EVALUATION OF DRIVE MECHANISMS ON OFFSHORE OIL RESERVOIRS BY ANALYTICAL METHODS

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Gum Deniz Oil Field played the important role in energy production from Caspian Region. The Field is still under production and needs further engineering studies to recover more energy from the remaining reserves by controlling environmental issues. Therefore, the reservoir performance and drive mechanisms of an oil reservoir in Gum Deniz Oil Field, Azerbaijan, were determined by material balance and simulation studies. The oil in place, average reservoir pressure, amount of water encroachment, fluid saturations, recovery factor and the type of reservoir drive mechanisms were estimated based on field production data. The estimated oil in place was 35.4 MMstb. Initially, the dominant reservoir drive mechanism was depletion drive together with compaction drive and fluid expansion mechanisms. After water encroachment, both water drive and depletion drive mechanisms played important roles on fluid production. The current and ultimate recovery factors were obtained as 25 and 37% of OOIP, respectively.

FIELD AND RESERVOIR DESCRIPTION

Gum Deniz (GD) was one of the important oil fields of Azerbaijan at Caspian Sea. The GD Oil Field lies in shallow water approximately 20 km southeast of Baku immediately off the coast of Azerbaijan. Following discovery in the early 1950's, production began from the GD oil Field in 1955. As of the end of 2009, ~32.9 million m^3 (207 million bbls) of oil and ~16.5 Bm^3 (581Bcf) of gas were reported as having been produced from the field. The company reported that 484 wells have been drilled historically, with 61 wells reported on production at the end of September 2010 using gas lift. The GD Oil Field is a faulted anticline (16 fault blocks) located up dip from the Bahar Gas Field. Of the fault blocks, 11 are reported as having established commercial production. 12 separate pay zones over ~1525 m (IV, V, VI, VII, VIII, IX, X, SP, NKP, KS, PK, KaS) have been identified in the field, with three to four found (on average) in each of the productive fault blocks. These intervals are composed of alternating sandstones and shales. Average crude from the field has 36° API gravity; although this ranged from 30° API to 45° API. Similar to the Bahar gas field, the reservoir rocks (sandstone and siltstones) are of good quality, with 10% to 22% porosity and most of the producing zones display permeability in the 100 mD to 230 mD range. Historical peak production from the field was achieved to 7.378 m^3/d (46,400 bpd) in 1964.

The primary reservoir sands are contained in the upper and middle parts of the Productive Sequence – the Surakhany, Sabunchi, Balakhany and Pereryva suites. The lower parts of the Middle Miocene consist primarily of mudstone with thin impersistent sandy units. Reservoir quality in the Productive Sequence is a function of three main criteria – reservoir facies, the provenance of the sands and burial depth. Sandstone and siltstone reservoirs of the Productive Sequence are sealed by numerous intra-formational mudstones and shales (Abreu, Nummedal, 2007).

Rock and fluid data

Permeability-porosity relationship

The wells on the field have been logged using various Russian logging tools. Permeability was estimated from routine porosity and permeability measurements performed on cores. From the available data, the following relationship between permeability and porosity was established.

$$k = 0.1615 e^{0.3387\phi} \quad (1)$$

Where k (permeability) in mD and ϕ (porosity) is in percentage.

Pore compressibility

Rock strength is estimated from two common laboratory techniques; unaxial compressive strength (UCS) tests, and triaxial or confined compressive strength tests. UCS tests is used to determine the ultimate strength of a rock, i.e., the maximum value of stress attained before failure (Fjaer et al., 1992). UCS (Bruce, 1990) was calculated for unconsolidated (loose) sand. The correlation between the formation compressibility and porosity was developed by using Newman's study (1973). The properties can also be used for estimating sand failure problem during production (Collins, 2002).

PVT Data

The PVT properties can be obtained from a laboratory experiment using representative samples of the crude oils. However, the values of reservoir liquid and gas properties must be computed when detailed laboratory PVT data is not available. Correlations on PVT which is commonly used in the oil industry are important tools in reservoir-performance calculations. For developing PVT correlation, the chemical composition of crude oil must be considered (Mahmood, Al-Marhoun, 1996). Because of the availability of a wide range of correlations, it is beneficial to analyze them for a given set of PVT data belonging to a certain geological region. Therefore, PVT correlations need to be modified prior to their applications to account for regional characteristics. PVT correlations were modified for Gum-Deniz Field's SP reservoir oil (Gumrah et al., 2012).

