COMPARATIVE ANALYSIS OF REMAINING OIL SATURATION IN WATERFLOOD PATTERNS BASED ON ANALYTICAL MODELING AND SIMULATION

A Thesis

by

ANAR ETIBAR AZIMOV

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2006

Major Subject: Petroleum Engineering

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ABSTRACT

Comparative Analysis of Remaining Oil Saturation in Waterflood Patterns Based on Analytical Modeling and Simulation. (May 2006)

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Co-Chairs of Advisory Committee: Dr. Daulat D. Mamora
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In assessing the economic viability of a waterflood project, a key parameter is the remaining oil saturation (ROS) within each pattern unit. This information helps in identifying the areas with the highest ROS and thus potential for further development. While special core analysis, log-inject-log, and thermal-decay time-log-evaluation techniques are available, they provide only single-point values and a snapshot in time near a wellbore. Also, they can quickly add up to an expensive program.

The analytical areal distribution method estimates ROS in a waterflood pattern unit from material balance calculations using well injection and production data with no pressure information required. Well production and injection volumes are routinely measured in oilfield operations, making the method very attractive.

The areal distribution technique estimates two major uncertainties: vertical loss of injected water into nontarget areas or areal loss into surrounding patterns, and injected water for gas fill-up. However, developers tested it only in low-pressure conditions, which are increasingly rare in oilfield operations.

The main purpose of my research, then, was to verify whether or not the areal distribution method is valid in higher pressure conditions. Simulation of various waterflood patterns confirmed that the areal distribution method with its estimated ROS is capable of precise estimation of actual ROS, but at high pressures it requires consideration of pressure data in addition to injection and production data.

DEDICATION

I wish to dedicate my thesis:

To my father and mother, my uncle and aunt Eldar and Svetlana, my grandmother and grandfather, my sister Nigar and my mentor Oscar for all their love, support, and dedication.

ACKNOWLEDGEMENTS

I wish to express my sincere gratitude and appreciation to:

Dr. Daulat D. Mamora, co-chair of my advisory committee, for his continued help and support throughout my research. It was an honor to work with him.

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CHAPTER I

INTRODUCTION

1.1 The Areal Distribution Technique

In 1996, Sharma and Kumar[1] presented a technique, which we will call the *areal distribution* method, that can estimate the areal pattern distribution of remaining oil saturation (ROS) for low-pressure reservoirs from only injection and production data. This technique was based on material balance, which accounts for two main issues: gain and/or loss of water into adjacent patterns areally or vertically into non-target zones and progressive gas fill up, which starts with the waterflood initiation.

Sharma and Kumar[1] specified three assumptions that need to be considered before using the technique:

1. The technique presented is applied for the reservoir operating under the pressure of 150-300 psia, which maintains the oil and water formation volume factor nearly constant.
2. All free gas at waterflood initiation goes back into solution or is produced (that is, if trapped gas saturation is available, it can be incorporated into the material balance).
3. No production comes from noninjection zones.

The areal distribution technique consists of a series of basic material-balance equations to evaluate ROS, the key element of which is evaluating gas fill-up volume and time, and water lost and/or gained from adjacent patterns. The advantages of the technique presented are that the input data it requires are readily available, it requires no reservoir pressure information, and the calculations are simple.

This thesis follows the style and format of *SPE Reservoir Engineering and Evaluation.*

1.2 Problem Description

The ROS value is an important parameter in water-injection projects. Knowledge of ROS enables us to prioritize the work that is necessary to be done and locates the pattern units that would be most economically beneficial for further investments, as the high remaining oil value reflects the most attractive locations in the field. Other methods, such as special core analysis, log-inject-log, and thermal-decay time-log evaluation techniques, help to evaluate the remaining oil saturation, but they do not provide overall field or pattern unit ROS value. Because these methods provide only a single point value near a wellbore, many wells have to be selected for coring or logging to obtain an areal distribution of ROS within the field, and the evaluation can become an expensive program.

The areal distribution method might help to avoid implementation of expensive ROS evaluation techniques by introducing a set of equations that will simplify the evaluation of ROS in a certain pattern. The advantage of the method is the simplicity of the calculations and availability of required data. The only data required for the calculations are production and injection data, which are routinely collected in oilfield operation and are relatively precise.

However, Sharma and Kumar[1] developed the calculations for a low-pressure reservoir maintaining formation volume factor close to 1.0. Their work did not consider cases where formation pressure is considerably more than 150 to 300 psia, where this method might not still be applicable.

The main goal of this project was to verify the analytical method to estimate ROS in waterflood patterns. We considered four different major cases: Case 1 is a low-pressure reservoir with no boundary flow (no water loss or gain), Case 2 is an analogue of Case 1 but with considerably higher reservoir pressure, Case 3 reveals the applicability of the method for the scenarios when water is lost from one pattern to the adjacent ones, and

Case 4 relates the applicability of the method presented for a heterogeneous reservoir as well. All cases except Case 4 are for a homogeneous reservoir. As we had no field data, our first step was to generate the data from simulation. Using the production and injection values from simulation, then perform the calculations in the areal distribution method. Our comparison of the values of ROS from the two methods showed that the areal distribution method is quite accurate and could become a useful tool for engineers estimating ROS in waterflood patterns, especially since our addition of pressure data may extend it to use in high-pressure conditions.

CHAPTER II

LITERATURE REVIEW

2.1 Thakur's Reservoir Management Approach

In his work on the importance of waterflood reservoir management, Thakur[2] shows that the reservoir management aspects of waterflooding span the time before the start of waterflood to the time when the secondary recovery is either uneconomic or is changed to an enhanced recovery.

The role of reservoir management of a waterflood is to provide necessary information and knowledge for controlling the operations, and develop the flood into an economically viable project. Among the key factors in waterflood surveillance, Thakur includes precise reservoir description and injection/production data profiles, which are significant factors in Sharma and Kumar's[1] method. Thakur also shows the importance of material balance in interpreting the waterflood performance.

2.2 Development of the Areal Distribution Technique

Because ROS is a strategic factor in defining the position of injection wells in waterflood, the appeal of the areal distribution method is its simplicity and the fact that no data are needed except for the injection/production data profile.

Sharma and Kumar[1] developed their technique in response to the shortcomings of existing methods. These methods attempt to give a single, snapshot value of conditions next to the wellbore, which might not truly reflect the average reservoir value, and tend to be quite expensive. On the other hand, the areal distribution technique consists of a series of material balance calculations that estimates the average ROS value more precisely at low cost, since only injection and production data are required.

Buckley and Leverett[3] presented one of the most accurate analytical solutions of oil displacement with water in linear or radial system. The model assumes fractional flow and that displacement occurs at average water saturation behind the front. The distinctive feature of the model is that the waterflood front is a shock front.

The areal distribution technique uses coordinate plots of cumulative secondary oil and cumulative fluid produced against cumulative water injection to evaluate gas fill-up time. Jordan[4] had previously demonstrated the usefulness of these plots to reveal the interrelationship between oil volumes and either cumulative fluid volumes or volumes of water injected to evaluate waterflood behavior.

Sharma and Kumar[1] used Dake's[5] equations to define the free gas volume in the reservoir because gas fill-up calculations were not reflecting the true value of free gas in the reservoir at a certain time. Sharma and Kumar's[1] gas fill-up equation ignored the gas being produced from the reservoir during primary production, yet Dake's[5] equations precisely represented the value of free gas volume in the reservoir.

Sharma and Kumar[1] selected a west Texas San Andreas dolomite, low-permeability reservoir for their study. The unit was divided into a certain number of injector-centered pattern configurations created using boundaries and connecting the producers around the central injection well. They incorporated the streamline model presented by LeBlanc *et al.*[6] and Ramey *et al*.[7] Ramey *et al.'s* streamline model define a streamline as a drainage boundary between adjacent wells and show the applicability of the streamline to reveal the drainage areas of the wells.

