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Integrated and investigation Study on Mishrif Formation in Buzurgan Oil Field

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Abstract

Buzurgan oil field is one of the most important oil fields in Maysan Governorate in southern Iraq, it is characterized by its large size. The Buzurgan oil field was discovered due to the confirmation of the possibility of producing petroleum at an economic value after observing it in the Mishrif formation (early Cenomanian-Turnian). This effort is related to make comprehensive study of the Buzurgan oil field, this field is composed of two domes: north and south domes. The oil zone in Buzurgan is a mishrif formation that is divided into three basic units [MA, MB, MC], however, MB and MC are subdivided into [MB11, MB12, MBl21, MC1, MC2]. The study is done depending on data from ten wells in this field, which are divided into 5 wells in the northern dome and 5 wells in the southern dome. The tow Dimension model is built by using computer modeling group (CMG) software to find initial oil in place(IOIP), the daily production was 130000 bbl./day. The oil-water contact varies from the southern dome to the northern dome, and the water-occupied area in the northern dome is greater than in the southern dome. The analysis of net thickness (hnet) results for the north dome and south dome showed that: h net for the south dome > h net for the north dome. The initial pressure was 443 kg/cm2 and the bubble point pressure was 194 kg/cm2 so, the reservoir is under-saturated. From sw –kro, krw curves, the results showed that the rock in mishrif formation is water wettability because swc > 30% and the krw curve intersects the kro curve at sw > 50 %.

Keywords: *Reservoir, Formation, Permeability, Pressure, Oil Field.*

1. Introduction

Oil reservoirs are natural underground geological formations capable of storing oil, they are the rocks in which hydrocarbon fluids, including oil, natural gas, or both, accumulate in economic quantities and can be extracted using available methods [1]. These rocks are characterized by certain physical properties such as porosity. Reservoir management concepts require deep, numerous, and complex studies [2]. Simply put, reservoir management means developing long-term production strategies through which the movement of various fluids through the reservoir is controlled to achieve the maximum production of desired hydrocarbon fluids and reduce the production of undesirable hydrocarbon fluids [3]. Reliability in reservoir studies depends entirely on the accuracy of the data used in the calculations, as data processing is considered one of the most important parts of the reservoir study [4]. Ahmed and Samira,2022 used two different methods to calculate IOIP for the mishrif formation in buzurgan oil field, which are volumetric simulation methods [5]. The values calculated by the volumetric method are equal to 731 * 10^6 m^3, compared to the simulation method, which amounted to about 746 * 106 m^3. The rocks in the Mushrif Formation in the Bazargan field were identified by Munif et al., 2021, as limestone, based on probe reports. According to what they found, in general, the shale content is about 20% [6]. Al-Araji and Al-Mayahi's study of the Bazargan oil field using 3D seismic data proved that the field is an anticline with two peaks. The researchers also identified the presence of 31 faults in this field, most of which are in the southern part [7].

Laboratory experiments were developed to represent the displacing forces in the reservoir to calculate the capillary forces in it and thus calculate the amount of simultaneously trapped water in the reservoir. The permeability of the reservoir is as important as the porosity, as it is not the actual volume of oil that is important, but the speed at which the oil flows is also equally important. The study by Aqrawi et.al.showed that the Bazargan oil field is an anticline with two peaks separated by a depression and that the northern peak is shallower and less distorted [8]. Tiab, D. and Donaldson results showed that the Mushrif Formation consists mainly of limestone and that the size of the shale in the Mushrif Formation was estimated from the interpretation of the gamma-ray sensor, as the results proved that the size of the shale is about 20% of the total volume [9]. The porosity of the supervisor formation was calculated based on the interpretation of sensors Neutron, density, and sound sensor. Their results showed that the Mushrif formation is characterized by low to medium porosity values (about 5% to 18%). Volumetric methods are considered one of the most important methods through which oil reserves can be deduced. This method is based on calculating some reservoir parameters, as they can be deduced in more than one way and depend on the geological characteristics of the reservoir [10]. The most important of these parameters are porosity, permeability, saturation, net thickness, productive area only, reservoir area, and volumetric coefficient to calculate the difference between the volume in the reservoir and the volume on the surface [11]. This study aims to make a comprehensive study of the buzurgan oil field to find the values of its petrophysical properties, recovery, and initial oil in place.

