WELL TESTING MECHANISMS THROUGH MULTI – BEAM RESEARCH: SURVEY ON RESERVOIR PARAMETERS.

V. RAGUL- PETROLEUM ENGINEERING (MASTER OF TECNOLOGY). Mail id: **ragulvenkat111@gmail.com**

K. SABATINI - PETROLEUM ENGINEERING (BACHELOR OF TECHNOLOGY). Mail id: **sabatinik1397@gmail.com**

M. NAGAMANI- PROFESSOR OF MATHEMATICS (GLOBAL INSTITUTE OF ENGINEERING AND TECHNOLOGY). Mail id: **nagamanim1983@gmail.com**

ABSTRACT

Water injection is considered to be the secondary recovery mechanism, in case of depletion of pressure in the reservoir. Injecting water of required quality helps in maintaining the reservoir pressure and thereby improving the recovery. This mechanism has been followed as a traditional method for the secondary recovery. Normally only 10% to 20% of the oil can be extracted, however water injection augments the recover percentage and maintains the production rate of a reservoir over a longer period.

As water is available in large quantity and treatment of water is also economically viable, the reservoir has been studied for its reservoir parameters and based on the results obtained from pressure analysis through various well testing like pressure build – up test and pulse test or interference test and simulation studies, the techno-economical calculation have been made and the results proved to be more economical.

INTRODUCTION

WATER INJECTION

This refers to the technique in the oil industry where water is injected back into the reservoir, ordinarily to increase pressure and thereby stimulate production. Water injection wells can be discovered both on and off shore, to build oil recovery from an existing reservoir. The first use of water injection to increase production from failing oil wells was in the state of New York and Pennsylvania in the early 1930s.

- To reinforce pressure of the reservoir (also known as voidage replacement), and
- To sweep or displace oil from the reservoir, and impel it towards a well.

Typically, just 30% of the oil in a reservoir can be removed, however water injection increases that rate (known as the recovery factor) and keeps up the production rate of a reservoir over an extended period.

SOURCES OF INJECTED WATER

- Produced water
- Sea water
- Aquifer water
- River water
- Filter

WATER INJECTION PUMPS

The high-pressure high flow water injection pumps are put close to the de-oxygenation tower and boosting pumps. They fill the bottom of the reservoir with filtered water to push the oil towards the well like a piston. The consequence of the injection isn't brisk, it needs time.

Water injection is utilized to prevent low pressure in the reservoir. The water replaces the oil which has been taken, keeping the production rate and the pressure the equivalent over the long term.

PROCESS OF WATER INJECTION

In this process, the primary objective is to fill the voidage created by the produced oil fractions thus avoiding the reservoir pressure to decrease with the increased production. When the water is injected in the reservoir, it tends to push the oil towards thus upwards thus increasing the life and ultimate recovery o reservoir. Water injection and Water flooding are very comparable terms the main distinction being the level at which injection water is being release and displacement phenomenon.

In water injection work process, the injected water is released in the aquifer through few injection wells encompassing the production well. The injected water makes a bottom water drive on the oil zone promoting the oil upwards.

In earlier practices, water injection was done in the later phase of the reservoir life but now it is carried out in the earlier phase so that voidage and secondary gas cap in the reservoir are not created.

Utilizing water injection in the prior phase helps in improving the production as once secondary gas cap is framed the injected water initially tends to compact free gas cap and later on impelling the oil accordingly the measure of injection water required is significantly more. The water injection is generally carried out when solution gas drive is available or water drive is feeble.

Thus, for better economy the water injection is done when the reservoir pressure is more than saturation pressure.

The determination of injection water (displacing fluid) relies upon the mobility rate between the displacing fluid (injection water) and the displaced fluid (oil).

