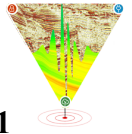


**Unveiling India's Pioneering Journey into Unconventional Well Exploration: V&V-UC-1**

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**Keywords**

Pure Shale play, Hybrid Interbedded play, Organic richness, Thermal maturity

Abstract

The Lower Barmer Hill (LBH) source rocks deposited in the syn-rift grabens within Barmer Basin, western India has substantial unconventional shale potential. The organic-rich shales deposited during a major transgressive event in a deep lacustrine setting during Eocene times. Unlike North American Shale plays deposited in passive margin and/or intercontinental marine setup, Barmer Basin source rock is deposited in the syn-rift grabens and each graben behave as a separate sub-basin, with different lithofacies and heat flow history. Potential target areas have been assessed on a play-based approach and volumetric approach have been used to estimate hydrocarbon in-place (HIP) and technical recoverable resources (TRR). Each of the grabens and thereby plays and sub-plays have been ranked based on the opportunities, uncertainties and risk assessments. Here we demonstrate the results of first unconventional well drilled in the graben and its implication on the unconventional opportunities within the graben. The pilot vertical well V&V UC-1 proved 4.8 mmoec/km² of HIP. The well encountered Hybrid interbedded turbiditic play and pure shale play analogous to Uteland Butte member in Uinta Basin, north Wyoming, USA. Petrophysical interpretation of wireline logs constrain the net pay thickness within the sub-play segments. The total organic content (TOC) measurement in the organic rich shales reaches upto 4 wt%. Rock eval and vitrinite reflectance data quantifies the thermal maturity of the source rock in the graben. The results show the uncertainty in thermal maturity measurements and however it ranges black oil to late volatile oil window suitable for unconventional systems. Further core studies integrating the V&V-UC-1 results is critical to determine optimal location for well testing as next steps of exploring the unconventional potential

Introduction

The Barmer basin, an NNW-SSE trending intra-cratonic rift in western Rajasthan, NW India, extends northward from the Cambay basin and forms a well-defined graben between the Barmer high and the Indian shield (Dolson et al., 2015; Farrimond et al., 2015). The Eocene Lower Barmer Hill (LBH) member

is the primary source rock for most major discoveries in the basin (Dolson et al., 2015). Kuila et al. (2020) delineated prospective areas and estimated the unconventional resource potential and chance of commerciality in the northern grabens of the basin using a play-based approach. We assessed and ranked the grabens and chose V&V graben as the first potential unconventional exploration target. It is a half graben structure in the central part of basin against the eastern basin margin fault (Fig 1). A prominent regional seismic marker-BH06 separates the target interval (LBH) from the upper Barmer Hill member (UBH) and its base is defined by Fatehgarh formation. The well (henceforth referred to as V&V-UC-1) intersected the LBH member in the thickest part of the

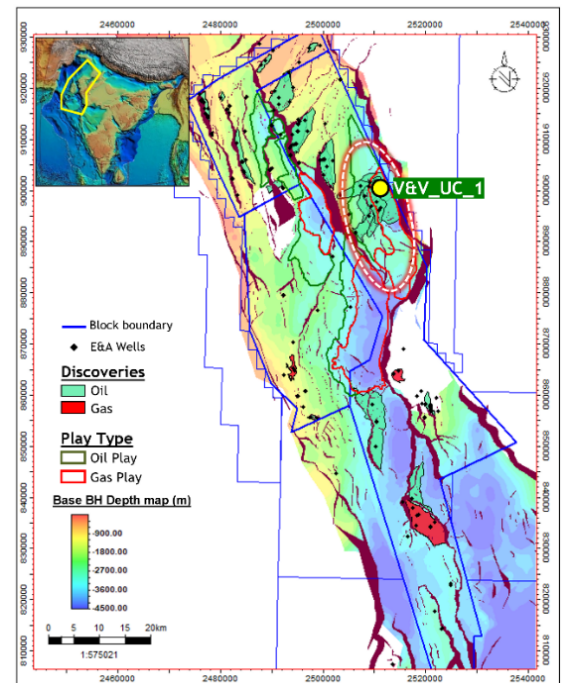


Figure 1: Map highlighting the unconventional prospective areas in northern Barmer Basin along with the V&V-UC-1 well location in V&V graben, Barmer basin. The major conventional fields are shown. Inset showing the basin location with yellow polygon in the SEEBASE™ depth to basement map of India