1.1.The studied area:

The Bazargan oil field is one of the most important border oil fields in southern Iraq in Maysan Governorate, 175 km north of the city of Basra, adjacent to the Al-Fakka and Abu Gharb fields, which are shared with Iran. Oil is produced from the Mushrif formation, which contains several production units, the most important of which is the MB21 unit. This study also included the use of three-dimensional data to determine the compositional and stratigraphic structure of the Barzakan field. The results showed that the structure is an anticline with two peaks separated by a depression, where the northern peak is shallower, less distorted, and contains large faults, while the southern peak is deeper, more distorted, and contains more faults. The porosity of the MB and MC units was evaluated using information from 10 wells (five in the northern peak and the other in the southern) in addition to the rock core information of the well. The inferred porosity was linked with the seismic profiles to find the porosity distribution over the field, as it was found that the porosity in the southern part is better than the Northern part.

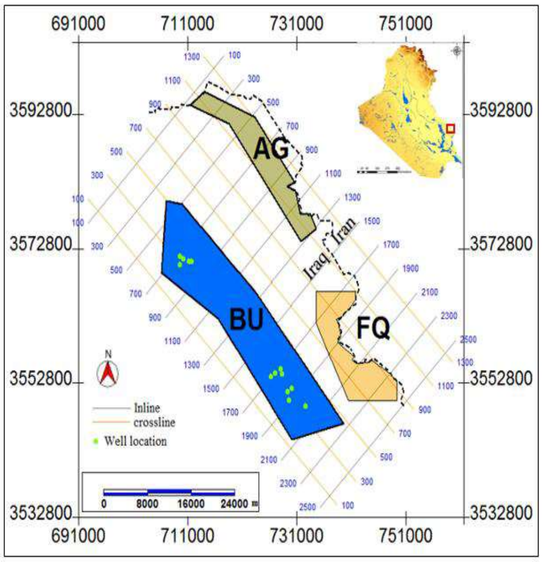

Fig.1. Location map of Missan fields that shown the studied area [7]

2.Methodology and Technical approach:

1- Drawing a structural contour map and forming a relationship between the porosity and the permeability. The depth that is used to form a structural contour map should be the net depths i.e. subtract ZRT from the given depth (ZRT represents the elevation above the datum due to topography). The drawing was constructed by firstly, setting the border of the map, scale, and the well sites on trace paper. Secondly, setting the net depth associated with the well location and the reservoir unit under drown. Then construct a contour line between the depths on the map by choosing a suitable contour interval, for example between 3780 m and 3850 m with a contour interval of 100 m there is a contour line of 3800 m set between these two points and its location on the map fit to the spacing between the two points (well sites). Finally, try to close these lines with the same value to form the top of the formation structural contour map. In case there is missing data (like the saddle area between the north and south domes because there is not any well drilled there) make use of the given contour structural map of Mishrif formation as a sky map hence all the reservoir units belong to the same formation. The structural contour maps of the reservoir units.

2-According to the core analysis data for the oil field relationship between porosity and permeability for each reservoir unit is established. The main purpose behind this relationship is to find the cut-off porosity which represents the minimum value of porosity that should be neglected because it represents the shale within the reservoir unit which creates errors in the calculation. This relationship can be constructed by using computer software (like the Excel program). Firstly, draw the porosity versus permeability by entering the values of horizontal porosity and permeability for each reservoir unit into the program and draw the best-fit line for these points (because the production depends on the horizontal values hence the drilled wells were vertical wells). The preferable form of the relationship is "y=aebx". Secondly, the form of the relation is a curve so; to change this curve to a straight line, the scale of the y-axis should be changed from linear scale to logarithmic scale. The resulting equation will be in this form:

$$k = ae^{b\emptyset} \quad (1)$$

Where: -

(a) and (b) are statistical constants.

k= permeability (md).

