Determination of Fluid Entry in Eocene Producers of Upper Assam Basin with the Help of New and Advanced Production Logging Tool*

Polash Gogoi[1] and B. Saha[1]

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[1] Oil India, Ltd., Duliajan, Assam, India (polashgogoi@oilindia.in) (biswajitsaha@oilindia.in)

Abstract

The complex production logging environment has driven the need to develop new production logging sensors and interpretation methods to provide data for confident remedial interventions. Here, we discuss an integrated PL tool that samples production volumes more representative of borehole fluids, having a better investigation radius than before. How technological advances have helped in pinpointing fluid entries in producers in multiphase flow. Advent of PL tool such as Gas holdup that can directly measure gas fraction irrespective of deviation or flow regimes, however careful in-situ calibration can provide good results with the tool. Full bore flow rate measurements with highly sensitive sensor having coverage close to borehole diameter can determine accurate volumes. However, in the flip side these spinners cannot measure directly individual phase rates. In interpretation process, given few rates, the dynamic flow model would predict the downhole flow regimes and slip values of phases and thereby holdups. With the holdup information and PVT model fluid properties, the model would then compute simulated fluid density flowing downhole. The transfer function of the tool is now used to predict theoretical density as would be measured by the tool. Another grey area discussed is the PVT data so critical to define accurately a model in the interpretation process; accurate PVT data helps in prediction of reservoir phase properties that ultimately helps in good reservoir management. In the study some of these tools have been used in combination to provide solutions to downhole problems, in spite of few inherent tool limitations. The PL data of two wells of upper Assam have been studied to provide an insight of major source of unwanted gas and water problem.

Discussion

Conventional Production Logging (PL) sensors provide a major challenge to interpreting its measurements especially in multiphase production wells. Production wells undergo lot of production problems that needs to be timely diagnosed in order to enhance the lifetime of the well. Production problems as coning and fingering, changing Oil-Water Contact, Gas-Oil Contact, and high permeability breakthrough can substantially reduce productivity and as such these situations needs to be amended. The problem with conventional PL sensors is that it measures fluid samples that may not capture signal corresponding to the complete borehole fluid flow. These sensors are acted simultaneously by more than one phase in a multiphase environment (global sensors). Due to the flowing environment becoming increasingly complex with increasing deviation and fluid phases travelling at very different velocities it poses a challenge to using correct slip models and mathematical correlations for characterizing dynamic fluid flow behavior. Improved sensors that are small enough and respond quickly enough can provide data in a single plane of measurement (local sensors) of the phase they are immersed in at the time. Local sensors provide measurements of a phase directly independent of changing flow regime in multiphase situations; they give a significant advantage in obtaining interpretable production logs. As such, PL measurement with conventional tools may not reliably represent the entire borehole phenomena and being center sampling tools may run into lot of errors. Hence, evaluating reservoir where the actual formation and injected breakthroughs are happening can be difficult and fluid quantification subject to lot of assumptions and approximations. Production logging sensors like spinners sense fluid being acted simultaneously by more than one phase cannot provide direct individual phase measurements .Direct phase velocity measurement of each of the phase is difficult and hence respective holdups are calculated in order to estimate individual rates. Ambiguities result in flow calculations due to constraint in measurement and identify flow regime.

Interpretation uses a non-linear regression technique generating simulated velocity and density channels which are dependent upon proper flow model selection and PVT model representing the reservoir fluid properties. The definition of a PVT model describes the nature of the flowing mixture, and the associated PVT properties as a function of temperature and pressure. The applicability of the results of laboratory PVT determination to problems in reservoir behavior depends on field information and representative samples. Samples representative to the original reservoir may be obtained only when the reservoir pressure is equal to or higher than the original bubble point or dew point pressure. Challenge lies in selection of proper PVT model parameters representing the hydrocarbon in the reservoir due to lack of data. Tool measurement limitation owing to its construction and the type of flow regime around the tool can also affect data quality, like the spinner in a slug flow and the water holdup sensor blinded by a persistent oil film in a fluid, giving false results.

