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Oil Reserves Evaluation and Field Development plan of Hakim Oil Field in Libya

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Abstract

The main objectives of this research are to estimate the oil reserves and set a development plan for Hakim Field in Libya, using three methods for calculating OOIP which are Volumetric (Monte Carlo), Decline curve analysis (DCA), Material Balance Equation, and establish the optimum development plan for Hakim field. Results showed that the OOIP of Hakim Field, calculated by volumetric method done through Monte Carlo tool given 90.2 MM STBO for Proven Reserves (1P) , 115.5 MM STBO for Probable reserves (2P) and 147.0 MM STBO for Possible reserves (3P). While OOIP estimated by Decline curve analysis given 82.4MM STBO for Proven Reserves (1P) , 102.8MM STBO for Probable reserves (2P) and 114.9MM STBO for Possible reserves (3P), and 112.18 MM STBO for Probable reserves (2P) by Material Balance. In addition, 14 prediction scenarios have been applied on the Material Balance Model to establish the optimum Field development Plan, results showed that from simulation model the optimal scenario is 8 Producing Wells, 4 Water Injector Wells and 8000 BWPD.

Keywords

Oil Reserves Evaluation - Field Development plan - Hakim Oil Field in Libya

Introduction

Oil reserves estimation is one of the most important tasks in petroleum engineering, because it is based on estimates of reserves can be created companies, or the increasing of the development plan for the field, And the consequent adoption of large financial investments, Therefore it is important both to governments and major oil companies, so it was interest in the development of tools that can be used to estimate oil reserves [1] and [2].

There are several methods used to estimate oil reserves, will be discussed during this thesis, and to highlight the precautions that must be taken into account while estimating oil reserves through oil reserves estimate for the Hakim field in Sirt Basin – Libya, By applying the three methods of the methods used to estimate oil reserves which are Volumetric (Monte Carlo), Decline curve analysis (DCA), Material Balance Equation [3] and [4].

Production predictions can be performed through the Model that was created by Material Balance Equation, that after set predictions data model and imposition of a number of scenarios which can use it to develop the field and Select of the best-case development option, among the alternatives considered, for further development of the reservoir to obtain the higher Recovery factor[5].

The main scope of this thesis is estimate oil reserves for Hakim Field estimate oil reserves using Volumetric (Monte Carlo), Decline curve analysis (DCA), Material Balance Equation, therefor set a development plan for Hakim Field.

To achieve this, some specific objectives need to be met:

- Estimate initial oil in place:
- Volumetric method (Monte Carlo Simulation).
- Decline curve analysis.
- Material balance equation.
- Compare the results from the above methods
- Degree of uncertainty for reserves estimation
- Establish a Field development plan (FDP)
- Number of infill producing wells can be drilled in the future ,
- Number of water injection wells to support for the reservoir pressure, and
- Determine an appropriate water injection rates.

Reserves in Oil Fields:

All oil and gas fields represent a limited geological structure, and consequently, they have an upper limit of how much hydrocarbons they contain. The size of the trap and reservoir, which can be defined by geological and geophysical methods, gives an estimate of the potential volume of oil in the field, before the drilling has begun. As borehole data and production data becomes available, the reserve estimate will tend towards increasing accuracy [2].

The recoverable amount of the oil in place is classified as the reserve; the recovery factor (RF) is a dynamic value, representing the estimated percentage of the total oil in place volume that can be recovered. RF depends on numerous parameters, such as rock and fluid properties, reservoir drive mechanism and production technology, variations in the formation and the development process. In some modern reservoir simulators it is not necessary to use OOIP or RF at all in order to estimate reserves (reserve = recovery factor * oil in place) [3].

Initially, oil is recovered through the energy that is occurring naturally in the reservoir. For instance via gas drive or water drive mechanisms. This can be called the primary recovery method and usually 10-30% of the oil in place can be recovered this type [4].

Secondary recovery methods utilize injection of water and/or gas to maintain pressure, thus feeding additional energy to the reservoir. About 30-50% of the oil in place can be recovered by use of primary and secondary recovery methods [4].

Tertiary recovery methods, or enhanced oil recovery (EOR), include more complex methods, such as injection of polymer solutions, surfactants, microbes, nitrogen or carbon dioxide, capable of influencing rock and fluid properties. Only a small fraction of the world's oil fields are using EOR [4].

The production of an oil field tends to pass through a number of stages. This can be described by an idealized production curve. A version of this curve can be seen in Figure 1 After the discovery well, an appraisal well is drilled to determine the development potential of the reservoir [3]. Further development follows and the first oil production marks the beginning of the build-up phase. Later the field enters a plateau phase, where the full installed extraction capacity is used, before finally arriving at the onset of decline, which ends in abandonment once the economical limit is reached. For many fields, especially smaller ones, the plateau phase can be very short and resemble more to a sharp peak, while large fields can stay several decades at the plateau production level. The life time of a field and the shape of the production curve are often related to the kind of hydrocarbon that is produced.

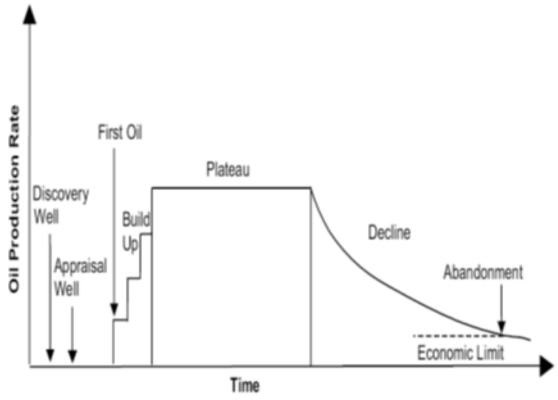

Figure 1 A theoretical production curve, describing the various stages.

In the PRMS (Petroleum Resources Management System)reserves and resources are classified according to the degree of certainty. The general cumulative terms used with reserves for low/best/high are 1P/2P/3P; the related incremental quantities are termed Proven, Probable and Possible. The general cumulative terms low/best/high estimates are denoted as C1/C2/C3 for contingent resources. The general cumulative terms low/best/high estimates still apply for prospective resources. There are no specific terms defined for incremental quantities within both Prospective Resources and Resources [10].

The Hakim Field

The Hakim Field located at the southwestern part of Sirt Basin in concession NC-74A, approximately 580 km Southeast of Tripoli.

The Hakim Oil Field (Hakim and S.W Hakim) belongs to Zueitina Oil Company. The first well discovered and drilled in this field was in 1978 with production tested at a rate of 1350 BOPD producing horizon from the Upper Facha Dolomite Member of the Lower Eocene Gir formation located at the southwestern side of Sirt Basin.

Available Data of Hakim Field

To calculate oil reserves in different method should provide some of field and laboratory data such as maps, petrophysical data, PVT analysis, SCAL, reservoir pressure data and production performance.

Hakim Field –General Data

Table 1 Table Show the General Data of HAKIM FIELD

No. of Producers:	**10 wells**
No. of Injectors:	4 wells
No. Of dry holes:	2 wells
Oil Cumulative:	27.93
Gas Cumulative:	8.83 BCF
Water Cumulative:	48.65 MMSTB
Cumulative injected Water:	64.08 MMSTB

Hakim Field – Map

The depth map shows the contour lines representing the depth of the field. Also, Oil down to (ODT) is given at 5871 ft and it is the deepest point at which oil was found. While, Water up to (WUT) is given at 5835 ft and it is the shallowest depth at which water was found.

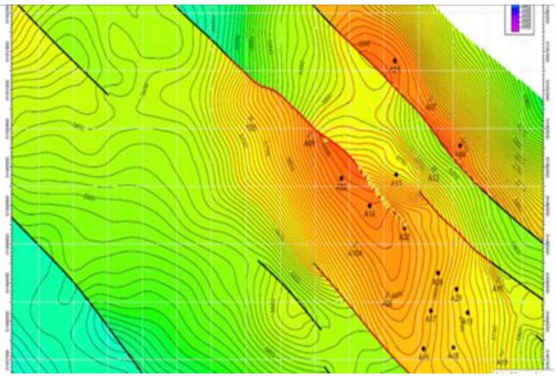

Figure 2 Top Structural Contour Map of Upper Facha Dolomite Member of the Lower Eocene Gir formation

Hakim Field - Petrophysical Data

Upper Facha Dolomite divided into the two block northern and southern parts of the f Hakim field and each is divided into three zones A, B and C.,

The table 2and 3 shows the petrophysical data (Porosity, Net Pay Thickness, and Water Saturation) of these three layers in both Hakim North block and South Block after reviewing the wells logging, taking into consideration the level of uncertainty and variability on the data, In order to calculate the different types of oil reserves (1P, 2Pand 3P).

