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Oilfield modeling and optimization of a mature field using Integrated Production Modeling Approach.

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Abstract

The Integrated production Modeling Approach is essentially a design methodology that integrates the subsurface and surface facilities as a single system as opposed to a silo design. It integrates the inflow and outflow performance of wells and multiphase flow analysis through the wellhead to the surface processing plant. This paper model and optimizes a mature oilfield of two (2) reservoirs and two (2) wells with both tied to a central inlet manifold by two separate flowlines and fluid delivered to a central separator at the process plant with limited capacity thereby requiring optimization. The models are implemented utilizing Petroleum Experts'(PETEXs) Integrated Production Modeling (IPM) tool kit comprising Pressure, Volume and temperature Package (PVTP), Material Balance Software (MBAL) for the Reservoir modeling, the Production and System Performance Analysis Software (PROSPER) for well modeling and nodal analysis, the General Application Package (GAP) for multiphase network modeling and optimization. The IPM toolkit also provides for a field numerical reservoir modeling called REVEAL and an Interface called RESOLVE for explicit coupling of the reservoir and network simulator. The facility achieved a combined production of 20,806STB/day exceeding the process facility separator capacity of 18,000STB/day which resulted in optimizing the production rate by choking back a well thereby achieving an optimized production rate of 17,000STB/day. The accumulated forecast production stands at 117MMSTB over the period from 2008 to 2030.

Keywords- Oilfield, Integrated Production Modeling, Production Optimization, MBAL, PROSPER, GAP.

1.0 Introduction

The traditional Oil and Gas field development designs took the form of uncoupled or silo-designs and reservoir model execution followed stand-alone mode. The results from the network model are then passed onto the surface facility model for capacity availability verification [1]. The stand-alone model can be adequate for history matching purposes but it is insufficient and less accurate in prediction mode especially when necessary hydraulic calculations are needed to demonstrate pipeline network and facility flow characteristics since flow within and between the reservoir and wellbore is decoupled from the surface network including the injection facility in a stand-alone reservoir model. The resultant effect of a stand-alone or silo design is unrealistic production prediction leading to a suboptimal solution when subjected to production optimization constraints especially when networks and facilities are present. Another setback from stand-alone reservoir simulation is inaccuracy in production forecasting especially in deep water areas or when surface network is shared by many wells using bottom hole pressure constraints [2]. Okafor [3], addressed the benefits of applying integrated modeling for flow assurance engineers which led to cost-saving by reducing mis-design including oversized or undersized pipelines and facilities. Some leading multi-national Oil and Gas companies addressed the benefits or significance of integrated production modeling or integrated asset modeling [4, 5, 6]. These include:

1. Achieves a more accurate forecast when production assets are integrated.
2. Productive optimization of the system is better achieved when all constraints are considered
3. Enhanced decision-making process due to removal of bureaucratic bottlenecks.

The pipeline network model comprises of 1. models that describe the multiphase flow in the reservoir, 2. models that deal with the multiphase flows (wells, pipelines, and surface processing facilities network), and 3. a global coupling scheme that couples the reservoir and well domains. The following issues are usually considered while developing an integrated production system:

- Reservoir dynamic modeling.
- Production network modeling.
- Coupling the reservoir network.

There are three modeling techniques with progressive complexity available to model the reservoir. These are (1) the lookup table, (2) the tank model, and (3) the full-field numerical reservoir simulation model (3-D model). The lookup table considers the relationship among input parameters such as the cumulative rate, GOR, reservoir pressure, water cut, and productivity index [7]. We cannot evaluate production system impact on reservoir recovery with this approach. However, the accelerated production amount due to artificial lift and natural production can be quantified thereby helpful in equipment sizing. The tank model analysis on the other hand is a material balance that is anchored on the mass conservation principle. The tank can either be a one-cell tank or a multi-layer tank model to capture the reservoir dynamics. The material Balance Equation does not provide for the well geometry orientation and drainage area hence the material balance equation is often referred to as zero-dimensional [8]. The 3-D model is based on mass conservation and simple momentum conservation law in the form of Darcy's equation. The production variation and the reservoir states are derived by solving sets of relevant either one or multiphase partial differential equations and it is most reliable with proper tuning of history matching though most complex.

It is also useful to distinguish between the steady-state flow model and transient flow model in the pipeline network. The steady-state temperature and pressure calculation describe the behavior of multiphase flow in wells and networks. Calculations can either be empirical correlations and/ or mechanistic models or simply the use of lookup tables where the inlet pressure is listed with other parameters including GOR water-cut and outlet pressure. The transient flow on the other hand offers benefits due to the setback of not being able to properly describe flow assurance issues such as liquid loading, slugging, depressurization, shutdown, and so on [9].

The mode of network integration is also important in integrated designs. It could be either explicit or implicit. In explicit coupling, the network models are implemented independently and alternatively, and only the boundary conditions are interchanged and the mode of information interchange between the network model and the reservoir is through message passing open interface [10]. However, the main setback of the explicit coupling is that the simulator may require more steps to converge. The implicit coupled network reservoir simulation describes reservoir multiphase flow and the pipeline network, well flow and are simultaneously modeled. The implicit coupled models provide better convergence but suffer in software choice due to their lack of flexibility [11].

2.0 Related Literature

Dempsey et al [12] pioneering integrated design was embraced by multinational oil and gas companies who developed their respective integrated designs in their organizations [13, 14, 15, 16].

The Petroleum Experts' (PETEXs) Integrated Production Modelling (IPM) suite comprising (PVTP), (MBAL), (PROSPER) and the (GAP) suite provides an efficient multi/ cross-disciplinary understanding of the complete production process. The integrated model comprises the reservoirs and wells (sub-surface) and the surface facilities. The IPM provides a robust integrated analysis of components leading to effective development, forecasting, production network, and optimization. The IPM provides users with an MBAL toolkit for reservoir modeling and a field numerical reservoir modeling tool called REVEAL.

IPM also contains a module called PROSPER for well modeling and nodal analysis and a multiphase network modeling and optimization model called GAP. It also provides for an interface called RESOLVE that does the explicit coupling of the reservoir and network simulators. [17]. PETEX released its first commercial version of the IPM suite in 2006 and consolidated on a fair market share and was subsequently adopted as a tool for field design and management by major oil companies as a corporate standard [18,19,20,21,22]. The IPM suite can be depicted as:

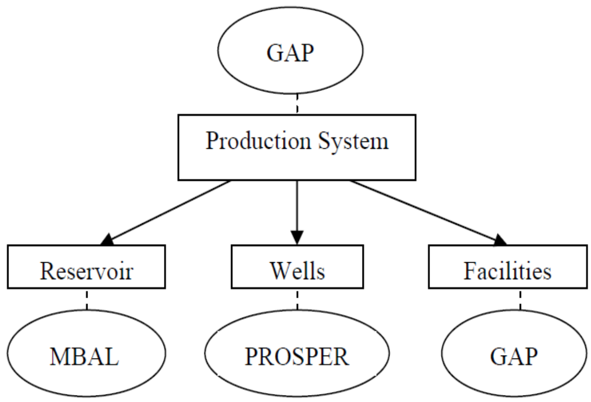

Fig 1. Production System Modelling

Gina Vega Riveros et al [23] work combined volumetric analysis, Monte Carlos, and material balance and outcome led to improved recovery factor of original oil in place (OOIP). Tuong-Van Nguyen [24] "Novel methodology suggested a processing plant design that maximizes hydrocarbon production and minimizes power consumption, cooling and heating demands. The methodology layout included prediction to the production profile, process plant assessment, process plant optimization, plant sizing, and heating and cooling demands.