PARAMETERS TO BE CONSIDERED BEFORE WATER INJECTION

- Fluid properties
- Areal geometry
- Reservoir depth
- Fluid saturation
- Reservoir uniformity and pay thickness
- Cumulative water injection
- Areal sweep prediction method
- Vertical sweep efficiency

LITHOLOGY AND ROCK PROPERTIES

Porosity: Fracture porosity

Permeability: Tight (low - permeability) reservoir or reservoirs with thin net thickness possess water-injection problems in terms of the desired water injection rate or pressure.

Note that the water – injection rate and pressure are generally related by the following expression:

$$P_{inj} = I_w/\mathrm{HK}$$

Where,

P_{inj} = Water-injection pressure

I_w = Water-injection rate

H = net thickness

K = absolute permeability

Testing of well in different process

The three components of the classic well testing problem are flow rate, pressure and the formation. During a well test, the reservoir is exposed to a known and controllable flow rate. Reservoir response is measured as pressure versus time. The goal is then to characterize reservoir properties. For a typical pressure build up test, the test would have to be run until all after flow and phase redistribution effects cease.

Types of Pressure Transient Test

Different types of pressure transient test carried out in oil, gas and water injection wells are as per following:

- Pressure Build up test
- Pressure draw down / Reservoir Limit test
- Pressure fall off test
- Interference test/ Pulse test
- Two rate flow test

The accompanying generic analysis procedure is utilized to test and evaluate wells after completion:

- Stabilize the well's rate for quite a while after well completion and estimate the well productivity index dependent upon estimates of reservoir parameters.
- Build up a well-reservoir model for rate-time prediction (based on Step 1) and tune the model by history matching the observed data.
- Design and direct a pressure buildup test dependent on the parameters assessed from the previous two steps
- Interpret the pressure test data and confirm the model set up by the accessible rate-time data by means of an iterative process.

Interpretation Method

The destination of pressure transient testing is to determine reservoir and well properties in the well drainage area so that the well performance can be predicted. The pressure transient response can take on several particular flow regime early radial flow and linear flow, late radial flow and boundary –affected flow. Outcomes that obtained from well testing survey are a function of the range and the quality of pressure and rate data available, and of the approach used for the analysis.

With the introduction of the pressure derivative analysis in 1983 and the development of complex interpretation models that are able to account for detailed geological features, well test analysis has become a powerful tool for reservoir characterization. A new milestone has been reached by the introduction of the deconvolution. The deconvolution process converts any variable rate pressure record into an equivalent constant rate drawdown response with duration equal to the total duration of the pressure record. Thus, more data available for the interpretation than the original data set, where only periods at constant rate are analysed. Consequently, it is possible to see boundaries in the deconvolution, a considerable advantage compared to conventional analysis, where boundaries are not seen and must be inferred. This has a significant affect on capacity to certify reserves.

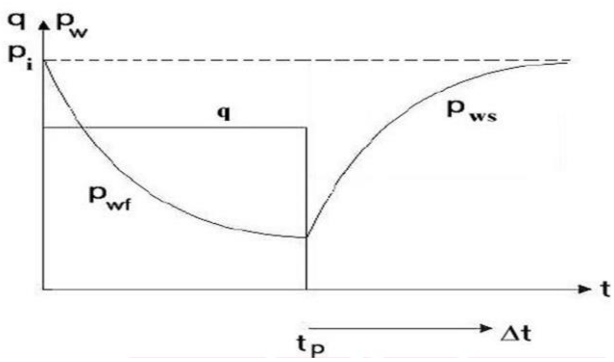
PRESSURE BUILD UP TEST

Definition

In a build up test, a well which is priory flowing is shut in and the downhole pressure is measured as the pressure buildups. The limitation of the method is that the well has to be closed and will not generate income. The shut-in time should be as short as possible for an economic perspective.

Procedure:

- Produce the well at constant rate. At time t_p close the well.
- Measure the last flowing pressure $P_{wf}(t_p)$, and the shut-in pressure, P_{ws}.
- Interpret by use of the matched method



BUILD-UP INTERPRETATION

Build-up test data is interpreted using EPS Pan System software.