Hakim Field - Reservoir Fluids Analysis (PVT)

one sample was collected from North Hakim as bottom hole sample (BHS) and one sample was collected from South Hakim as bottom hole sample (BHS), pressure in North Hakim sample was 2667 psi and pressure in South Hakim sample was 2715 psi with almost same oil density was 0.78 g/cm³, Bubble point pressure 655 psi , Initial the firgures 3,4,5,6,7and 8shown the summery and result of PVT analysis of the fluid of both compartment North Hakim and South Hakim.

Table 2 The Petrophysical Data of Hakim South Block Zones A, B and C

Zone	Case	Net Pay Thickness ft	Water Saturation %	Porosity %
A	1P	1	18%	15%
	2P	2.27	28%	19%
	3P	4.04	40%	24%
B	1P	3.69	15%	15%
	2P	6.33	30%	20%
	3P	7.72	47%	24%
C	1P	33	20%	18%
	2P	37.06	30%	21%
	3P	41.9	40%	24%

Table 3 The Petrophysical Data of Hakim North block Zones A, B and C

Zone	Case	Net Pay Thickness ft	Water Saturation %	Porosity %
A	1P	1.00	15%	8%
	2P	2.27	32%	17%
	3P	4.04	50%	26%
B	1P	3.69	13%	14%
	2P	6.33	36%	20%
	3P	7.72	60%	25%
C	1P	33.00	8%	8%
	2P	37.06	50%	18%
	3P	41.90	92%	29%

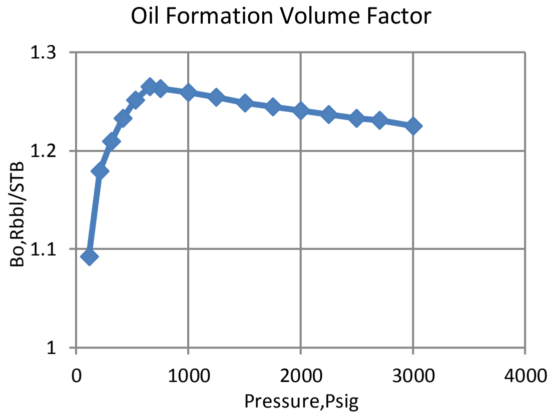

Figure 3 Oil Formation Volume Factor, BO for South Hakim PVT.

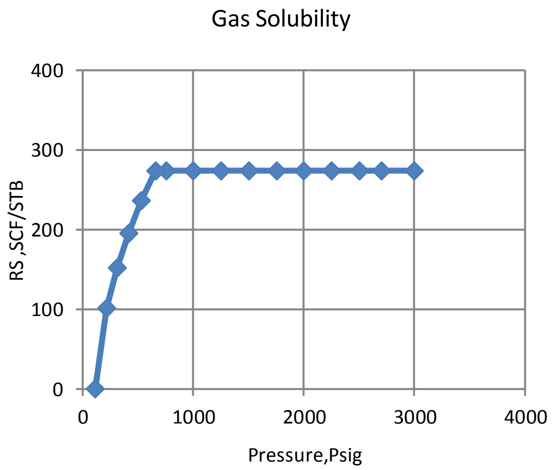

Figure 4 Gas Solubility, Rs for South Hakim PVT

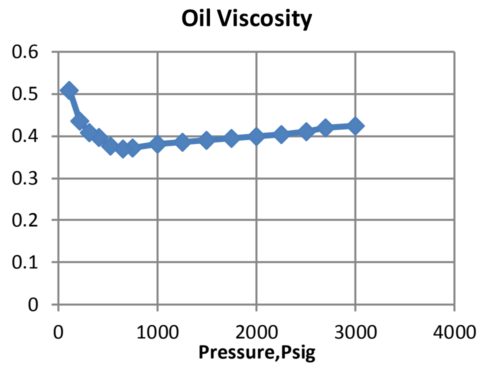

Figure 5 Oil Viscosity, μo for South Hakim PVT

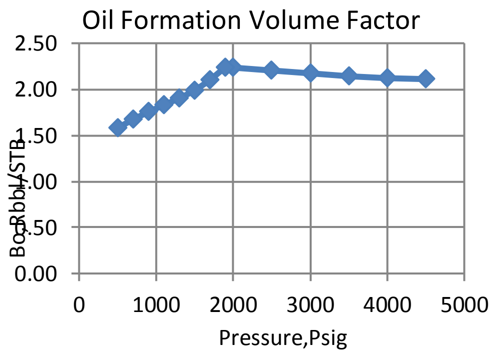

Figure 6 Oil Formation Volume Factor, BO for North Hakim PVT

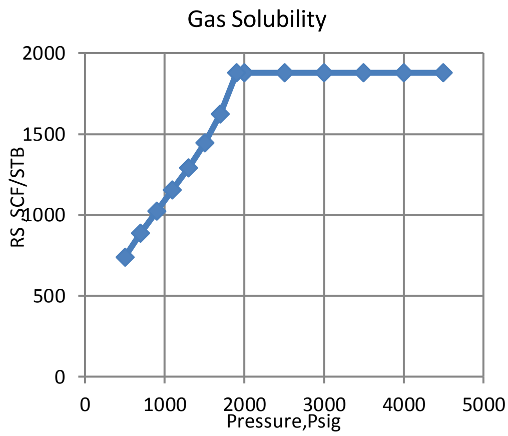

Figure 7 Gas Solubility, Rs for North Hakim PVT

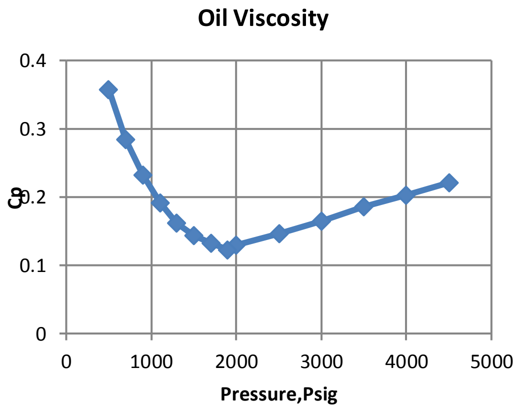

Figure 8 Oil Viscosity, μo for North Hakim PVT

Hakim Field - Relative permeability data

Special core analysis provided the most important parameter to transfer the model to dynamic case by relative permeability and capillary pressure, both of them responsible about fluid saturations distribution and fluid movement later on during production.

Table 4 Relative permeability data for zone A and B

Sw	Swn	K^*_{rw}	Son (1- Swn)	K^*_{ro}
0.2290	0.0000	0.0000	1.0000	0.9013
0.2500	0.0397	0.0032	0.9603	0.8043
0.3000	0.1342	0.0224	0.8658	0.6010
0.3500	0.2287	0.0528	0.7713	0.4342
0.4000	0.3233	0.0918	0.6767	0.3006
0.4500	0.4178	0.1385	0.5822	0.1969
0.5000	0.5123	0.1921	0.4877	0.1197
0.5500	0.6068	0.2519	0.3932	0.0653
0.6000	0.7013	0.3177	0.2987	0.0301
0.6500	0.7958	0.3891	0.2042	0.0103
0.7000	0.8904	0.4657	0.1096	0.0018
0.7500	0.9849	0.5475	0.0151	0.0000
0.7580	1.0000	0.5610	0.0000	0.0000

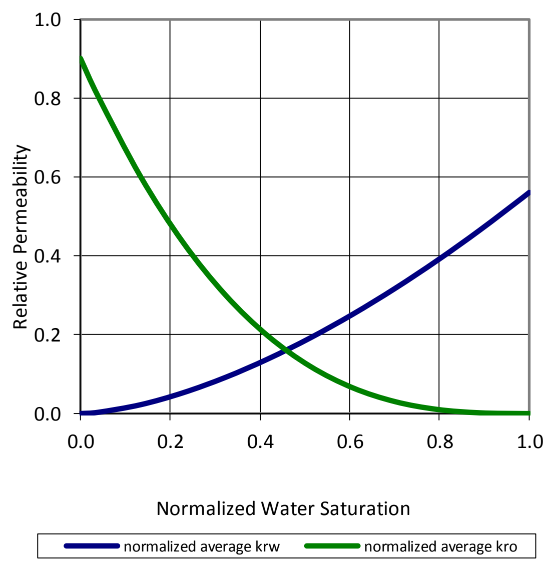

Figure 9 Normalized Average Relative Permeability, Zones A and B

Table 5 Relative Permeability Data for Zone C

Sw	Son	Swn	kro	Krw
0.1177	1.0000	0.0000	0.9671	0.0000
0.1500	0.9325	0.0675	0.8083	0.0009
0.2000	0.8282	0.1718	0.5961	0.0081
0.2500	0.7238	0.2762	0.4218	0.0253
0.3000	0.6195	0.3805	0.2829	0.0548
0.3500	0.5151	0.4849	0.1762	0.0981
0.4000	0.4108	0.5892	0.0985	0.1568
0.4500	0.3064	0.6936	0.0464	0.2321
0.5000	0.2021	0.7979	0.0159	0.3252
0.5500	0.0977	0.9023	0.0025	0.4370
0.5968	0.0000	1.0000	0.0000	0.5597