Some credible lessons learned show that the difference in weights in IPM simulation compared to stand-alone is a function of the accuracy of boundary conditions. Hatvik et al [25] made a performance comparison among; a stand-alone dynamic reservoir model, a stand-alone flow network model, and a fully coupled reservoir network model and concluded that a fully coupled model is the only one that reflected integrated behavior of the entire system that reduces the uncertainty or forecast.

3.0 Methodology

3.1 Development of reservoir Model (MBAL)

The introduction of MBAL accounts for materials entering or exiting the system. The set of calculations derived considers the reservoir as a large tank and uses measurable quantities to ascertain materials that are difficult to measure. The measurable quantities are the cumulative fluid for water, oil, and gas, fluid property, and reservoir pressure. The material balance is premised on the mass conservation principle.

Initial Hydrocarbon originally in place = Fluid produced + Remaining fluid in place

Production = STOIIP * Unit Expansion + Water Influx

Material balance implies producing a certain amount of fluid and measuring the average reservoir pressure before and after production, and with the hindsight of PVT properties of the system calculate a mass balance. The Material Balance Equation [MBE] was modified by Havlena and Odeh to derive a straight-line equation with parameters expressed as a function of others [26]. The MBE can be mathematically expressed as:

$$N_p*[B_o+(R_p - R_s)*B_g]+W_pB_w = N*[(B_o-B_{oi}) + (R_{si} - R_s)*B_g + MNB_{oi}*(B_g/B_{gi} - 1) + (1+M)*NB_{oi}*(C_wS_w + C_f)\ \Delta P/1-S_w + W_eB_e \quad \text{Equation (1)}$$

The simplified straight-line form can be given as:

$$F=N*(E_o+E_{fw}+E_g)+W_eB_w \quad \text{Equation (2)}$$

Therefore, taking a plot of $[F/(E_0 + E_{fw} + E_g)]$ Vs $W_eB_w/(E_0 + E_{fw} + E_g)$ gives a linear relationship estimating the Original Hydrocarbon in Place (OHIP) with a unit slope meaning a reservoir model and the aquifer is identified. A situation where this does not exist implies the deviation is a dynamic mechanism and further tuning of parameters is required to obtain linearity and presence of corrupted data for the analysis.

3.2 Development of Well Model (PROSPER)

PROSPER is a package of the PETEX IPM suite for production modeling. While MBAL is used to model the reservoir, PROSPER is for the modeling of the well. It serves as a tool for the modeling of Well and Pipeline as well as for the nodal analysis for the utilization of specific field information. The Well model created forms the link between the reservoir and surface production system components [27]. The characteristics of the Well however accounted for the fluid characterization (PVT) and other essential components of the PROSPER suite are the Vertical Lift Performance (VLP), Inflow Performance Relationship (IPR), Tubing Transverse curves, and Absolute Open Flow (AOF).

3.3 Development of a Surface Facility Model (GAP)

While the MBAL and PROSPER are used for the Reservoir and Well, the GAP suite is used for developing the surface facility model [28]. The creation of GAP requires all Well details (Well type, name, and location), flowline and pipe specifications (land roughness and diameter), and elevation. In the surface model, all active and inactive Wells are included in the surface network observed in both Reservoir and Well development. The GAP design in this Model does not have a compressor due to low gas requirements. The general GAP workflow is as detailed below:

- Construct a surface model (GAP).
- Link MBAL and PROSPER models to GAP.
- Add Q_{max} and Downtime or Wellhead abandonment pressure and MRTLL.
- Generate IPR and VLP curves.
- Perform Simulation.

3.4 Input Parameters

The Input parameters for the MBAL, PROSPER, and GAP models are as follows:

3.4.1 MBAL: The MBAL input comprises the PVT data, Tank data, history matched aquifer properties, relative permeability data, production data (history), and reservoir thickness. The input parameters are as summarized in the tables below:

Table 1 PVT Data

Reservoir Name	X	Y
Reservoir Fluid	Oil	Oil
Tank Model	Single Tank	Single Tank
PVT Model	Simple PVT	Simple PVT
Formation GOR	325.028 scf/stb	768 scf/stb
Oil Gravity	35.2 API	51.81 API
Gas Gravity	0.8718	0.7579
Water Salinity	78000ppm	120000
Mole percent H2S	0	0
Mole percent CO2	2.17%	0.59
Mole percent N2	0.6%	0.88
Reservoir Temperature	215°F	215°F
Bubble point	1537.85 psia	2786.84 psia
Oil Viscosity at Pb	0.698534 cp	0.249926 cp
Bo @Pb	1.23047 bbl/stb	1.4316 bbl/stb

Table 2 Tank Data

RESERVOIR	X	Y
Initial Reservoir Pressure	5150 psia	4800 psia
Porosity	0.21	0.23
Connate water saturation	0.15	0.1
Initial Gas cap	0	0
STOIIP	425.704 MMSTB	762.053 MMSTB
Start of Production	01-01-2006	01-01-2006
Reservoir Thickness	120 ft	110 ft
Reservoir radius	4200 ft	6500 ft
Outer/Inner Radius ratio	6	6.25341
Encroachment Angle	360 degrees	359.739
Aquifer Permeability	10md	19.4396
Aquifer Model	Hurst-van Everdingen-Modified	Hurst-van Everdingen-Modified
Aquifer System	Radial Aquifer	Radial Aquifer

Table 3 Relative Permeability of X

	Residual Saturation	End Point	Exponent
Krw	0.15	0.676301	0.527657
Kro	0.15	0.8	0.710008
Krg	0.01	0.9	1

Table 4 Relative Permeability of Y

	Residual Saturation	End Point	Exponent
Krw	0.15	0.396165	1.43809
Kro	0.15	0.8	0.01002
Krg	0.01	0.9	1

Table 5 Reservoir X Data

Time (dd-mm-yyyy)	Reservoir pressure (psig)	Cumulative Oil Produced (MMSTB)	Cumulative GOR (Scf/Stb)	Cumulative Water Produced (MMSTB)
01-01-2006	5150	0	0	0
02-04-2006	5092.89	0.4277	325.027	0.0121601
01-05-2006	5078.26	0.564	325.028	0.0200325
31-07-2006	5010.96	1.18744	325.029	0.0704627
30-10-2006	4956.73	1.81088	325.028	0.141712
29-01-2007	4910.14	2.43432	325.028	0.231005
30-04-2007	4868.96	3.05776	325.028	0.336346
30-07-2007	4831.86	3.68121	325.026	0.456274
29-10-2007	4797.98	4.30465	325.028	0.589664
28-01-2008	4766.79	4.92809	325.029	0.735621
28-04-2008	4737.84	5.55153	325.028	0.893424
01-08-2008	4709.46	6.20237	325.027	1.07008
01-10-2008	4681.16	6.6825	325.028	1.20747

Table 6 Reservoir Y Data

Time (dd-mm-yyyy)	Reservoir pressure (psig)	Cumulative Oil Produced (MMSTB)	Cumulative GOR (Scf/Stb)	Cumulative Water Produced (MMSTB)
01-01-2006	4800	0	0	0
02-04-2006	4783.48	0.3276	0.251597	7.63e-8
01-05-2006	4778.94	0.432	0.331776	1.93e-7
31-07-2006	4761.89	0.842501	0.647041	1.55e-6
30-10-2006	4747.17	1.253	0.962304	5.3e-6
29-01-2007	4734.09	1.6635	1.27757	1.28e-5
30-04-2007	4722.28	2.074	1.59283	2.54e-5
30-07-2007	4711.5	2.48451	1.9081	4.44e-5
29-10-2007	4701.59	2.89501	2.22337	7.11e-5
28-01-2008	4692.42	3.30551	2.53863	0.000106843
28-04-2008	4683.9	3.71601	2.8539	0.000152861
01-08-2008	4675.59	4.14455	3.18301	0.000213147
01-10-2008	4663.49	4.55325	3.4969	0.000281778