RESULTS AND DISCUSSION

The hydrocarbon in place for SP oil horizon in Block 7 was estimated. The volumetric method based on area, porosity, saturation and thickness was conducted. Then, the material balance method was applied with the use of field production data. The reservoir simulation model was constructed. The fluid productions and pressures were matched. The results were compared with that of material balance analysis.

Estimating hydrocarbon in place by volumetric method

The average reservoir parameters for SP horizon are given in Gumrah et al. (2012). The bulk volume was determined from the isopach map of the reservoir, average porosity and oil saturation values from log and core analysis data, and oil formation volume factor from correlations. The volumetric initial oil in place was 38.5 MMstb and the recovery factor was 23.1 % of OOIP (181.4 stb/acre-ft). In volumetric method, the net pay (30.9 m), areal extent (483.7 Acre), water saturation (0.24) and porosity (0.17) data were taken as average values and there are many uncertainties with regard to these parameters.

Estimating hydrocarbon in place by material balance analysis

One tool the reservoir engineer uses to monitor field/well performance quickly and accurately is the material-balance plots. The material balance method for solution gas drive reservoir is given below in a linear from. In this type of reservoir, the principal source of energy is a result of gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced. As pressure falls below the bubble-point pressure, gas bubbles are liberated within the microscopic pore spaces. These bubbles expand and force the crude oil out of the pore space. As the reservoir pressure declines, the rock and fluids expand due to their individual compressibility.

The summation of production terms (F);

$$F = N_p \left[B_{o2} + \left(R_p - R_{so2} \right) B_{g2} \right] + W_p B_{w2} \quad (2)$$

Oil and Dissolved gas expansion terms (E_o);

$$E_o = (B_{o2} - B_{o1}) + (R_{so1} - R_{so2}) B_{g2} \quad (3)$$

Gas cap expansion term (E_g);

$$E_g = B_{o1} \left(\frac{B_{g2}}{B_{g1}} - 1 \right) \quad (4)$$

Rock and water compression/expansion terms ($E_{f,w}$)

$$E_{f,w} = -(1+m) B_{o1} \frac{C_r + C_w S_{w1}}{1 - S_{w1}} \Delta P \quad (5)$$

Both of the above two factors are the results of a decrease of fluid pressure within the pore spaces, and both tend to reduce the pore volume through the reduction of the porosity. This driving mechanism is considered the least efficient driving force and usually results in the recovery of only a small percentage of the total oil in place. Abasov et al. (2012) studied the hydrogasdynamics of deep deposited deformable porous media in Caspian region.

The complete material balance equation (MBE) is

$$F = N\left(E_o + mE_g + E_{f,w}\right) + \left(W_i + W_e\right)B_{w2} + G_i B_{g2} \qquad (6)$$

Equation 6 can be modified as equations of straight lines, which can be applied to different types of reservoirs. In our case, without water injection (W_i=0), gas injection (G_i=0) and no initial gas cap (m=0), the equation becomes;

$$F=N(E_o+E_{f,w})+W_eB_{w2} \qquad (7)$$

Figure 1 shows the estimated initial oil in place with rock and water compression/expansion terms. The calculated initial oil in place was 35.4 MMstb that is less than 38.5 MMstb obtained by volumetric estimation. The effect of rock and water expansion on N value was insignificant.