LeBlanc and Caudle[4] presented a mathematical model based on the streamlines generated by the superposition of line sources that is easily adaptable to well patterns and fluid-displacement mechanisms. The main concept of the study is that flow through the stream channel may be completely represented by velocities along the streamline in the center of the channel. These authors included a computational method to develop specific models for the secondary production prediction with arbitrary well patterns.

One of the advantages of Sharma and Kumar's[1] method is that no pressure data are required for the calculations, although known pressure profiles they might be incorporated for cases when pressure changes dramatically over time. Chapman and Thompson[8] presented a method for verifying the production and injection profile when pressure data are available that uses a material balance technique to back-calculate pressure from production and injection, which are allocated by pattern. The calculated pressures are matched with actual pressures to check the production and injection allocation factors.

Lo *et al.*[9] showed the applicability of plotting the log of water/oil ratio against cumulative oil in estimating original oil in place (OOIP), water/oil ratio, and relative permeability. Originally this plotting technique has been used to estimate the ultimate oil recovery from waterflooding. When plotting log (WOR) versus cumulative oil produced, the data from the straight line can be extrapolated to predict future performance and can evaluate ultimate oil recovery from waterflooding. The results presented help to diagnose the waterflood performance.

The difference between initial oil saturation and ROS is obtained by the change in oil, water, and gas volumes. Craft and Hawkins[10] presented equations that calculated change in oil, water, and gas volumes. They also described changes in void space volume and initial free-gas volume, which are useful for understanding the material balance and calculations for water injection cases.

Davies *et al.*[11] presented a systematic analysis of core waterflood data for a single reservoir conducted to define the relationship between initial oil saturation and ROS.

Their approach was useful for rescaling relative permeability data in regions of the field by considering variations in initial water saturation.

Sharma and Kumar[1] created the existing technique to give an approximation of average ROS in the reservoir during the waterflood process. Their areal distribution method was accurate in the low-pressure conditions they evaluated, but it was not extended to more realistic high-pressure conditions.

CHAPTER III

ANALYTICAL METHOD

3.1 Calculations Procedure Based on Areal Distribution Technique

The material balance calculations procedure (Appendix A) presented by Sharma and Kumar[1] consists of the following steps:

1. Identify pattern configurations and allocate production and injection data on the basis of well angle open to flow within a pattern. Patterns can be centered on either injector or producer.
2. Use material balance to estimate gas fill-up volume at the waterflood initiation.
3. Plot cumulative secondary oil production, cumulative water produced, and cumulative total fluid produced against cumulative water injected to estimate gas fill-up and observe water loss and/or gain.
4. Build a pattern fluid-saturation history spreadsheet.
5. If more than one pattern is observed, repeat Steps 2 to 4 for each and every pattern in the field to generate a field-wide saturation database.

The only data required for the calculations is production and injection data; formation volume factors can be included if they are available. We use these data to calculate the first step in the calculations procedure, the gas fill-up volume.

The gas fill-up volume is a reservoir volume occupied by gas and is calculated during the primary production:

$$G_f = NB_{oi} - (N - N_{pp})B_o, \quad \text{.........} \quad (3.1)$$

where G_f is fill-up gas volume at waterflood initiation and N_{pp} is cumulative oil produced during primary recovery at waterflood initiation.

Sharma and Kumar[1] used data from a west Texas reservoir where waterflood was initiated when reservoir pressure dropped to between 100 and 300 psia. For black oil in this pressure range, an oil formation volume factor might be reasonably taken to be 1.0, so Eq. 3.1 becomes:

$$G_f = NB_{oi} - N + N_{pp} \,. \quad \text{(3.2)}$$

The gas fill-up volume is equal to the volume of water needed to fill up the gas pore space in the pattern.

OOIP calculations can be accomplished using pressure profile data, injection/production data, and gas/oil ratio values. Considering no water influx, gas cap, or compressibility effects allowed Sharma and Kumar to simplify the material balance to:

$$F = N \times E_o \,, \quad \text{(3.3)}$$

where F is withdrawal and E_o is expansion of oil.

Total underground withdrawal, F, can be calculated using:

$$F = N_p \times \lfloor B_o + (R_p - R_s) \times B_g \rfloor + W_p \times B_w \,. \quad \text{(3.4)}$$

Expansion of the oil, E_o, can be calculated using:

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s) \times B_g \,. \quad \text{(3.5)}$$

By plotting F versus E_o on a scatter plot, if the driving mechanisms were considered correctly, the data should be linear with a zero intercept, and the slope of this line should provide the oil in place N. This is very close to the result provided by simulator 100 and will be illustrated in following chapters.

The physics of Eq. 3.1 or 3.2 will not exactly represent the amount of the free gas in the reservoir at a certain time, which in our case is at waterflood initiation. The concept of the equation might be right as it represents the fill-up volume equal to volume of the primary production and the change in fluid volume during the primary production, or the liquid expansion. Yet throughout the primary production a certain amount of gas was produced, which means that Eqs. 3.1 and 3.2 do not include the amount of gas produced in gas fill-up calculations. That might not give a very big error factor nor will it change the applicability of the technique presented, but physically and from a material-balance point of view, it is false and can't be used with reservoirs that have a large amount of free gas.

Logically, the simple way to estimate the free gas volume in the reservoir at a certain time step would be by multiplying the reservoir pore volume by the gas saturation at that exact time:

$$G_f = V_p \times S_g \quad (3.6)$$

We can certainly double check this equation by performing a proper material-balance calculation provided by Dake[5]:

$$G_f = \left\lfloor NR_{si} - G_p - (N - N_{pp})R_s \right\rfloor \times B_g \quad (3.7)$$

Yet probably the most convenient and efficient methodology to estimate the gas fill-up volume in conjunction with time simultaneously would be by plotting the material balance.

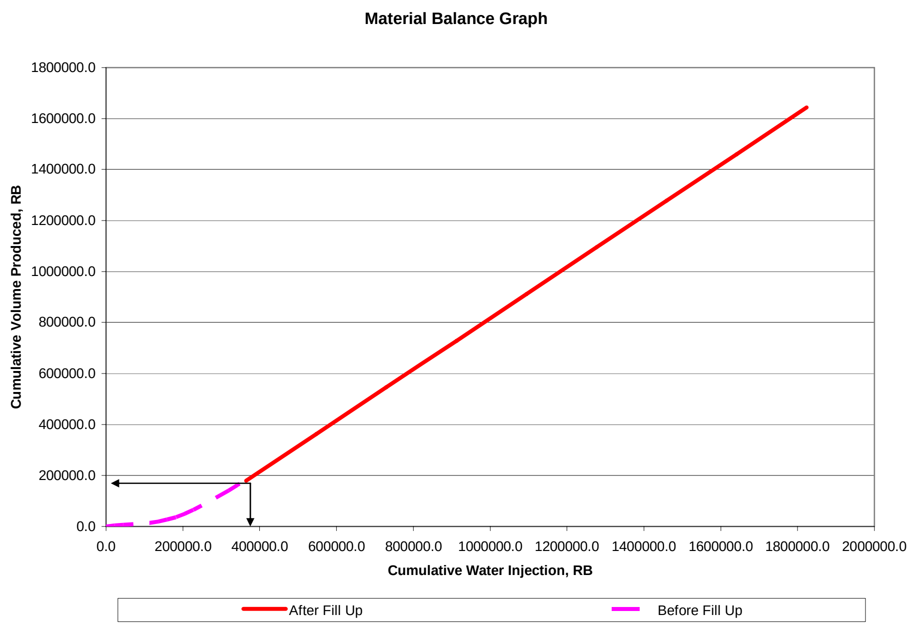


Fig. 3.1—Material-balance graph allows estimation of gas fill-up from slope.