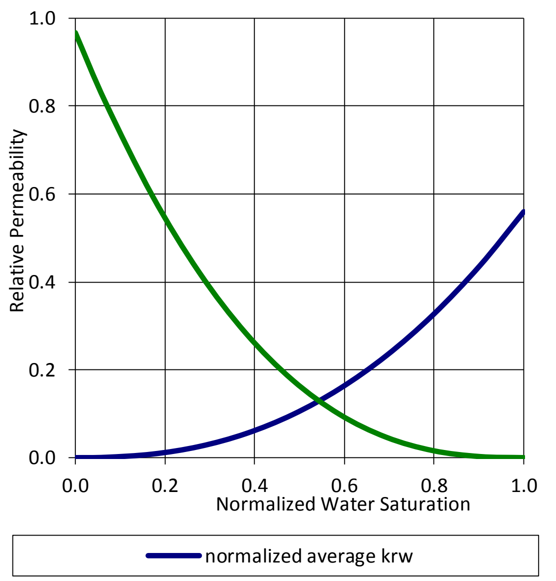

Figure 10 Normalized Average Relative Permeability, Zones c

Hakim Field – Historical Data

The historical data includes the production and pressure values for Hakim Field from 1/12/1984 to 1/4/2004

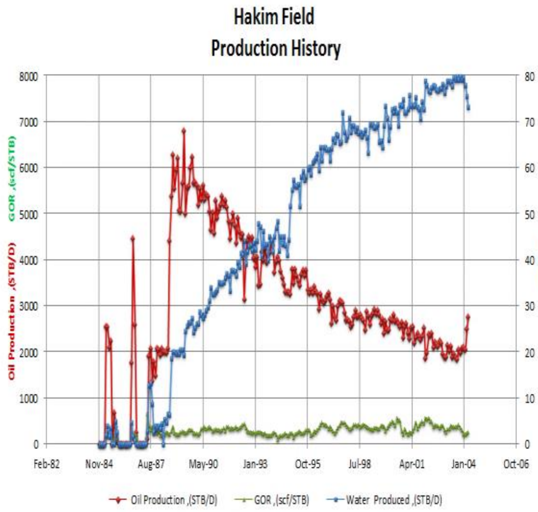

Figure 11 Hakim Field Production Performance

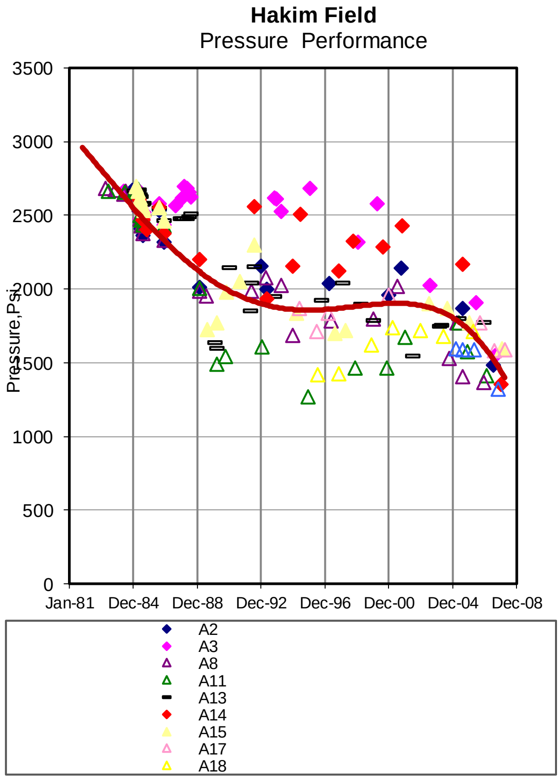

Figure 12 Hakim Field Pressure Performance

Reserves Evaluation and Field Development plan of Hakim Field

The reserves will be estimated using three methods, then a comparison between the values obtained from the three methods will be done, these Tree methods are:

- Volumetric (Monte Carlo) using MBAL.
- Material Balance using MBAL.
- Decline curve analysis (DCA) using OFM.

Volumetric (Monte Carlo)

After making sure that there is no interference from the bottom layer, we need to determine the minimum and maximum values for the given petro-physical data, the minimum and maximum values will then be used along with the minimum and maximum bulk volume as input in by MBAL software [Commercial Program of Petroleum Expert] in order to calculate P90, P50, and P10 [7].

Step-1: Area calculation:

The process starts by calculating the area of the reservoir, this is done using PETREL software, can get the exact distance of the X and Y of the reservoir, multiplying these two values by each other we get the area of the reservoir, the margin is taken into consideration by allowing for a maximum and minimum value of the area with the calculated value in the middle of these two values.

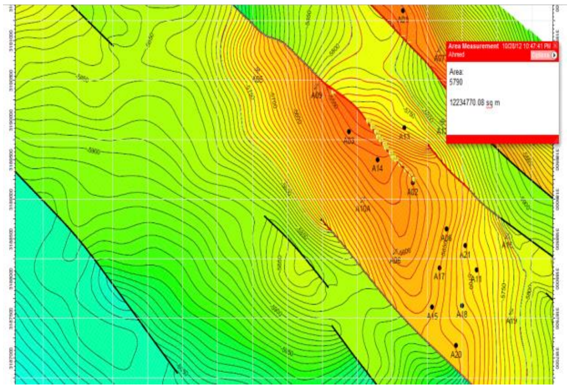

Figure 13 Top Structural Contour Map of Upper Facha from PETREL software

Step-2: Determination of Lowest Known Hydrocarbon:

Oil down to (ODT) is given at 5871 ft and it is the deepest point at which oil was found. While, Water up to (WUT) is given at 5835 ft and it is the shallowest depth at which water was found.

Table 6 Lowest Known Hydrocarbon

Zone	WUT Depth		ODT Depth	
	K.B.	TVDss	K.B.	TVDss
A	6802	5771	6777	5726
B	6814	5783	6791	5740
C	6866	5835	6832	5781

Step-3: Gross Rock Volume Calculation:

Gross rock volume can be calculated by drawing the contour areas with depth as shown in Figure 14.

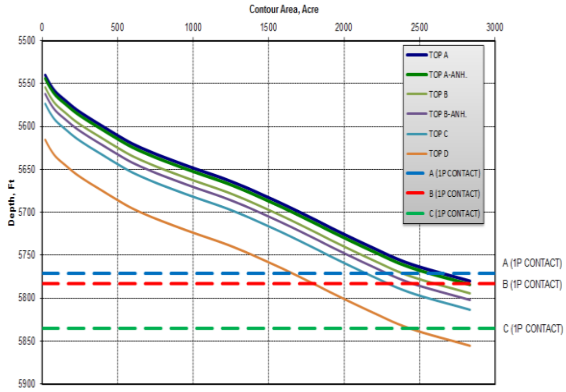

Figure 14 contour areas Vr Depth

Step-4: Determine Properties Distribution (Phi, SW):

The histograms shows the properties distribution (porosity and saturation), which it determined from different wells (well logs).

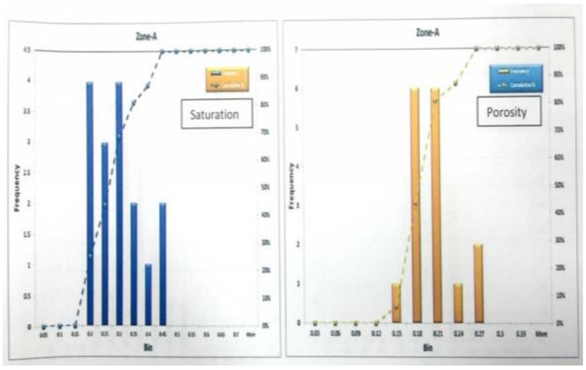

Figure 15 the properties distribution saturation (A) and porosity (B) for Zone A

Step-5: PVT modeling:

The PVT table is also entered from the given data to build the fluid model.

Step-6: Monte Carlo Input Distribution and Results:

After defining the input parameters, the program calculates many values for the OOIP using millions of values for the input parameters. The software then plots the OOIP values with the frequency and the probability of their occurrence. This can be used to determine P90, nP50, and P10.