Pressure history matching

Historical data goes back to 1960 and are updated occasionally. Material Balance (MB) study was done based on gas, oil and water production data. The average reservoir and aquifer pressures were predicted through MB analysis by matching the recorded well static pressures. The average reservoir pressures were compared with measured data by changing the water influx rate till getting reasonable match. The aquifer influx rate (J) was obtained as 2 bbl/psi. The total water encroachment was 25.95 MMstb. The cumulative oil production was 8.895 MMstb. The cumulative water production was 7.99 MMstb and the cumulative gas production was 21.04 Bcf. The water production was higher in few wells; this might be attributed to the possible locations of water entry into the SP reservoir. Since the calculated N by MB method is less than that of volumetric method, the fluid production from SP reservoir within the boundaries of Block 7 was verified. The faults or boundaries set for Block-7 were defined well. The current recovery factor (RF) reached to 25% of OOIP. The ultimate oil recovery factor of individual reservoirs under primary and/or conventional recovery methods may range from 5% of OOIP for the poorest reservoir characteristics or for viscous oil, to as high as 55% of OOIP for the best reservoir characteristics or for light oil.

Oil, water and gas saturations

The fluid saturations were calculated with the following equations:

Oil saturation;

$$S_{o2} = \frac{(N - N_p)B_{o2}}{V_{p2}} \qquad (8)$$

Water saturation;

$$S_{w2} = \left[(1+m)NB_{o1}\left(\frac{S_{w1}}{1-S_{w1}}\right)\left(\frac{1}{B_{w1}}\right) + \left(W_i + W_e - W_p\right)\right]\frac{B_{w2}}{V_{p2}} \qquad (9)$$

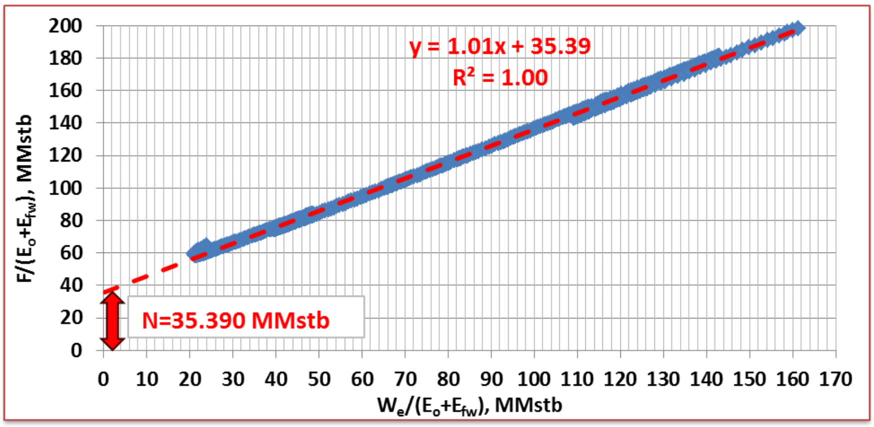

Figure 1. Material balance plot for N with E_{fw} term

Gas saturation;

$$S_{g2} = \left[N\left[\left(R_{so1} - R_{so2}\right) + m\left(\frac{B_{o1}}{B_{g2}}\right) - N_p\left(R_p - R_{so2}\right) + G_i \right]\right] \frac{B_{g2}}{V_{p2}} \quad (10)$$

And

$$S_o + S_w + S_g = 1 \quad (11)$$

Reservoir drive mechanisms

Table shows the indices for depletion drive (DDI), segregation drive (SDI), compaction drive (CDI) and water drive (WDI) mechanisms (Smith et al., 1992). The denominator for each index is the same; total cumulative oil-zone production on a reservoir volume basis. This is the factor to normalize the energy (expansion) associated with each of the drive mechanisms. When production begins from a new reservoir, the pressure declines. So, every reservoir operates, in the beginning, predominantly by expansion drive. Whether much water drive occurs depends upon the proximity of water (bottom or edge), the volume of water, and the permeability-area product available to the water. A drive index may be considered as the fraction of total oil zone withdrawals due to a particular drive mechanism.