The PL technology used here for case study consisted of tools that combined global sensors with sensors that responded locally to changing downhole flow phenomena, an approach that could counter different flow regime measurements with confidence; with conventional PL sensors such fluid movements would completely go undetectable or could provide partial answers.

An attempt is also made to understand tool capabilities through a dissection of these tools, and how these tools stand in specific cases of difficulties in quantification. New PL Gas Holdup Tool (GHT) provides direct and highly accurate quantitative full bore measurement of gas holdup in multiphase mixtures. The data provided is not affected by deviation (stratification of fluids) or horizontal boreholes and does not require identification of flow patterns (Flow regimes). GHT can detect gas even when turbulence has distributed or broken the gas bubbles into sizes so small (like aerosol spray) that they are undetectable by conventional PL tools. The GHT response is basically the backscattered count rate of the fluid surrounding the GHT to the detector which is at 2.5" distance from the source. The tool uses an algorithm which has been developed based upon Monte Carlo modelling (using MCNP) and experimental data collected over a range of casing sizes at standard temperature and pressure conditions are used to validate the model. The GHT provides high vertical resolution to detect the presence of gas and hence its major application is to identify gas entries in oil/water wells or oil/condensate in gas condensate wells. Because of its high sensitivity to minor amount of gas, the tool can be used to locate bubble point fluid pressure an important element in understanding oil reservoir production behavior, overall GHT simplifies the understanding and tracking the movement of multiphase fluids within casing and monitoring the movement of reservoir fluid contacts; hence it aids in better reservoir management and surveillance. The additional information provided by the GHT eliminates ambiguities that the interpreter of conventional production logging sometimes encounters.

Using CFB, spinner rates are directly related to fluid mixture velocity using calibrated spinner pitch, having high efficiency and low threshold parameters (low inertia). Spinner rotational velocity is also dependent upon the mixture fluid density and viscosity, as such in-situ CFB calibration is done for spinner having 90% borehole coverage, provides close to true apparent fluid velocity. Difficulties in interpretation arises when spinner rates are affected by amount of deviation whereby the calculated slope can be misleading mainly due to the phases getting segregated and depend upon their respective holdups, this leads to making few assumptions by the interpretation software. Also, fallback of the heavier phase may lead to negative flow rate calculation in case of low flow rate well producing a much lighter phase at the surface. Such a problem is dealt with by first making few assumptions within the model, making synthetic rate calculations for local faults and integrating results through global regression technique.

This improvement in understanding of multiphase flow in producing wells has helped develop sensors that can detect fluid flow better. In this paper we summarize the most current understanding of multiphase flow in vertical wells, pinpointing fluid entry points, and fluid type with new innovative PL sensors (Gas Hold-Up Tool, Full Bore Spinner, Enhanced Capacitance Water Holdup Tool-ECWH) and using an integrated approach to interpret results with a high degree of confidence for a few wells of Oil India Limited in Upper Assam. A case study is carried out in Well-A producing 3 phase high flow rate oil with high GOR and another Well-B producing low flow rate oil with high water cut (WC).

Well-A is situated in one of the oilfields of the Upper Assam Basin, producing mainly from Eocene clastic reservoirs, consisting of thin sands interbedded with carbonaceous shales and coals. The occurrence of individual sands in this reservoir lies in between 3600 m to > 4000 m with the thickness of the sands varying from 2 to 6 m. This thin sand group is characterized by wide variations of porosity and permeability (low as

10-50 md to 6 Darcy) in different sands of the Lakadong member and is prolific producers in the middle part of the Lakadong sand where it is thick (2-6 m), clean, porous, and permeable sandstone.