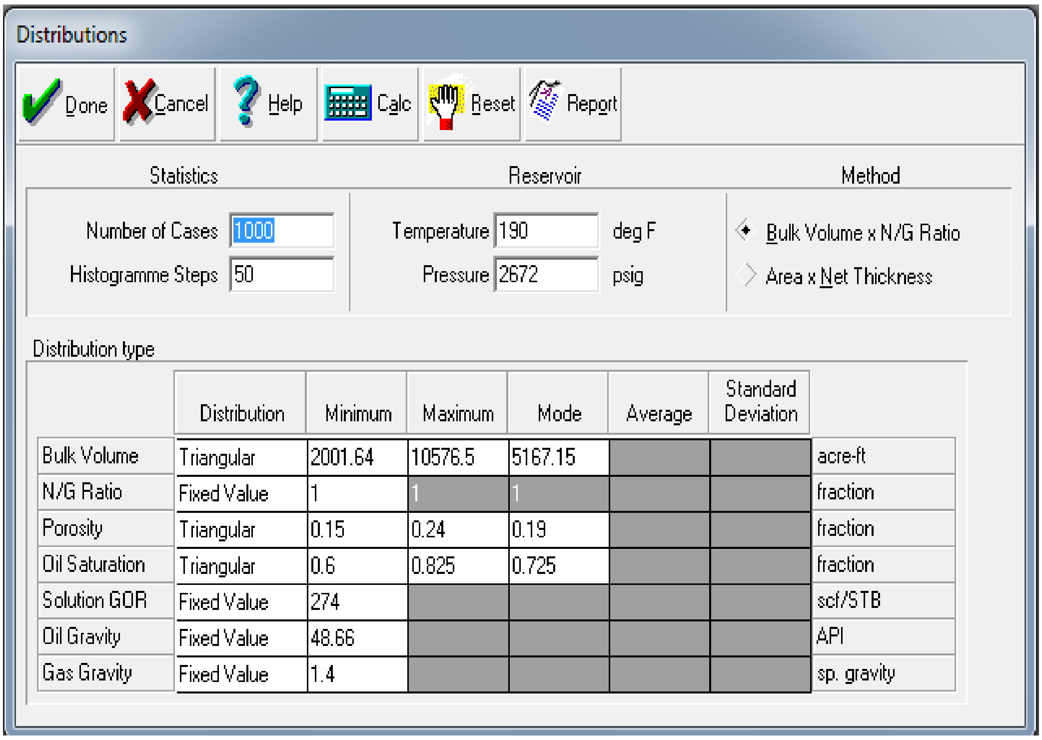

Figure 16 Monte Carlo OOIP calculation Input Parameter for South Hakim -Zone A, [MBAL version 10.0]

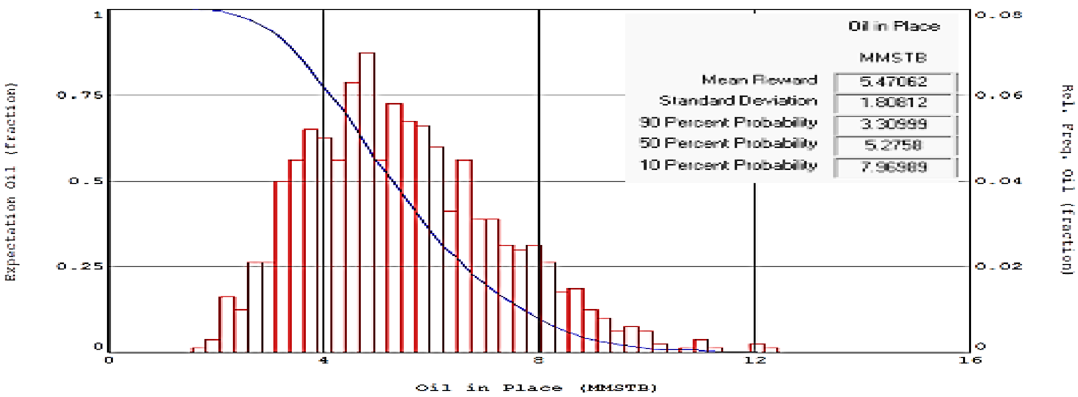

Figure 17 Monte Carlo OOIP calculation Results for South Hakim -zone A, [MBAL version 10.0]

Table 7 summary of input and results from Monte Carlo calculation for South Hakim - the three zones A, B and C

Zone	Case	Net Pay Thickness	Water Saturation	Porosity	STOIIP
		ft	%	%	MMSTB
A	1P	1.00	18	15	3.3
	2P	2.27	28	19	5.27
	3P	4.04	40	24	7.97
B	1P	3.69	15	15	8.65
	2P	6.33	30	20	12.15
	3P	7.72	47	24	16.75
C	1P	33.00	20	18	75.87
	2P	37.06	30	21	92.883
	3P	41.90	40	24	113.29
TOTAL	1P				87.82
	2P				110.303
	3P				138.01

Table 8 summary of input and results from Monte Carlo calculation for North Hakim - the three zones A, B and C

Zone	Case	Net Pay Thickness	Water Saturation	Porosity	STOIIP
		ft	%	%	MMSTB
A	1P	1.0	0.2	0.1	0.16
	2P	2.3	0.3	0.2	0.28
	3P	4.0	0.5	0.3	0.45
B	1P	3.7	0.1	0.1	0.72
	2P	6.3	0.4	0.2	1.10
	3P	7.7	0.6	0.3	1.56
C	1P	33.0	0.1	0.1	1.45
	2P	37.1	0.5	0.2	3.81
	3P	41.9	0.9	0.3	7.02
TOTAL	1P				2.33
	2P				5.19

	3P		9.03

Summary of OOIP from Monte Carlo Calculation for North and South Hakim Field

Table 9 Summary of OOIP from Monte Carlo calculation for North and South Hakim Field

Zone	Case	South Hakim	SOUTH HAKIM	TOTAL
		OOIP		
		MMSTB	MMSTB	
A	1P	3.3	0.2	3.5
	2P	5.3	0.3	5.6
	3P	8.0	0.5	8.4
B	1P	8.7	0.7	9.4
	2P	12.2	1.1	13.3
	3P	16.8	1.6	18.3
C	1P	75.9	1.5	77.3
	2P	92.9	3.8	96.7
	3P	113.3	7.0	120.3
TOTAL	1P	87.8	2.3	**90.2**
	2P	110.3	5.2	**115.5**
	3P	138.0	9.0	**147.0**

Decline curve analysis (DCA)

This technique involves using the production history in order to make a decline curve analysis using ARPS'[22].

The first step involves loading the production history to the OFM software [a commercial program by Schlumberger for well and reservoir analysis.

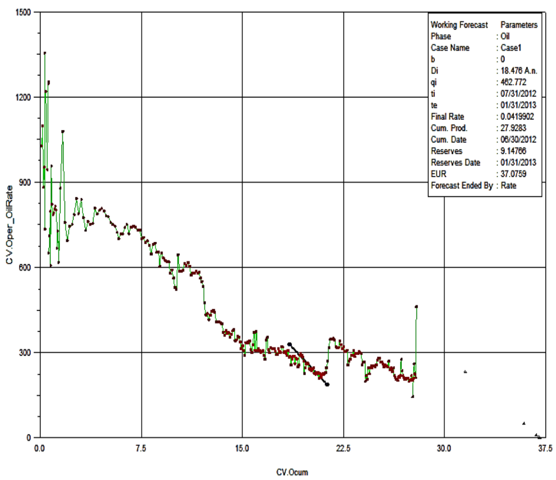

Figure 18 Hakim Field –DCA- 1P Case [OFM version 2010]

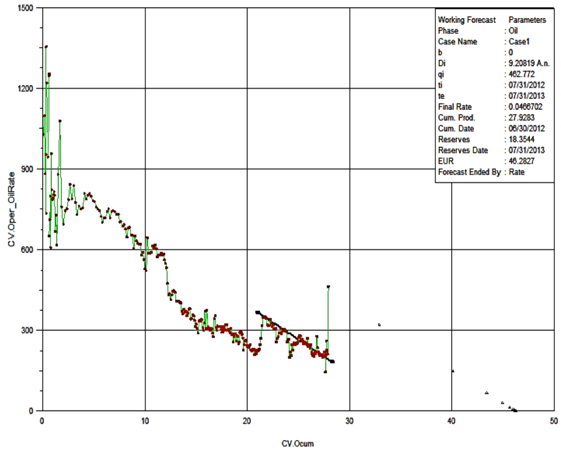

Figure 19 Hakim Field –DCA- 2P Case [OFM version 2010]

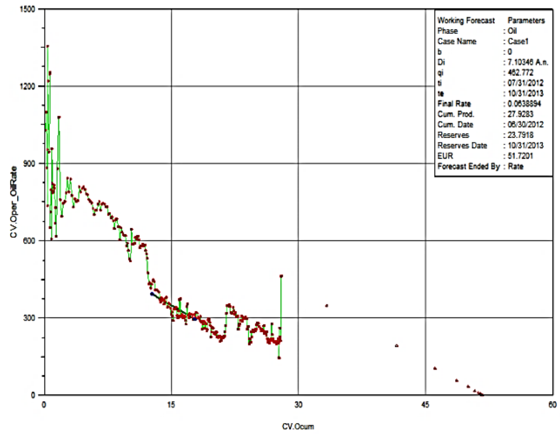

Figure 20 Hakim Field –DCA- 2P Case [OFM version 2010]

Summary of OOIP from DCA for Hakim Field

Table 10 Summary of OOIP from DCA for Hakim Field

	1P MMSTB	2P MMSTB	3P MMSTB
Cum. Production	27.93	27.93	27.93
Reserves	9.15	18.35	23.79
EUR	37.08	46.28	51.72
OOIP	**82.4**	**102.8**	**114.9**

Material Balance Technique

This tool incorporates the classic use of material Balance calculations for history matching through graphical and Analytical methods in addition to Energy Plot [27].