After water injection, the reservoir takes a certain period of time to fill up the volume occupied with gas, as only part of the injected water uses the gas volume and the other part replaces the fluid produced. Before the end of gas fill-up time when all the gas is replaced with water, the total curve of fluid produced, shown as dashed line on **Fig. 31,** will tend to progressively build up to 1.0. After fill-up the slope will be constant, which indicates the end of fill-up time. Thus, we can evaluate the gas fill-up volume because the start of the curve of total fluid produced at 1.0 corresponds to the amount of cumulative water injected to cumulative volume produced. By subtracting those values, we can get the gas fill-up volume in the reservoir.

Eqs. 3.6 and 3.7 help to estimate the gas fill-up volume at the waterflood initiation. The partial gas fill-up volume has to be estimated as well, but before doing that we must find the water loss and/or gain from the pattern. The cumulative water loss from the pattern is presented by the material balance equation given as Eq. 3.8:

$$W_l = W_i - G_f - N_{ps} - W_{ps} \quad \text{(3.8)}$$

In cases when we have one consistent pattern, which means no boundary flow, the water loss and/or gain will be very close to 0. In cases when the reservoir is split into a certain number of patterns, the loss or gain of water is considered as volume lost to either nontargeted zones vertically and/or adjacent patterns areally.

The graph from the material balance calculation **(Fig. 3.2)** reveals and water loss and/or gain between patterns.

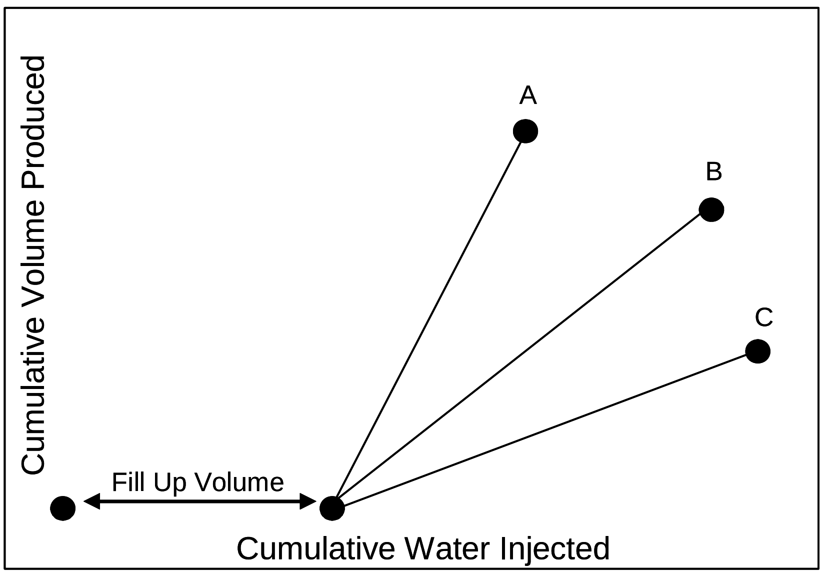


Fig. 3.2—Material balance graphs shows (A) fluid gain from adjacent patterns, (B) no flow between patterns, or (C) loss to adjacent patterns.

Fig. 3.2 shows the possible scenarios of water lost (A), no water lost (B**)**, and water gained (C). Where the angle between the slope and cumulative water injected (x-axis) is greater than 45,º the pattern gains the fluid from outside; the angle equal to 45º means that the volume injected is equal to volume produced, and an angle less than 45º indicates loss of water vertically into nontargeted zones or into adjacent patterns.

Only a part of the injected water is available to fill up the gas space – a partial gas fill-up. The remaining water injected might be lost from the pattern, used as produced water, or replace the secondary oil production. Fig. 3.2 represents ideal reservoir cases, whereas in real life the slope the curve of total volume produced builds up from 0 to unity gradually. The point when the slope reaches its maximum and stabilizes is considered the end of gas fill-up.

The equation for cumulative water required is different for the time before and after fill-up. The cumulative injected water required, W_r, at fill-up and beyond is:

$$W_r = G_f + (N_{ps} + W_{ps}) \,, \quad \text{for } t \geq t_f, \quad \text{.. (3.9)}$$

where t_f is time to fill-up.

If we incorporate Eq. 3.7 into Eq. 3.9 we have:

$$W_r = \lfloor NR_{s\,i} - G_p - (N - N_{pp})R_s \rfloor \times B_g + N_{ps} + W_{ps} \,, \quad \text{at } t_f. \text{ .... (3.10)}$$

Sharma and Kumar[1] assumed $B_o = B_w = 1$. However, if formation volume factors are known or required ,they can be incorporated appropriately.

The volume of water required to fill up is:

$$W_r = \frac{W_{rf}}{W_{if}} W_i \,, \quad \text{for } 0 \leq t \leq t_f, \quad \text{... (3.11)}$$

where W_{rf} is volume of net water required at fill-up, W_{if} is cumulative water injected at fill-up, and W_i is cumulative water injected at time t.

Having estimated the water required, we can calculate the partial gas fill-up with time:

$$G_{pf} = W_r - (N_{ps} + W_{ps}), \quad \text{for } 0 \le t \le t_f \text{ ....} \quad (3.12)$$

Cumulative injected water lost in Eq. 3.8 can be incorporated using Eq. 3.11:

$$W_l = W_i - W_r \text{ . ...} \quad (3.13)$$

The evaluation of gas fill-up and water loss is very important for preciseness of the technique's results and are key elements in evaluation of ROS. Once we have accurately calculated them we can move on to estimation of oil, water, and gas average saturation in the pattern with time.

The volume of water in reservoir pore space is:

$$V_w = V_{wi} + W_i - W_l - W_{ps} \text{ , ...} \quad (3.14)$$

where V_{wi} is initial water volume in the reservoir and W_l is water lost from the pattern.

Combining Eqs. 3.13 and 3.14 we can present the change in the water volume by:

$$\Delta V_w = V_w - V_{wi} = W_r - W_{ps}, \quad \text{for } t \ge 0 \quad \text{..} \quad (3.15)$$

and the change in water saturation by:

$$\Delta S_w = \frac{\Delta V_w}{V_p} \text{ . ...} \quad (3.16)$$

Water saturation at time t, where (n+1) and n refer to time steps:

$$(S_w)_{n+1} = (S_w)_n + \Delta S_w \text{ . ... (3.17)}$$

Change in gas volume is given by:

$$\Delta V = G_f - \Delta V_w \text{ , ... (3.18)}$$

and

$$(S_g)_{n+1} = (S_g)_n - \Delta S_g \text{ . ... (3.19)}$$

We can calculate the oil saturation using Eqs. 3.18 and 3.19:

$$(S_o)_{n+1} = 100 - (S_w)_{n+1} - (S_g)_{n+1} \text{ . ... (3.20)}$$

Eq. 3.20 completes Sharma and Kumar's[1] technique for fluid saturation history with time evaluation. Incorporating different cases and scenarios into the calculation procedure reveals the advantages and disadvantages of their areal distribution technique.

3.2 Case 1 – Low Pressure Reservoir Model (150 to 300 psia)

Sharma and Kumar[1] analyzed a west Texas low-pressure reservoir where the pressure ranges from 150 to 300 psia. For most west Texas reservoirs with pressure of 150 to 300 psia, the oil and water formation volume factors remain very close to 1.0, so they used stock-tank barrel values throughout the calculations. In cases where formation volume factors are known and differ from 1.0, calculations should use reservoir-barrel units. To illustrate the importance of using correct units, we applied the technique to both low-pressure reservoir conditions and to high-pressure and heterogeneous conditions.