Φ = porosity (%).

To find the cut-off porosity value substitute the value of (k=0.01) md in eq. 1, this value came from laboratory measurements and the result value represents the cut off porosity as shown in Fig. 2

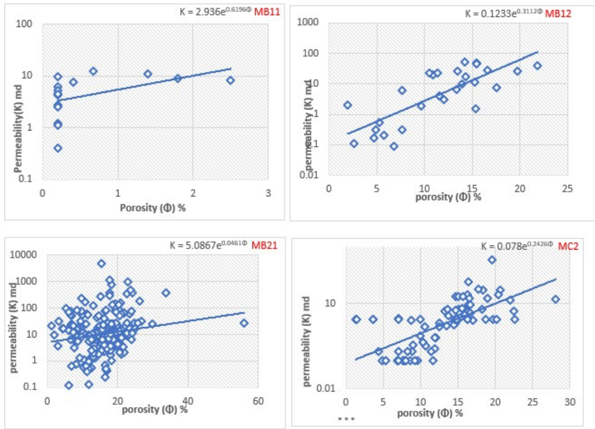

Fig.2. The relation between porosity and permeability.

2- Finding porosity, water saturation, and net thickness for a layer by using interpreted logging data. Well log provides the required data to calculate the porosity, water saturation, and net thickness for a stratum. These data are given for well penetrating that layer. The readings number is not a small number of values and that depends on the spacing between the depths that are interpreted i.e. if the interpretation is done on the interval of one or two feet; in each point, there is a reading of porosity and water saturation. On the other hand, the thickness will take the major part affecting the final value i.e. the values taken from a layer of five feet in thickness should not treated in the same way that we treat other values taken from a layer of thirty feet in thickness. Balance or weighting for those values was needed and that problem was solved by using the weighted average to find the values of porosity and water saturation. For each well the log data is given in the form of CPI (computerized programmed interpretation) which contains readings for each one foot, quarter meter, less or more according to the company standards. Each reading includes reading depth, matrix density, clay content, water saturation, porosity, and movable hydrocarbon. For each well determine the range between the top and the bottom of the layer. Now test each reading if the porosity value is greater than 6% and the water saturation is less than 60% select this reading(depth) as a reading containing the thickness of the reading spacing (one foot or quarter meter as mentioned), porosity, and water saturation. Repeat this process for each point within the range of the layer. The result is a group of points each point has its value of porosity (Φ) and water saturation (Sw) as illustrated in Table 1. For a certain well the thickness of the layer in this well is given by using eq.2 to eq.7:

$$\text{h net well} = \text{n} * \text{reading spacing} \quad (2)$$

Where

n is the number of points

Also, the average porosity for the layer in this well is:

$$\Phi \text{ avg. well} = \Sigma\, \Phi \,/\, \text{n} \quad (3)$$

In the same way the average water saturation:

$$\text{Sw avg. well} = \Sigma\, \text{Sw} / \text{n} \quad (4)$$

For all wells repeat the above procedure. The result will be for each well there is a value of h net well, Φ avg. well, Sw avg. well. Now to find the average porosity and the average water saturation for the layer using the values obtained from wells; use the weighted average.

$$\Phi \text{ avg. layer} = \Sigma\, \Phi * \frac{\text{h net well}}{\Sigma \text{ h net well}} \quad (5)$$

Similarly, average water saturation

$$\text{Sw avg. layer} = \Sigma\, \text{Sw} * \frac{\text{h net well}}{\Sigma \text{ h net well}} \quad (6)$$

Also, the average net thickness for the layer obtained from net thickness of wells is

$$\text{h net avg. layer} = \frac{\boldsymbol{\Sigma} \textbf{ h net well}}{\textbf{no.of wells}} \quad (7)$$

Where:

h net well: net thickness of the layer in the well.

Φ avg. well: average porosity of the layer in the well.

Sw avg. well: average water saturation of the layer in the well.

h net avg. layer: average porosity of the layer.