The Graphical Method:

The graphical method plot is used to visually determine the different Reservoir and Aquifer parameters [27].

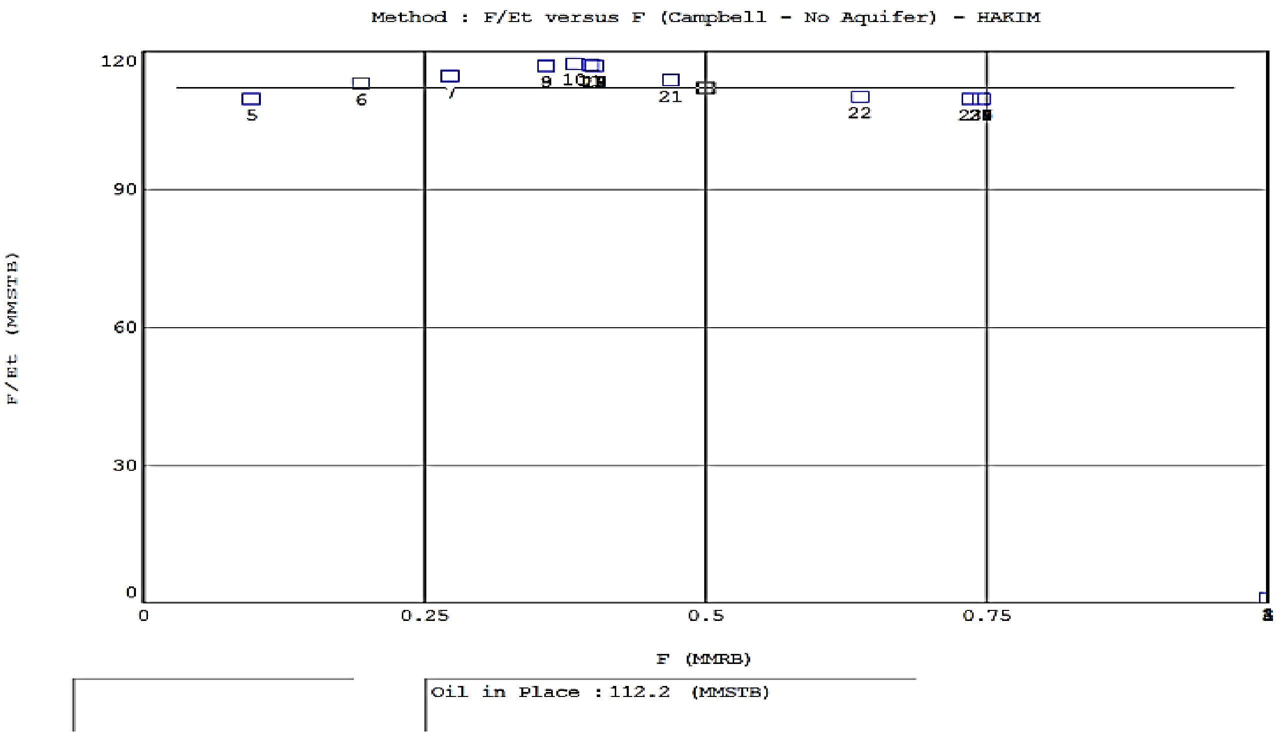

Figure 21 MBE for OOIP Calculation Graphical Method, [MBAL version 10.0]

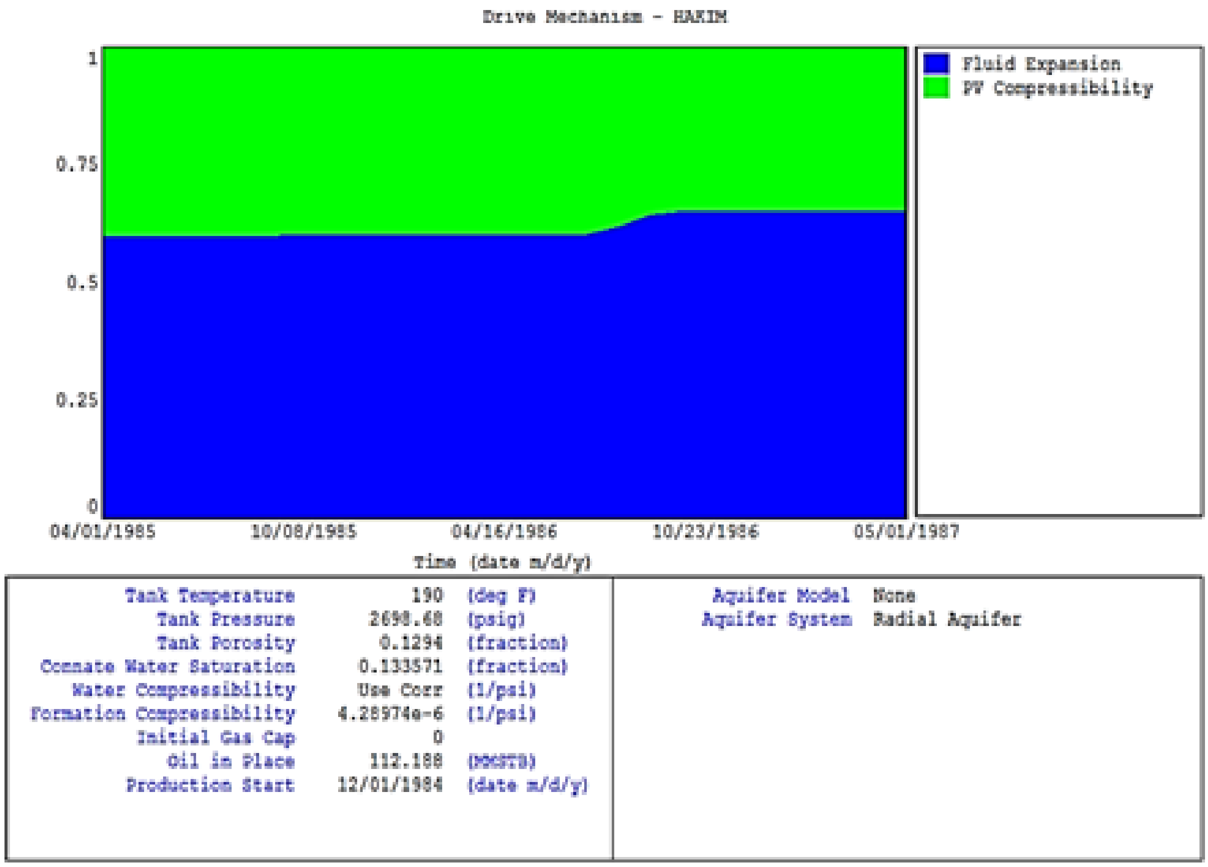

Figure 22 The Rerservoir Energy from MBE Calculations, [MBAL version 10.0]

The Analytical Method

The analytical plot shows the Reservoir Pressure vs. Cum Production from the historical data and the model [27].

