shale interval and to estimate the net organically-rich thickness of the shale. In the geochemical log of well E (Fig. 7) of this block, it is observed that 10 to 15% of the total Cambay Shale thickness show higher TOC (2.5% to 3.5%) with HI more than 150. So, for the present study a mere 10% of the total shale thickness has been considered as organically rich thickness or effective thickness for the whole area.

Oil and Gas filled porosity: The porosity data from

Fig. 5: Cambay Shale Layer-1 Geoscientific parameters (AU-wise)

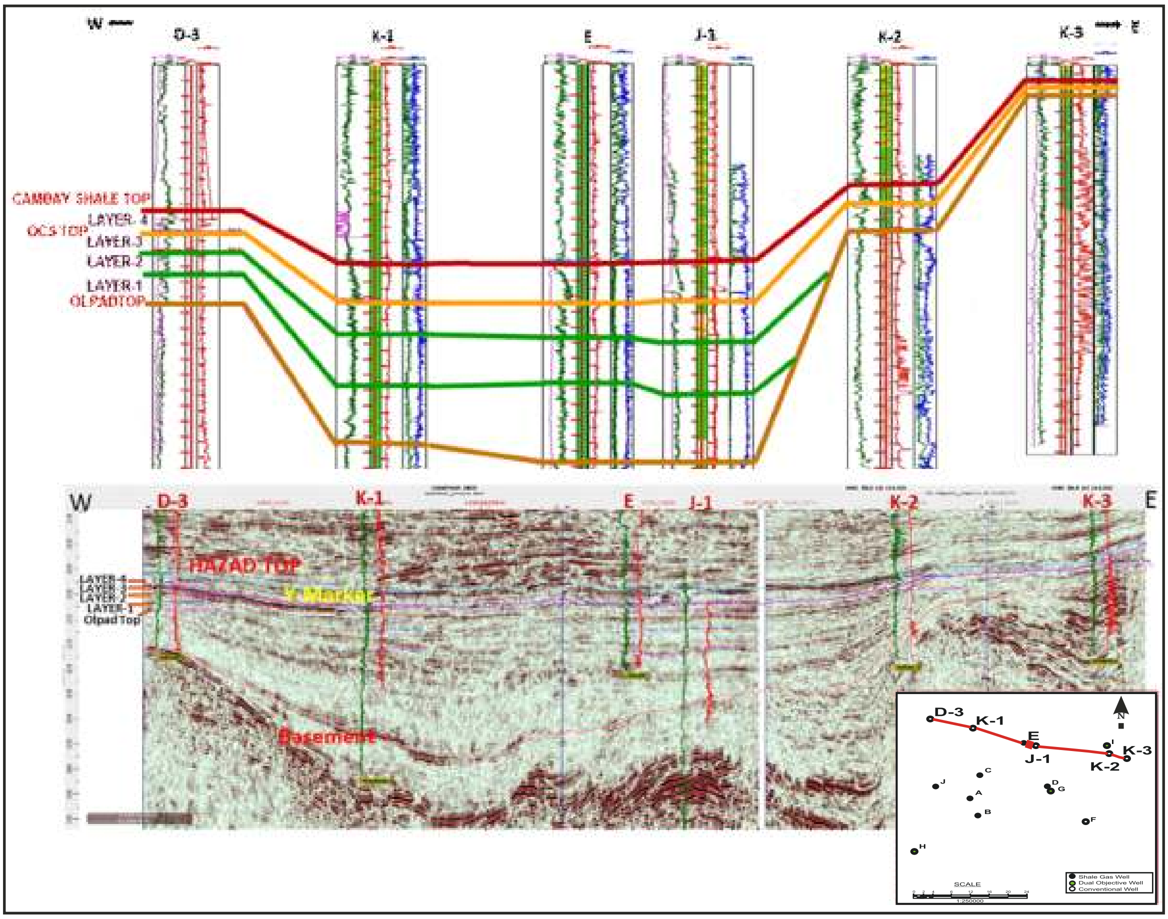

Fig. 6: Electrolog Correlation & RC Line along wells D-3, K-1, E, J-1, K-2 & K-3

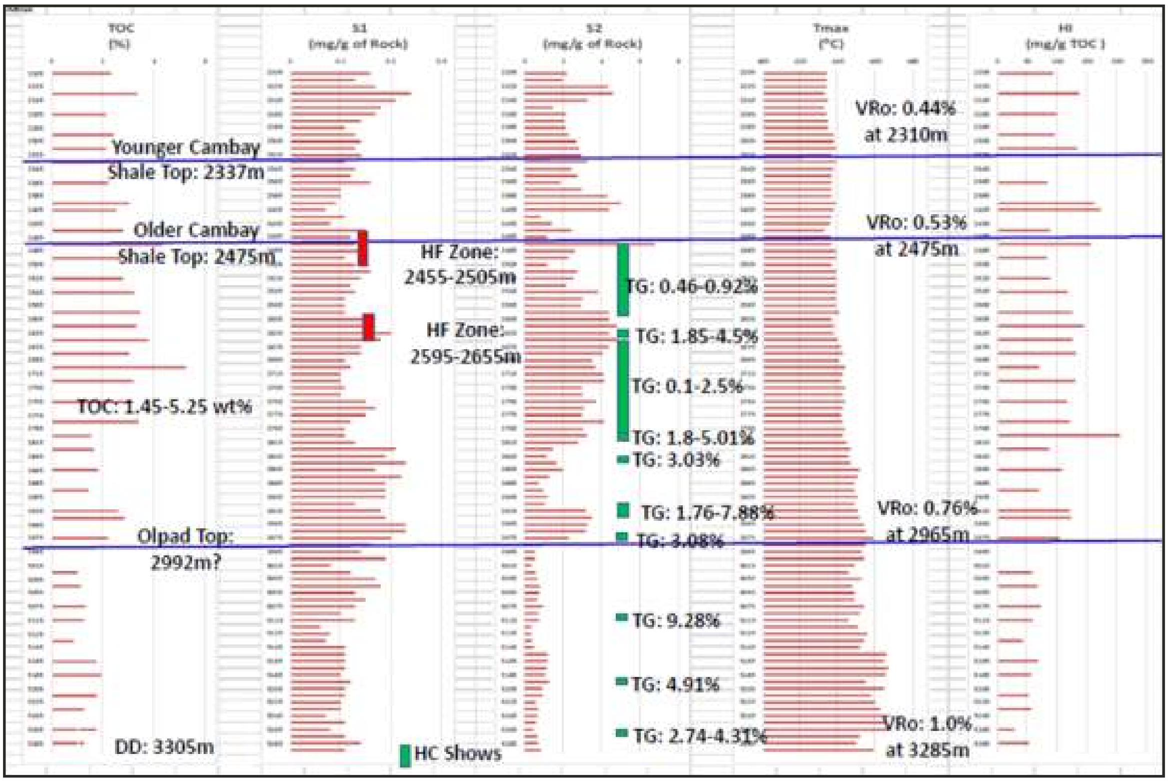

Fig. 7: Geochemical log of Cambay shale section of well WELL-E (Chandra et al., 2017)

core and/or log analyses available in various reports has been compiled. The study assumes the pores are filled with oil, including solution gas, free gas and residual water.

Saturation of oil (So): It is the fraction of the porosity filled by oil (So) instead of water (Sw) or gas (Sg), a dimensionless fraction (the established value for porosity (φ) is multiplied by the term (So) to establish oil-filled porosity; the value Sw defines the fraction of the pore space that is filled with water, often the residual or irreducible reservoir water saturation in the natural fracture and matrix porosity of the shale; shales may also contain free gas (Sg) in the pore space and it further reduces oil-filled porosity.

Formation Volume Factor (FVF): A factor that models oil shrinkage (Boi) or gas expansion (Bg) between the reservoir and the surface. In other words, Boi is the oil formation gas volume factor that is used to adjust the oil volume in the reservoirs, typically swollen with gas in solution, to oil volume in stock tank barrels.

Unrisked and Risked Shale Oil and Gas Resources

The probability (minimum, most likely and maximum) values of parameters considered for simulation of unrisked resources, Layer-wise and AU wise are tabulated. The simulation data for AU-1 and AU-2 of Layer-1 is furnished in the following table-1:

Unrisked Shale Oil volume: All the P90, P10 and mean values of simulated resources of AU -1 & 2 of Layer-1 are given in Table-1. The respective simulation figures are placed in Fig. 8.