BUILD-UP TEST RATE HISTORY

After activation, well was flowed through 6MM#3 bean for till flow rate is stabilised. Well closed for 24hrs pressure build-up test. Rate history used for build-up analysis is given below

Time (Hrs)	Pressure (psia)	Rate (STB/day)
-45	3000	0
2.462	2725.36	503
25.78	2772.97	0

TABLE :1 BUILD-UP TEST RATE HISTORY

Parameter	Value
Formation thickness	32.8 ft
Average formation porosity	0.12
Water saturation	0.45
Formation compressibility	4.5080e-6 psi-1
Total system compressibility	1.0424e-5 psi-1
Layer pressure	3200
Temperature	204^0F

TABLE :2 BUILD-UP TEST INPUT DATA: LAYER PARAMETER

Parameter	Value
Well radius	0.354 ft
Well offset – x direction	0.0 ft
Well offset – y direction	0.0 ft

TABLE :3 WELL PARAMETER

FLUID PARAMETER:

P_b, R_s, B_o Correlation : Standing

U_o Correlation : Beal et al

U_gCorrelation : Carr et al

Oil gravity	38.5 API
Gas gravity	0.615 sp gravity
Gas-oil ratio (produced)	702.0 scf/STB
Water cut	0

Check Pressure	3200.0 psia
Check Temperature	204.0 deg
Gas-oil ratio (solution)	661.53 scf/STB
Bubble-point pressure	3152.52 psia
Oil viscosity	0.869 cp
Oil formation volume factor	1.096 RB/STB
Gas viscosity	0.018 CP
Gas formation volume factor	5.7e-3 ft3/scf
Oil compressibility	1.05e-4 psi-1
Initial Gas compressibility	3.03e-4 psi-1

TABLE :4 FLUID PARAMETER

BUILD-UP INTERPRETATION:

- Discontinuity in the derivative is observed and to investigate further the nature of this discontinuity PPD (Primary Pressure Derivative) is plotted. Increase in primary derivative is observed and this increase in PPD cannot be conventional reservoir phenomena (Conventional reservoir behavior always shows decreasing PPD trend).
- Hump detected in early portion of build-up can be attributed to the phase segregation of oil & gas phases after shut-in the well. Analysis of static gradient survey conducted after build-up shows presence of gas column till a depth of 450m in the tubing i.e. this segregation of oil and gas phases after shut-in might have caused the sudden increase in build-up pressure and eventually pressure stabilized to normal build-up pressure.
- Clear radial flow is not established. Phase segregation and the resulting humping effect might have masked the radial flow.
- Fair variable well bore storage model is chosen to account for change in well bore storage and match is reasonably good
- Uptrend in the derivative is observed and this could be due to presence no flow barrier.

- Radial homogeneous Parallel fault with variable well bore storage model is chosen and match is fairly good.

RESULTS DISCUSSION:

- C_{phi} is estimated to be 95.71 psi i.e. maximum phase redistribution pressure change is calculated to be around 95 psi
- Tau is 0.287hr i.e. time at which 63% of total phase redistribution pressure change has occurred
- Permeability of reservoir is good and it is calculated to be around 415md.
- Skin is estimated to be 0.44 and it shows well bore is clean and no damage caused to well bore during drilling
- Bubble point pressure is estimated from the correlations as 3152psi. Reservoir is saturated and the electro log indicates an existence of a gas cap of 10m just above the current perforated interval. But the effect of gas cap is not visible in the buildup.
- Distance to no flow parallel barriers is estimated to be 650ft and 670ft.