Rock properties of loose sand (SP Reservoir)

LOOSE SAND					
E,psi	12,000	16,250	21,000	32,000	72,000
v	0.478	0.467	0.456	0.425	0.300
UCS, psi	**117**	**145**	**178**	**238**	**437**
TWC, psi	774	867	966	1127	1555
C_f, 1/psi-Eqn 3	1.115E-05	1.218E-05	1.257E-05	1.406E-05	1.667E-05
C_f, 1/psi-Eqn 4	1.143E-05	1.206E-05	1.275E-05	1.388E-05	1.700E-05
C_f, 1/psi-Eqn 7	1.199E-05	1.264E-05	1.334E-05	1.450E-05	1.776E-05
Porosity,%	24.0	22.7	21.3	19.4	15.4
V_{shale},%	34.0	37.0	46.0	55.0	71.5

Since the initial gas cap (m) for SP reservoir is zero, SDI is also zero. The reservoir drive mechanism indices were calculated with production and PVT data. In early production time, depletion drive together with compaction drive and fluid expansion mechanisms were dominant. After water entrance into the reservoir, water drive mechanism played an important role together with depletion drive mechanism. This type of information will be useful for the reservoir development strategies that lead to possible improved oil recovery activities.

The summation of all reservoir drive indices is one.

$$DDI+SDI+CDI+WDI=1 \quad (16)$$

Ultimate recovery factor

The current recovery factor was obtained as 25% of OOIP. The decline curve analyses for the wells were done to estimate the remaining recoverable reserve from SP Horizon in Block 7. The past annual decline rate ranged between 0.11 and 0.25 1/year (average of 0.18 1/year). The project time is 15 years after 2012 and the remaining recoverable reserve was estimated as 4.246 MMstb. Therefore, the ultimate oil production will be around 13.141 MMstb. It corresponds to the ultimate recovery factor of 37.0% of OOIP. The additional production from SP reservoir will be obtained by drilling new wells. This recovery factor is within the recovery range of combined drive mechanisms of solution gas drive and partial water drive.

Reservoir modeling study

The upper and lower flow units of SP reservoir were constructed by using all available data. All rock and fluid properties gathered in material balance analysis were used in reservoir simulation study. Knowledge of reservoir characteristics, which include drainage area size, rock and fluid properties, change in pore volume, amount of water influx and type of reservoir drive mechanisms, gives insight into well spacing efficiency and the need for reservoir development strategies that lead to possible improved oil recovery activities. All the production wells have been drilled on the region having good reservoir quality (Figure 2). The resultant relative permeability curves are given in Figure 3.

The history matching study was done till getting a good match between the simulated and recorded production data (Figure 4). The measured and the calculated average reservoir pressures by material balance analysis and modeling study were in good agreement.

The future production till 2025 was forecasted by producing from 5 new wells. The ultimate recovery factor was obtained as 37% of OOIP. The recoveries and the remaining oil reserve are shown in Figure 5.