Because we had no real-life data for the study, we generated all the required data with a commercial simulator. We defined a five-spot pattern representing a homogenous, 40-acre reservoir with 10 communicating layers for Cases 1 and 2; we modeled only a quarter of the pattern to reduce computational time. **Table 3.1** presents the main features of the model; the simulation data file for the case can be found in Appendix B.

The reservoir model for this case has an initial pressure of 525 psia, which obtains an oil formation volume factor very close to the water formation volume factor of 1.06. The example presented by Sharma and Kumar[1] has very close pressure and formation volume factor values, which assures us we maintained the similar conditions required to check the applicability of the method. Even though Sharma and Kumar used stock-tank barrel units, which are correct for low-pressure reservoir conditions, we performed all our calculations using reservoir barrel units.

The initial and current oil formation volume factors for Case 1 are presented in **Table 3.1.**

TABLE 3.1—RESERVOIR PROPERTIES FOR CASE 1

Reservoir properties	**Value**
Reservoir length, L	660, ft
Reservoir width, w	660, ft
Reservoir height, h	200, ft
Reservoir porosity, ϕ *	28 %
Horizontal permeability, k *	430, md
Vertical permeability, k *rv	43, md
Initial oil saturation, S_{oi}	80%
Connate water saturation, S_{wc}	20%
Oil viscosity, μ_o	18.58, cp
Water viscosity, μ_w *	0.7, cp
Water injection rate, i_{wt} *	500, STB/D
Initial oil formation volume factor, B_{oi} *	1.17, RB/STB
Oil formation volume factor, B_o *	1.06, RB/STB
Water formation volume factor, B_w	1.06, RB/STB

* These values subject to change during the sensitivity analysis.

The reservoir was exploited for 13 years, the first 3 of which included the primary production. At the end of the third year as the pressure dropped to 190 psia, the waterflood was initiated for the next 10 years to maintain the pressure and production. **Fig. 3.3** is the reservoir pressure plot for Case 1. By the time of 1,095 days, which is the end of the third year, the waterflood started and the pressure remained very close to 200 psia.

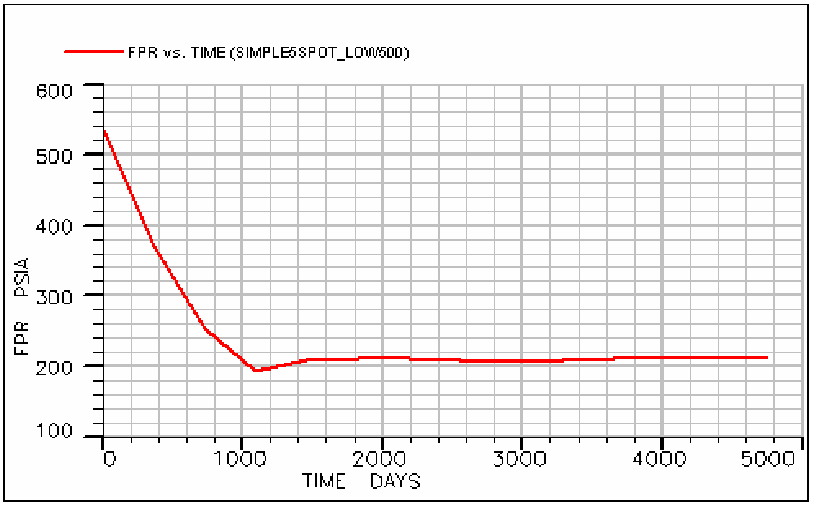


Fig. 3.3—Reservoir pressure stabilized after waterflooding began at the end of Year 3.

Having run the simulation for Case 1, we generated the required information for the areal distribution technique, including cumulative water injected; cumulative water produced; cumulative oil produced; water, oil, and gas saturation; pore volume; OOIP; and original water in place.

Table. 3.2 presents part of the data provided by simulator 100 used to evaluate remaining oil saturation.

Following the calculation procedure presented at the beginning of Chapter III, we evaluated ROS using the areal distribution technique and compared the results with ROS values presented by our simulator. **Fig. 3.4** shows the material-balance plot of cumulative secondary oil produced, cumulative secondary water produced, and total fluid produced.

TABLE 3.2—DATA PROVIDED BY SIMULATOR FOR CASE 1

S_{wi}	S_{oi}	B_{oi}	$N_{ps} + W_{ps}$	V_p	OOIP	WIP
0.2	0.8	1.17	179845.3	2800771	2116631	180801.0
			Simulator Data			
YEARS	**FOSAT**	**FGSAT**	**FWSAT**	**FWPT**	**FOPT**	**FWIT**
YEARS	**fraction**	**fraction**	**Fraction**	**RB**	**RB**	**RB**
0.0	0.80	0.00	0.20	0.0	0.0	0.0
1.0	*0.76*	*0.04*	*0.20*	*6.2*	*115161.6*	*0.0*
2.0	*0.74*	*0.06*	*0.20*	*11.5*	*166941.5*	*0.0*
3.0	*0.73*	*0.07*	*0.20*	*15.0*	*191649.1*	*0.0*
4.0	*0.73*	*0.05*	*0.21*	*15.2*	*193556.0*	*36467.0*
5.0	*0.73*	*0.04*	*0.23*	*15.4*	*195141.8*	*72934.9*
6.0	0.73	0.03	0.24	15.7	197514.0	109402.6
7.0	0.73	0.02	0.25	16.0	200815.9	145870.8
8.0	0.73	0.01	0.27	16.5	205316.7	182338.0
9.0	0.72	0.00	0.28	18.8	225560.6	218806.3
10.0	0.71	0.00	0.29	23.0	261912.2	255274.5
11.0	0.70	0.00	0.30	27.2	298433.5	291742.7
12.0	0.68	0.00	0.32	31.4	334954.7	328209.9
13.0	0.67	0.00	0.33	35.5	371473.8	364678.2

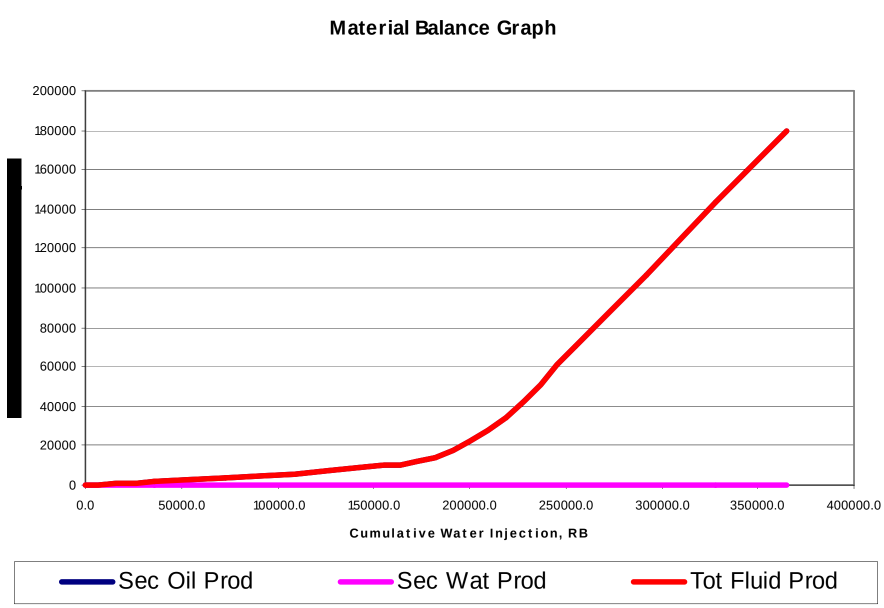


Fig. 3.4—Material-balance graph shows that fill-up ends after approximately 220,000 RB water injected.