Parameter	**Value**
Permeability (md)	415
Flow capacity (md-ft)	13623.5
Skin factor	0.44
Initial reservoir pressure(psi)	2788
Distance to no flow boundaries (ft)	
L1	650
L2	670

TABLE :5 RESULTS DISCUSSION

PULSE TEST:

Well tests in which a pressure disturbance is created in one well and the pressure response is measured in one or more wells are called multiple well tests. Multiple well tests are designed to establish communication and to determine average reservoir properties in the area separating the wells. A common multiple test is the interference test. The test involves creating a significant pressure disturbance, either by producing from or injecting into one well, called the active well, and observing the pressure response in at least one other well, called the observation well, which is located at a distance from the active well. Interference tests are typically carried out to test for reservoir continuity and to evaluate intra well permeability. In fact, the characteristics of the pressure behaviour as a function of time reflect the reservoir properties between the active and observation wells. A procedure by which non-engineered fluctuations can be used to assess the permeability between multiple well pairs was reported by Yousefetal (2009). Pulse testing was proposed by Johnson et al.(1966) and is a form of interference testing. The main difference between interference and pulse testing lies in the propagation of a coded signal, generated at the producing or injecting well (also called active well or pulser) and, according to reservoir continuity, observed at the observation well (responder). The signal is generated by alternating production(injection) and shut-in periods having constant duration and rate. The rate and the duration of each flow are the same. All shut-in periods also have the same duration, not necessarily equal to the flow time. The magnitude of the pressure response measured at the observation well is small, frequently less than10 psi and sometimes less than 1 psi (highly sensitive pressure gauges are used to detect these small disturbances), but the test duration could be as long as 2 or 3 months because of the time lag existing between the time when a rate change is made at the active well and the time when the pressure transient is seen in the observation well. The duration of the pulse and the flow (injection) rate are assessed from the earlier based on a given set of reservoir parameters in order to ensure that a pressure variation could be clearly identified at the responder. Interference tests are particularly complex in producing fields where a general pressure declining trend is present. Even though they are more difficult to interpret, pulse tests are often preferred because the oscillating response due to few pulses is easier to identify in a noisy reservoir environment than a single interference signal and it is less affected by a possible drift of the pressure gauge. Results that can be obtained from well testing area function of the range and the quality of the pressure and rate data available and of the approach used for their interpretation. Since their introduction in 1983 pressure derivatives and interpretation models have been the most used techniques for the conventional well-test analysis. However, advanced techniques like deconvolution were recently created to extract a maximum amount of information from the pressure response of a single well with a varying flow rate. At long last, new developments in well testing are centred on richer signals, proper incorporation of uncertainties, more complex models, and numerical solutions. This work manages with one of these possibilities: harmonic interpretation of pulse testing, additionally called harmonic well testing.

porosity	20%
Irreducible water saturation	0.20
Residual oil saturation	0.2
Water compressibility	3×10^{5} bar^{-1}
Water viscosity	0.3 cP
Water relative permeability end point	0.43
Oil compressibility	1.2×10^{-4} bar^{-1}
Oil viscosity	2 Cp or 4 cP
Oil relative permeability end point	0.9
Rock compressibility	4×10^{-5} bar^{-1}

TABLE: 6 Reservoir and simulation parameters of pulse test.

MULTI BEAN STUDY & IPR

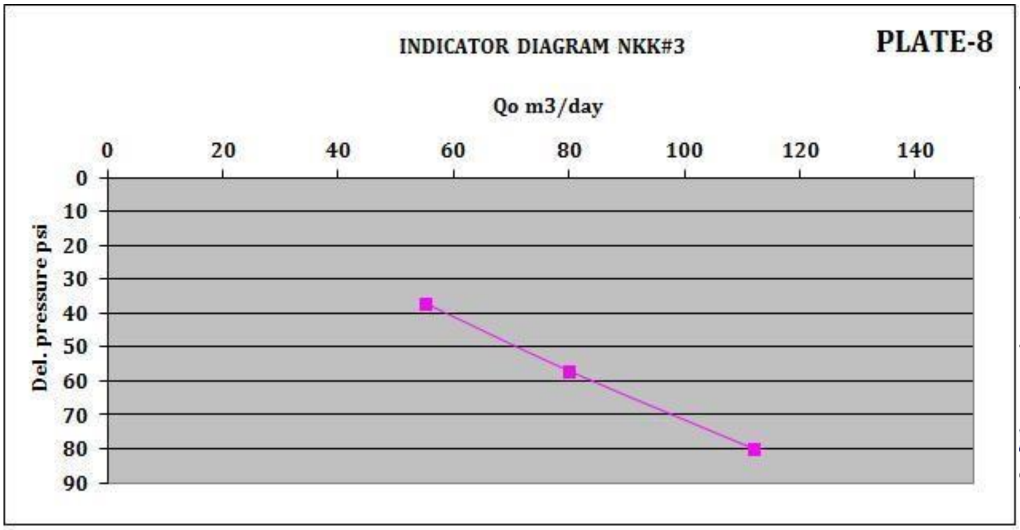
Multi bean study was carried out by flowing the well through 5, 6, 7MM#3 beans and with each flowing period stabilized flow rate of oil & gas and stabilized flowing pressures were recorded. Results of bean study is given below.