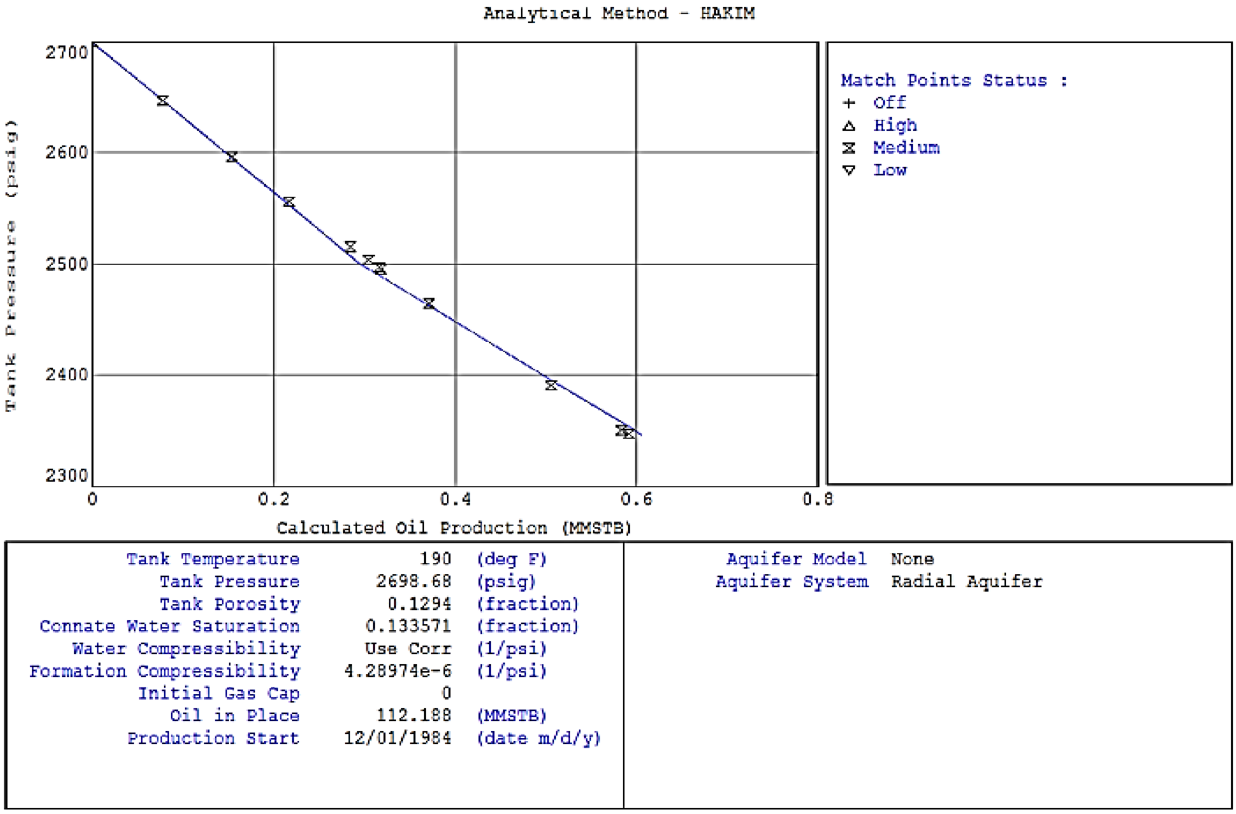

Figure 23 MBE for OOIP Calculation Analytical Method, [MBAL version 10.0]

Energy Plot

Energy Plot shows the relative contributions of the main source of energy in the reservoir and aquifer system [27].

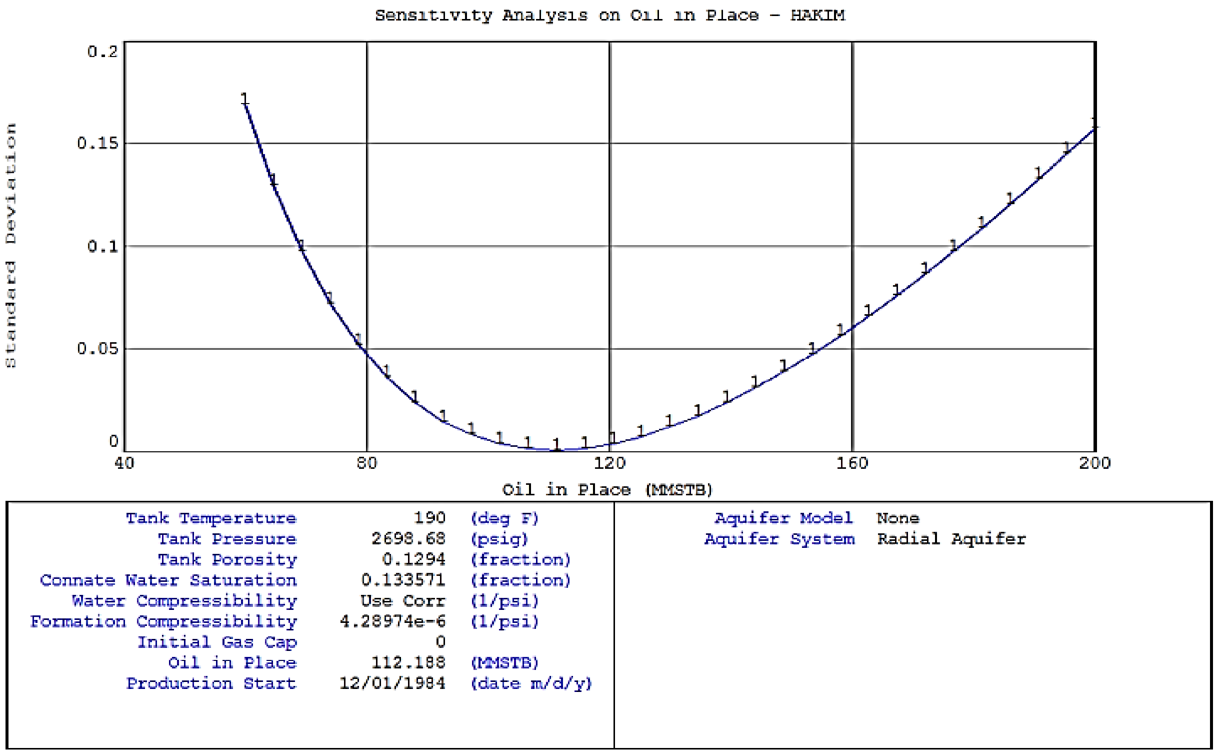

Figure 24 Sensitivity Analysis on OOIP [MBAL version 10.0]

Sensitivity Analysis

This option is used for running sensitivity on one or two variables at a time. A certain number of values between a minimum and a maximum can be defined for each variable [27].

Simulation Plot

The simulation calculations can serve as a final quality check on the history matching carried out earlier before transfer to prediction step.

It can conclude from material balance calculations that the OOIP is 112.188 MMSTB of oil at standard conditions, and the reservoir can be classified also as depletion drive reservoir.

As is clear that the calculated data are consistent with historical data, therefore it can rely on this model to predict the future reservoir data.

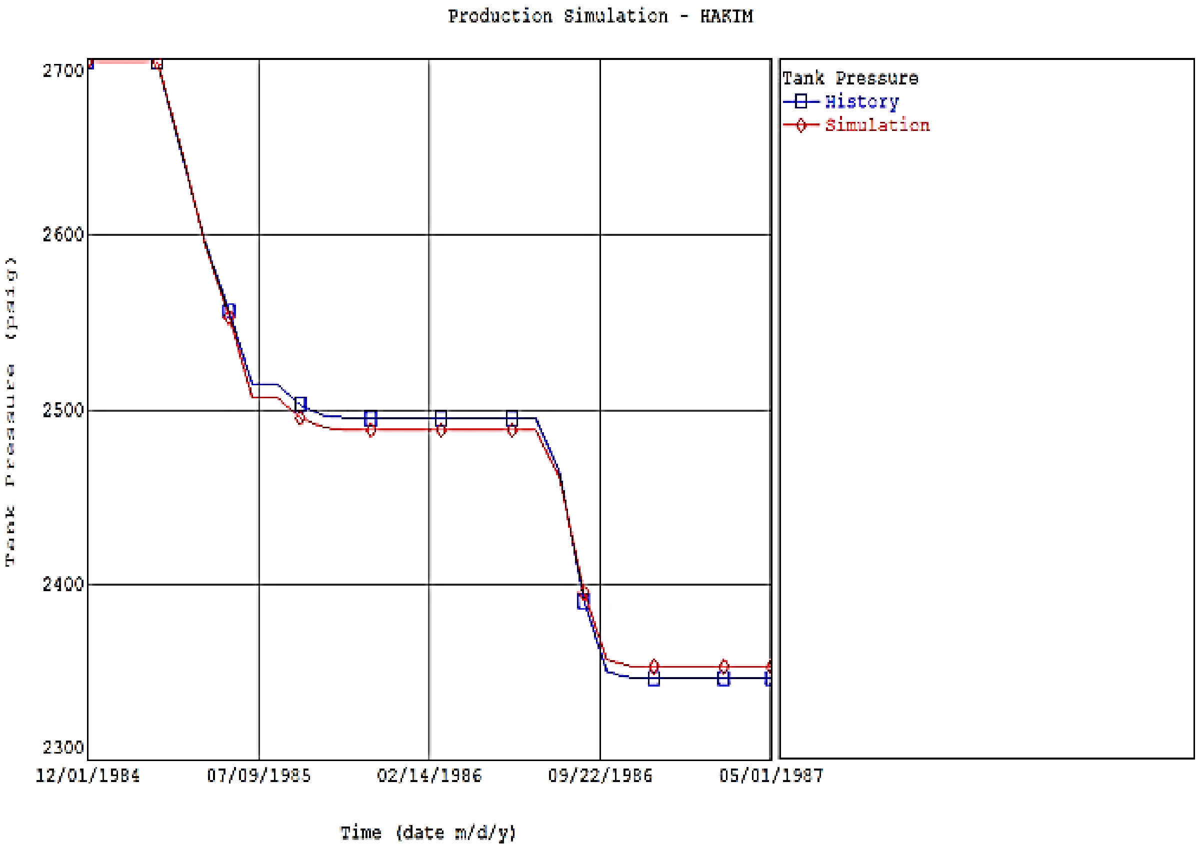

Figure 25 comparison between historical data and calculated data while the simulation[MBAL version 10.0]