Risked Shale Oil Volume: The mean risked Shale

Table 1 : Assessment Unit Wise Resource Simulation Data for Layer -1

AU-1	**Area (SKM)**	**Thickness (M)**	**Porosity (%)**	**Saturation (%)**	**Sp.Gr.**	**1/FVF**	**Shale Oil Resources MMtOE**	**Simulated Resources**
Minimum	250	7.00	0.14	0.18	0.84	0.55		43.166 (P90)
Likeliest	300	10.00	0.16	0.20	0.88	0.70	59.136	53.385 (Mean)
Maximum	350	11.00	0.18	0.22	0.90	0.80		64.032 (P10)
AU-2								
Minimum	400	6.00	0.14	0.16	0.85	0.55		48.013 (P90)
Likeliest	450	8.00	0.15	0.18	0.88	0.70	59.8752	59.628 (Mean)
Maximum	500	10.00	0.17	0.20	0.90	0.85		71.770 (P10)

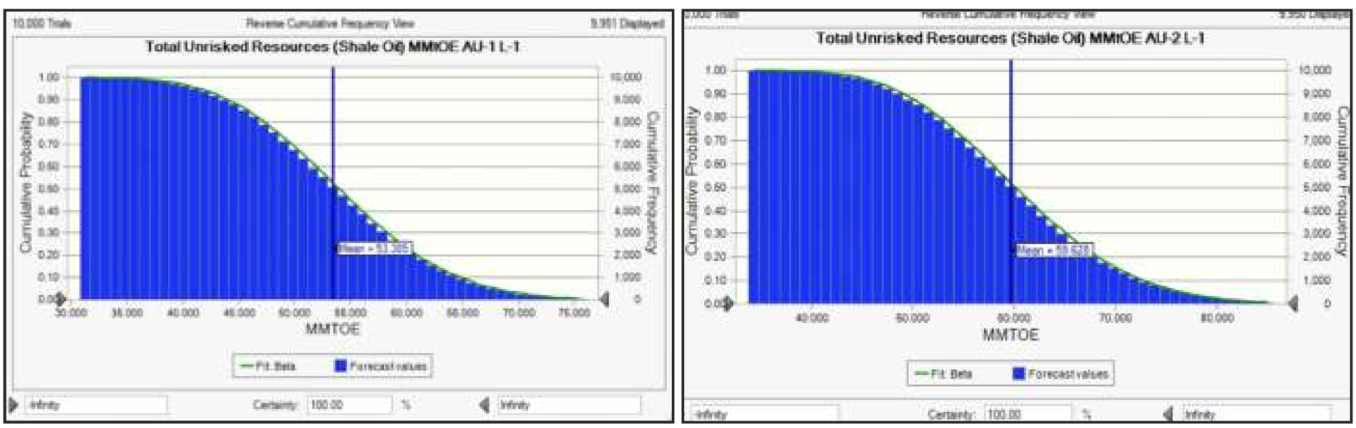

Fig. 8: Unrisked Shale Oil/Gas Resources Simulation Figures of AU-1 and AU-2 of Layer-1

oil resources are worked out by multiplying unrisked resources with their respective Play chances. The risk factor and play chance estimation Assessment unit and Layer wise are discussed below.

ESTIMATION OF PLAY CHANCE

The chance that all petroleum system elements (trap, seal, reservoir, source, and migration) necessary for hydrocarbon accumulation are favourable within an Assessment unit. Play elements are major geological factors that must be evaluated to determine if a play will be successful and if successful, where within the play area it will be successful. In this case three major elements viz., Geological, Geochemical and Geomechanical elements are considered. Each of the elements have few risk/chance factors. Considering all the risk/chance factors, Play chances of all AUs Layer-wise are estimated.

The Play chances AU wise and layerwise are multiplied with the corresponding unrisked volumes to give the risked volumes of shale oil/gas for the Assessment units of various layers.

Geological, Geochemical and Geo-mechanical Risk factors and Play Chance

Play Chance is the probability that all petroleum system elements (trap, seal, reservoir, source, and migration) necessary for hydrocarbon accumulation are favourable within an Assessment unit. The required petroleum system elements are known as “risk factors.”

A wide variety of schemes for defining risk/chance factors are used for risk analysis. For shale oil / gas resource estimation, the risk factors have been classified into three major categories, viz., Geological, Geochemical and Geomechanical factors.