3.4.2 PROSPER Model: The PROSPER input Well X1 data is as contained in the tables below;

Water Cut: 22.2%

Productivity Index = 11.6 STB/day/psi

Reservoir Pressure: 4680psig

Total GOR: 325.028 SCF/STB

Table 7 Well Deviation

Measured Depth (ft)	True Vertical Depth (ft)
0	0
3200	3200
5800	5700
7600	7200
9200	8100
9750	8300

Table 8 Downhole Equipment Data for Well X1

Label	Measured Depth (ft)	Inside Diameter (in)	Inside roughness (in)	Rate Multiplier
Xmas Tree	0	-	-	-
Tubing	1200	2.992	0.0006	1
SSSV	-	2.8	-	1
Tubing	9710	2.992	0.0006	1
Casing	9750	6	0.0006	1

Table 9 Geothermal Gradient for Well X1

Formation Measured Depth (ft)	Formation Temperature (degF)
0	60
600	50
9750	215

Table 10 Test Data Point for Well X1

Test Point Date	Tubing Head Pressure (psig)	Tubing Head Temperature (degF)	Water Cut (%)	Liquid Rate (STB/day)	Gauge Depth – MD (ft)	Gauge Pressure (psig)	Reservoir Pressure (psig)	Gas Oil Ratio (scf/STB)	GOR Free (scf/STB)
10-01-2008	378	163.4	22.2	9427.2	9200	3753.4	4680	325.03	0

The input **Well Y1** data is:
Water Cut: 0 %
Productivity Index = 7.03 stb/day/psi

Reservoir Pressure: 4660psig
Total GOR: 768 scf/stb

Table 11 Well Deviation for Well Y1

Measured Depth (ft)	True Vertical Depth (ft)
0	0
3200	3200
4500	4480
6510	6400
8900	8400
10210	8500

Table 12 Down Equipment Data for Well Y1

Label	Measured Depth (ft)	Inside Diameter (in)	Inside roughness (in)	Rate Multiplier
Xmas Tree	0	-	-	-
Tubing	800	3.96	0.0006	1
SSSV	-	3.8	-	1
Tubing	10100	3.96	0.0006	1
Casing	10210	6	0.0006	1

Table 13 Geothermal Gradient for Well Y1

Formation Measured Depth (ft)	Formation Temperature (degF)
0	60
600	50
9750	215

Table 14 Test Data Point for Well Y1

Test Point Date	Tubing Head Pressure (psig)	Tubing Head Temperature (degF)	Water Cut (%)	Liquid Rate (STB/day)	Gauge Depth – MD (ft)	Gauge Pressure (psig)	Reservoir Pressure (psig)	Gas Oil Ratio (scf/STB)	GOR Free (scf/STB)
10-01-2008	359	160	0	13970	8900	2595	4660	768	0

3.4.3 GAP Model: The input parameters for the GAP surface facilities model is as in the table below (Pipeline properties).

Separator Capacity: 18,000 bbl/day

Separator Pressure: 250 psig

Table 15 Pipeline Properties

	Pipe Segment Length	Pipe ID	Upstream TVD	Downstream TVD	Overall Heat Transfer Coefficient
Unit	Km	Inches	M	M	Btu/h/ft2/F
Line_A	0.2	4	0	20	8
	0.3	4	20	0	8
Line_B	0.2	4	0	20	8
	0.1	4	20	0	8
Pipeline	5	12	0	20	8
	5	12	20	10	8
	1	12	10	20	8

4.0 Data Collection and Organization.

4.1 Data Integrity Check

Data preparation and consistency checks were carried out on the relevant input parameters. These include PVT data, the average pressure, production history, and aquifer parameters. The available PVT data were matched using different Black Oil PVT models to select the model that provides the best match for the acquired data. The Glaso correlation and the Petrosky were useful.

4.2 The Reservoir System and Correlation

The available PVT data for Reservoir X was matched using different Black Oil PVT models to select the model that provides the best match to the acquired data. From the analysis, the Glaso correlation was found to provide the best match for Bubble point, Oil formation volume factor, and solution Gas-Oil Ratio whereas the best matches for gas formation volume factor, gas viscosity, and oil viscosity were offered by the Petrosky correlation. However, for Reservoir Y, Vasquez-Beggs correlation was found to provide the best match for Bubble Point, Solution Gas-Oil ratio, and Oil formation volume factor. The Beal et al correlation provided the best match for Oil viscosity, Gas viscosity, and Gas formation volume.

4.3 Data Analysis and Validation

Field data is generally prone to several errors including sampling error, systematic error, random error, and others. Therefore, the research data was validated by careful review, accuracy checks, and consistency. Comparison between laboratory PVT data and the Black-Oil PVT model was adequate and consistent.

4.4 History Matching

The Energy needed to drive the hydrocarbon from the reservoir to the surface comes basically from three (3) sources namely: Fluid expansion, PV compressibility, and water influx, and this is determined by history matching. It determines the source of the drives, size and the aquifer type, and also its strength. The best fit is derived through a trial error on material balance by comparing the observed data and calculated value at a zero-dimensional level.

4.5 Analytical Method

The analytical method is a nonlinear regression-based technique employed in estimating the unknown reservoir and the aquifer parameters. It minimizes the difference between the observed and measured and reservoir model production and assesses the effect of parameter variations. The regression quality explains the difference between the model standard deviation and measured values. The analytical plot determines the OOIP, inner and outer radius, encroachment angle, and aquifer permeability.

4.6 Graphical Method

After a proper quality match observation from the analytical plot, Havlena and Ode linear plot (F/E_t vs W_e/E_t) can be used to determine the size of the aquifer in the graphical method. This is also known as the Campbell plot with no initial aquifer and flow expansion becoming the only source of energy drive of the reservoir.

4.7 Energy Plot

The energy plot defines the existing energy drive of the reservoir. These are either or all of the fluid expansion, water influx, and injection or pore-volume compressibility. This is the energy system contribution to the reservoir.

4.8 Material Balance Evaluation Assumptions

Due to the vulnerability of material balance calculations even with small pressure changes, certain assumptions are made:

- Constant temperature
- Pressure equilibrium
- Constant reservoir volume

4.9 Black Oil correlation model: This described the fluid behavior in both wells X and Y due to limited PVT data. The black oil model usually accounts for retrograde condensate fluids and allows for the production of liquid dropout in Wellbore.

4.10 Stable and Cyclic Wells: Wells can be classified as either stable or unstable. Wells producing at constant Wellhead Rate (WHR) are classified as stable whereas cyclic (unstable) Wells exhibits constant BHP pressure build-up in short bursts of Gas and under liquid loaded conditions. Reservoir Y in our study contains volatile crude whereas X does not.

4.11 IPR/ VLP Match

Before my analysis is carried out in PROSPER, the IPR and VLP must be matched with correlations for accurate sensitivity analysis. IPR is defined as "the Well flowing bottom-hole pressure (P_{wf}) about production rate". It shows what reservoirs can deliver to the bottom hole. It describes the flow rate behavior with respect to pressure and represents an important tool to understand productivity. VLP curve shows the amount of pressure required to lift an amount of fluid to the surface at a given WHP. The essence of the matching is to ascertain the percentage difference of the measured rate and calculated rate of gas and Bottom hole pressure.