Fig. 3.4 identifies the end of fill-up time, which is approximately 220,000 RB water injected, corresponding to Year 9. As very little water is produced, the secondary oil production curve matches the total fluid production curve. As the plot suggests, the angle between total fluid produced and the x-axis is quite close to 45^o, which means that no water is lost to or gained from the reservoir because the model represents no boundary flow conditions and has no adjacent patterns.

Having conducted all the calculations in the technique, we generated the second part of the spreadsheet containing the results. Whereas the first part of the spreadsheet shows the given data provided by the simulator in Table 3.2, the second part represents the final results, showing gas fill-up, water required, water lost, change in water volumes, and finally, remaining oil saturation.

TABLE 3.3—FINAL CALCULATION RESULTS FOR CASE 1

G_f	μ_o	B_w	B_o	W_l @ 13	W_r @ FU	V_w	V_{wi}	W_{ps}	ΔV_w
191649.06	12.58cp	1.06	1.06	-6816.2	225564.4	931789.8	560316	20.5	371473.8
			Data Obtained Using Areal Distribution Technique						
N_{ps}+W_{ps}	**N_{pp}+W_{pp}**	**N_{ps}**	**W_{ps}**	**W_r**	**W_l**	**ΔV_w**	**ΔS_w**	**S_w**	**ROS**
RB	**RB**	**RB**	**RB**	**RB**	**RB**			**frac**	**frac**
0.0	0.0	0	0						
0.0	*115167.8*	*0*	*0*						
0.0	*166953.0*	*0*	*0*						
0.0	*191664.1*	*0*	*0*						
1907.1	*0.0*	*1906.9*	*0.2*	*37593.3*	*-1126.3*	*37593.1*	*0.0*	*0.21*	*0.73*
3493.1	*0.0*	*3492.7*	*0.4*	*75187.6*	*-2252.7*	*75187.2*	*0.0*	*0.23*	*0.73*
5865.6	*0.0*	*5865.0*	*0.6*	*112781.6*	*-3379.0*	*112781.0*	*0.0*	*0.24*	*0.73*
9167.8	*0.0*	*9166.9*	*1.0*	*150376.3*	*-4505.4*	*150375.3*	*0.1*	*0.25*	*0.73*
13669.1	*0.0*	*13667.6*	*1.5*	*187969.8*	*-5631.8*	*187968.3*	*0.1*	*0.27*	*0.73*
33915.3	*0.0*	*33911.5*	*3.8*	*225564.4*	*-6758.1*	*225560.6*	*0.1*	*0.28*	*0.72*
70271.1	*0.0*	*70263.2*	*8.0*	*261920.2*	*-6645.7*	*261912.2*	*0.1*	*0.29*	*0.71*
106796.6	*0.0*	*106784.4*	*12.2*	*298445.6*	*-6702.9*	*298433.5*	*0.1*	*0.31*	*0.69*
143322.0	*0.0*	*143305.6*	*16.3*	*334971.0*	*-6761.1*	*334954.7*	*0.1*	*0.32*	*0.68*
179845.3	*0.0*	*179824.8*	*20.5*	*371494.3*	*-6816.2*	*371473.8*	*0.1*	*0.33*	*0.67*

The last column in Table 3.3 shows ROS values obtained from the areal distribution technique, with 73% ROS at the beginning of waterflood and 67% ROS at the end of Year 13.

With ROS values both from our simulator and the areal distribution technique, we could compare them to reveal the degree of match and compatibility. **Fig. 3.5** shows the results for our low-pressure reservoir.

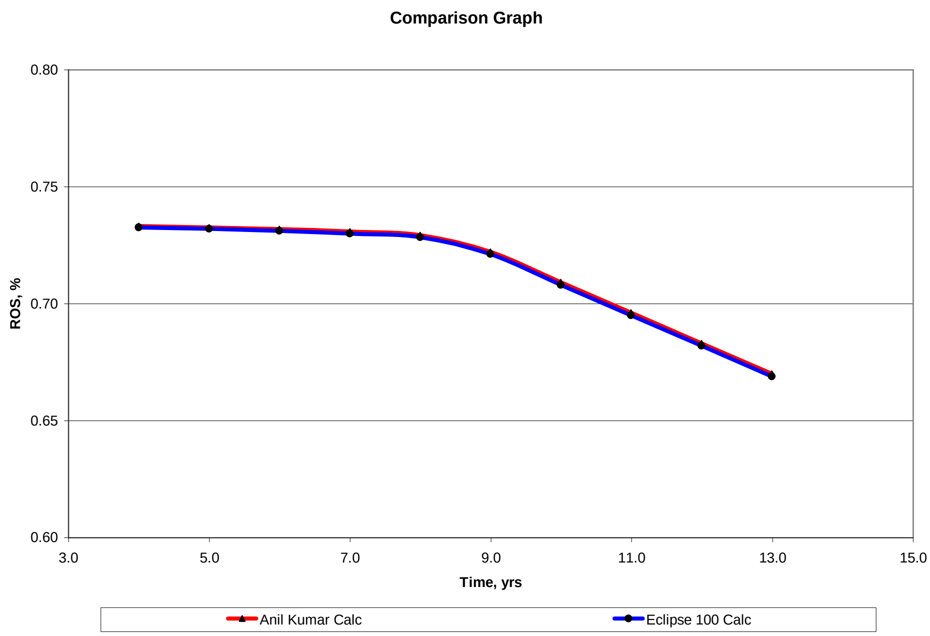


Fig. 3.5—Areal distribution results match our simulation for Case 1.

The error factor below 1.0% means that the areal distribution technique is applicable for Case 1 and succeeds in providing an acceptable ROS value.

3.3 Case 2 – Average Pressure Reservoir Model (800 to 1200 psia)

Case 1 represented reservoir pressures down to 200 psia that maintain formation volume factors close to 1.0. Yet many reservoirs operate under much higher pressure, and the technique might not maintain its precision for all those cases. Case 2 provides an overview of one of those scenarios. Case 2 is very similar to Case 1; the only difference is that reservoir operates under the higher pressure. **Table 3.4** shows the features of Case 2.

TABLE 3.4—RESERVOIR PROPERTIES FOR CASE 2

Reservoir properties	**Value**
Reservoir length, L	660, ft
Reservoir width, w	660, ft
Reservoir height, h	200, ft
Reservoir porosity, ϕ *	28 %
Horizontal permeability, k *	430, md
Vertical permeability, k *	43, md
Initial oil saturation, S_{oi}	80%
Connate water saturation, S_{wc}	20%
Oil viscosity, μ_o	18.58, cp
Water viscosity, μ_w *	0.7, cp
Water injection rate, i_{wt} *	500, STB/D
Initial oil formation volume factor, B_{oi} *	1.277, RB/STB
Oil formation volume factor, B_o *	1.241, RB/STB
Water formation volume factor, B_w	1.06, RB/STB

* These values subject to change prior to case during the sensitivity analysis.