Each risk factor has been evaluated individually, and assigned a chance of success. The risk factor's chance of success is the probability that the element is favourable somewhere within the Assessment unit. So these risk factors are the chance factors also. 'Favourable' means that the geologic element has the minimum characteristics (area, net thickness, porosity, maturity, saturation etc.) needed to support a discovery somewhere within the Assessment unit.

The risk/chance factors have been assigned after taking analogy from the producing basins of the world as best case, moderate case and low case. Best case has been assigned value of 0.7-1.0, moderate case has been assigned value from 0.4 – 0.7 and the low case has been assigned values from 0.1- 0.4. Each risk/chancefactors and their values are shown in Table-2.

The average of all Geological risk/chance factors, Geochemical risk/chance factors and Geomechanical risk/ chance factors are considered as geological, geochemical and geomechanical risks respectively. Finally the product of these three risk factors have been considered as the Play Chances of corresponding Assessment units Layer-wise (Table-2).

Geological risk/chance factor

The geological factors include, Age of the formation, Thickness of the formation, Environment of deposition and Resource concentration (in vertical column) in the formation.

Age of the Formation: According to H.D. Klemme and G.F. Ulmishek, AAPG, 1991, six stratigraphic intervals, representing one-third of Phanerozoic time, contain petroleum source rocks that have provided more than 90% of the world's discovered original reserves of oil and gas (in barrels of oil equivalent). The six intervals are (1) Silurian (generated 9% of the world's reserves), (2) Upper Devonian-Turonian (8% of reserves), (3) Pennsylvanian-Lower Permian (8% of reserves), (4) Upper Jurassic (25% of reserves), (5) middle Cretaceous (29% of reserves), and (6) Oligocene-Miocene (12.5% of reserves). So for risk factor (Chance of success) of age of deposition, Mesozoic is considered as the best case, Paleozoic is considered as the moderate case and Cenozoic is the low case.

Thickness of the Formation: For gross Shale thickness more than 100m is considered as the best case and in case of Cambay Shale the total thickness is mostly more than 100m (Best case).

Vertical resource concentration: For vertical resource concentration 50m resource concentration in every 100m column is the best case 20-50m concentration in every 100m column is the moderate case and 10 – 20m resource concentration in each 100 m column is the low case. In the present case it is always low case and so 10% of the total thickness is considered as effective thickness having matured source rock.

Depositional environment: Black shales are mixtures of terrigenous, biogenous and hydrogenous sediments in which organic matter constitutes at least 0.5% of the material. The composition, texture, structure and fossil content of a shale depend on depositional environment, i.e., on a complex interplay of physical, chemical and biological variable and processes. Pattern of vertical and lateral variability are the expressions of dynamic nature of processes and preserve a record of evolving depositional environment in which they formed. Shales are deposited in a wide range of sedimentary environment, however, most ancient black shales appear to have been deposited in shallow marine epicontinental environment.

Organic matter rich rocks deposited in continental environment account for more than 20% of the worldwide current hydrocarbon production (Bohacs et al., 2000; Pottar et al., 2005).

Shale of Fluvial or floodplain deposits holds mainly type III kerogen with average TOC of 2%. HI is about 150 on an average and the thickness ranges from 10-70m. The shale of lake deposits hold mainly Type I and sometimes Type III kerogen with TOC varying from 1.5 to 15. The shale deposits in shelfal environment hold Type I and Type II kerogen mainly with TOC ranging from 1.1 to 20%. In this case the value of average HI value is 530 (Bohacs et al., 2000; Pottar et al., 2005). The shelfal shales are most widespread in nature and the thickness of shale deposit vary from 3-40m. Marine environment of deposition of shale is considered as the best case and mixed and fluvial environment of deposition is considered as the moderate case. In present case the environment of deposition is mixed and sometimes fluvial. The average of all the parameters of geological chance is considered as Geological chance factor and is given in Table-2.

Geochemical risk/chance factors

The geochemical factors include, Kerogen type, TOC, VRo, HI etc. Source rock with Type-II kerogen is considered as the best for Shale Oil and gas case and with Type-III kerogen is considered good for Shale gas case. In the present case, mix of Type II and Type III is considered as the moderate case. Source having TOC more than 5-10 and > 10 are the best case, 3-5 is the moderate case and < 3 is the low case. VR0 >1 is considered as the best case, 0.6 to 1 is considered as the moderate case and 0.5-0.6 is the low case. In the present case it is mainly in the moderate to low case range. HI 300-500 is considered as best case, 100 to 300 is the moderate case and < 100 is the low case. In the present study it is a low case.The average of all the parameters of geochemical chance is considered as Geochemical chance factor (Table-2).