Table 1. Rock properties for the studied layers

Rock Unit	**Φ_{avg} layer %**	**So_{avg} layer %**	**h_{net} layer(m)**
MA	9.2	50.2	0.6
MB11	12.95	53.93	5.4
MB12	10.33	74.72	3.9
MB21	14.87	65.2	34.5
MC1	13.36	63.59	19.675
MC2	13.53	81.563	15.9

3-Calculations of bulk volume and oil in place

The main purpose behind the above procedure is to use the values of porosity, water saturation, and net thickness for a reservoir layer to find the oil in place. There are many different methods to find the oil in place. Some of those methods are applicable before drilling the production from the field and others use the production data to determine the oil in place. The main methods are

Volumetric method.

Material balance method.

Production decline method.

In this section, the volumetric method will be discussed. This method is applicable after discovering the oil field as well as in the presence of structural contour maps or isopach maps which designate the rock volume between two limits. By this method, we should find the bulk volume (reservoir volume) of the oil zone. It represents the volume between the top and the bottom of the formation except the volume occupied by water i.e. the volume under the oil-water contact. Bulk volume can be found by use of the graph between areas enclosed by contour lines in the structural contour map (above the oil-water contact) as a function of contour lines' depth or thickness. Later find the area under the curve using the graphical integration. First, set the oil-water contact and gas-oil contact (it disappears in the under-saturated reservoir) on the structural contour maps for both the top and bottom of the formation. Second, calculate the area enclosed by contour lines starting from the peck of the dome to the out for both the top and bottom. The last area should have enclosed by the water-oil contact. The area is calculated by setting grid lines. Each unit in the grid has an area of 1 cm2 so, this 1 cm2 represents the area that it has according to the scale of the map. Also, the area enclosed by a contour line has a value of depth associated with it which is represented by the enclosing contour line depth. Third, plot the area enclosed by contour versus the associated depth. The result is two sets of points connect the upper points which belong to the area calculated from the top of the formation similarly for the lower set which belongs to the bottom. The bulk volume is represented by the area under the curve. The last can be calculated by graphical integration since we draw area versus depth the integration result is

Res.	Core . no	Drilled depth (ft)	Length ft	Recovery %
MB11	1	12354 -12401	47'	91%
MB11	2	12401 -12433	32'	100%
MB12	3	12433 -12492	59'	100%
MB12	4	12492 -12559	59'	98 %
MB21	5	12559 -12681	59'	100 %

volume and that finding is by calculating the squares bounded by the two curves i.e. the curve formed from the area enclosed by contours from both top and bottom. The resulting volume unit is km2 .m or acre. ft. according to the unit system that is used. Each square volume is given by the original scale of the map and the scale of the area-depth plot. Finally, the bulk volume (gross) should be corrected to the net thickness as in eq. 8

$$\text{Vb net} = \text{Vb(gross)}\ \frac{\textbf{h net avg.layer}}{\textbf{h gross}} \qquad (8)$$

Where

Vb net is the net bulk volume km^3

h gross is the gross thickness of the layer, which is found by the average thickness of the layer from wells or from the average thickness of the layer from the structural map (average from top and bottom), m or ft.

After finding the bulk volume and the presence of porosity and water saturation it is easy to find the oil in place by volumetric method. For the field units, the initial oil in place is given by this equation 9

$$\text{Ni} = 7758\ \text{Vb}\ \Phi\frac{1-\text{Sw}}{\text{Boi}} \qquad (9)$$

Where:

Ni: the initial oil in place, STB

Φ: average porosity, fraction

Sw: average water saturation, fraction

Boi: oil formation volume factor at initial pressure BBL/STB.