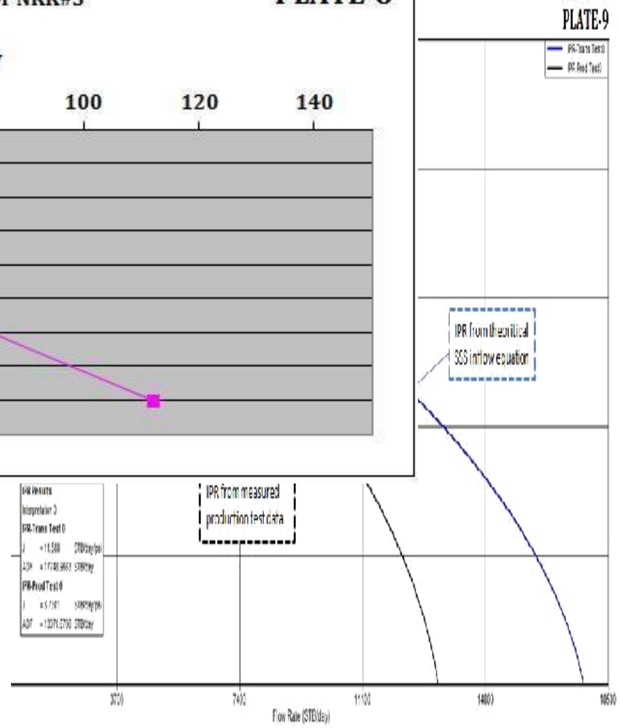
SI.NO:	BEAN (M M# 3)	FTHP/ STHP (psi)	FBHP/ SBHP (psi)	FCHP/ SCHP (psi)	DELTA P	Q_o m^3/d	Q_g m^3/d	Q_w m^3/d	GOR v/v	API deg
1	6	1200	2704	1200		80	10000	0		3805
2		1325	2760	1225		24hrs build up				
3	5	1175	2720	1225	37	55	7000	0	127	
4	6	1200	2700	1200	57	80	10000	0	125	38.5
5	7	1200	2677	1200	80	112	13000	0	116	

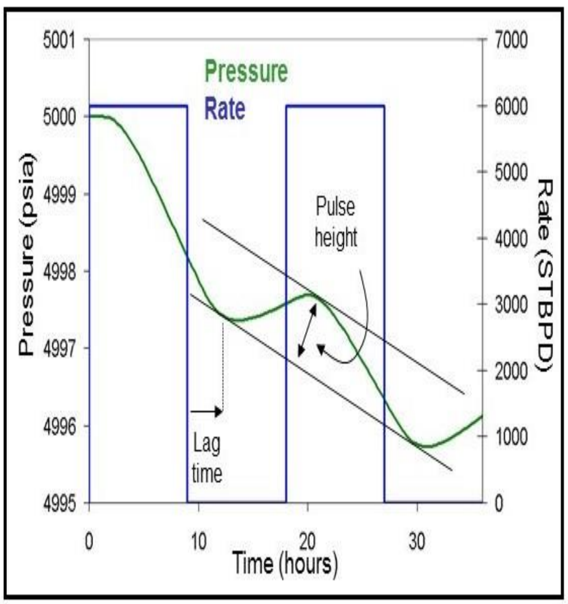
Indicator diagram is drawn between Del P vs. Flow rate of oil and plot is given below.

