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Integrated Approach to Reserve Estimation and Reservoir Simulation of ENI Offshore Field, in Niger Delta Nigeria

J. O. Ayorinde[1*], O. O. Osinowo[2] and P. Nwankwo[2]

[1]Department of Geology and Mineral Sciences, University of Ilorin, Nigeria.
[2]Department of Geology, University of Ibadan, Nigeria.

Authors' contributions

This work was carried out in collaboration among all authors. Author JOA designed the study, performed the statistical analysis, wrote the protocol and wrote the first draft of the manuscript. Authors OOO and PN supervised the study and also edited the manuscript. Author JOA managed the literature searches. All authors read and approved the final manuscript.

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ABSTRACT

Two producing reservoirs (H10 and E40) in Eni field Offshore Niger Delta were studied with intent to enhance their rate of recovery while mitigating water production. The material Balance software MBAL was used to estimate the Stock tank oil reserves and then compared to reserve estimates determined by both deterministic and stochastic techniques for improved validation. The MBAL model was also used to identify positions of fluid contacts and determine predominant drive mechanisms. These serve as guide in making informed decisions towards if and how best to economically produce remaining unproduced oil in place. Input parameters were average values derived from core and well logs analyses.
History matching of historical data enabled forecasts of possible future production life and volume at multiple scenarios.
Final outcomes show that after sixteen and forty five years of continuous production from the reservoirs studied (H10 and E40, respectively), remaining unproduced oil in place are still significant and can be economically produced by infill wells, which will in return increase the

**Corresponding author: E-mail: ayorinde.jo@unilorin.edu.ng;*

average production by nothing less than 33% of remaining oil in place, a substantial value bearing in mind the growing demand for oil, gas and other energy sources to lessen the apparently unquenchable world energy needs.

Keywords: Reserve estimation; reservoir simulation; ENI offshore field; reservoirs.

ABBREVIATIONS

Bopd : Barrel of oil per day;
CGOC : Current Gas Oil Contact;
COWC : Current Oil Water Contact;
COGC : Current Oil Gas Contact;
GOR : Gas Oil Ratio;
MBAL : Material Balance;
MD : Measure Depth;
MMBO : Million Barrel of Oil;
MMSTB : Million Stock Tank Barrel;
MRWO : Major Rig Work Over;
Psi : Pounds per Square Inch;
PV : Pressure Volume;
PVT : Pressure Volume Temperature;
SCF/STB : Standard Cubic Foot per Stock Tank Barrel;
STOIP : Stock Tank Oil in Place;
STOOIP : Stock Tank Oil Originally in Place;
TTPB : Through Tubing Plug Back;
TVDSS : True Vertical Depth Sub-Sea;

1. GENERAL STATEMENT

With an ever-increasing rate of development and production of oil and gas, one frequently asked questions by investors and stakeholders is “when do we run out of oil”? Naturally the hydrocarbon reserves should decrease due to continued increase in production and consumption, but with the help of advanced technology and skills, deeper reservoirs can be explored, new reserves deep offshore can be explored and developed, and existing fields with compartmentalized reservoirs can be restudied and characterized, to increase the recovery of oil in place.

The Eni Field is located offshore, western Niger Delta (Fig. 1). It lies about 8 Miles offshore Nigeria in approximately 40 feet of water [1] consisting of interstratified sandstones and shales, usually representing shore face to shelf deposition [2]. The reservoirs are located in NW-SE trending Miocene depocenters in the wave-dominated Niger Delta depositional system. They are located in the Agbada Formation and comprise stacked shallow marine fluvio-deltaic sediments separated by major marine shale [3]. The sands were deposited in middle to upper shoreface, wave-influenced environments. The underlying Eocene-Oligocene Akata marine

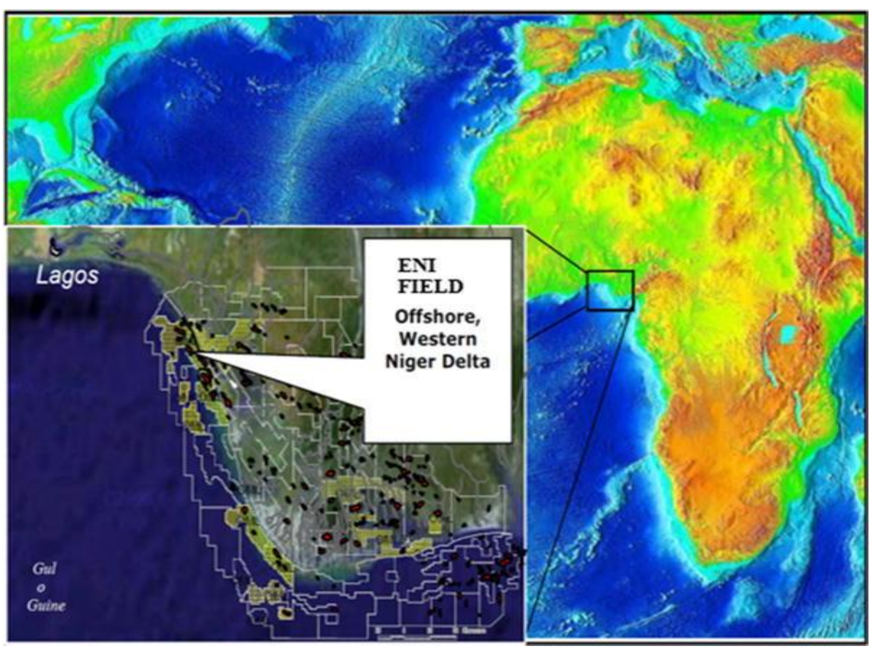

Fig. 1. Location of the studied field

shales are the source of the hydrocarbons. The oldest stratigraphic unit encountered is of Miocene age. The water depth in the field varies from 48 ft. to 60 ft. [3].

The Field has a faulted, roll-over anticlinal structure located between two major NW-SE trending listric fault systems. The Field comprises six fault blocks with approximately 80% of the oil reserves located in Blocks A and B [3]. Lumley, et al. [4] also noted that there are six major fault blocks, each block containing up to a dozen productive reservoir sands, with more than 40 total producing sands. The trapping mechanism is largely structural with some stratigraphic control. There is evidence of compartmentalization and cross-fault fluid communication.

1.1 Objectives of the Study

- To validate the quantity and amount of Stock Tank Original Oil in Place (STOOIP).
- To estimate the current oil in place.
- To facilitate proper reservoir management by suggesting the best location for recompletion or perforation add which enhances recovery.
- Propose a possible plan to develop the field which might include recommendation of a majorrig work over (MRWO).