The production in this particular Eocene play well had been hampered by frequent water production issue with decline in oil production from the lower Lakadong sands (Figure 1). The well produced 452 B/D oil and 12 B/D water from three sets of perforation however after a production of two years, the well started to produce with very high GOR with corresponding decline in the oil rate and increased water production. A production logging job was carried out to locate the source of gas and water entry in the wellbore and possible reason of sudden outbreak of this unwanted gas flow. The SRO (surface read out) type PL string lowered in the well comprised of fullbore spinner (90% coverage),Water Holdup, Gas Holdup, Radioactive(RA) fluid density, Quartz pressure gauge tool, and Temperature tools in order to characterize fluid type and its corresponding origin into the borehole. Multiphase flow analysis in wellbore is always a complex issue, accurate quantitative evaluation depends on identifying the dynamic flow patterns at different flow rates establishing flow regimes and successfully using a model to understand the flow.

This paper highlights some the issues that make quantitative analysis complex due to lack of direct tool measurement in specific situations and how using a combination of various tool options and interpretation - that uses minimization technique (non-linear regression process) generates synthetic velocity and density models for multiphase downhole flow rate characterization.

The following well data has been analyzed with different tool options and interpretation carried out using different models for getting insight to downhole problems. The interpretation of the PL data from the well indicated that the middle and bottom perforation(Perf#2 and Perf#3) is mainly water with little oil. The RA type fluid indicator does not show recognizable lighter phase oil from its response due to higher water volume. The other fluid indicator GHT is best used as a 2 phase tool to provide gas holdup information. To compute gas holdup correctly the interpreter needs to state whether the heavy phase is oil or water. In 3 phase flow the water oil ratio needs to be known to compute multiphase flow rates with the tool. As oil has a slightly lower photoelectric absorption than water, their frequency response is slightly different, which enables water and oil identification. Also, to ascertain oil water volumes we had to rely on the enhanced water holdup (ECWH) tool whose interpretation is qualitative. The ECWH showed superior response without the sensor signal getting saturated at high borehole water fraction. During interpretation a non-linear regression process is used employing a Liquid-Liquid model based upon Dukler correlation to determine the phase holdup relationship with phase flow rates against the zone of interpretation. The top most perforation (PERF#1) utilized a 3 phase Liquid-Gas model and to ascertain slip velocities between Liquid-Gas and Liquid-Liquid phases, Dukler and Choquette correlations were respectively used. Downhole PL measurements showed that 96% of the well production took place from the topmost zone, the surface flow rates of oil was 68-72 m3/D with around GOR 2000 v/v. Many times when a well flows with high GOR, it becomes difficult to conclude that high GOR is because of gas cap or there is channeling from the other gas zone. Though the log may indicate the oil zone as well as gas zone but it is not always possible to say that both zones are having vertical communication.

Geologically complex Eocene reservoirs provide a challenge to establish vertical and lateral continuity of their thin laminated sandstone bodies. Gas channeling from the upper sand body was ruled out from temperature log interpretation, as no appreciable change was noticed in dT/dz (Temperature derivative over depth) curve. From PVT data the reservoir seems to be a under saturated reservoir, the initial reservoir pressure was more than the solution pressure. In such reservoirs fluid exists in only one phase that is under saturated oil and the driving mechanism for this kind of reservoir is through expansion of this under saturated oil. Hence, all the gas produced shall be from the solution gas in oil once the reservoir pressure is below the bubble point pressure. The downhole flowing pressure Pwf was measured below the solution pressure. This may be the reason why the top zone was producing lot of unwanted gas.

Case study in Well-B was done in the Lakadong sand body in another oilfield of the Upper Assam Basin. The well initially produced at a rate of 364 B/D with 70% oil from the two sets of perforation in the same Lakadong sand. During later stage of production the water cut increased to 81% of total liquid production. Viewing this situation PL string was lowered to locate the source of water. The GHT tool responds to electron density. Water has a high electron density but as the salinity increases (Figure 2), the increase in count rate due to density increase is offset by decrease in count rate due to greater photoelectric absorption. Oil, in general, has a lower electron density than water and thus should give less back scatter but this is compensated somewhat by lower photoelectric absorption which has the effect of raising the count rate. The overall effect is to reduce the difference in frequency between oil and water. In the lowermost zone to establish the frequency end points for oil water we need to shut-in the well and calibrate the tool response in stratified oil water phase and then compute the slope and offset, assuming that the response between oil water is linear we could quantify respective holdups. For the top zone a 3 phase Liquid gas model was selected with a Liquid-Gas and Water-Oil correlation for analysis. Interpretation results indicate that the lower zone is contributing to around 40% of the total well production with minor quantity of oil.