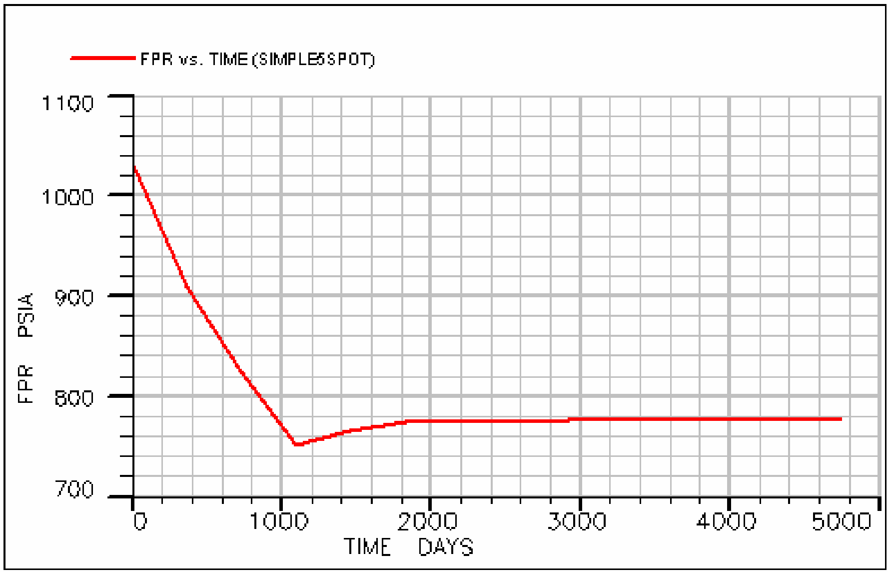


Fig. 3.6—Waterflooding sustained pressure Case 2 after Year 3.

The goal of Case 2 was to show the applicability of areal distribution technique for high-pressure cases. As Fig. 3.6 shows, the reservoir is operating under pressures of 760 to 780 psia, with the initial pressure before exploitation at time zero of 1,025 psia. The values of the simulated pressure data maintain the oil formation volume factor greater than 1.0. **Table 3.5** shows the parameters for Case 2.

Once again a quarter of a five-spot pattern reservoir was modeled in the simulator to get the required injection and production data. From the data presented in Table 3.5, we followed the technique's procedure to find the average ROS values for every time step.
As we can see from the table, the original oil in place value was provided by our simulator. Another way of estimating the original oil in place value is using the oil, water, and gas production data, solution-gas and cumulative gas/oil ratio, pressure profile with corresponding oil and gas formation volume factors (water formation volume factor is constant), and water injection data.

TABLE 3.5—DATA PROVIDED BY SIMULATOR FOR CASE 2

S_{wi}	S_{oi}	B_{oi}	$N_{ps} + W_{ps}$	V_p	OOIP	N_{pp}
0.2	0.8	1.27	1639472.3	4344686	2724917	79160.2
			Simulator Data			
YEARS	**FOSAT**	**FGSAT**	**FWSAT**	**FWPT**	**FOPT**	**FWIT**
YEARS	**fraction**	**fraction**	**Fraction**	**RB**	**RB**	**RB**
0.0	0.80	0.00	0.20	0.0	0.0	0.0
1.0	*0.78*	*0.02*	*0.20*	*2.0*	*64180.8*	*0.0*
2.0	*0.77*	*0.03*	*0.20*	*3.1*	*84917.3*	*0.0*
3.0	*0.76*	*0.04*	*0.20*	*4.1*	*98237.8*	*0.0*
4.0	*0.75*	*0.01*	*0.24*	*6.8*	*134840.9*	*182374.1*
5.0	*0.72*	*0.00*	*0.28*	*19.2*	*277375.9*	*364752.4*
6.0	*0.67*	*0.00*	*0.33*	*34.7*	*459618.0*	*547133.8*
7.0	*0.63*	*0.00*	*0.37*	*49.4*	*641981.7*	*729515.3*
8.0	*0.59*	*0.00*	*0.41*	*771.4*	*823672.8*	*911895.7*
9.0	*0.55*	*0.00*	*0.45*	*19363.6*	*987765.3*	*1094280.4*
10.0	*0.53*	*0.00*	*0.47*	*98715.2*	*1091263.4*	*1276664.0*
11.0	*0.51*	*0.00*	*0.49*	*212492.9*	*1160130.2*	*1459037.0*
12.0	*0.50*	*0.00*	*0.50*	*343336.1*	*1211850.2*	*1641420.6*
13.0	*0.49*	*0.00*	*0.51*	*482554.4*	*1255159.8*	*1823804.2*

We incorporated these estimated values into Eqs. 3.4 and 3.5 to calculate total underground withdrawal, F, and expansion, E_o, values. Once we have those values we can plot a graph using F and E_o data, which should be interpolated with the data resulting as linear, with zero intercept, and with the slope of the line providing the value of original oil in place, N. **Fig. 3.7** represents the oil in place for Case 2.

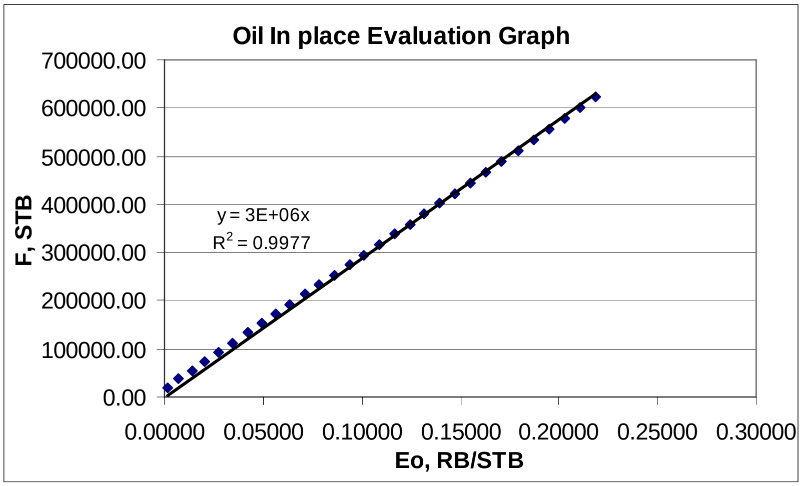


Fig. 3.7—Oil in place from areal distribution matches simulation almost exactly for Case 2

The value of oil in place, *N*, provided by the simulator is equal to 2.7 million STB and *N* evaluated using the graph above is 2.8 million STB, which is quite close as it gives an error factor just over 3%.

Table 3.6 shows the water loss from the pattern; the values are very small and caused by the fluid and rock volume changes. As we explained for Case 1, Sharma and Kumar's[1] evaluation of gas fill-up doesn't represent the true process mechanisms in the reservoir. The gas fill-up volume is calculated using Eq. 3.4. However, Case 1 and Case 2 use different gas fill-up volume values to reveal the effect of the gas fill-up value on evaluation of remaining oil saturation. In Case 1, the difference is quite large, as the pressure was low and there was a significant amount of free gas in the reservoir by the end of the third year. As advised in the Case 1, we must use the proper gas fill-up volume value to get precise results.

Now we can compare the areal distribution technique's results with those presented by the simulator. **Fig. 3.8** reveals a very precise match.