2. MATERIALS AND METHODOLOGY

The methodology adopted is a numerical simulation method using the one-dimensional material balance equation technique to validate reserves estimates determined by both deterministic and probabilistic (stochastic) methods. The MBAL simulator was used for achieving research objectives.

The dataset available for this study includes:

- 3D Seismic data (SEGY format)
- Well log data
- Production data
- Pressure data
- Base map

2.1 Production Data

Performance/ Production data from the time of production till date was available for integration into the study. The reservoir daily oil rate production, cumulative production, solution gas produced and water produced were all available. A graphical plot of the data is displayed in Fig. 2.

2.2 Pressure Data

The reservoir pressure data of the reservoir as measured in two of the wells that penetrated it since the start of production till date was made available and this information was used to predict the future reservoir pressure and decline rate. The plot of the pressure over time is displayed in Fig. 3.

2.3 Material Balance

Material balance is the process of using the application of conservation of mass to the analysis of a reservoir (tank) system (Table 1). They are routinely used co estimate oil and gas reserves and predict future reservoir performance, Schilthuis, in 1936 was among the first to formulate and apply material balances. An MBAL tool software was used to achieve this process by identifying reservoir characteristics and properties using the material balance concept. MBAL (Material Balance) is used to estimate the oil or gas originally in place and understanding drive mechanisms, and to estimate the current fluid contacts in the reservoirs. The main purpose of a material balance study is to calculate the remaining hydrocarbon reserves and future reservoir performance. MBAL is used for either a single tank or multiple tanks, but in this study a single tank model was developed.

Data that is needed in material balance includes

- A geological model: Porosity, permeability, reservoir and aquifer radius
- PVT data: Reservoir temperature, static pressure
- production and pressure histories

2.4 History Matching

History matching involves integrating pressure and production history data of the reservoir measured from the start of production to date and inputting it into a reservoir model for the development and management of a reservoir. The purpose of history matching is to produce a history match of the model as well as a predictive reservoir model that will help in forecasting the production performance of the reservoir. One of the first studies on history matching was done by Kruger [5]. Kruger estimated the areal permeability distribution of the reservoir. Jacquard and Jain [6] developed a method to automate the history matching. Chavent et al. (1973) studied history matching in single phase oil reservoirs. The purpose was to reduce the difference between observed and actual pressures at the wells with the permeability-thickness product and porosity-thickness product as adjustable parameters.

History matching can be done manually or automatically. The MBAL tool was used to speed up the matching process through a non-linear regression, which automatically chose the best fit value for a given reservoir property. Before getting a reasonable matched model, the history matching for this study was run several times based on this non-linear regression method by selecting matching parameters that align within the geological range. Parameters such as porosity and tank volume (STOOIP) were kept constant, while the aquifer permeability and radius were left variable because they are uncertain parameters.