It is not possible to take both directional (horizontal and vertical), but horizontal values of porosity and permeability were taken. Depending on a core report that provides information useful for the field engineer on which a record is kept of the depths of the interval cored, coring time for each foot, litho logic description of core, sample number and depth fractures, and any other notable features of the core, recover length, recovery, and type properties of drilling fluid. Since the recovery is the percentage of recover length to the total depth, and depending on eq. 10 . For example if the total logged interval is 20m and the recover length is 18 m, the recovery is equal to recovery = (18 \20)*100 =90%. The recovery for each layer is illustrated in table 2

$$\text{Recovery} = \frac{\text{recover length}}{\text{total logged}} * 100 \qquad (10)$$

Table 2. Recovery for the south dome

Data management

A - Raw data sheet

In this work, depth data for (10) wells were included in 7 tables. This data helped to draw the contour map for each layer, where we took the highest value according to the depth to sea level. For example, formation MB21 has 21 higher depth values compared to 21 wells, but these values do not take into account sea level, so they have been corrected, and the correction process will be like this:

Value respect to sea level = value in the table – ZRT

Where ZRT can be defined as a constant value of each well representing the difference between table surface and sea level, the values of ZRT and depth for each formation.

B – Computer Process Interpretation CPI report

From this report, it becomes possible to estimate the value of the net fish. The net thickness is defined as the good area with reservoir properties (Φ, K, and Sw), and this net thickness is relied upon in evaluating the value of the initial oil place (IOIP).

C- Core Report

This report helps to evaluate the value of cutoff porosity. Cutoff porosity is value under this porosity value that don't take it in our calculation because it's consider bad because it so little, as shown in Fig 3.

3.Building two dimensional model

Early in the oil industry, the need for simulators was a basic need. To obtain optimal performance of the tank, it is preferable to represent the tank in the laboratory to study the flow and expected problems. The representation requires a core sample of reservoir rock. This process is not easy as it requires a well that penetrates the reservoir and a core sample must be recovered. Core recovery is an expensive process, so, to reduce the cost, experts suggested building a digital model to represent the reservoir. That mathematical model is called a "simulator". The flow equations contain derivatives to the pressure concerning the direction also to time if the flow regime was unsteady state. The job of numerical methods is to replace the mathematical derivatives with numerical derivatives because it is so hard to find the integral of the pressure derivative in more than one direction also under the state that the fluid properties are changing concerning the pressure. In the early fifteens, numerical simulators had been developed and the development of the computer helped that development. The first step is to create a grid or in other words divide the reservoir into grids. Starting with the top of the formation structural contour map for unit Mb 21 divide the south dome into squares with (1 cm *1 cm). The wells should be contained in the grids and the well should be in the center of the grid. Here we divide the south dome into (28) grids in (i) direction and (9) grids in (j) direction. The grid mesh is shown in Figure 3. Each grid should have a value at its top which is given to the center of the grid according to the contour lines that pass near it. The black oil model was chosen for this simulation. After that PVT tables were prepared for Bo, Rs, Bg, μo, μg versus pressure by digitizing the given graphs in Figures,4,5, and 6. Production data must also be available to run this simulation. If all the aforementioned information and well locations are available, the simulation will be applied. Figures 7,8,9 ,10and 11 show the other simulators' results. Table2illustrates the initial oil in place for both domes, where the south dome has IOIP greater than the north dome.