5.0 Results and Discussion for field X

5.1 A brief History of field X

Reservoir X is an undersaturated oil reservoir with the following specifications:

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Initial pressure=5150psia
Temperature=215⁰F
Bubble point pressure=1537.85psia
API=35.2
Initial solution Gas ratio=352.028scf/STB
Thickness=120ft
Initial Oil in place=425MMSTB
Results of History Matching

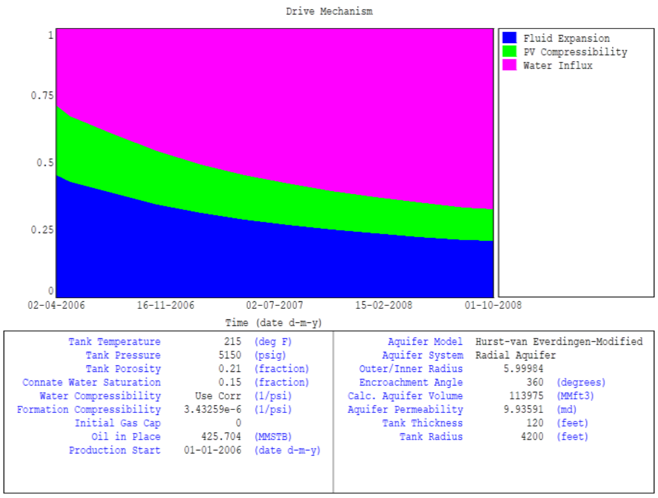

Fig.2: Plot of the Drive mechanism for field X

5.2 Energy Plot

After a proper aquifer fitting was performed on historical production and aquifer parameters, a pictorial view of the fractional distribution of energy responsible for hydrocarbon recovery of field X was obtained as shown in figure 2. The energy plot shows that fluid expansion was initially the major drive mechanism, after which water drive became a major contributor to production and Pore Volume compressibility the least.

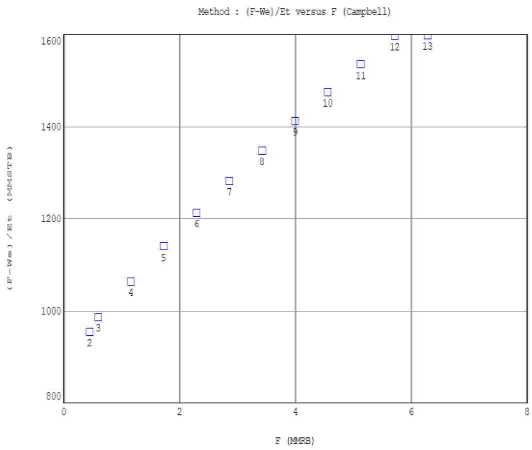

Fig.3: Graphical plot (Campbell) for field X before Regression

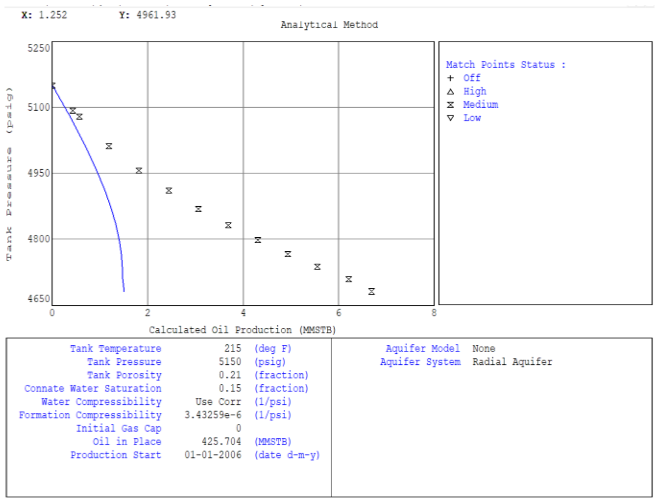

Fig.4: Analytical plot results for field X before Regression

5.3 WITHOUT AQUIFER

From the production history match without adding an aquifer, the above plots were obtained for **the analytical and graphical methods** as shown in figures 3 and 4. From the Campbell plot, the history data points do not lie on a straight line, showing that a good match has not been made and there may be the presence of an aquifer.

The **Analytical plot** also shows a mismatch between historical cumulative production and that derived from the model. It shows an underprediction of cumulative oil produced for a given pressure drop. For this reason, the presence of an aquifer is also suspected to be contributing to historical production.

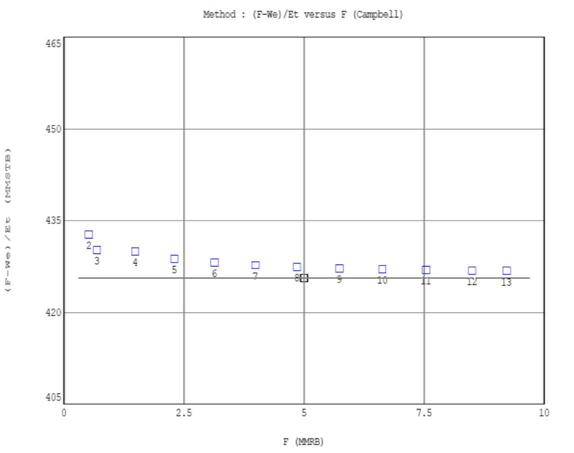

Fig.5: Graphical plot (Campbell) for field X after Regression

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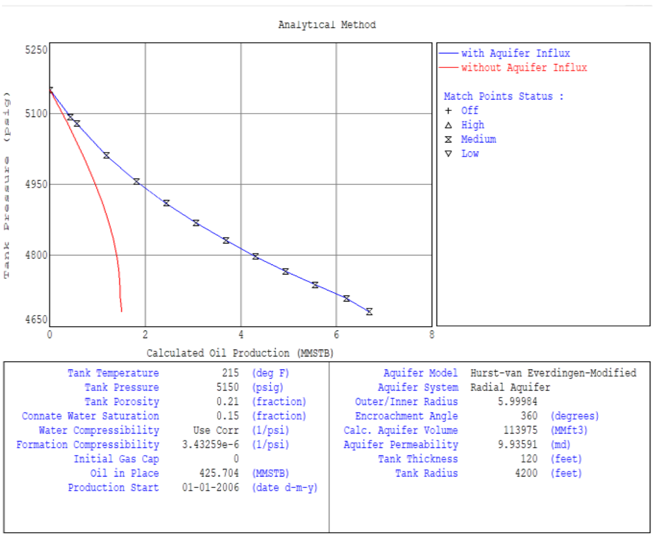

Fig.6: Analytical plot results for field X after regression

5.4 WITH AQUIFER:

A modified van-Everdingen and Hurst aquifer model was set up to match historical production and the aquifer parameters with the highest uncertainties were regressed on to match historical data, all within well-defined boundaries that suit reasonable engineering and geological judgment. The parameters regressed on include: The encroachment angle, outer/inner radius, and aquifer permeability. The plots in figures 5 and 6 were generated after the regression on the different parameters.

After defining the aquifer, and regressing on the uncertain parameters, it can now be seen that the **graphical plot (Campbell)** now falls on a straight line and the **Analytical plot** now follows the historical trend. The matched aquifer properties can be seen in the analytical plot which shows: encroachment angle 360(degrees), calculated Aquifer volume(113975mmft^3), Aquifer permeability(9.93591mcl), and OIP (425.704MMSTB). With this, a good historical match has been made and predictions can now be carried out after a good fractional flow model is obtained.