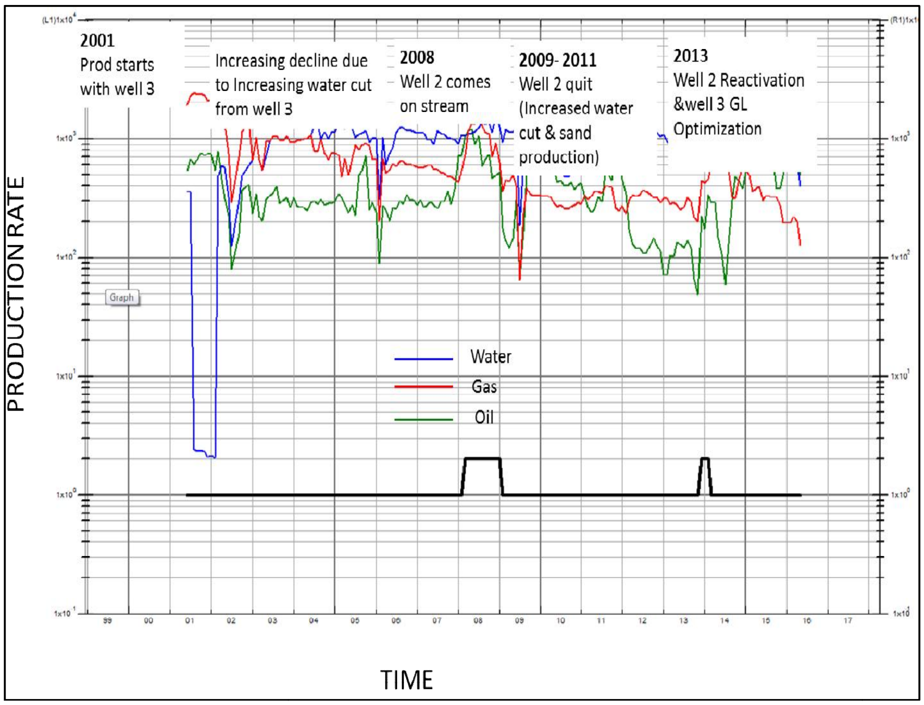

Fig. 2. Production performance plot of reservoir H10

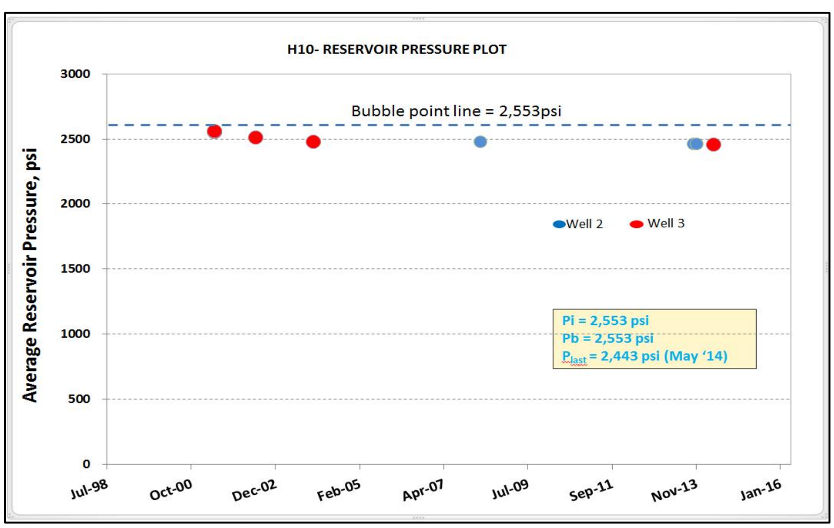

Fig. 3. H10 reservoir pressure plot

Table 1. Summary of material balance equation

Term	Description
$F = NE_t + W_eB_w$	Simplified general material balance equation.
$F = N_p[B_o + B_g(R_p - R_s)] + W_pB_w - W_{inj}B_{w_{inj}}B_{w_{inj}} - G_{inj}B_{g_{inj}}$	The volume of withdrawal (production and injection) at reservoir conditions is determined by the oil, water, and gas produced at the surface.
$E_t = E_0 + \frac{B_{oi}}{B_{gi}}mE_g + B_{oi}(1+m)E_{fw}$	Total expansion.
$E_o = B_o - B_{oi} + B_g(R_{si} - R_s)$	If the oil column is initially at the bubble point, reducing the pressure will result in the release of gas and the shrinkage of oil. The remaining oil will consist of oil and the remaining gas still dissolved at the reduced pressure.
$E_g = B_g - B_{gi}$	Gas expansion factor. For example, as the reservoir depletes, the gas cap expands into reservoir volume previously occupied by oil.
$E_{fw} = \frac{c_f + c_wS_w}{1 - S_w}\Delta P$	Even though water has low compressibility, the volume of connate water in the system is usually large enough to be significant. The water will expand to fill the emptying pore spaces as the reservoir depletes. As the reservoir is produced, the pressure declines and the entire reservoir pore volume is reduced due to compaction. The change in volume expels an equal volume of fluid as production and is therefore additive in the expansion terms.
$m = \frac{GB_{gi}}{NB_{oi}}$	Ratio of gas cap to original oil in place. A gas cap also implies that the initial pressure in the oil column must be equal to the bubble point pressure.
W_eB_w	If the reservoir is connected to an active aquifer, then once the pressure drop is communicated throughout the reservoir, the water will encroach into the reservoir resulting in a net water influx. To calculate the amount of water influx, either the Fetkovich, Carter Tracey,

The following steps were followed in the material balance study:

1. The following data are available (Table 2).
   - PVT data
   - Production history
   - Reservoir average pressure history
   - All available reservoir and aquifer data
2. The data was entered into the MBAl tool and the validity and consistency at every point was checked as this is a very important step in building a good representative model.
3. The best possible match was found using the tools non-linear regression in the analytical method plot.
4. The quality and accuracy of the model was confirmed using the graphical method.
5. A simulation was run to test the validity of the model.

3. RESULTS AND DISCUSSION

3.1 3D Property Modelling

After reservoir properties have been established at the well locations, stochastic algorithms were used to statistically distribute properties in the inter-well spaces in the reservoir. The stochastic algorithm was used because it is believed to produce a more realistic result than the model generated through the deterministic (kriging) method [7].

The Gaussian random function simulation was used to model the porosity and H, and E sands and they have an average porosity of 0.28, and 0.32. The porosity distribution model are shown in Figs. 4 and 5. The Sequential indicator simulation was used to model the facies distribution as shown in Figs. 5 and 6.

The models were then used to estimate the remaining oil in place in the H10 reservoir. The result of the calculation is displayed in Tables 2 and 3.

3.2 Stock Tank Oil in Place (STOIP)

After running an MBAL model, the current fluid contact of reservoir H10 was established and this was used to calculate the remaining oil in place. The STOIP (Stock Tank Oil In Place) was estimated to be 4.9 MMSTB (Table 2). Table 3 indicates that for H10 reservoir has a P10 STOIP of 3.88 MMSTB, P50 of 4.96 MMSTB and the P90 of 5.55 MMSTB. The P10 shows a 10% probability of getting a volume of fluids in place lesser than 39.5 MMSTB. This is equivalent to a 90% probability of getting a STOOIP greater than 39.5 MMSTB.

3.3 Material Balance Discussion

The purpose of carrying out an MBAL analysis for this study is to validate the original oil in place (OOIP) and to monitor the current fluid contacts in the reservoir, by using a pore-volume versus depth data in the MBAL model. Another reason for the MBAL analysis is to know the energy drive of the reservoir. When a reservoir is produced using its natural drive, it is called a primary recovery [8]. A reservoir can have more than one drive mechanism, for example, water drive and gas cap drive, but there is always a dominant reservoir mechanism. Secondary and Tertiary reservoir recovery mechanisms are methods that are used to enhance or maximize the production of oil and to decide the type of Secondary/Tertiary mechanism to use always depends on the dominant Primary reservoir drive [9].