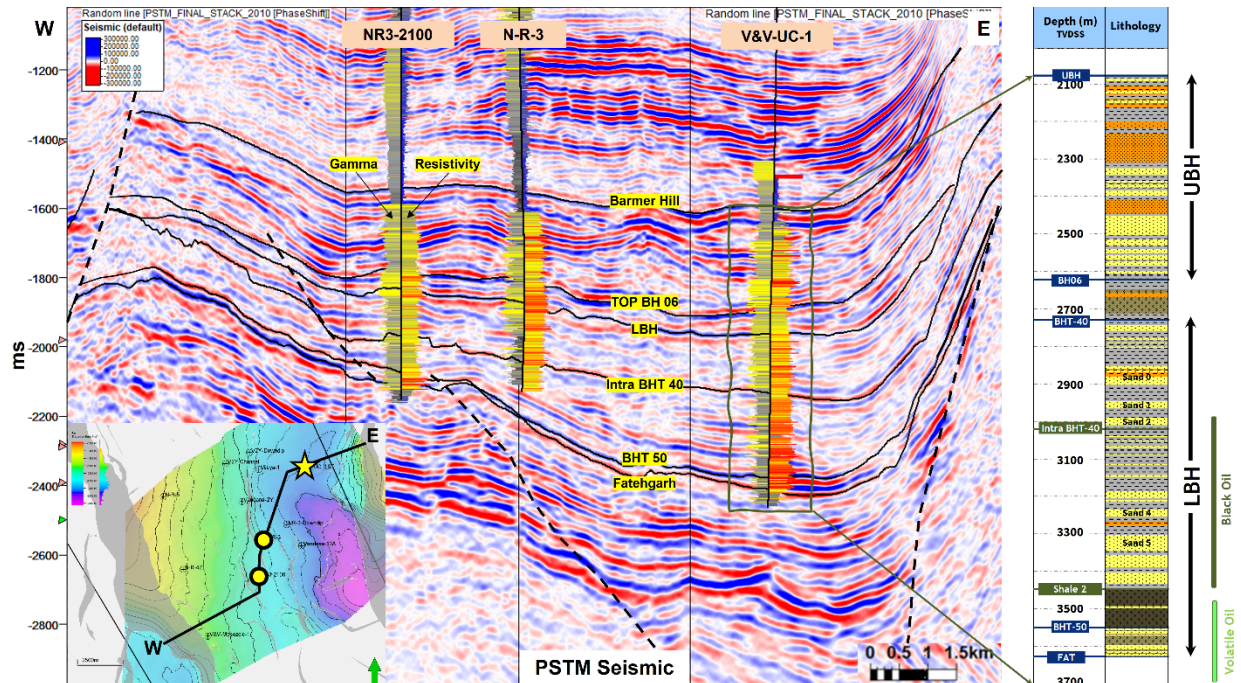
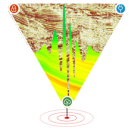


Figure 2: E-W Seismic composite line across the V&V graben passing through the pilot V&V-UC-1 well and updip wells. The lithocolumn for the Barmer Hill interval is shown in the right. Multiple sub-members is observed with the LBH member. Upper units BHT-40 and Intra BHT-40 are more sand prone, while the bottom unit Shale2 is a pure source rock interval and BHT 50 is interbedded organic-rich shales and sandstone unit.

graben (Figure 1) with prognosed thermal maturity near peak oil window. In this paper, we present post-drill results of the V&V UC-1 well to demonstrate the unconventional potential in the V&V graben and its implications for understanding key uncertainties, risks, and opportunities in other potential grabens of Barmer basin.

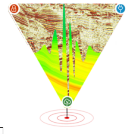
Methods and Materials

We obtained basic and advanced wireline logs, including gamma ray, neutron, density, resistivity, and sonic logs, as well as advanced nuclear magnetic resonance (NMR) data, electrical & acoustic image data and elemental spectroscopy log, in the entire Barmer Hill interval, using our drilling service partner Halliburton tools. GEOLOG International provided advanced mudlogging services, including rig-site XRD, XRF, TOC, S₂, and T_{max} measurements in cutting samples at 5 m intervals. We also collected 30 sidewall cores in the Barmer Hill interval. Using a deterministic methodology, we determined petrophysical properties such as matrix volumes, porosity and saturation for the clastic facies. We calibrated the porosity from the density-neutron log using NMR total porosity and Resistivity based S_w with irreducible bound water saturation from the NMR log. We used modified Passey's method (Passey et al., 1990, Kuila et. al. 2020) to estimate TOC from logs.