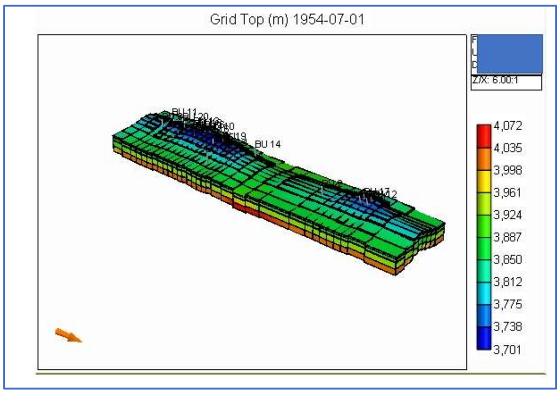

Fig .3. Top grid for the five studied layers

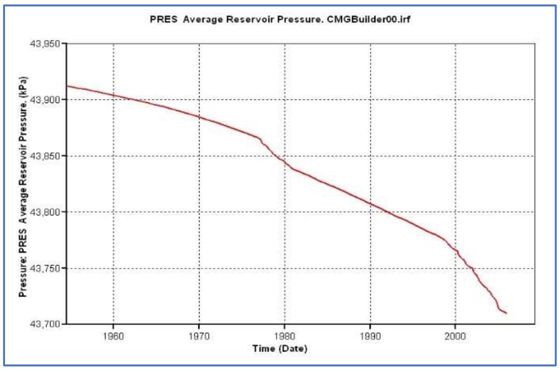

Fig. 4. Average reservoir pressure for BU 6 well

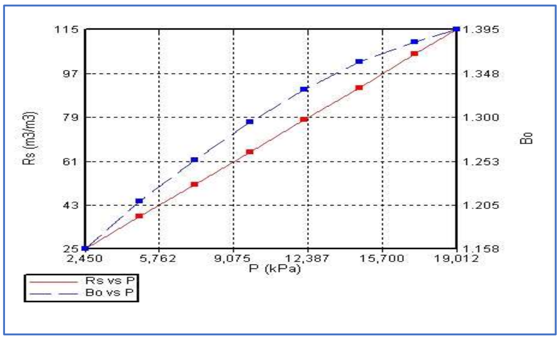

Fig. 5. Gas solubility and oil volume formation factor for BU 6 well.

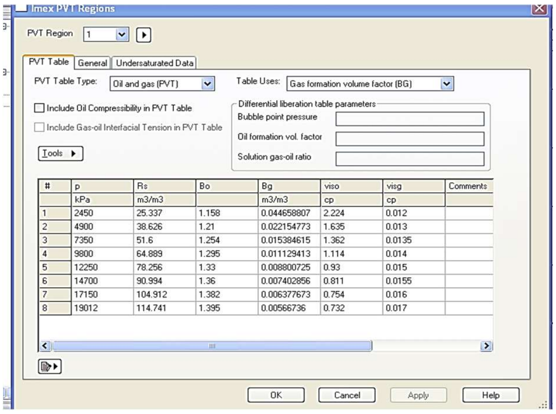

Fig. 6 PVT input data for BU 6well.

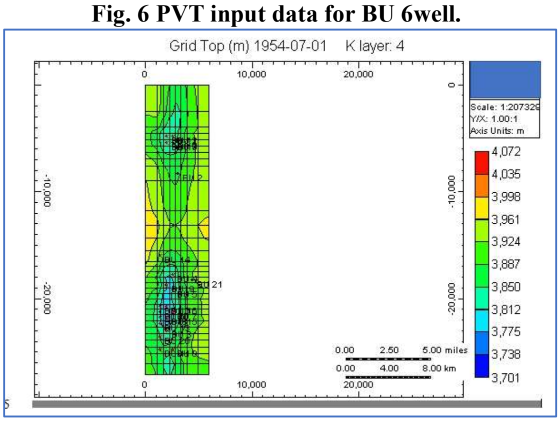

Fig. 7. Oil saturation for the studied wells

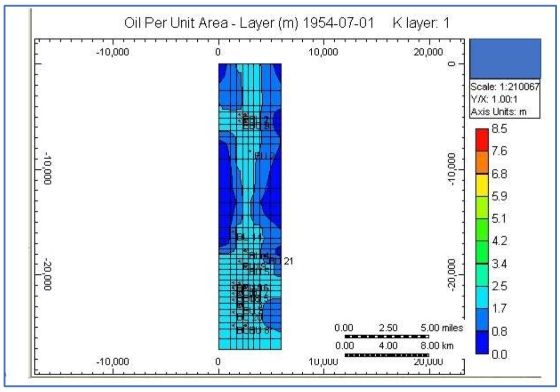

Fig. 8. Oil per unit area for the studied wells.

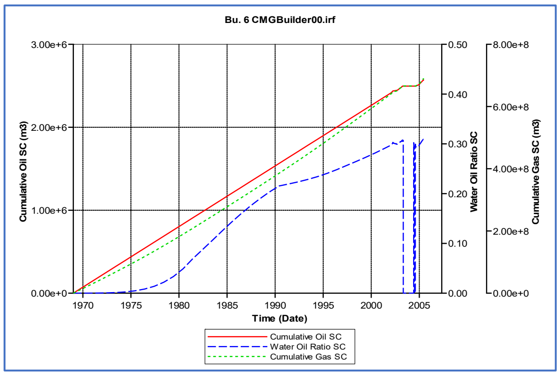

Fig.9. Gas , oil production and water cut in Bu. 6 well

Table 2. Initial oil in place for north and south domes using volumetric method.