PVT data of the field showed that the reservoir pressure is close to the solution pressure of the hydrocarbon, as such the reservoir hydrocarbon is in near saturated state. The flowing pressure Pwf for the well was identified to be much below the initial reservoir pressure for the well. The lower zone was producing minor amount of oil with more than 60% of the water produced, from this zone. The top zone produced all the oil from the well with some water production. A bridge plug shut-in job was advised below the top zone, in order to cut down water production by about 273 B/D, without affecting oil productivity by much. This would reduce the cost involved for disposing unwanted water produced from the bottom zone without losing significant oil.

The complex production logging environment has driven the need to develop new production logging sensors and interpretation methods to provide data for confident remedial interventions. Here, we discussed an integrated PL tool that samples production volumes more representative of borehole fluids, having a better investigation radius than before. How technological advances have helped in pinpointing fluid entries in producers in multiphase flow. Advent of PL tool such as Gas holdup that can directly measure gas fraction irrespective of deviation or flow regimes, however careful in-situ calibration can provide good results with the tool. Full bore flow rate measurements with highly sensitive sensor having coverage close to borehole diameter can determine accurate volumes. However, in the flip side these spinners cannot measure directly individual phase rates. In the interpretation process, given few rates, the dynamic flow model would predict the downhole flow regimes and slip values of phases and thereby holdups. With the holdup information and PVT model fluid properties, the model would then compute simulated fluid density flowing downhole. The transfer function of the tool is now used to predict theoretical density as would be measured by tool. Another grey area discussed is the PVT data so critical to define accurately a model in the interpretation process; accurate PVT data helps in prediction of reservoir phase properties that ultimately helps in good reservoir management. In the study some of these tools have been used in combination to provide solutions to downhole problems, in spite of few inherent tool limitations. The PL data of two wells of upper Assam have been studied to provide an insight of major source of unwanted gas and water problem.