Geomechanical risk/chance factors

The Geomechanical factors include Depth, Poisson's ratio, Clay content, Porosity, Hydrocarbon Saturation etc.

Depth of occurrence range between 1000m and 1500m is considered as the best case, between 1500m and 3000m is moderate case and > 3000m is a low case. Depth in the present case between 2500m and 3000m is taken as moderate to low case and risk factor 0.3 – 0.5 has been considered. Porosity value 5-10 percent is considered as the moderate to best case and in the present case porosity less than 5% is taken as low case.

Mineralogy, viz., Clay content more than 60% is the low case and higher quartz and siderite content is considered as moderate to best case. Shale with high silica (quartz) and low clay content may have high Young's modulus and low Poisson's ratio making them more brittle, more prone to natural fractures and good candidate for fracture stimulation. In WELL-E the Poisson's ratio is measured as less than 0.3 and thus has a good brittleness. In the present case it is mostly moderate case and risk value of around 0.5 has been taken for risk assessment. The average of all the parameters of geomechanical chance is considered as Geomechanical chance factor and is furnished in Table-2.

The product of the geological, geochemical and geomechanical chance factors give the Play chance of particular AU layer wise.

Table 2: Assessment unit wise Play Chance calculation of Layer-1

Geochemical Parameters (Risk/ Chance of success)	**AU-1**	**AU-2**	**AU-3**	**AU-4**	**AU-5**	**AU-6**	**AU-7**	**AU-8**	**AU-9**
Kerogen Type	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
TOC	0.3	0.25	0.3	0.3	0.2	0.2	0.25	0.2	0.2
VRo	0.4	0.4	0.3	0.4	0.3	0.2	0.2	0.2	0.2
HI	0.3	0.25	0.3	0.25	0.2	0.2	0.2	0.2	0.2
Chance Factor	**0.375**	**0.35**	**0.35**	**0.363**	**0.3**	**0.275**	**0.2875**	**0.275**	**0.275**

Geochemical Parameters (Risk/ Chance of success)	**AU-1**	**AU-2**	**AU-3**	**AU-4**	**AU-5**	**AU-6**	**AU-7**	**AU-8**	**AU-9**
Depth	0.3	0.25	0.4	0.25	0.5	0.5	0.5	0.5	0.5
Poission's Ratio	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Clay Content	0.6	0.43	0.4	0.4	0.4	0.5	0.5	0.6	0.6
Porosity	0.85	0.85	0.8	0.82	0.8	0.85	0.8	0.85	0.8
Hydrocarbon Saturation	0.3	0.25	0.3	0.25	0.2	0.2	0.2	0.2	0.2
Chance Factor	**0.53**	**0.456**	**0.5**	**0.455**	**0.5**	**0.51**	**0.5**	**0.513**	**0.52**

Geochemical Parameters (Risk/ Chance of success)	**AU-1**	**AU-2**	**AU-3**	**AU-4**	**AU-5**	**AU-6**	**AU-7**	**AU-8**	**AU-9**
Age	0.3	0.3	0.3	0.3	0.3	0.3	0.28	0.28	0.28
Thickness	0.8	0.8	0.7	0.9	0.7	0.75	0.5	0.5	0.5
Resource conc. vertical	0.3	0.25	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Env of deposition	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Chance Factor	**0.475**	**0.4625**	**0.45**	**0.475**	**0.425**	**0.438**	**0.37**	**0.37**	**0.37**

Play Chance Layer-1	**0.0944**	**0.0738**	**0.08**	**0.078**	**0.064**	**0.061**	**0.05319**	**0.052**	**0.053**