TABLE 3.6 —FINAL CALCULATION RESULTS FOR CASE 2

G_f	B_w	B_o	W_l @ 13	W_r @ FU	V_w	V_{wi}	W_{ps}	ΔV_w
182710	1.06	1.241	1621.6	361863.5	2159585.2	819953	482550.3	1339632.2
Data Obtained Using Areal Distribution Technique								
$N_{ps}+W_{ps}$	N_{ps}	W_{ps}	W_r	W_l	ΔV_w	ΔS_w	S_w	ROS
RB	RB	RB	RB	RB			frac	frac
0	0	0						
0	*0*	*0*						
0	*0*	*0*						
0	*0*	*0*						
36605.8	*36603.0*	*2.7*	*180929.7*	*1444.4*	*180926.9*	*0.0*	*0.24*	*0.75*
179153.3	*179138.1*	*15.2*	*361863.5*	*2888.9*	*361848.3*	*0.1*	*0.28*	*0.72*
361410.8	*361380.2*	*30.6*	*544121.0*	*3012.8*	*544090.4*	*0.1*	*0.33*	*0.67*
543789.2	*543743.9*	*45.3*	*726499.4*	*3015.9*	*726454.1*	*0.2*	*0.37*	*0.63*
726202.3	*725435.0*	*767.3*	*908912.6*	*2983.2*	*908145.2*	*0.2*	*0.41*	*0.59*
908886.9	*889527.5*	*19359.5*	*1091597.2*	*2683.2*	*1072237.7*	*0.2*	*0.45*	*0.55*
1091736.7	*993025.6*	*98711.1*	*1274446.9*	*2217.1*	*1175735.8*	*0.3*	*0.47*	*0.53*
1274381.2	*1061892.4*	*212488.8*	*1457091.5*	*1945.5*	*1244602.7*	*0.3*	*0.49*	*0.51*
1456944.4	*1113612.3*	*343332.0*	*1639654.6*	*1766.0*	*1296322.6*	*0.3*	*0.50*	*0.50*
1639472.3	*1156922.0*	*482550.3*	*1822182.6*	*1621.6*	*1339632.2*	*0.3*	*0.51*	*0.49*

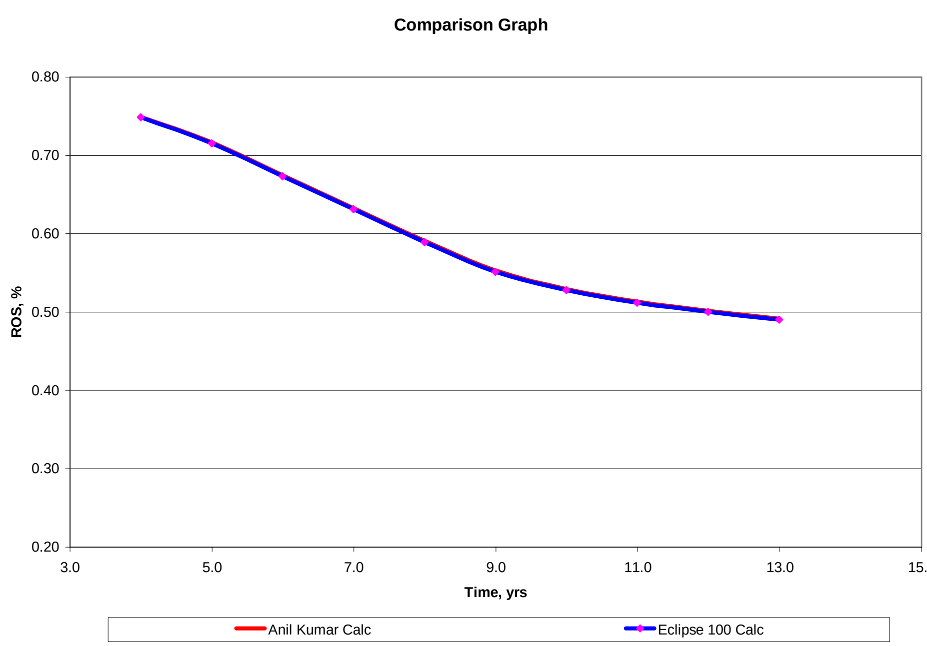


Fig. 3.8—ROS from the areal distribution method matches results from our simulator, even under the high pressure conditions of Case 2.

3.4 Case 3 – Water Loss and/or Gain Scenario

Case 3 is different from the previous two cases because it is designed to have a water loss and/or gain from one pattern to another. The goal of Case 3 is to reveal the applicability of areal distribution technique for situations when water is lost from one pattern to adjacent patterns, and therefore, whether the ROS values would be precise in this case. We used the data presented in **Table 3.7.**

TABLE 3.7—RESERVOIR PROPERTIES FOR CASE 3

Reservoir properties	**Value**
Reservoir length, L	1353, ft
Reservoir width, w	660, ft
Reservoir height, h	200, ft
Reservoir porosity, ϕ *	28 %
Horizontal permeability, k *	430, md
Vertical permeability, k *	43, md
Initial oil saturation, S_{oi}	80%
Connate water saturation, S_{wc}	20%
Oil viscosity, μ_o	18.58, cp
Water viscosity, μ_w *	0.7, cp
Water injection rate, i_{wt} *	1000, STB/D
Well 1 Production Rate *	700, STB/D
Well 2 Production Rate *	300, STB/D
Initial oil formation volume factor, B_{oi} *	1.317, RB/STB
Oil formation volume factor, B_o *	1.273, RB/STB
Water formation volume factor, B_w	1.06, RB/STB

* These values subject to change prior to case during the sensitivity analysis.

The five-spot patterns considered for Cases 1 and 2 represented whole reservoirs; so no water was lost or gained at the reservoir boundaries. In Case 3, the reservoir consisted of four five-spot, producer-centered patterns. For simplicity and less computational time, we modeled eight portions of four patterns, as shown in **Fig. 3.9.**

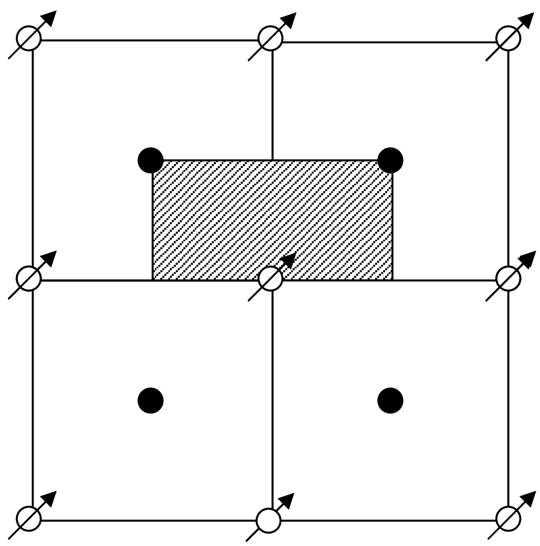


Fig. 3.9—For Case 3, we modeled 1/8 of four five-spot patterns, representing ½ of one injector and ¼ of two producers.

With a reservoir model consisting of four different patterns, we could input different parameters and thereby cause the migration of water from one pattern to another. This could have been achieved by a couple of methods, such as different permeability values, and different production and injection values. It's not coincidental that we chose a producer-centered pattern for Case 3; as a matter of fact, it would have been far easier to define a water movement between the patterns by injecting different amounts of water. For example, if we modeled two injection wells and one production well, and we injected 300 STB/D into Well 1 and 700 STB/D into Well 2, the water injected in Well 2 would partly displace oil in the production well. In addition, it would somewhat occupy the pores of the pattern with injection Well 1, which is a water loss.

But the technique requires the calculation of the ROS by patterns for more precise results. That is why a model represented in Fig. 3.9 was chosen as it appears to be the best equivalent option for the case described above.

We have two producers that make it possible to evaluate the exact volume of fluid produced from each pattern and 1 injector with an open angle towards both patterns. Production Well 1 located on Pattern 1 has a constraint of a maximum 700 STB/D production rate, and production Well 2 has a rate of 300 STB/D. A total of 1,000 STB of water is injected daily. The water injected will equally spread to both patterns, but as the constraint put on production Well 2 helps to decrease the amount of fluid produced, part of the water injected in Pattern 2 will not be able to displace the oil and will therefore, migrate to adjacent Pattern 1. For Pattern 2, the amount of water migrated to pattern 1 is defined as water lost, and for Pattern 1 the same amount is defined as water gained.