5.5 Results and discussion for field Y

5.6 A brief History of field Y

Reservoir Y is an undersaturated oil reservoir with the following properties:

Reservoir X is an undersaturated oil reservoir with the following specifications:

Initial pressure=4800psia

Temperature=215^{0}F

Bubble point pressure=2786.84psia

API=51.84

Initial solution Gas ratio=768scf/STB

Thickness=110ft

Initial Oil in place=762MMSTB

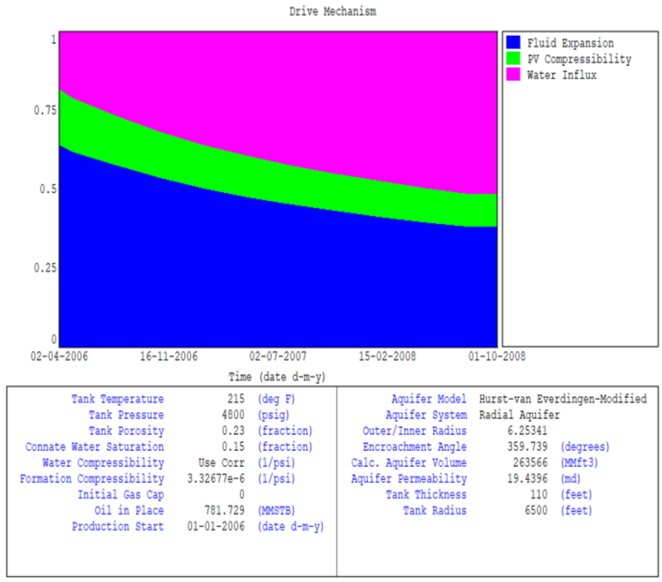

Fig.7: Plot of the Drive mechanism for field Y

5.7 Energy Plot

After a proper aquifer fitting was performed on historical production and aquifer parameters, a pictorial view of the fractional distribution of energy responsible for hydrocarbon recovery of field Y was obtained as shown in figure 7. The energy plot shows that fluid expansion was initially the major drive mechanism, after which water drive became a major contributor to production and Pore Volume compressibility the least.

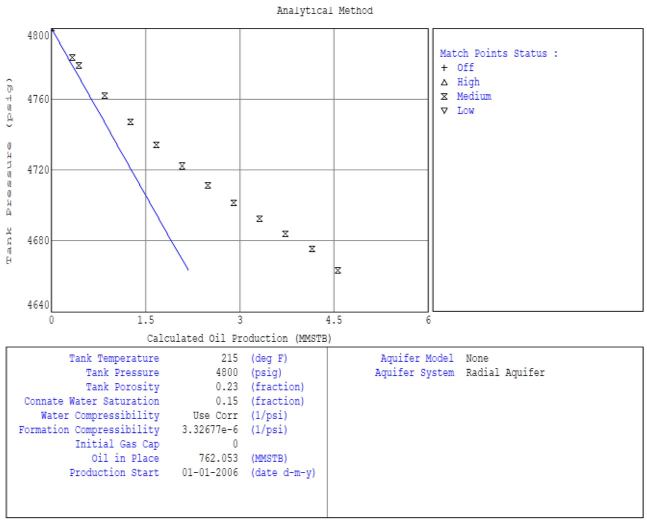

Fig.8: Analytical plot results for field Y before regression

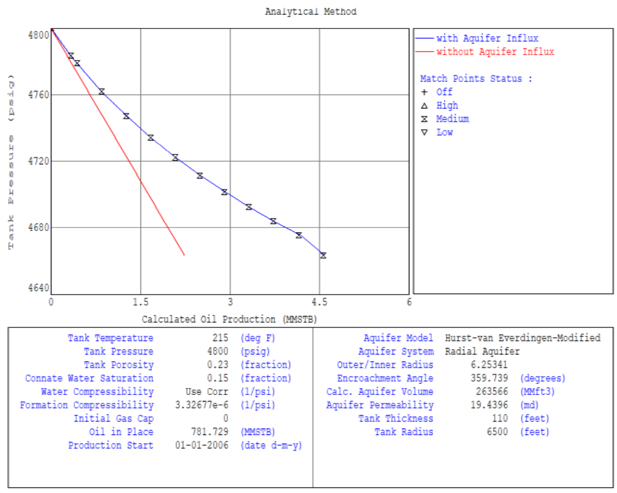

Fig.9: Analytical plot results for field Y after regression

5.8 Analytical plot

From the production history match, the following Analytical plots as in figures 8 and 9 were derived for without/with Aquifer respectively. The plot without Aquifer shows a mismatch between historical cumulative production and that derived from the model. This signifies the presence of an aquifer and is also suspected to be contributing to historical production. While after defining the aquifer, and regressing on the uncertain parameters, it can now be seen that the **Analytical plot** now follows the historical trend. With this, a good historical match has been made and predictions can now be carried out after a good fractional flow model is obtained.

5.9 Model Validity

Based on the Analytical plot, pressure simulation was also carried out to determine the validity of the model, as shown below in figure 10. Both History and simulation plots lie on the same line showing a good match.

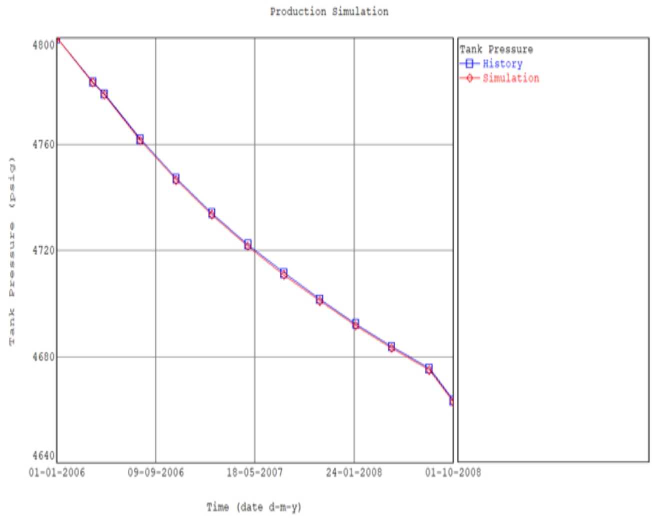

Fig.10: Pressure Simulation showing the validity of the model

From the pressure simulation, we can see a good match between historical pressure and simulated pressures for reservoir Y. More so, using the historical data, a good fractional flow match was also obtained as shown in figure 11.

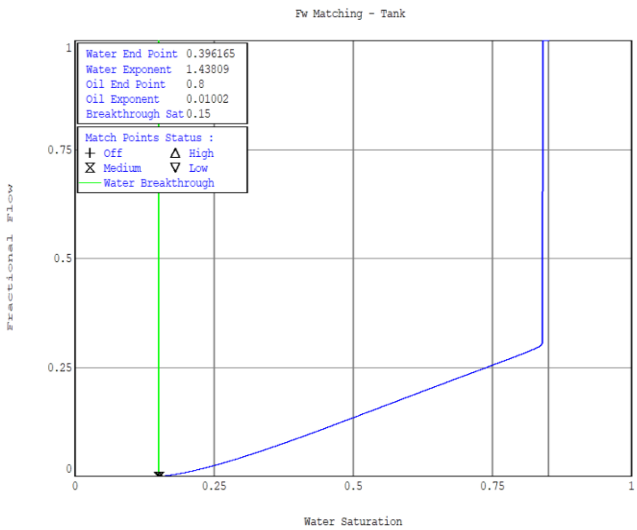

Fig.11: Shows Fractional Flow between Historical and Simulated pressures.