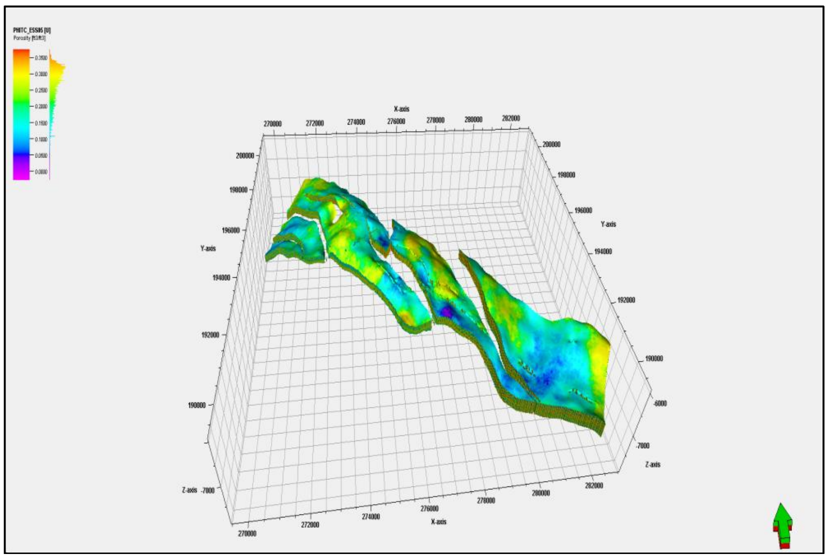

Fig. 4. Porosity model of H sand

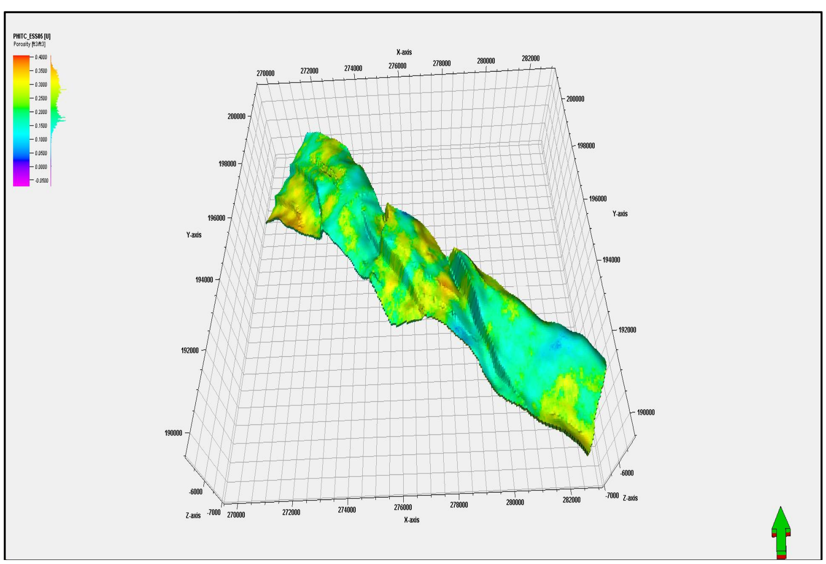

Fig. 5. Porosity model of E Sand

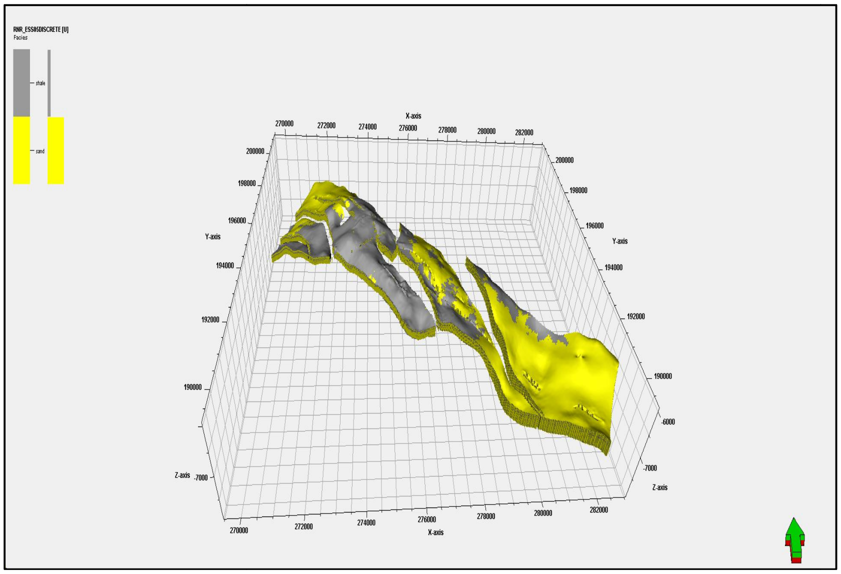

Fig. 6. Facies model of H Sand

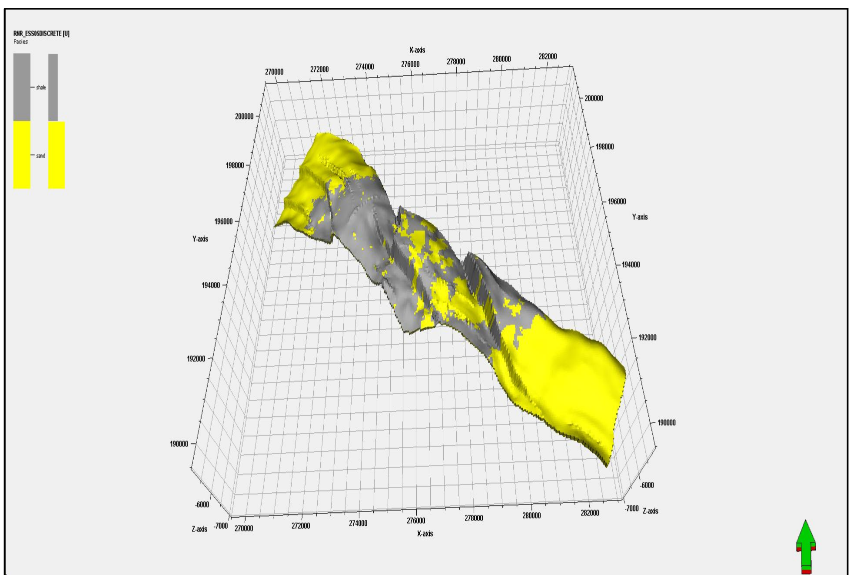

Fig. 7. Facies model of E Sand

Table 2. Current volume estimation of H10 reservoir(deterministic)

Parameters	**Reservoir H10**
Porosity	0.277
S_W	0.209
NTG	0.873
CGOC(TVDSS)	-6005
COWC(TVDSS)	-6100
STOOIP(MMSTB)	4.91

The energy plot is an important plot that shows the relative contribution of the source of energy in the reservoir. The energy plot of the H10 reservoir indicates that about 95% of its energy comes from the water drive while the fluid expansion and PV compressibility contributes negligible energy. This means that the H10 reservoir has a primary recovery and a dominant energy drive from water influx. (Fig. 8).

Water influx is also the main energy drive in the E40 reservoir accounting for about 95% of the total energy drive, accompanied by fluid expansion and PV compressibility (Fig. 9).

Table 3. Current volume estimation of H10 reservoir(probabilistic)

	STOIP(MMSTB)	Porosity	NTG	S_W
P10	3.88	0.234	0.824	0.142
P50	4.96	0.278	0.875	0.205
P90	5.55	0.316	0.916	0.270

Table 4. Tank and PVT parameters for H10 and E40 reservoir

Tank and pvt Data	H10	E40
Reservoir temperature	170˚F	180˚F
Porosity	0.283	0.24
Water Saturation	0.127	0.13
Oil API	34.2	20.5
Boi	1.33Rb/Stb	1.209 Rb/Stb
Initial Pressure	2553Psia	2328psia
Bubble Point Pressure	2553psia	2328psia
Water Compressibility	Use correlation	Use correlation
Water Influx	Hurst-van Everdingen modified	Schihthius steady state
Relative Permeability	Corey function	Corey function
Initial GOR	350	396
Oil Viscosity	0.57cp	2.51cp
Gas Viscosity	0.65cp	0.65cp
Production Starts	6/30/2001	9/30/1972
Proved OOIP	14 MMSTB	43.08MMSTB