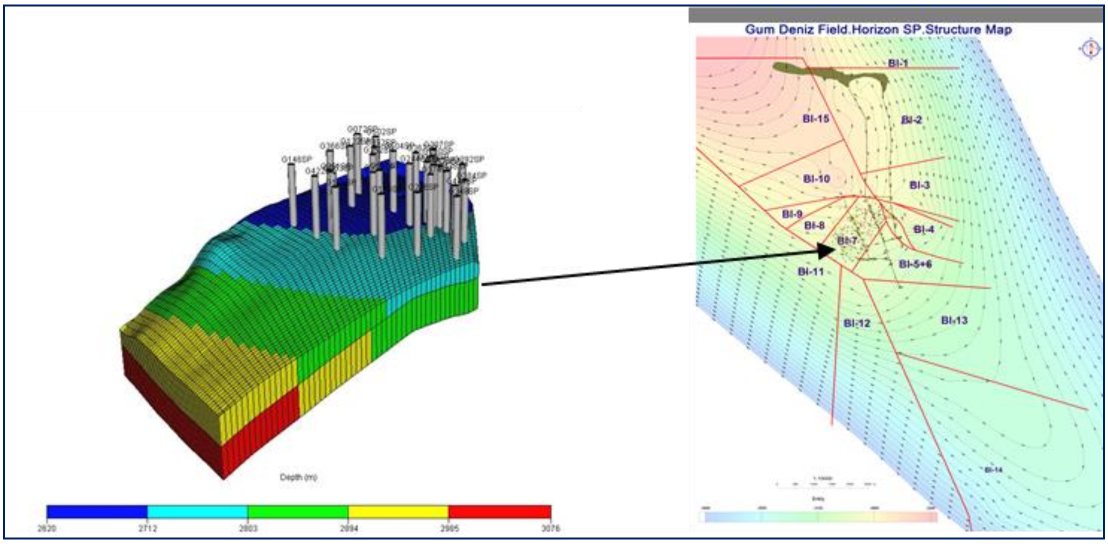

Figure 2. SP structure map with blocks and reservoir model with production wells

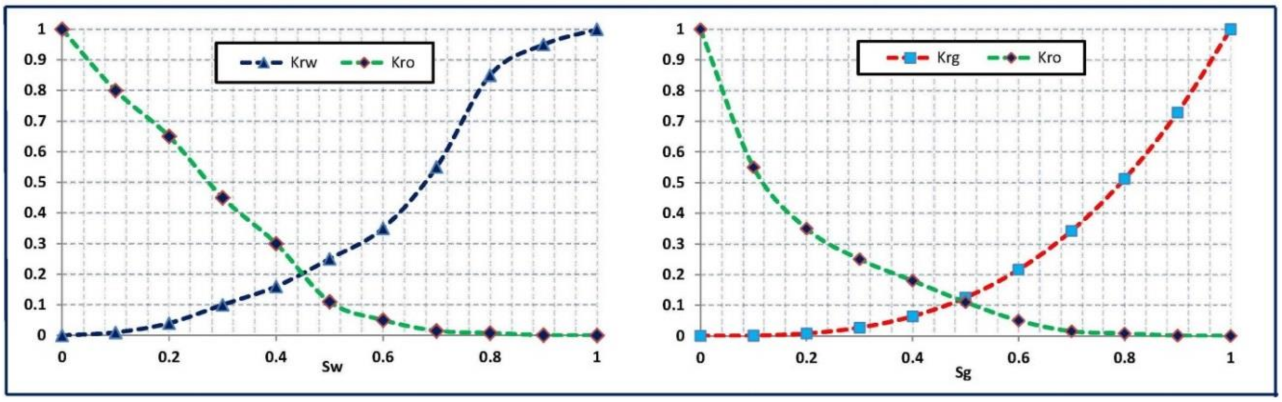

Figure 3. Oil-water & gas-oil relative permeability

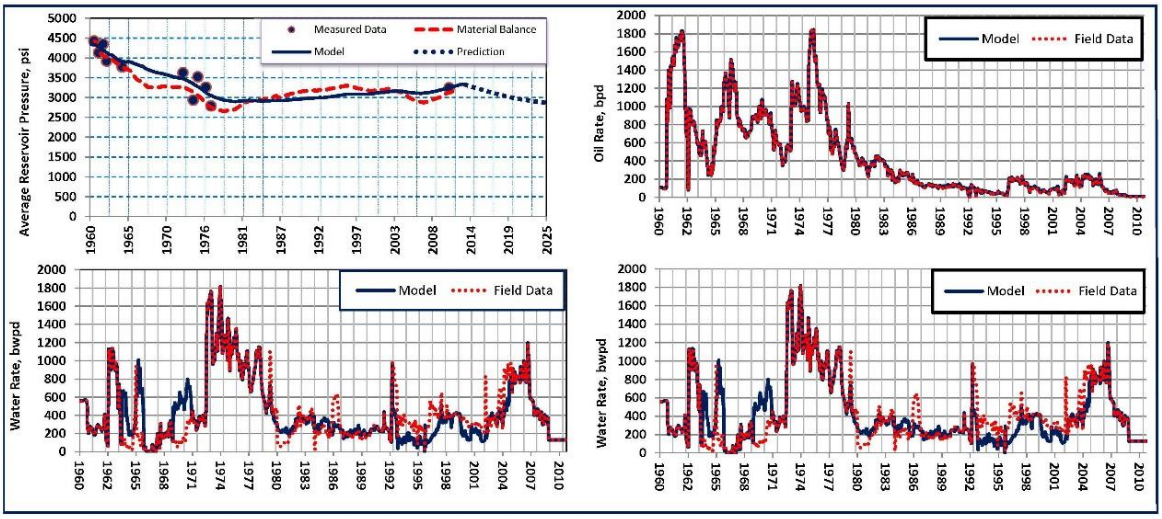

Figure 4. History matching of field data and model results

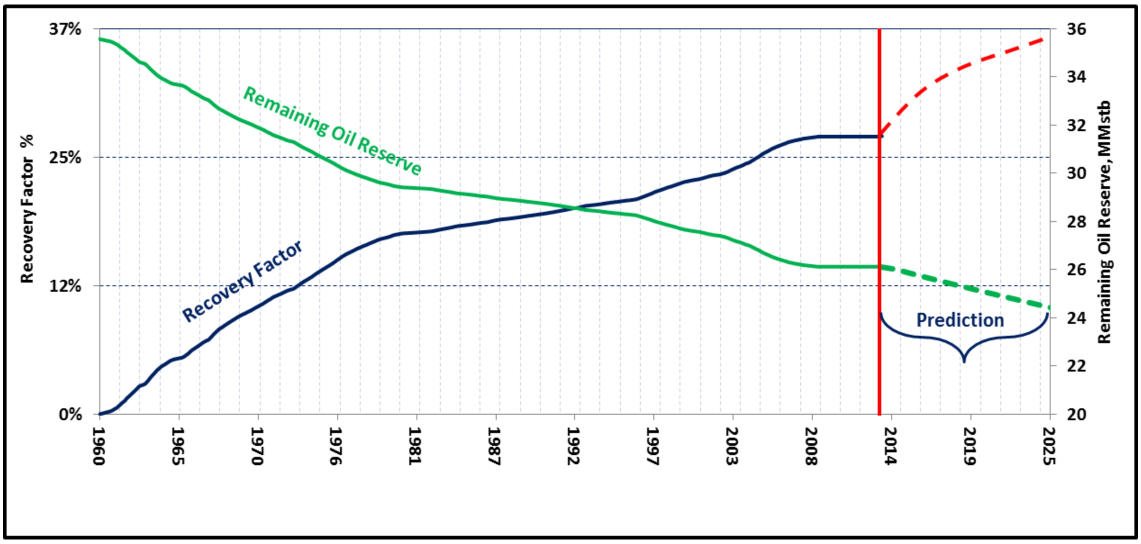

Figure 5. Oil recovery factor &remaining oil reserve (simulation)

CONCLUSIONS

- Since the calculated oil in place (N) by material balance method is 35.4 MMstb which less than that of volumetric method (38.5 MMstb), it was verified that the fluids were mainly produced from SP reservoir within the boundaries of Block 7. The faults or boundaries set for Block-7 were defined well.
- In early production time, compaction drive and fluid expansion mechanisms were dominant. After water encroachment, water drive mechanism played an important role together with depletion drive mechanism. The current recovery factor was obtained as 25.0% of OOIP. The ultimate recovery factor was estimated as 37.5% of OOIP by decline curve analysis of well data.