Stratum Reservoirs performed petrographic and vitrinite reflectance studies using sidewall core samples. They also ran the RockEval pyrolysis and TOC measurements, and XRD analyses in laboratory on both cuttings and sidewall core samples. We measured TOC on acid-treated crushed samples using a LECO elemental analyzer. We conducted RockEval pyrolysis of solvent washed powdered shale samples (to clean oil-based mud impurities) using a Rock-Eval 6 apparatus to measure hydrocarbon yield (S₂), temperature of maximum hydrocarbon generation (T_{max}), hydrogen index (HI), and oxygen index (OI).

V&V-UC-1 Unconventional Target

The LBH member have multiple sub-units with different lithofacies association. The topmost units BHT 40 and Intra-BHT 40 are clastic rich with interbedded lean shales (TOC <2%). BHT 40 sands have pay in log, however these might be stratigraphic conventional hydrocarbon systems (Figure 2). The unconventional primary target in V&V-UC-1 are the BHT 50 sub-unit analogous to the Uteland Butte member in Uinta Basin, north Wyoming, US. BHT50 is hybrid unconventional system with intercalated turbidite sand (TBD) with organic-rich shales interbeds. The pure source rock play overlying BHT50



interval (Shale 2 unit) within LBH is organic-rich lacustrine shale deposits with TOC upto 4 wt%, which is our secondary target.

V&V UC-1 Results

Figure 3 shows the log-motif of the two LBH unconventional target Shale 2 pure source play and BHT 50 Hybrid play, encountered in V&V-UC-1. The detailed petrophysical, petrographic and organic matter characterization are presented below.

Petrophysical Characterization

Within the ~90 m thick Shale 2 unit, we have identified three major shale packages. The log-derived TOC curves match well with the measured Leco TOC data (Fig. 3). Using a >2% TOC cut-off for a prospective pure source rock pay, we have identified ~30 meters of possible pay. The organic-rich shales have an average total NMR porosity of ~12% and an average log-derived TOC of 3 wt% from resistivity. The resistivity in the organic-rich interval shows moderately high values, suggesting lower thermal maturity with some hydrocarbons.

In the ~70 m thick BHT50, we have encountered two major packages showing characteristic low gamma, overlapping neutron-density with high resistivity signatures with interbedded shales high gamma and neutron-density separation (Fig. 3). The Tgas peaks and presence of shows corroborate the presence of hydrocarbons. The serrated GR response and image log data suggest an interbedded sand and organic-rich shale system. These hybrid interbedded TBD sands have an average total porosity of 11% and an average HC saturation of 47%, with a total net pay over 25 meters.

Petrographic Analyses

Petrographic investigation of studied Shale 2 sidewall core samples suggests abundant argillaceous matrix embedded with a sub-ordinate amount of silt to fine-sand size detrital quartz grains. These are laminated, bioturbated, organic-rich mudstones consisting of organic laminations and phosphatic fragments stained with organic matter (Fig. 4). Thin section study of sandstone samples from the BHT50 interval shows a texture comprising a detrital framework of quartz grains within a sub-ordinate proportion of quartz-dominated matrix. The detrital grains consist of little or no feldspars with small proportion of clay and significant proportion of bitumen (Fig. 4). No lithic fragments are observed in any of the studied thin sections in BHT50 interval. This quartz-dominant

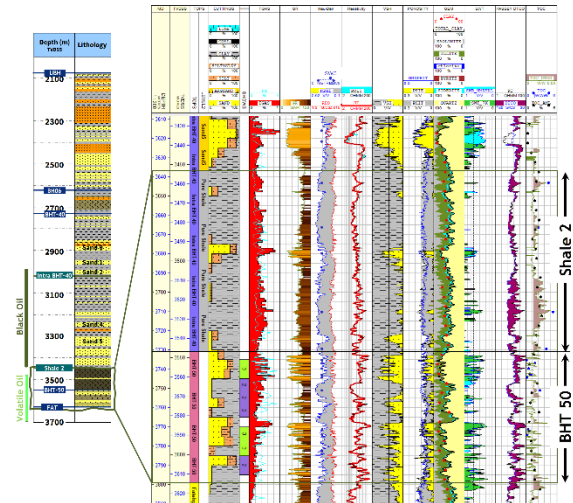


Figure 3: Log motif of V&V UC-1 showing wireline logs and petrophysical parameters and estimated TOC from R-overlay in Pure Source play and BHT 50 Hybrid play. Note post-drill lithology for entire Barmer Hill section is shown in the left.