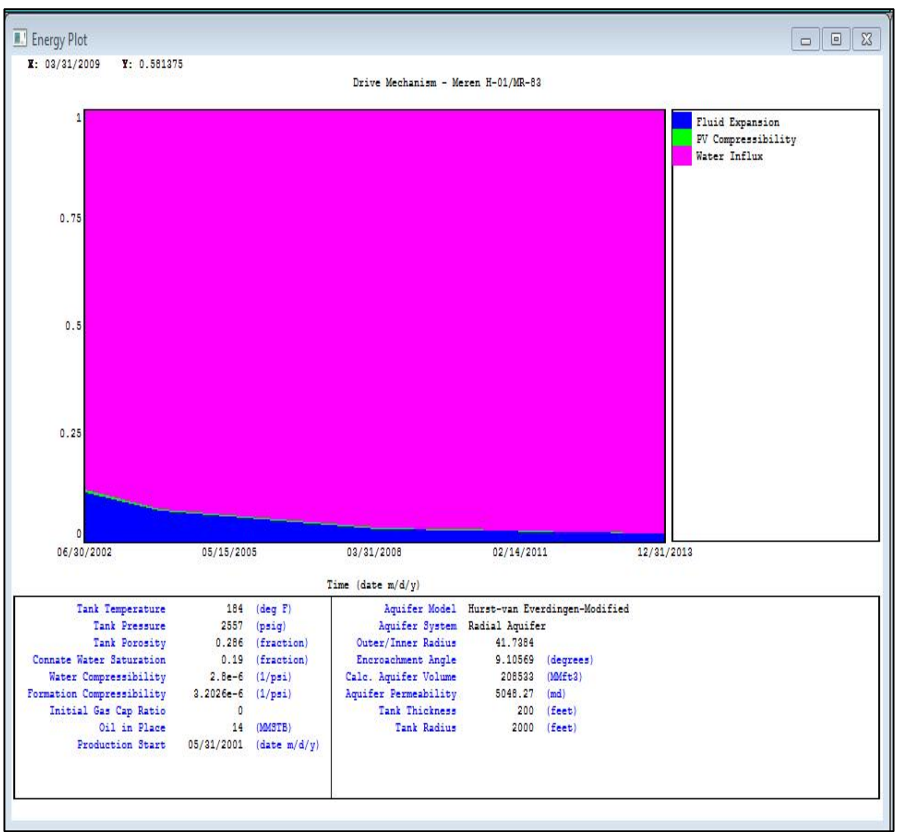

Fig. 8. The material balance energy plot of reservoir H10

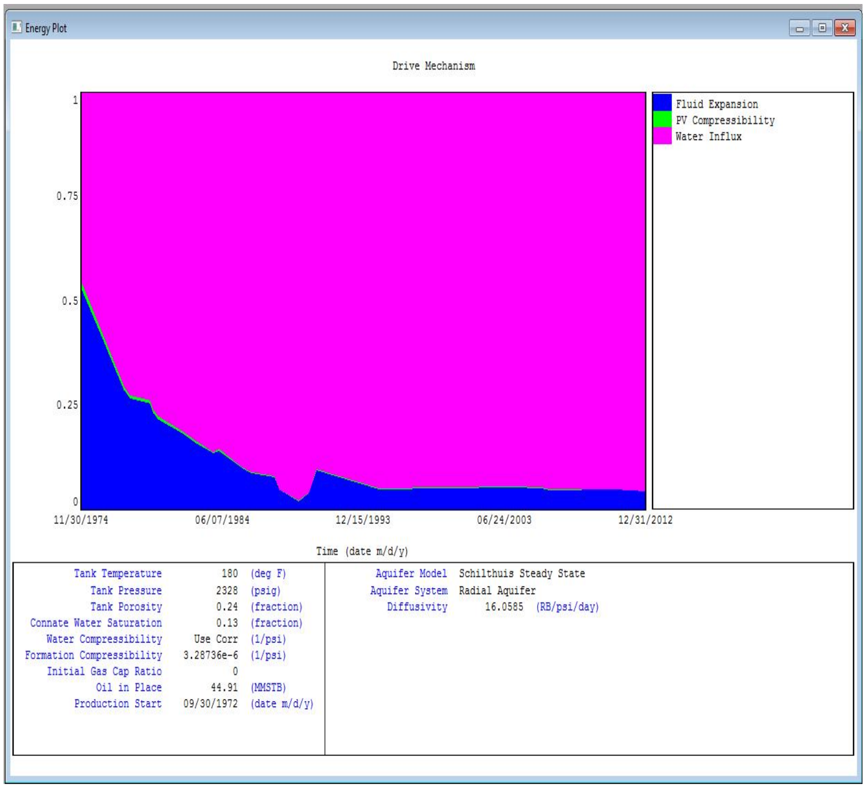

Fig. 9. The material balance energy plot of reservoir E40

The Campbell plot is a diagnostic tool that is used to identify the presence of aquifer in a reservoir based on the pressure and production behavior of the reservoir. This is inferred from the shape of the plot withdrawal over total expansion against total withdrawal. This gives an insight into the strength of the aquifer and the intercept on y-axis gives an estimate of the oil in place. The Campbell plot (F/Et versus F) of the H10 reservoir (Fig. 10) indicates that the reservoir has a strong water drive which is consistent with the energy plot (Fig. 7) that shows about 95% contribution of water influx in the reservoir. This plot gives estimated oil in place of 14MMSTB. The Havlena-Odeh method plots F/Et versus sum (dPˆQ(tD)/Et gives an oil in place(N) of 14.06MMSTB. All other graphical plots such as the plot of F/Et versus We/Et, (F-We)/Et versus F, and plot of (F-We)/(Eo+Efw) versus Eg/(E0+Efw) also estimated oil in place of approximately 14MMSTB.

The Campbell plot (F/Et versus F) of E40 reservoir indicates that the reservoir has a strong water drive which is consistent with the energy plot that shows about 92% contribution of water influx in the reservoir (Fig. 11). This plot gives estimated oil in place of 42.75 MMSTB. The Havlena-Odeh method plots F/Et versus sum (dPˆQ (tD)/Et gives an oil in place (N) of 43.075MMSTB. All other graphical plot such as the plot of F/Et versus We/Et, (F-We)/Et versus F, and plot of (F-We)/ (Eo+Efw) versus Eg/ (E0+Efw) also estimated an oil in place of ranging from 42-43MMSTB, which falls between the range of STOOIP estimated using core values 40.12MMSTB and the STOOIP estimated using property maps average 47.6MMSTB.