- The results obtained by material balance and simulation studies are consistent and these models can be used for future plans to develop the reservoir on a field base.

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NOMENCLATURE

B_{gi} = Initial gas volume factor at P_i (ft^3/scf)
B_g = Gas volume factor at current pressure P (ft^3/scf)
B_{oi} = Initial oil volume factor at pi (rb/stb)
B_o = Oil volume factor at current pressure P (rb/stb)
B_w = Formation volume factor of water at current pressure P (rb/stb)
B_t = Total volume factor at current pressure P (rb/stb)
c_f = Compressibility of formation (psi^{-1})
c_w = Compressibility of water (psi^{-1})
f_w = Water-cut (fraction)
G_p = cumulative gas produced (scf)
N_p = Cumulative oil produced (stb)
p_i = Initial mean pressure in the reservoir (psi)
p = Current average pressure in the reservoir, (psi)
$R_p = G_p/N_p$ = Cumulative produced gas-oil ratio (scf/stb)
R_{si} = solution gas-oil ratio at initial pressure P_i (scf/stb)
R_s = solution gas-oil ratio at current pressure P (scf/stb)
S_{wc} = Connate water saturation, (fraction)
S_o = Oil saturation, (fraction)
S_g = Gas saturation, (fraction)
W_p = Cumulative water produced (stb)

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