Table 3: Layer-wise and AU wise simulated unrisked and risked resources

		AU-1	AU-2	AU-3	AU-4	AU-5	AU-6	AU-7	AU-8	AU-9	Total
Layer-1	P90	43.166	48.013	9.981	13.930	2.939	23.268	3.757	0.873	0.878	146.804
(Unrisked)	**Mean**	53.385	59.628	13.420	19.276	4.880	30.511	5.843	1.281	1.205	189.428
	P10	64.032	71.770	17.262	25.066	7.047	37.969	7.963	1.717	1.564	234.391
PlayChance		0.0829	0.0736	0.0707	0.0678	0.0512	0.0528	0.0471	0.0439	0.0397	
Layer-1	P90	3.577	3.535	0.705	0.944	0.150	1.229	0.177	0.038	0.035	10.391
(Risked)	**Mean**	4.424	4.390	0.948	1.307	0.250	1.611	0.275	0.056	0.048	13.310
	P10	5.307	5.285	1.220	1.699	0.361	2.005	0.375	0.075	0.062	16.388

Table 4: Assessment unit wise UnriskedShale oil/gas Resource Density Calculation of AU-1 & AU-2 Layer-1

	Simulated Resources	Most Likely Area (SKM)	Resource Density (t/SKM)	Resource Density ('000 t/SKM)	Resource Density Range ('000t/ SKM)	Play Chance	Risked Resource Density ('000 t/SKM)	Risked Resource Density Ranges ('000 t/SKM)
AU-1 L-1								
Minimum	43.166	300	0.1439	143.8867			11.9246	
Likeliest	53.385	300	0.1780	177.9504	150-200	0.082875	14.7476	15-18
Maximum	64.032	300	0.2134	213.4397			17.6888	
AU-2 L-1								
Minimum	48.013	450	0.1067	106.6945			7.8560	
Likeliest	59.628	450	0.1325	132.5067	100-150	0.073631	9.7566	9-12
Maximum	71.770	450	0.1595	159.4894			11.7434	

Table 5: Unrisked Shale Oil/Gas Resource Density ('000t/skm) ranges AU-wise and Layer-wise

	AU-1	AU-2	AU-3	AU-4	AU-5	AU-6	AU-7	AU-8	AU-9
Layer-1	150-200	100-150	100-150	100-150	50-100	100-150	50-100	50-100	0-50

Table 6: Risked Shale Oil/Gas Resource Density ('000t/skm) ranges AU-wise and Layer-wise

	AU-1	AU-2	AU-3	AU-4	AU-5	AU-6	AU-7	AU-8	AU-9
Layer-1	15-18	9-12	6-9	9-12	3-6	6-9	3-6	0-3	0-3

Risk Assessment and Play Chance

The various risk factors considered for various Geological, Geochemical and Geo-mechanical parameters for Layer-1, Assessment unit wise in the present case are estimated and given in Table-2 below:

Once the Play Chance is estimated, the unrisked layer wise and AU wise Resources are multiplied with their respective play chances to get their corresponding risked resources.The AU wise simulated unrisked and risked resources of Layer-1 are shown in Table-3.

Layer-wise Unrisked and Risked Shale Oil/Gas Resource Density Maps

After simulation of unrisked hydrocarbon resources, a range of values viz., maximum (P10) and minimum (P90) are arrived at Assessment unit-wise and layer-wise. By aggregating the resources of all the layers Assessment unit-wise, a range of values are fixed according to the resource figures. Considering the most likely area of the AU, the Resource density ('000 tons/ SKM) is calculated for each AU in all layers. Table-4 shows resource density calculation of AU-1 and AU-2 of Layer-1. A colour scheme is chosen to depict ranges of resource