The analytical plot is a plot that shows how well the inputted data matches the simulation model produced by MBAL. The two analytical plot below shows that the model is well matched (Figs.12 and 13). These were achieved by using a non-linear regression method in MBAL. The analytical plot uses a non-linear regression method to assist in estimating the unknown reservoir parameters, as well as aquifer parameters and the response of the model, is plotted against the historical data. After the regression and a best match is achieved, the values of each parameter that achieved the best fit were noted. The best fit for OIIP from the material balance analysis in the H10 reservoir is 14MMSTB, which is closed to the estimated OIIP using core data values, while that of the E40 reservoir is 43.02 MMSTB which is close to the average of OOIP estimated from Core data and petrophysical data 43.64 MMSTB.

The simulation model for the H10 reservoir was used to estimate the current fluid contacts in the reservoir (Fig. 14), and these current contacts were used to calculate the oil in place and to create a map showing the remaining oil in the reservoir in ft. (Fig. 15) The stared area (well 3) in the map has the highest oil thickness and hence is the reasonable location for a perforation add which will help to drain the reservoir.

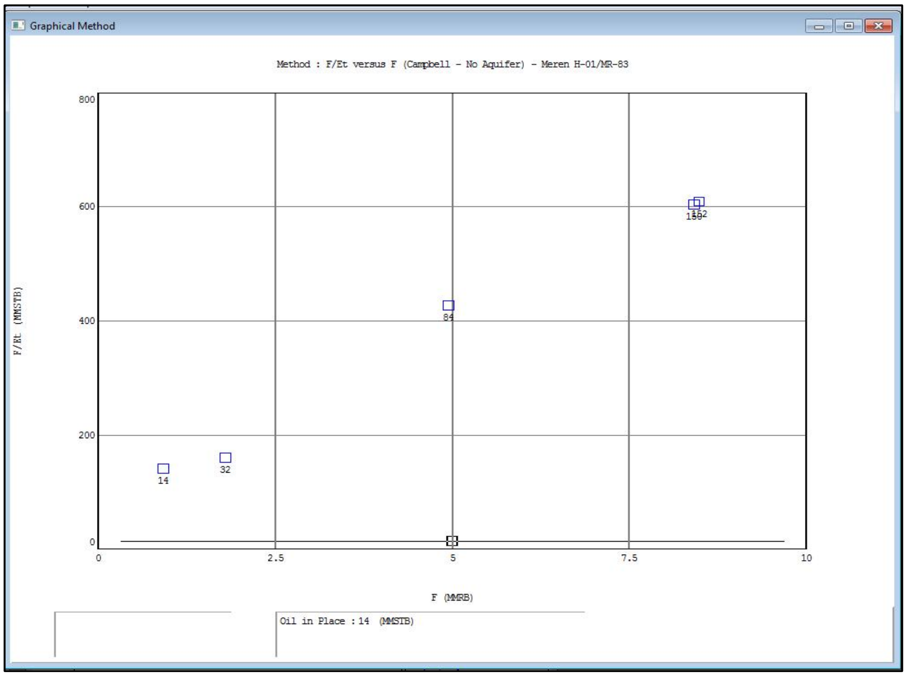

Fig. 10. Campbell(no aquifer) plot of reservior H10

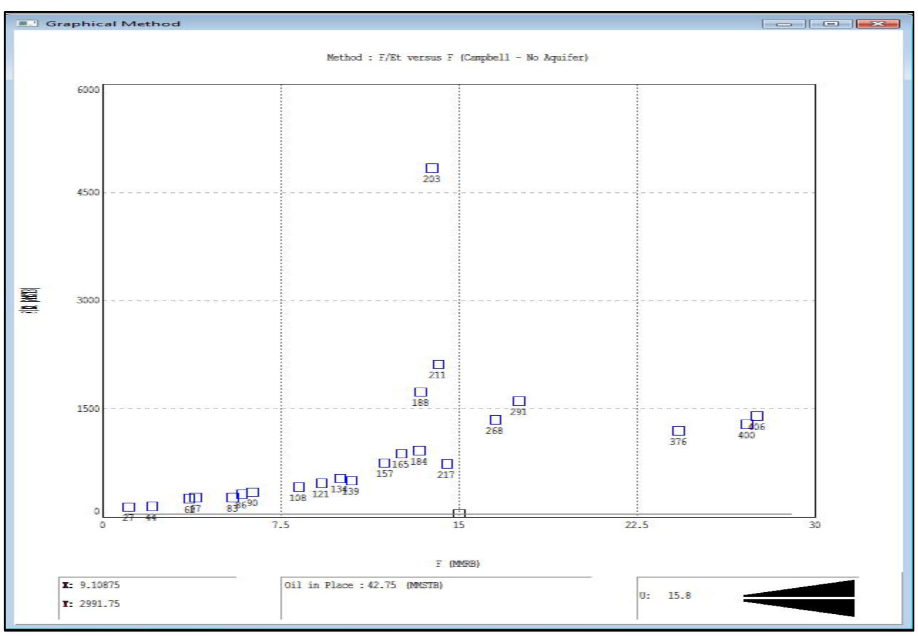

Fig. 11. Campbell(no aquifer) plot of reservior E40

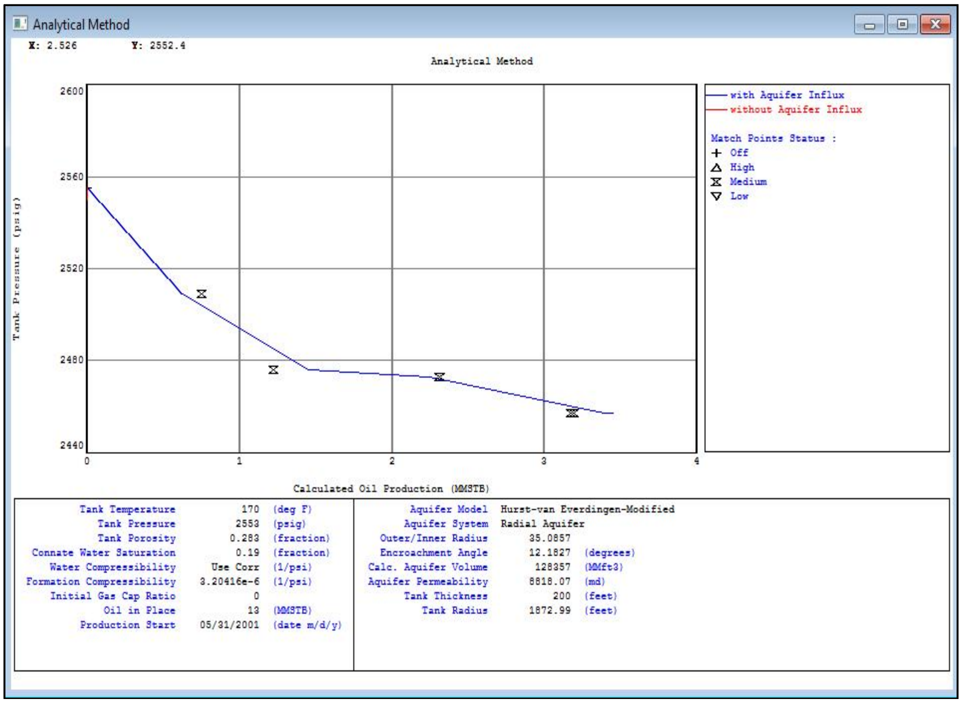

Fig. 12. Analytical plot of the tank pressure vs oil production for H10 reservoir

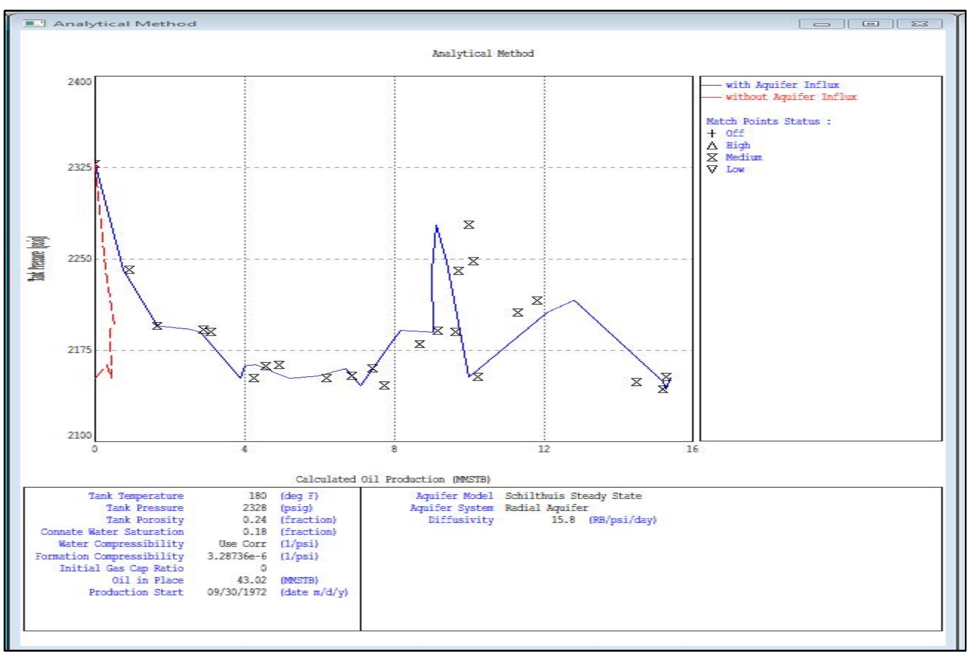

Fig. 13. Analytical plot of the tank pressure vs oil production for E40 reservoir