6.0 Well Model (PROSPER): This model the well for optimization and performance.

6.1 Well X1

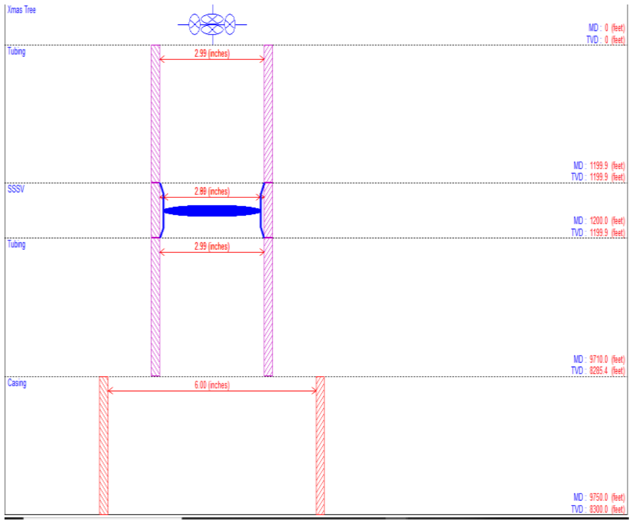

Fig.12: Downhole Schematics of Well X1

6.2 IPR

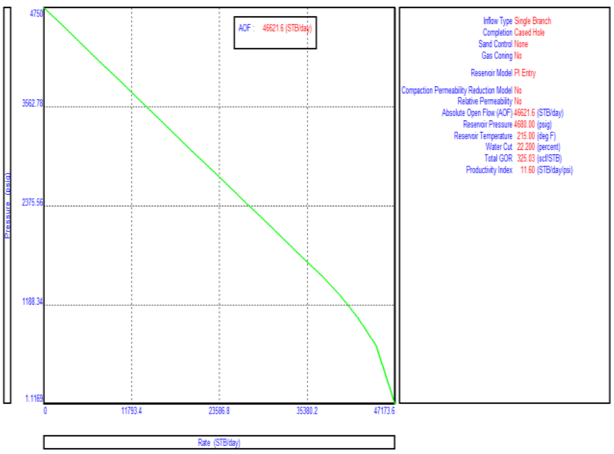

Fig.13: Plot of IPR showing Absolute Open Flow (AOF)

After PVT matching and defining the well properties, the well IPR was modeled as shown in figure 13 with the Absolute Open Flow Potential to be 46621.6 STB/day.

Sensitivities were also carried on reservoir pressure and the IPR can be seen to vary as shown below in Figure 14

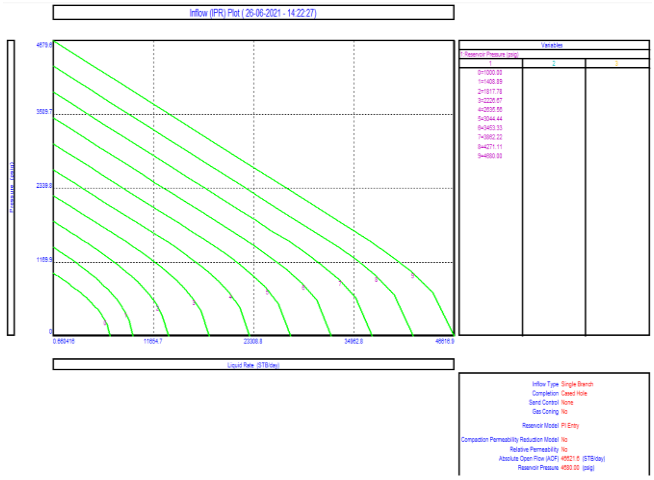

Fig.14: Plots of IPR after Sensitivity on Reservoir Pressure

6.3 VLP

In figure 15 different correlations were matched to the test point to obtain the tubing traverse curve, all giving a good match at the test data point. However, the Petroleum Experts 2 correlation was selected as it shows to give more correct predictions over a larger range of data.

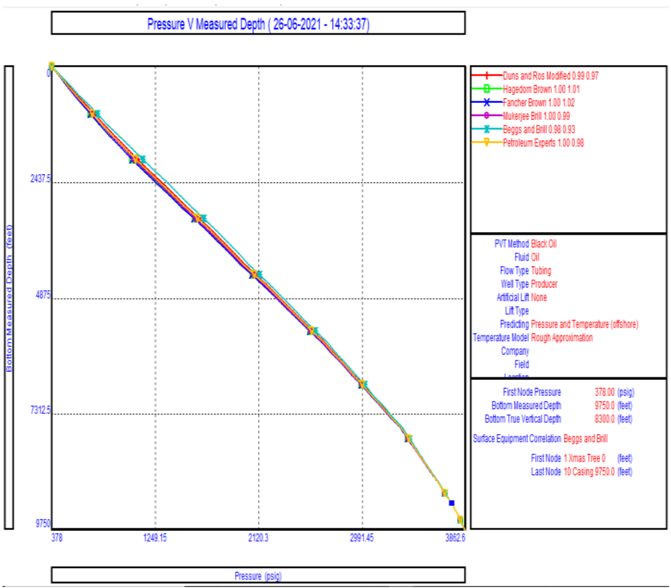

Fig.15: VLP showing tubing traverse curve (Pressure Vs Measured Depth)

6.4 VLP/IPR Match

The IPR is the Well flowing bottom-hole pressure (P_{wf}) in relation to production rate and the VLP curve shows the amount of pressure required to lift an amount of fluid to the surface at a given WHP. The matching is carried out to show the measured percentage difference concerning the calculated percentage difference of gas and Bottom hole pressure. VLP/IPR is needed for accurate sensitivity analysis as seen in figure 16 showing a good match at the test rate and bottom hole pressure.

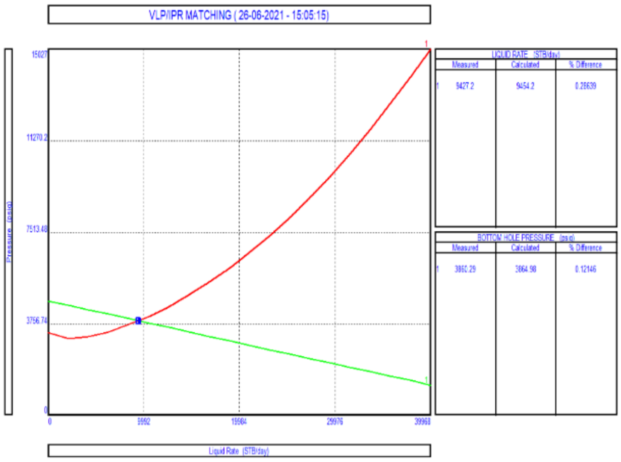

Fig.16: VLP/IPR Match

With the good match obtained for VLP/IPR, sensitivities were carried out, and lift curves were generated for Production Performance Prediction as shown in figure 17 below.

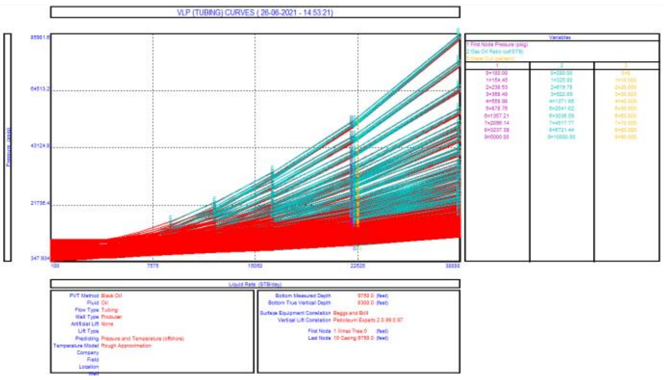

Fig.17: VLP (Tubing) curves for Production Performance Prediction

7.0 WELL MODEL(PROSPER)

7.1 Well Y1

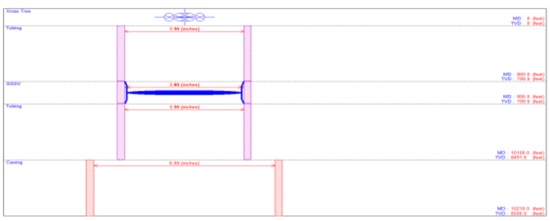

Fig.18: Downhole Schematic for Well Y1

7.2 IPR

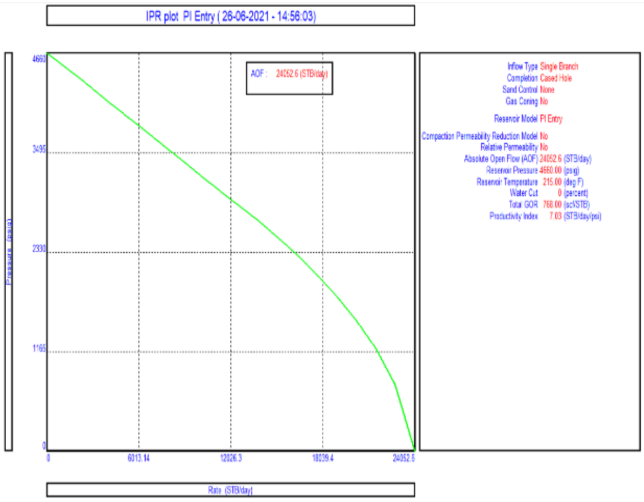

Fig.19: Plot of IPR showing Absolute Open Flow (AOF)