mineralogy with >15% matrix content classifies these rocks as quartz arenites. Texturally the sandstones are poor to moderately sorted with angular to sub-rounded quartz grains indicating low transportation. Visible primary and some secondary porosities in these sandstones elucidates its potential reservoir quality. Mineralogically, the clays are dominantly kaolinite, illite and chlorite with some fractions of siderite as evident from the XRD analyses and elemental spectroscopy logging results. Clay content is less than 50% indicating sufficient brittleness of the tight unconventional reservoirs (Fig 5)

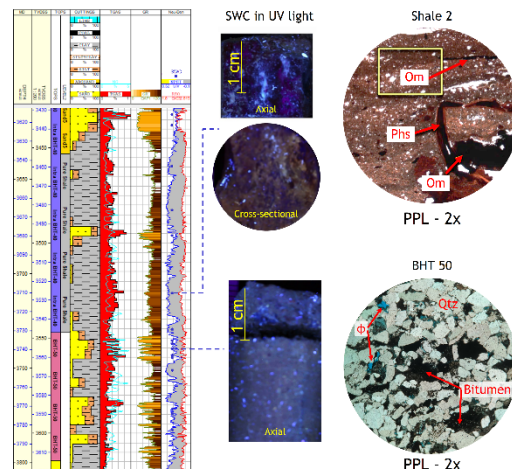


Figure 4: Petrographic thin section in plane polarized light and sidewall core under ultraviolet (UV) light from Pure Source play and BHT 50 Hybrid play intervals in V&V UC-1 well.

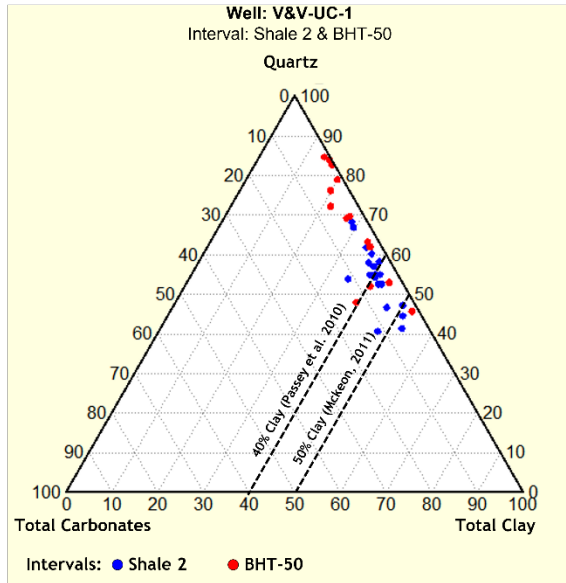
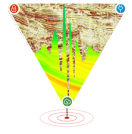


Figure 5: Ternary diagram of the relative abundance of quartz, carbonates and clays in Shale 2 and BHT50 intervals in V&V UC-1 well.

Organic Matter Characterization

The TOC content of the Shale 2 organic-rich shale samples ranges from 2.32 to 5.31 wt% with a mean value of 3.64 wt%, in congruence with the log derived average TOC estimation. The organic-rich shales from BHT50 Hybrid TBD have a relatively lower TOC content ranging from 1.11 to 2.78wt% with an average value of 1.83 wt%.

Organic petrographic studies indicate Type II organic matter, comprised dominantly of amounts of diffuse amorphous organic matter (AOM) in Shale 2 organic rich unit. Rare algal materials (Type-I) and lenticular amorphous organic matter (AOM) are present. A common view exists that organic matter in lacustrine systems is Type-I, however Type II organic matter can prevail in shallow lake facies (e.g., Cretaceous source rock of Songliao Basin; Wangli et al. 1985). The lenticular form exhibits moderate to high micrinitisation, indicating significant thermal conversion and advanced oil generation.

We observed mixed Type III/II kerogens in BHT 50 source rock interbeds. Terrigenous organic matter in the samples consists of few to common occurrences of vitrinite and inertinite (Fig. 6). The material is well-preserved, with rare, large fragments, semifusinite with preserved cellular structure and rare observation of intact fungal spores. This suggests a depositional environment with good access to detrital terrigenous

input with short transportation and deposited in a turbiditic system.