3.4 Reservoir Recovery Strategy

The Cumulative production of reservoir H10 as of July 2016 is approximately 3.54 MMBO representing a 28% recovery factor. Well 3 is currently the only active completion in the reservoir producing 157 bopd, 2573 GOR SCF/STB and 80% of water as of June 2016. Well 2 came on stream in March 2008 and produced 0.2 MMBO before quitting in January 2009 due to high water cut. The reservoir was initially saturated with pressure of 2,553 psi. The last measured pressure in well 3 in May 2014 was 2,453 psi indicating about <5% pressure decline (Fig. 3). The pressure data and MBAL analysis shows the reservoir has a strong aquifer (Figs. 8 and 9).H10 reservoir is not under water-injection, but Gas lift optimization was introduced to improve the performance. However the current performance is low, hence the reason for this study.

The CGOC and COWC were estimated from MBAL analysis at -6,005'TVDSS and -6,100 TVDSS respectively. Based on production data from well 3, an alternative interpretation was made, and a COWC @ 6,056 TVDSS was estimated. There is a large difference between the Mbal COWC @-6100TVDSS and Production data COWC @-6056 TVDSS, however, the current contact from the Mbal model is more reliable because it was calibrated with well 2 open-hole logs which identified OWC @ 6,122 TVDSS vs MBAL @ 6,113 TVDSS in 2008. However, there is the suspicion that the water production in well 3 is from a different source and local to the well, and these may be the reason why the COWC from production data much shallower than the Mbal contacts. Conversely, based on the conservative estimated COWC of -6100'TVDSS from Mbal and COGC of 6,005' TVDSS from Mbal, there is about 100' TVD of oil column remaining in the well.