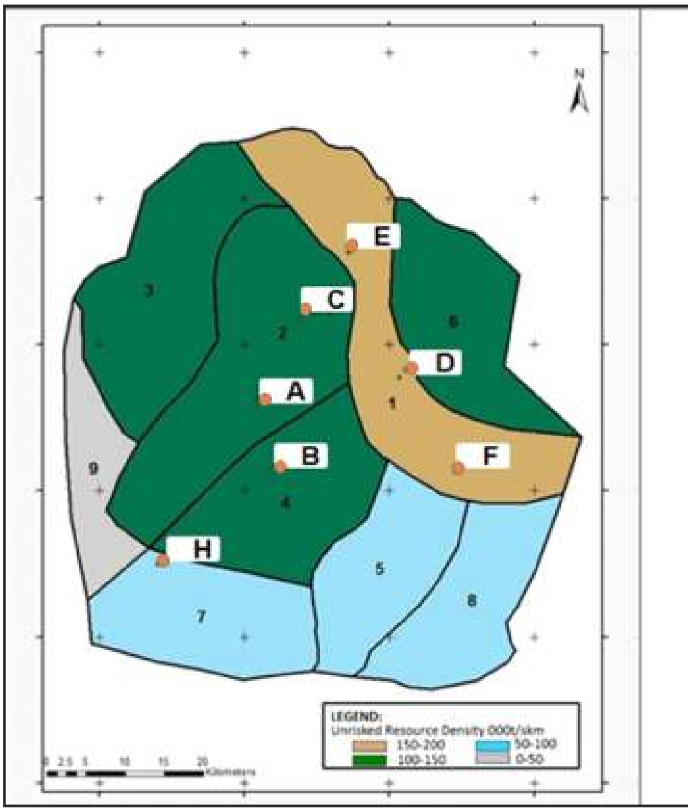

Fig. 9: Unrisked Shale oil Resource Densiry Map of Layer-1 (AU-wise)

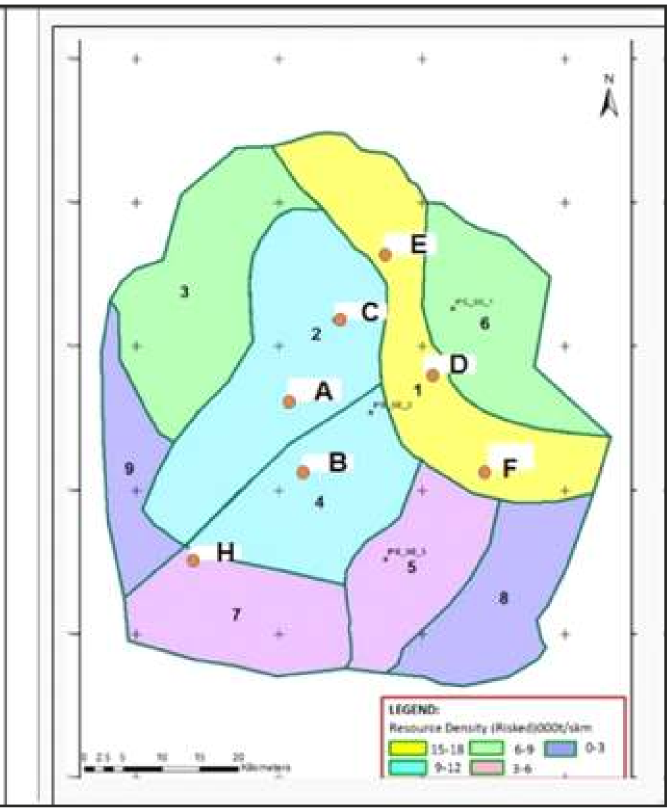

Fig. 10: Risked Shale oil Resource Densiry Map of Layer-1 (AU-wise)

densities in the AU map of all the layers. After aggregating the P10 (maximum) and P90 (minimum) values (Table-4, 5 & 6) of all the layers in each AU, a composite Resource density map for total Cambay Shale sequence of the block AU-wise is prepared. The unrisked and risked Shale Oil Resource Density Maps of Layer 1 (AU wise) are shown in Fig. 9 and Fig. 10.

CONCLUSIONS

Resource Assessment of Shale oil/gas in any basin needs to be done for unrisked and risked resource volume. The risked volume indicates the play chance in the block or basin. The detailed risk matrix also indicates the main challenges in the discovery process. Especially in India, the risk involved in the shale oil/gas project are manifold. Geochemically the shales are mostly mature and rich in organic matter.The challenges are mainly geological and geomechanical. These are:

- Deeper occurrences of the shale bed
- Thickness of the organic matter rich source rock
- Environment of deposition
- Brittleness of the formation

Identification of the risk factors vis-à-vis estimation of play chance arethe foremost job in evaluation of shale/oil gas potential of any area. In the present case although the assessed unrisked volume is considerable but the play chance is only around 10%. However, with the progress of exploration, with the generation of more and more exploratory data and geo-scientific knowledge of the basin and moreover with the induction of new technology, the uncertainty is lessened and play chance is automatically improved.

The Resource density maps depict the areas with high prospectivity of the individual layers as well as for the total formation thickness of Cambay Shale (including all the layers), Assessment unit-wise.

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