IPR is plotted using PAN system and results were given below.

Indicator diagram is given between pressure vs. time and flow rate of oil and plot is given below.







RESULTS AND INFERENCE:

Static bottom hole pressure recorded after 24hrs closure is 2758psi and bottom hole temperature is 204° F at 2114m.

The straight-line indicator diagram indicates no phase separation in the reservoir so there is a steady state single phase fluid flow from reservoir to wellbore. The same is also corroborated by the consistent GOR thru different beans during production testing.

Draw down of less than 3% thru 7MM#3 bean indicates good permeability and good pressure support available in the Reservoir.

ISSN No : 1006-7930

The Q max at the sand face is estimated to be 2170m^3/day.

Productivity index of the well is estimated to be 1.408m^3/day/psi

The electro log indicates an existence of a gas cap of 10m just above the current perforated interval hence, to avoid gas coning and for reservoir management it is suggested that the well should not be flowed beyond 6MM#3 bean

Indicator Diagram & IPR plot is given in Plates-8, 9

FBHP GRADIENT SURVEY:

FBHP gradient survey was conducted before closing the well for pressure build-up.

The well was flowing through 6MM#3 bean and stabilised bottom hole flowing pressure measured as 2704.8 psi

Entire tubing is found to contain the uniform column of oil and flowing gradient at bottom hole is 0.567 kg/cm^2/10m

SBHP GRADIENT SURVEY:

SBHP gradient survey was conducted at the end of 24hrs pressure build-up. Stabilized bottom hole pressure at a depth of 2115m is measured as 2758 psi

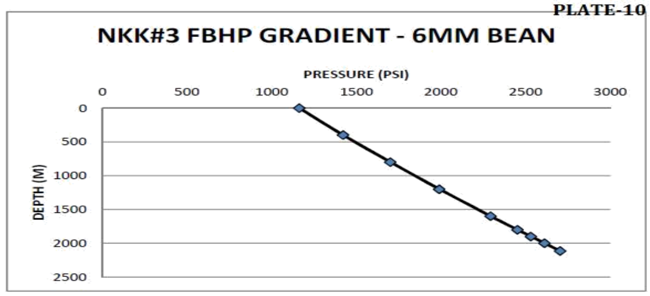
Tubing column is found to contain distinct phases of gas & oil. Gas column is formed till a depth of 450m in the tubing and the remaining portion was found to contain oil

Static flowing gradient at a depth of 2115m is estimated to be 0.587 kg/cm^2/10m

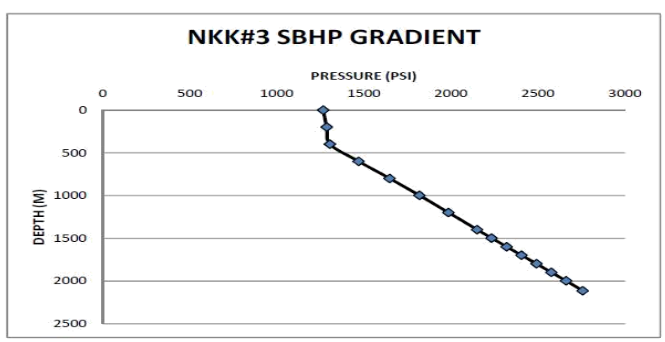
FBHP & SBHP Gradient plot is given in Plate-10.