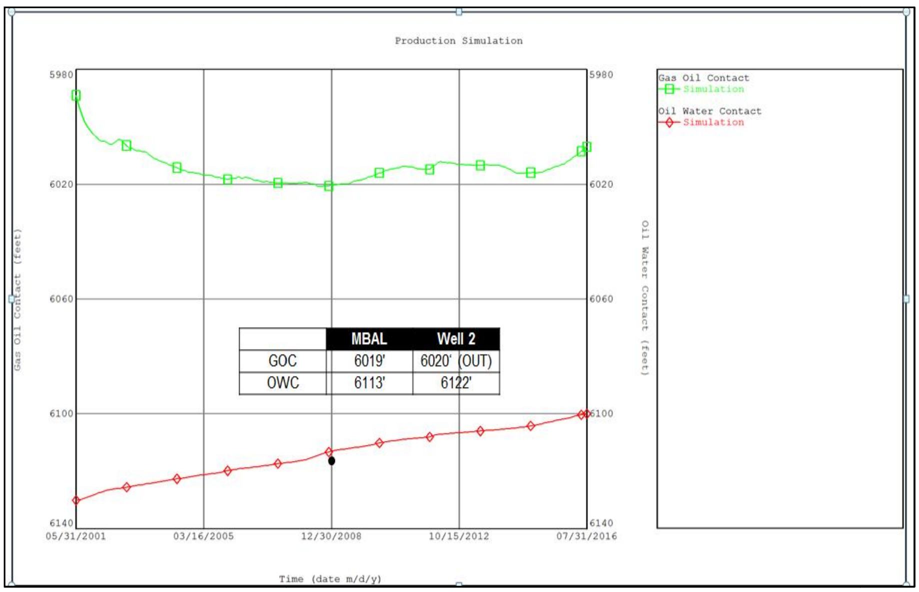

Fig. 14. Simulation plot of the current fluid contacts in the H10 reservoir

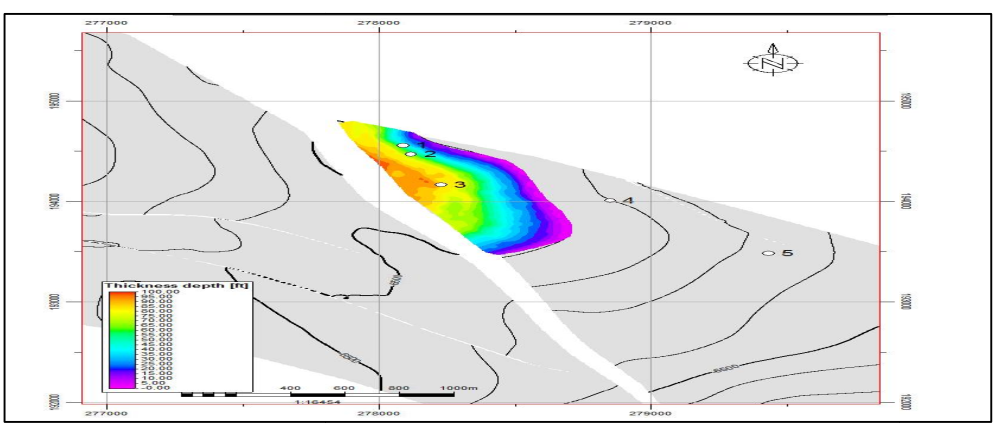

Fig. 15. Remaining net oil map of reservoir H10

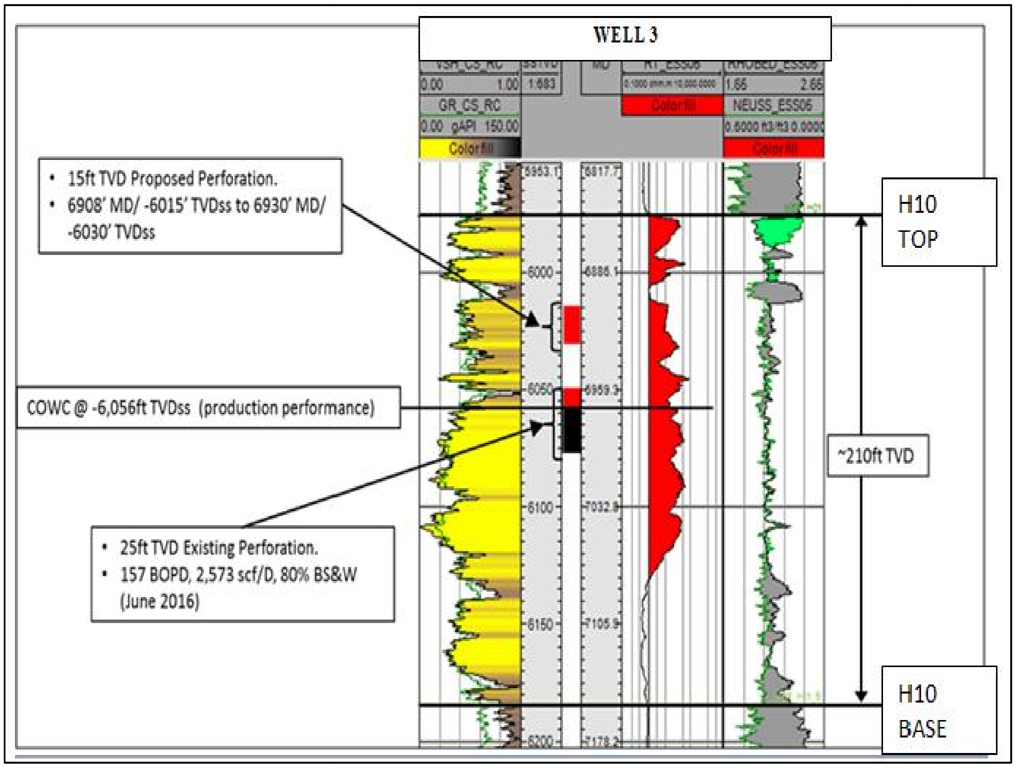

Fig. 16. A type log of well 3 showing perforation intervals

Therefore a through tubing plug back (TTPB) and perforation add operation in well 3 will be proposed. The TTPB has been proven to have a high success rate, and it is less costly than a rig job. The objective of this proposal is to plug-back the existing perforation at -6049'TVDSS to -6075'TVDSS to reduce the water cut in the well, and then add 15ft TVDSS (22ft MD) of perforation at -6015' TVDSS to -6030'TVDSS (Fig. 16). This is expected to mitigate water production and allow for more fluid production, especially to increase oil production over a period of time.

E40 reservoir has been producing since 1972 with a cumulative production of 18.7MMSTB representing a 45% recovery factor. Well 1 and well 4 are the active producers in this well, each about producing 508bopd. The reservoir was initially saturated with pressure of 2,328 psi. The last measured pressure in December 2012 was 2,145 psi indicating about <8% pressure decline for 40 years. The low decline in pressure in this reservoir can be explained by the strong water drive present in the reservoir shown by the MBAL analysis (Fig. 9). To adequately drain this reservoir, well 4 can be sidetrack.

4. CONCLUSION AND RECOMMENDATION

The material balance model was effective at history matching the production performance of the reservoirs and at estimating the current fluid contacts in the reservoirs, which was used to determine the remaining oil in place in H10 reservoir to be 4.9 MMSTB. The primary drive mechanism of the reservoir is the water drive. The current contacts from MBAL suggest about 100 feet of oil in the reservoir, which means there is more room for perforation in H10 reservoir. The following recommendation is suggested for the reservoirs

1. Carry out Geochemical Analysis on well 3 to confirm source of water production in H10 reservoir
2. Check the cement bond logs on well 3 (H10 reservoir) to confirm good cement job was achieved at initial well completion
3. Opportunity exists to add ~20' of perforations on well 3 in H10 reservoir
4. Conduct saturation logging to confirm current fluid distribution in the H10 reservoir

5. Well 4 can be sidetracked in reservoir E40 to adequately drain the remaining reserves in E40.

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COMPETING INTERESTS

Authors have declared that no competing interests exist.

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