Summary of OOIP Calculation by Different Methods:

From all discussed previously can be summarized accounts OOIP as shown in the Table 11 What can be observed that the numbers of OOIP calculated by three methods are close to each other, with little increasing in Monte Carlo method resulting from this method calculate the static volumes, but in Material Balance the calculation depending on the dynamic data so the results from Material Balance it's more reliable, the numbers from DCA also close to the others but little higher than Material Balance causing by that calculation accuracy depend on level of production data organized or scattered .

Table 11 Summary of OOIP Calculation by Different Methods

	OOIP,MMSTBO		
	1P	2P	3P
Monte Carlo	90.2	115.5	147.0
DCA	57.2	114.7	148.7
Material Balance	112.19		

Production Prediction

The prediction start date is set to the production start date at December 1984 and the prediction end date at end of year 2050.

In this part will have been building a number of scenarios for the development of the reservoir through the three levels of sensitivity analyzes, first to impose different numbers of producing wells can be drilled in the future, the choice of the optimal number to reach the highest reserves.

The second level is the selection of the optimal number of water injection wells to get the best pressure support for the reservoir, in order to be given the highest reserves, through the imposition of a number of scenarios to predict containing different numbers of water injection wells.

And then can move to the third level, after the selection of the appropriate number of production wells and water injection wells, will be specifies an appropriate water injection rates, by testing a number of water injection rates and choose the optimal rates.

The following mention scenarios that have been imposed on the three levels of sensitivity analysis

Level I Numbers of Producing Wells Selection:

- 2 Producing Wells (base case)
- 4 Producing Wells
- 6 Producing Wells
- 8 Producing Wells
- 10 Producing Wells
- 12 Producing Wells

Numbers of Producing Wells Selection Discussion:

It can be observed from the Figure 26, the three scenarios 12 producing wells, 10 producing wells and 8 producing wells are given higher reserves (52.17 MM STBO), but economically preferred the scenario which is a smaller number of wells, so 8 producing wells has been selected.

Level II Numbers of Water Injection Wells Selection:

- 8 Producing Wells and 2 Water Injection Wells
- 8 Producing Wells and 4 Water Injection Wells
- 8 Producing Wells and 6 Water Injection Wells

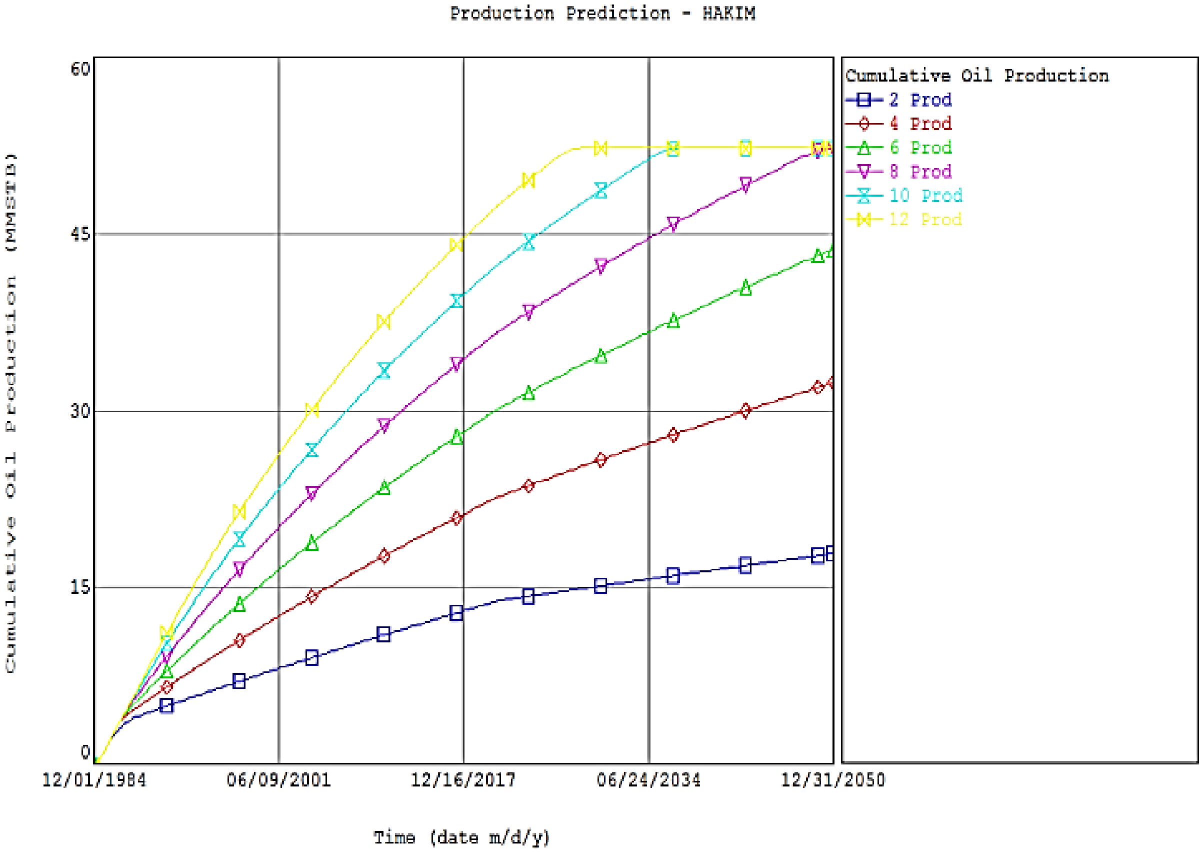

Figure 26 Production Prediction - Numbers of Producing Wells Selection [MBAL version 10.0]

Numbers of Water Injection Wells Selection Discussion:

It can be observed from the Figure 27, the two scenarios (8 Producing Wells and 4 Water Injection Wells) and (8 Producing Wells and 6 Water Injection Wells) are given higher reserves (52.42 MM STBO), but economically preferred the scenario which is a smaller number of wells ,so 8 Producing Wells and 4 Water Injection Wells has been selected.

Level III Rates of Water Injection Wells Selection:

- 8 Producing Wells , 4 Water Injection Wells and 2000 BWPD
- 8 Producing Wells , 4 Water Injection Wells and 4000 BWPD
- 8 Producing Wells , 4 Water Injection Wells and 6000 BWPD
- 8 Producing Wells , 4 Water Injection Wells and 8000 BWPD
- 8 Producing Wells , 4 Water Injection Wells and 10000 BWPD