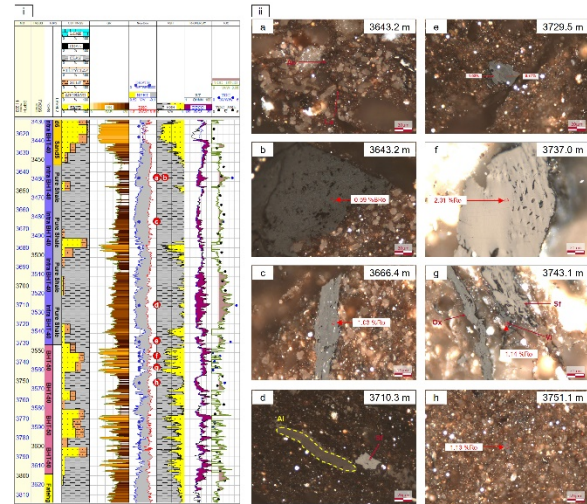


Figure 6: (i) V&V UC-1 log motif showing the sample depths for Vitrinite Reflectance; (ii) Organic petrographic photomicrographs in Shale 2 and BHT50 intervals (a) Amorphous organic matter-Ao and degraded lamalginite-La, (b) solid bitumen with 0.59 %BRo, (c) representative vitrinite with 1.03 %Ro, (d) mineralized algal body-AI possibly related to Tasmanites-like alga, within a brown AOM/mineral matrix and a semifusinite particle-Sf, (e) vitrinite with 1.03 %Ro reflectance and 0.77 %Ro from darker internal cells, possible residual exsudatinitite, (f) fairly well-preserved semifusinite with 2.01 %Ro, (g) representative vitrinite lens with a reflectance of 1.14 %Ro surrounded by mildly oxidized(?) vitrinite-Ox and semifusinite-Sf, (h) small representative vitrinite particle

The HI values of samples from the Intra-BHT40 section range from 211 to 387 mg HC/g TOC with an average value of 296 mg HC/g TOC (Fig. 7). In comparison, the HI values of organic-rich shale samples from BHT-50 Hybrid TBD are much lower, with a range of 89 to 328 mg HC/g TOC with a mean value of 170 mg HC/g TOC. Modified Van-Krevelen plot of HI vs OI illustrate Type-II kerogen in Intra-BHT40 and mixed Type-III/II kerogen in BHT50 shales (Fig. 7).

Measured vitrinite reflectance (VR) values range from 0.95%Ro to 1.02%Ro in Shale 2 interval and ~1.1 in the BHT 50 interval, suggesting that the examined section has reached peak to late oil. This is corroborated by liptinite fluorescence colors in the Shale 2 samples range from moderate yellow/orange to through to orange, suggesting a maturity estimate range of 0.65-0.90%VR/e, before fluorescence is extinguished in the BHT 50 samples, suggesting a maturity estimate >1.1%VR/e. Bitumen occurrences are generally rare and mostly have a 'rough' or poorly polished texture. Equivalent VR values based on bitumen reflectance, is showing a good agreement with the measured VR data but are consistently, marginally lower which may be related to the poor

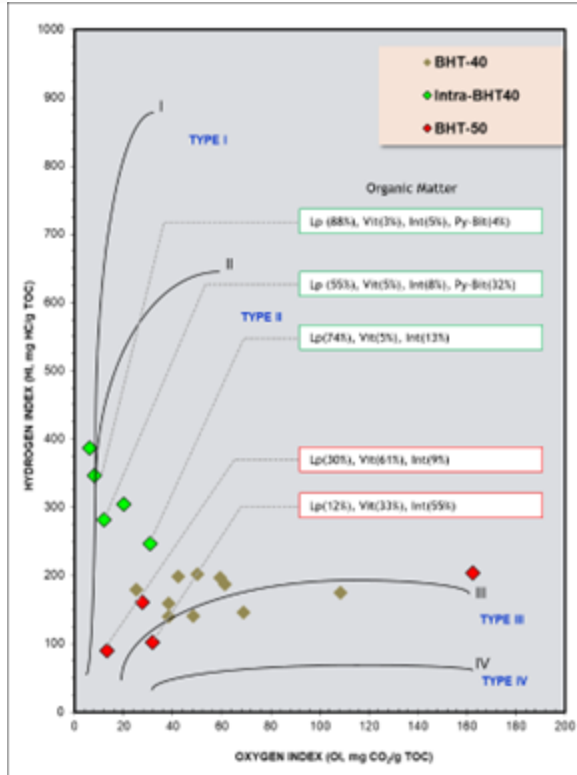
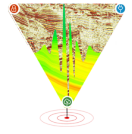