After PVT matching and defining the well properties, the well IPR was modeled as shown in figure 19 with Absolute Open Flow Potential to be 24052.6 STB/day

Sensitivities were also carried on reservoir pressure and the IPR can be seen to vary as shown below in Figure 20.

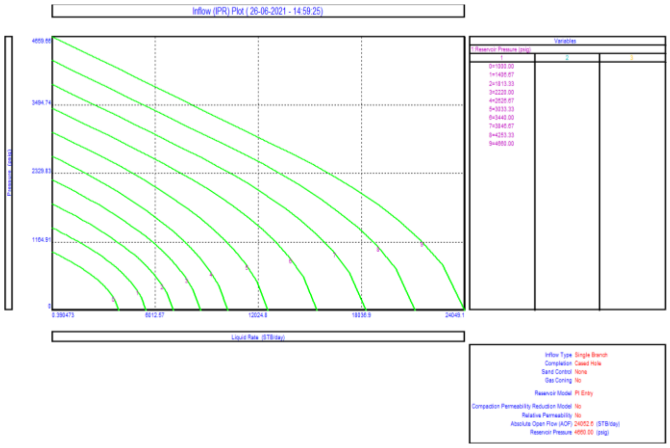

Fig.20: Plots of IPR after Sensitivity on Reservoir Pressure

7.3 VLP:

As shown below in figure 21, different correlations were used to match the test point, to obtain the right tubing traverse curve. However, only the Petroleum experts 2 correlation was able to correctly match the test data point.

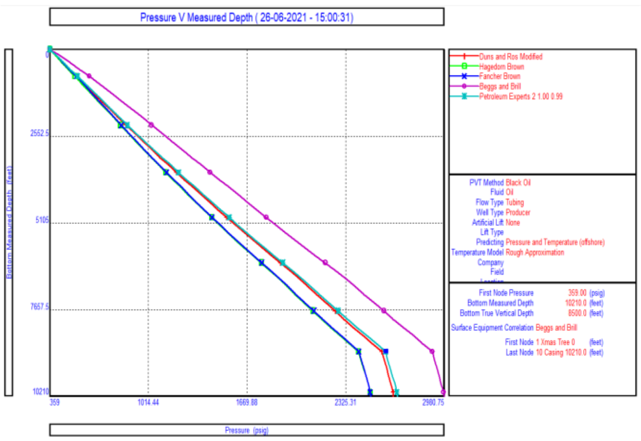

Fig.21: VLP showing tubing traverse curve (Pressure Vs Measured Depth)

7.4 VLP/IPR Match

The IPR is the Well flowing bottom-hole pressure (P_{wf}) in relation to production rate and the VLP curve shows the amount of pressure required to lift an amount of fluid to the surface at a given WHP. The matching is carried out to show the measured percentage difference with respect to the calculated percentage difference of gas and Bottom hole pressure. VLP/IPR is needed for accurate sensitivity analysis as seen in figure 22 showing a good match at the test rate and bottom hole pressure.

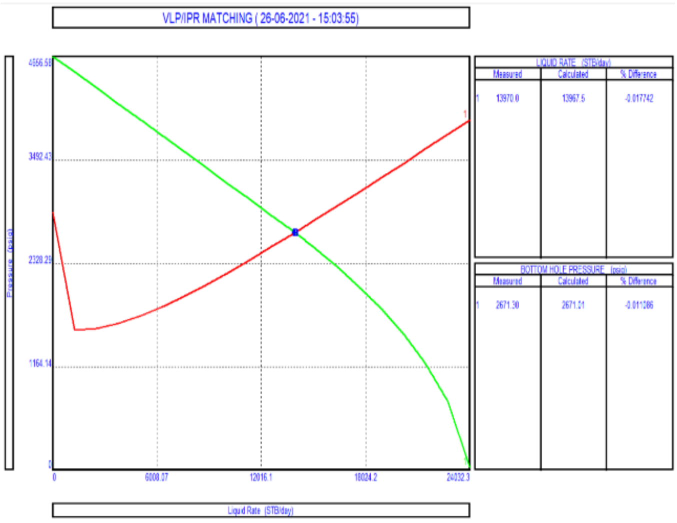

Fig.22: VLP/IPR Match

With the good match, sensitivities were carried out, and lift curves were generated for production performance prediction, as shown below in figure 23.

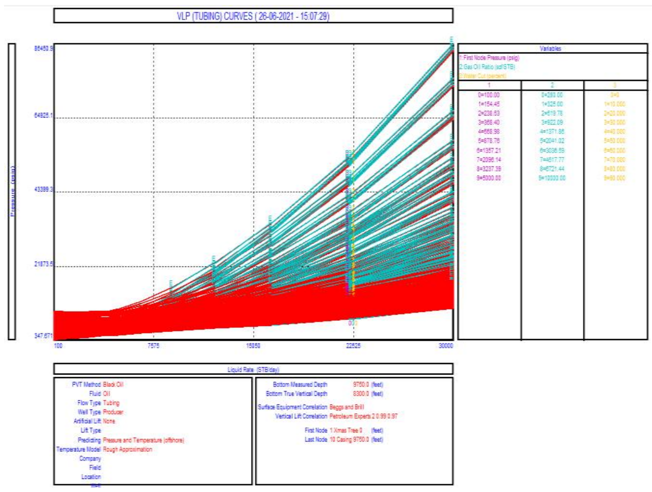

Fig.23: VLP (Tubing) curves for Production Performance Prediction

8.0 SURFACE MODEL (GAP)

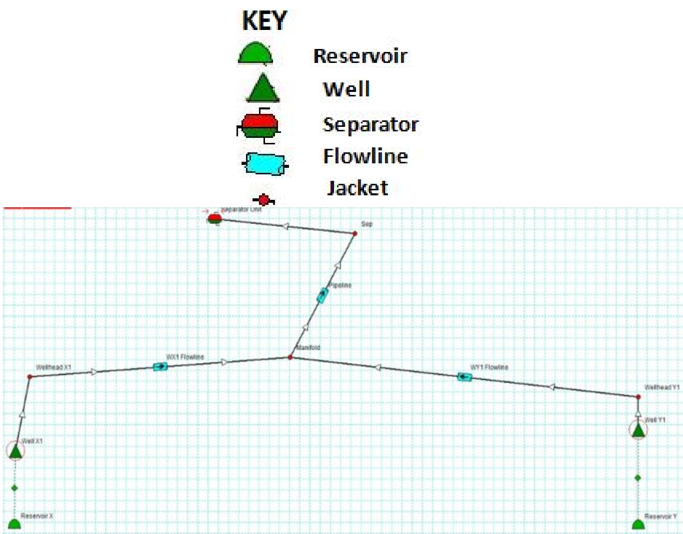

Fig. 24: GAP Model for Fields X and Y

Figure 24 above is the generated GAP Model for the reservoirs and wells in the study. It consists of two reservoirs, each of which is produced by one well. The two wells are tied to a central manifold by separate flowlines and production is delivered to a central separator 11km away. The separator is operating at a pressure of 250psig and can process about 18,000 STB/day of oil. This model will help to optimize recovery from these wells by providing choke back options, to meet the capacity of the central separator.