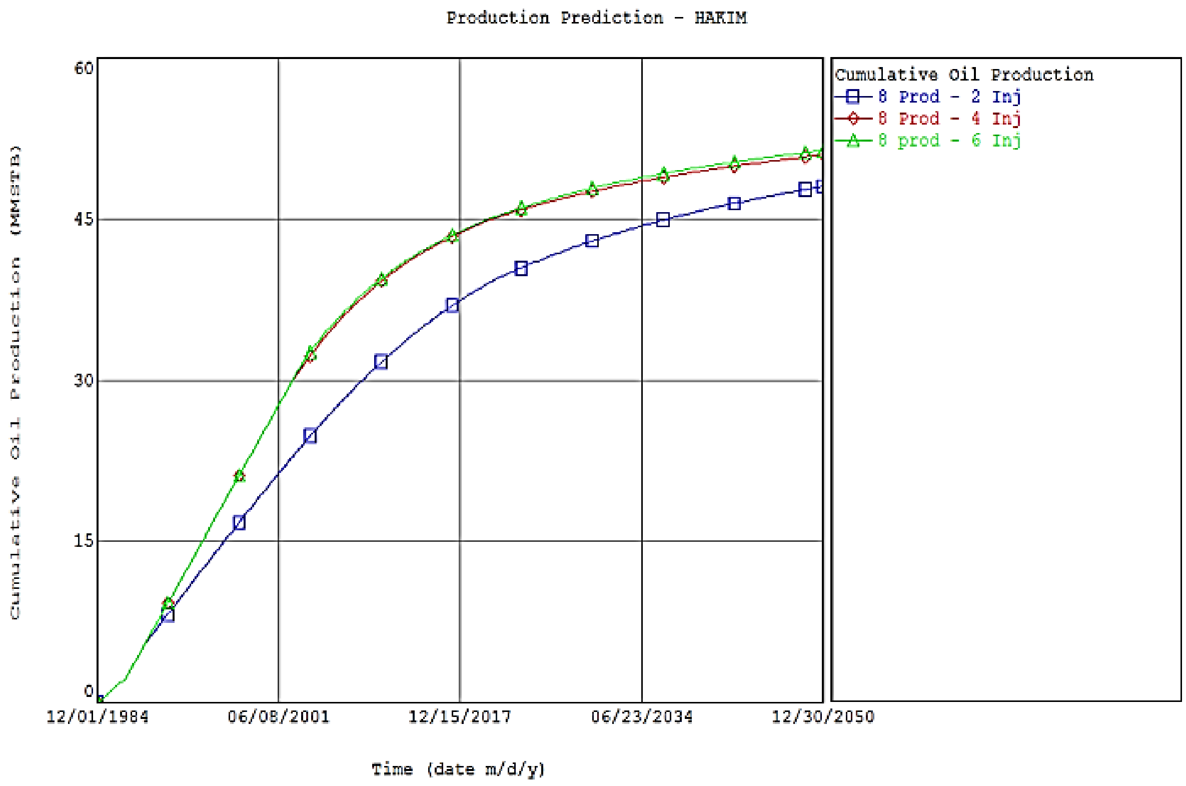

Figure 27 Production Prediction - Numbers of Water Injection Wells Selection[MBAL version 10.0]

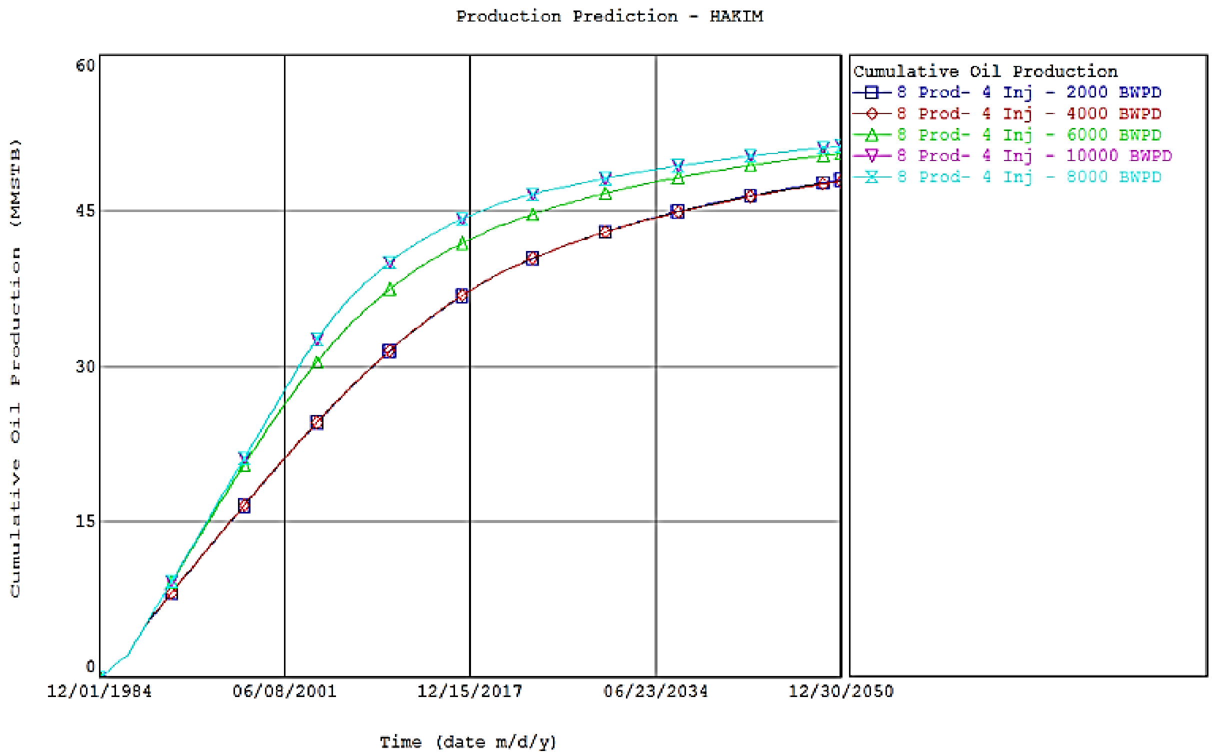

Figure 28 Production Prediction - Rates of Water Injection Wells Selection [MBAL version 10.0]

Rates of Water Injection Wells Selection Discussion

It can be observed from the Figure 28, the two scenarios (8 Producing Wells, 4 Water Injector Wells and 8000 BWPD) and (8 Producing Wells, 4 Water Injector Wells and 10000 BWPD) are given higher reserves (52.7 MM STBO lead to 46.97 % recovery factor), but economically preferred the scenario which is minimum injection rates, so 8 Producing Wells, 4 Water Injector Wells and 8000 BWPD has been selected.

Conclusions

The scope of the thesis is to estimate the oil reserves and set a development plan for Hakim Field, through the use of three methods for calculating OOIP which are Volumetric (Monte Carlo), Decline curve analysis (DCA), Material Balance Equation, therefor predict the reservoir behavior to set the optimum development plan for Hakim field.

The following conclusions are made on the basis of this study:

- The OOIP of Hakim Field calculated by volumetric method done through Monte Carlo tool given 90.2 MM STBO for Proven Reserves (1P) , 115.5 MM STBO for Probable reserves (2P) and 147.0 MM STBO for Possible reserves (3P).
- The OOIP of Hakim Field calculated by Decline curve analysis given 82.4 MM STBO for Proven Reserves (1P) , 102.8 MM STBO for Probable reserves (2P) and 114.9 MM STBO for Possible reserves (3P).
- The OOIP of Hakim Field calculated by Material balance given 112.18 MM STBO for Probable reserves (2P).
- 14 prediction scenarios have been applied on the Material Balance Model using Mbal software in three level of sensitivity analyzes as follows:
- The first level is selection of the optimal number of producing wells can be drilled in the future ,
- The second level is selection of the optimal number of water Injector wells to get the best pressure support for the reservoir,
- The third level is the identification of an appropriate water injection rates after selection of the appropriate number of production wells and water injection wells, by testing a number of water injection rates and choose the optimal rates.
- According to prediction simulation results the optimal scenario is 8 Producing Wells, 4 Water Injector Wells and 8000 BWPD.
- Decline curve analysis through production histories of oil and gas wells can be analyzed to estimate reserves and future oil and gas production rates and to validate results of complex reservoir studies. Because accurate production data are commonly available on most wells, production data analyses can be widely applied.
- Material balance equation is one of the important methods for estimating oil reserves; in addition to their ability to build scenarios for predict the future reservoir behavior.

Nomenclatures

1P	Proven
2P	Probable
3P	Possible
BCF	Billion Cubic Feet
BHS	Bottom Hole Sample
Bo	Oil Formation Volume Factor
BWPD	Barrel Water per Day
DCA	Decline Curve Analysis
EOR	Enhanced Oil Recovery
FDP	Field Development Plan
Ft	Feet
Kro	Relative Permeability of Oil at Different Sw
Kro (Swc)	Relative Permeability of oil at Connate Water Saturation
Kro*	Normalized Relative Permeability of OIL
Krw	Relative Permeability Of Water At Different Sw
Krw (Soc)	Relative Permeability of Water Critical Oil Saturation
Krw*	Normalized Relative Permeability of Water
MEB	Material Balance Equation
MMSTBO	Million Stock Tank Barrel Oil
Mo	Oil Viscosity
ODT	Oil Down-to
OFM	Oil Field Manager - Software
OOIP	Original Oil in Place
Psig	pound per square inch - gauge
PRMS	Petroleum Resources Management System
PVT	Pressure - Volume - Temperature
RF	Recovery Factor
Rs	Gas Solubility
SCAL	Special Core Analysis
Son	1-Sw
STBOPD	Stock Tank Barrel Oil per day
Sw	Water Saturation
Swn	Normalized water saturation
WUP	Water Up-to

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