Dome	Area(under the curve)cm^2	Vb(gross) m^3	Vb net m^3	h net/h gross
North dome	50	1000*10^6	454*10^6	34.5/76
Vb net m^3	So %	Φ %	Ni (m^3)	IOIP (bbl)
454*10^6	65.2	14.87	44*10^6	277*10^6

Dome	Area(under the curve)cm^2	Vb(gross) m^3	Vb net m^3	h net/h gross
South dome	121	5050*10^6	3636*10^6	56.7/85
Vb net m^3	So %	Φ %	Ni (m^3)	IOIP (bbl)
3368*10^6	68.74	15.082	394*10^6	2195*10^6

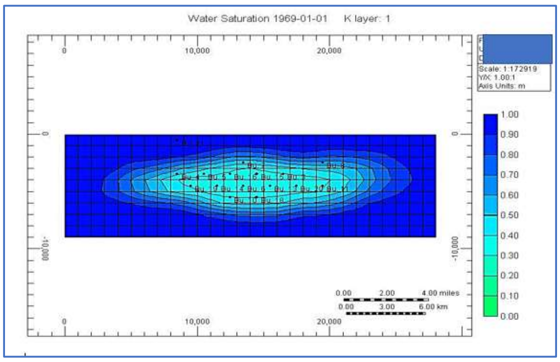

Fig.10. Water saturation distribution for the studied wells.

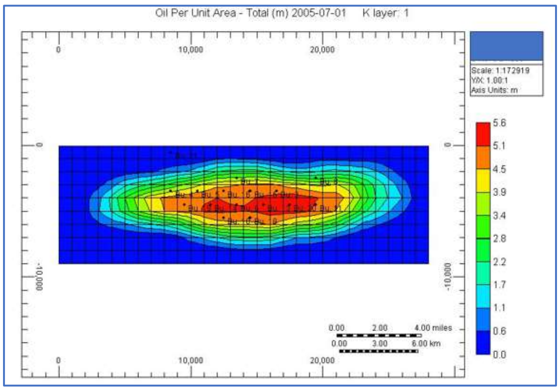

Fig.11. oil per unit area for the studied wells.

Res.	Core. no	Drilled depth (ft.)	Length ft.	Recovery%
MB11	1	12354 - 12401	47'	91%
MB11	2	12401 - 12433	32'	100%
MB12	3	12433 - 12492	59'	100%
MB12	4	12492 - 12559	59'	98 %
MB21	5	12559 - 12681	59'	100 %

Table 3. Recovery for the south dome

4.History Matching

It is a process of comparing the IOIP which is calculated by the volumetric method and the IOIP that is obtained by CMG. If there is no difference between them, the model is good otherwise, checking should be done for the model to solve the problems. As for the results of the study, there is a difference between the IOIP obtained from the volumetric method, as it was about.2462 * 10^6 bbl. for both domes. The IOIP obtained from the program was approximately about 2337 * 10^6 bbl.

Table 3. Initial oil in place for north and south domes using volumetric method.

5. Conclusion:

1-Initial pressure was 443 Kg/cm 2, datum 3850m. The initial oil in place in the south dome is greater than the initial in place for the north dome which was 2195*106 and 277*106 respectively.

2- Bubble point pressure was 194 Kg/cm2 so, this reservoir is under saturated reservoir because initial pressure > bubble point pressure

3- W.O.C was 3885m (mean sea level), so in this part, the reservoir is considered as one zone.

4-API is 28 degrees (heavy oil)

5- Permeability is 10 md for I.J K directions i.e. isotropic homogenous reservoir

6- Water density was about 1250 kg /m3 (because of the effect of salinity).

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