Figure 7: Modified Van Krevelen plot of HI vs OI displaying Type II and Type III kerogen for Shale 2 (green markers) and BHT50 (red markers) intervals respectively. Note the percentage organic matter from few samples as determined from organic petrography within the highlighted boxes. Lp: Liptinite, Vit: Vitrinite, Int: Inertinite and Py-Bit: Pyro-Bitumen

polish quality of the bitumen. However, the average Tmax values of the Shale 2 and BHT50 shale samples is 445 and 452 °C which translates to VRo of 0.80% and 0.94% respectively based on the empirical equation $\%Ro = (Tmax/50) - 8.10$, modified after Galimov and Rabbini (2001). The calculated Tmax equivalent %VRo values of samples from both the intervals are lower than the measured %VRo (Fig. 8).

Discussion

The LBH member was deposited during the maximum transgression at the Palaeocene-Eocene boundary after Fatehgarh. In the V&V graben, it displays an increasing thickness against the eastern margin basin fault, suggesting deposition against an active fault scarp. The BHT50 unit was deposited as turbiditic sands sourced from the eastern basin margin fault into the deep lacustrine. The lithofacies association of interbedded sand-organic rich shale and well-preserved vitrinite macerals support this interpretation. The Shale 2 organic-rich pure shales resulted from rapid lake deepening and transgression throughout the northern part of the basin. However,

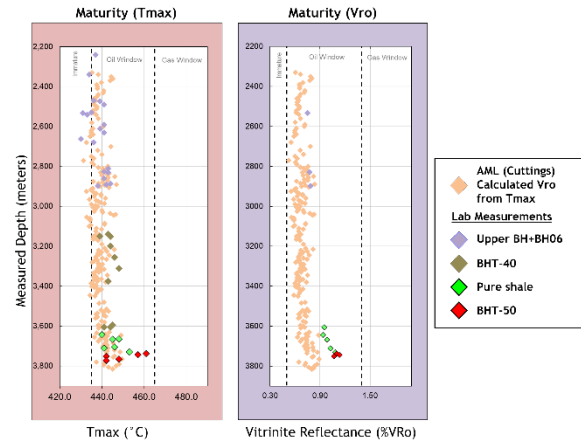
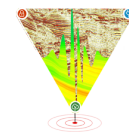


Figure 8: Plots of maturity indicators - Tmax (left) and calculated and measured VRo (right) across depth for studied samples from entire Barmer with the Shale 2 and BHT50 samples are highlighted in green and red markers respectively.

the absence of Type I alginite macerals may indicate deposition in shallower water dysoxic conditions.

According to Katz et al. (2021) classification, the BHT 50 can be classified as a ‘highly interbedded model’ from an unconventional target perspective, with interbedded reservoirs and thin source rocks analogous to the Wolfcamp Formation and Uteland Butte member in the Uinta Basin, north Wyoming, USA. Petrophysical analysis suggests the presence of hydrocarbons with a net pay of at least 25 m and a minimum hydrocarbon-in-place resource density of 4.8 mmbo/km². This does not take into account the potential pay in interbedded source rock units if lab studies can prove organic hosted porosity development. The overall clay content is low (<40%), suggesting brittle behavior favorable for hydraulic fracturing. Assessing the thermal maturity level based on different measurements presents uncertainty, however, the range from early volatile oil window to late oil window indicates a working unconventional system. This uncertainty could affect fluid viscosities and pore pressure, thereby predicting well deliverability. Further lab studies and a well test with a short lateral is warranted to derisk the potential.

The Shale-2 is also an attractive unconventional target as a “pure-source play” target, analogous to Barnett, Marcellus systems (Katz et. al 2021). The organic carbon content in the V&V system is over 2 wt% TOC, exceeding the threshold value for commercial unconventional system. However, reducing the uncertainty in thermal maturity and proving development of organic porosity is critical for success of these pure source rock systems.



Conclusion

V&V-UC-1 pilot hole proved a working unconventional hydrocarbon system in V&V graben in Barmer Basin. The main findings of the study are as follows:

1. A hybrid unconventional system comprising of a ~70 m package of organic-rich shales and sandstone interbeds with >25 m net pay was encountered in the lowermost subunit (BHT 50) with a minimum estimated hydrocarbon-in-place of 4.8 mmbo/km²
2. A pure source rock play consisting of 90 m gross interval and >30 m of potential organic-rich shale pay was also encountered.
3. Thermal maturity measurements (from black oil to late volatile oil window) suggest working unconventional system, however, the uncertainty can affect the extent of sweet spot within the graben.

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