8.1 Without optimization (Wells fully open)

The combined production for both wells is about 20,806 STB/day, as shown below. This is above the separator capacity of 18,000 STB/day and needs to be optimized by choking back on the wells.

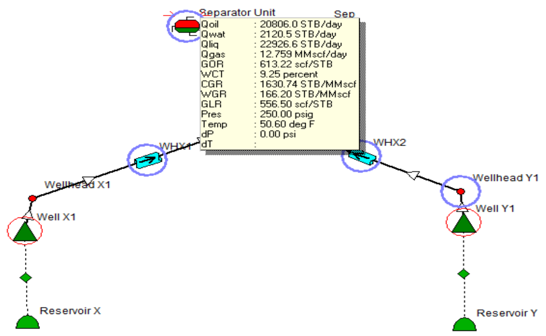

Fig. 25: GAP Model for Fields X and Y without Optimization

8.2 After optimization (Choke back option)

The well-combined rate to the separator is now 17011 STB/day, which was obtained by choking back well X1 and leaving well Y1 fully opened, as shown in figure 26.

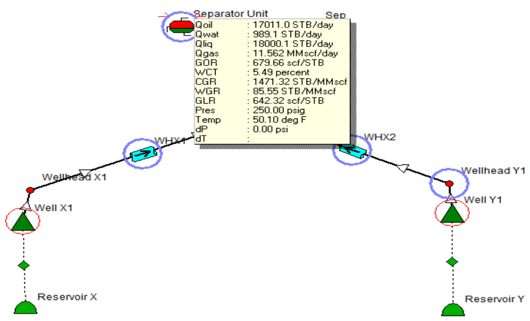

Fig. 26: GAP Model for Fields X and Y with Optimization.

8.3 PRODUCTION PREDICTION:

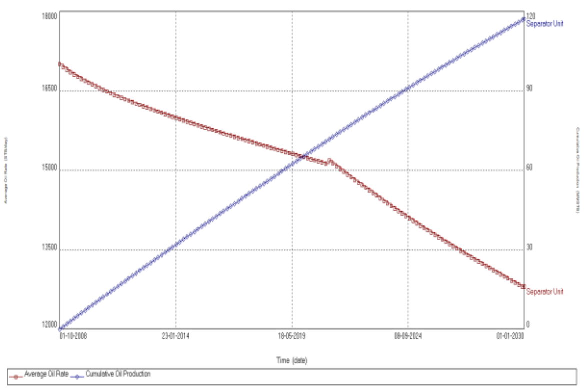

Fig. 27: Shows Production Prediction from 01-10-2008 to 01-01-2030.

The plot above shows how the oil production rate will change over time, from 2008 to 2030. Cumulative production of about 117 MMSTB of oil would have been produced.

General Result and Discussion

Observation 1.

The results derived from MBAL analysis indicate that reservoirs X and Y have been affected by adjoining aquifers which may have affected the historical data used in the analysis. From the MBAL analysis, a significant aquifer permeability of 10mb and 19.439mb and an encroachment angle of 360degrees and 359.739 degrees respectively for reservoirs X and Y indicating the attainment of a radial. The energy plots indicate that fluid expansion and water drive are the major sources of energy.

Observation 2

The MBAL method was used to estimate the hydrocarbon reserve in preference for other methods. Other methods may include Volumetric estimation, Numerical reservoir simulation, Carbon reservoir estimation method, Uncertainty modeling, Probabilistic method, Monte Carlo technique, or Hypercube. Since the basic assumptions for each method are quite different, the methods may not account for the same volume hence different estimates.

Observation 3

After proper PVT matching with well properties properly defined, the IPR was modeled and the Absolute Oil Flow Potentials showed 4662.6STB/day and 24052.6STB/day for fields X and Y respectively which represent the maximum flow rate of a well at a zero back-pressure at perforations.

Observation 4

The VLP/IPR match relates the well-flowing bottom hole pressure in relation to the production rate and pressure required to lift an amount of fluid to the surface at a given WHP. It measures the percentage difference of the measured/calculated rate of oil/gas at a given BHP. It shows 13970.0 and 13967.5STB/day for the measured and calculated respectively and a percentage difference of 0.017742 for liquid rate and 2671.30 and 2671.01Psig measured/calculated and percentage difference of 0.11086 for BHP pressure.

Observation 5

The process separator capacity is 18000STB/day which is less than the 20806STB/day production hence the need for optimization by choking back a well which brings the total production to 17011STB/day. The cumulative expected oil production from 2008-2030 is seen to be at 117MMSTB/day.

9.0 Conclusions

The conclusions drawn from the work are as follows: The work considered a comprehensive oilfield study by deploying IPM to optimize the fields. It modeled and optimized the reservoir, well and surface facility using MBAL to model the reservoir, PROSPER for well, and GAP to model the surface production facility.

- Flow expansion and water drive mechanisms are the predominant sources of energy for both reservoirs X and Y. The work further shows that the analytical method is not adequate proof for the usage of a particular model with aquifer support hence the need for a graphical method for verification for both reservoirs X and Y.

- The data used is lacking in the geological dimension of (Area in acres) needed to estimate HC reserve using the volumetric method which would enable some comparative analysis of HC reserve using different methods.

- No alarming variance is observed showing that the use of MBAL for estimation of HC reserve is appropriate else a dynamic model like Eclipse would have been recommended.

Nomenclature

B_g	Gas Formation Volume Factor
B_{gi}	Initial Gas Formation Volume Factor
BHP	Bottom Hole Pressure
B_o	Oil Formation Volume Factor
B_{oi}	Initial Oil Formation Volume
CGR	Condensate Gas Ratio
Ct	Total Compressibility
C_w	Water Compressibility
EOR	Enhanced Oil Recovery
GA	Gas Analysis
GAP	General Allocation Package
QC	Quality Check
GOR	Gas Oil Ratio
IPM	Integrated Production Modeling
IPR	Inflow Performance Relationship
K	Permeability
Krgmax	Maximum Gas Relative Permeability
krwmax	Maximum Water Relative Permeability
MBAL	Material Balance
MRTLL	Minimum Rate to Lift Liquids
N	STOIIP
N_p	Cumulative Hydrocarbon Production
OGIP	Original Gas in Place
PETEX	Petroleum Experts
Pres	Average Reservoir Pressure
PROSPER	Production and Systems Performance Analysis Software
PVT	Pressure, Volume, and Temperature
PVTP	Pressure, Volume, and Temperature Package
Pwf	Average Flowing Bottom Hole Pressure
Q	Bottom Hole Flow Rate
Q_{max}	Maximum Flow Rate
Q_{min}	Minimum Flow Rate
q_g	Gas Flow Rate
RD	Outer/Inner Radius Ratio
R_P	Producing Gas Oil Ratio
R_s	Solution Gas Oil Ratio
w	Well Radius
Sg_{max}	Maximum Gas Saturation
S_{gr}	Residual Gas Saturation
STOIIP	Stock Tank Original Oil in Place
Swc	Connate Water Saturation
T	Time
T	Temperature
U	Aquifer Constant
VLP	Vertical Lift Profile
WGR	Water Gas Ratio
WHP	Wellhead Pressure
WHR	Wellhead Rates
Z	Compressibility Factor
η	Viscosity
ρg	Gas Density
ρL	Liquid Density
φ	Porosity

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