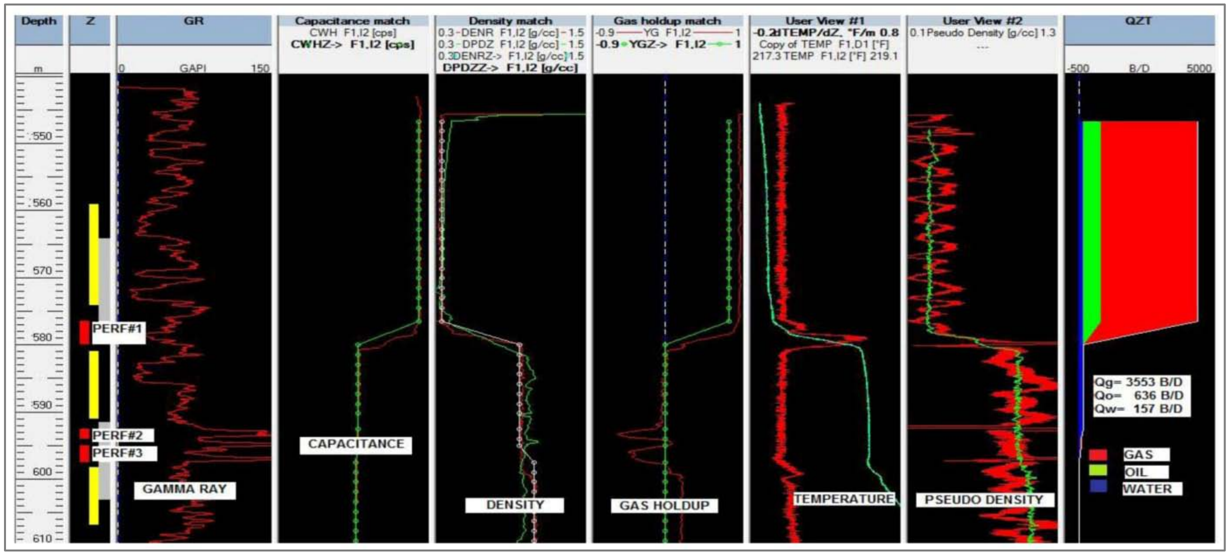

Figure 1: Well-A Upper Assam Basin, producing from Eocene clastic reservoirs. The thin sand groups are characterized by wide variations of porosity and permeability in different sands of the Lakadong member and are prolific producers in the middle part of the Lakadong sand where it is thick (2-6m), clean porous and permeable sandstone. Production was hampered by frequent water production issue with decline in oil production from the lower Lakadong sands.

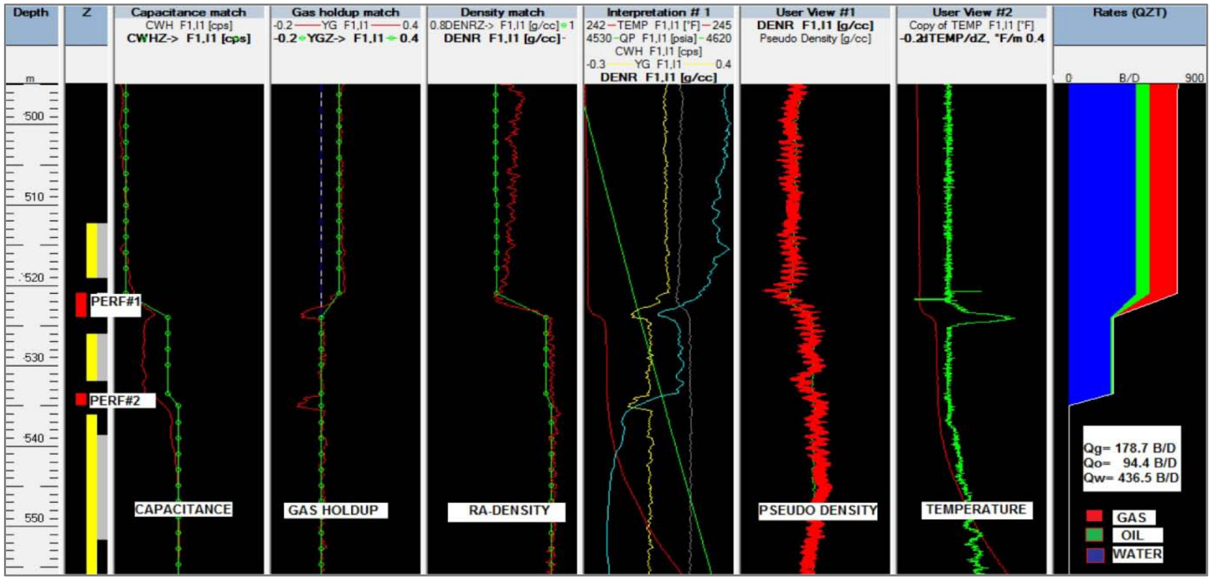

Figure 2: Well-B was done in Lakadong sand body in another oilfield of the Upper Assam Basin. The well initially produced at a rate of 364 B/D with 70% oil from the two sets of perforation in the same Lakadong sand. During later stage of production the water cut increased to 81% of total liquid production. Viewing this situation PL string was lowered to locate the source of water. The GHT tool responds to electron density. Water has a high electron density but as the salinity increases, the increase in count rate due to density increase is offset by decrease in count rate due to greater photoelectric absorption.