PLATE-10

Well No.	NKK#3	sand	OBJ-I	
Date	07.03.2012	Interval	2145-2135m	
Job	FBHP Gradient		Temp.	200F
M NO	EMR	6MM BEAN	DOM	2115m
Depth	Defln.	Pressure	Pressure	Pres. Grad.
(m)	(Inch)	(Psi)	(Kg/cm2)	((Kg/cm2)/10m)
0		1163.00	81.77	
400		1421.50	99.94	0.454
800		1701.10	119.60	0.491
1200		1991.10	139.99	0.510
1600		2293.80	161.27	0.532
1800		2452.00	172.40	0.556
1900		2531.90	178.01	0.562
2000		2612.10	183.65	0.564
2115		2704.80	190.17	0.567



Well No.	NKK#3	sand	OBJ-I	
Date	08.03.2012	Interval	2145-2135m	
Job	SBHP Gradient		Temp.	190F
M NO	EMR		DOM	2115m
Depth	Defln.	Pressure	Pressure	Pres. Grad.
(m)	(Inch)	(Psi)	(Kg/cm2)	((Kg/cm2)/10m)
0		1267.00	89.08	
200		1287.00	90.49	0.070
400		1306.40	91.85	0.068
600		1470.20	103.37	0.576
800		1649.30	115.96	0.630
1000		1820.70	128.01	0.603
1200		1986.70	139.68	0.584
1400		2151.30	151.26	0.579
1500		2235.30	157.16	0.591
1600		2320.80	163.17	0.601
1700		2406.30	169.18	0.601
1800		2492.10	175.22	0.603
1900		2577.40	181.21	0.600
2000		2662.00	187.16	0.595
2115		2758.00	193.91	0.587



DEVELOPMENTAL STUDIES

Based on the encouraging results of well, the block was declared as a hydrocarbon bearing and commercially viable for further development. Following parameters were considered for development studies of this block.

Based on the electro-log recorded, geological data and reservoir studies the initial oil in place is calculated using volumetric method and it is estimated to be around 1.0MM#3t.

Based on the log it is found that gas cap is available. Hence the perforation was done 10m below the gas cap so that gas cap is not disturbed. In build-up there is no indication of gas cap support, however bean study results indicate a strong pressure support and reservoir is under saturated.

From the log ratio of gas cap volume to oil volume of 1.44 is expected to render good pressure support.

Based on the shut in and bean study data bubble point pressure was estimated around 3152 psi. However, PVT study indicates that bubble point pressure is around 2740psi.

PVT study shows that the layer in which sub surface sample was collected is under saturated and oil rim near the gas cap is in saturated condition.

The well is consistently producing 55m^3/day of oil and 10000m^3/day. After a production of around 8000ton of oil there was pressure drop of just around 6kg/cm^2.

TECHNO-COMMERCIAL STUDIES:

- Drilling cost of Rs.50000/m is considered for estimating the well cost.
- Water injection plant with an injection capacity of around
- 350m^3/day was envisaged for injection. The total expenditure for new water injection facility is taken as 16crores.
- Water source for injection is located at a distance of around 10km from injection well. Hence, 10km injection line has to be incorporated in the techno-commercial study. Line cost 75lakh/km is considered for calculation.
- Operating expenditure of 6% per annum of the capital expenditure is envisaged. Based on the simulation study incremental gain of around 22000m^3 was expected in variant with water injection.
- Realization price for a ton of crude is taken as Rs.50000.
- Based on the API gravity of 36^0, specific gravity of the crude is calculated as 0.84.
- Price realization from gas production is assumed to be nil.
- Royalty needed to be paid on crude is taken as 20%, Sales tax of 4% and less of Rs.2700/ton is taken.

CONCLUSION:

From the above study it is determined that the well does not produce at its maximum on primary recovery hence Water injection as secondary recovery is needed, From various well test such as Build-up Pressure test, pulse test and Multi Bean test the well is considered to be good productivity well for the upcoming years and also by techno-commercial calculation it was evident that a gain of around 10.5crores is expected from the water injection variant.

However, two producers can be drilled at the earliest to get more geological input and accordingly the same can be incorporated in the simulation model for more accurate forecast. Performance of the currently producing well should be monitored closely so that any deviation from predicted performance can be taken into account. More detailed core study has to be done for accurately modelling the water flooding pattern.

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