Pattern 1. Now that we had a basic understanding of the concept of Case 3, we modeled it in a simulator to get the production and injection profile data required for. As we have the reservoir split in two patterns, we have two versions of every table, the graph and results. The goal is to estimate the ROS in both patterns in the water loss/gain situation.

Before proceeding any further, it’s worth mentioning that in Case 3 **(Table 3.8)** we have a pressure trend that is inconsistent with time. In Fig. 3.3 and Fig. 3.6, the pressure builds up after the waterflood initiation and flattens after a certain point. **Fig. 3.10** below presents the changes of pressure with time for Case 3.

TABLE 3.8—DATA PROVIDED BY SIMULATOR FOR CASE 3 PATTERN 1

S_{wi}	S_{oi}	B_{oi}	$N_{ps} + W_{ps}$	V_p	OOIP	N_{pp}
0.2	0.8	1.317	2327820.8	4026781	2445289	101098.0
			Simulator Data			
YEARS	**FOSAT**	**FGSAT**	**FWSAT**	**FWPT**	**FOPT**	**FWIT**
YEARS	**%**	**%**	**%**	**RB**	**RB**	**RB**
0.0	0.80	0.00	0.20	0.0	0.0	0.0
1.0	*0.78*	*0.02*	*0.20*	*2.6*	*84327.5*	*0.0*
2.0	*0.76*	*0.04*	*0.20*	*4.0*	*111643.2*	*0.0*
3.0	*0.75*	*0.04*	*0.20*	*5.2*	*128697.8*	*0.0*
4.0	*0.75*	*0.00*	*0.25*	*7.0*	*153420.7*	*182377.2*
5.0	*0.70*	*0.00*	*0.30*	*29.2*	*393108.8*	*364763.0*
6.0	*0.64*	*0.00*	*0.36*	*51.3*	*655625.6*	*547150.8*
7.0	*0.58*	*0.00*	*0.42*	*135.4*	*917974.3*	*729534.4*
8.0	*0.53*	*0.00*	*0.47*	*29853.6*	*1142383.8*	*911928.6*
9.0	*0.50*	*0.00*	*0.50*	*167431.2*	*1260593.3*	*1094344.0*
10.0	*0.49*	*0.00*	*0.51*	*350133.9*	*1335797.1*	*1276764.7*
11.0	*0.48*	*0.00*	*0.52*	*551306.0*	*1391821.8*	*1459185.4*
12.0	*0.47*	*0.00*	*0.53*	*762807.8*	*1437140.6*	*1641611.4*
13.0	*0.46*	*0.00*	*0.54*	*981244.1*	*1475279.7*	*1824032.1*

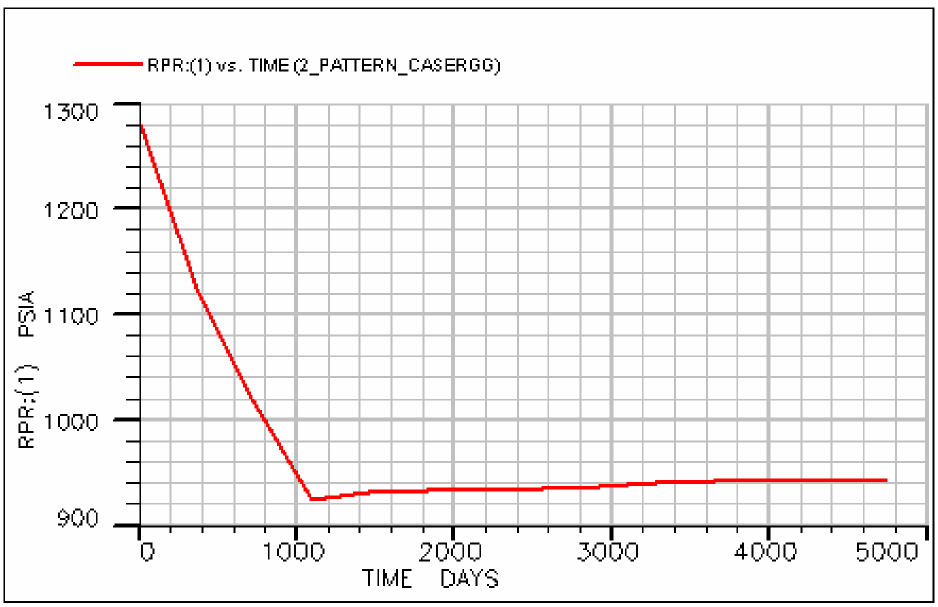


Fig. 3.10—Reservoir pressure begins a slow rise after waterflooding commences for Case 3 Pattern 1.

The only difference between the third case calculations and Case 1 and 2 is that cumulative oil and water produced and injected should be converted into reservoir barrels with respect to formation volume factor corresponding to every pressure value and time step. We cannot take a single flat value of oil formation volume factor as we did in Case 1 and Case 2 because it will jeopardize the precision of the calculations and will certainly increase the error factor.

Having calculated the production and injection data correctly, we proceeded to the remaining oil calculations.

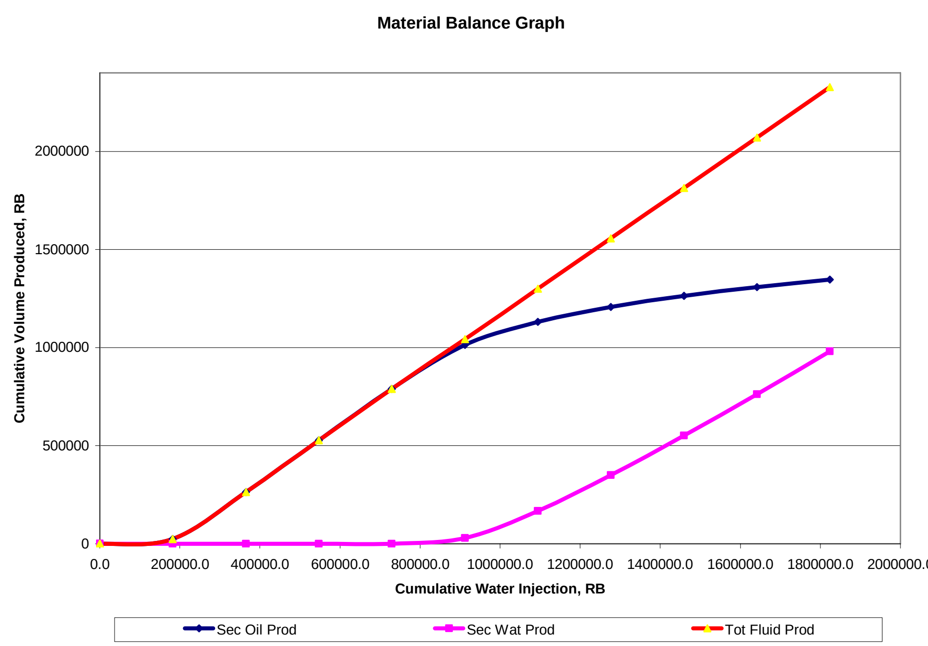


Fig. 3.11—Material balance graph for Case 3 Pattern 1 does not clearly identify gas fill-up time.

The graph of material balance in **Fig 3.11** is supposed to help estimate and visually allocate the gas fill-up time, but we found it simpler to calculate the gas fill-up volume with Eq. 3.7 as the areal distribution technique's method of evaluating gas fill-up from Eq. 3.1 is not precise and cannot be applied for large-gas-volume scenarios. This is because it doesn't take into consideration the amount of gas produced during the primary production.

Using **Fig. 3.12,** we can easily estimate the end of gas fill-up in the reservoir. Moreover, the peak of the gas saturation trend multiplied by pore volume in reservoir barrels gives the amount of free gas in the reservoir that represents the value of gas fill-up.

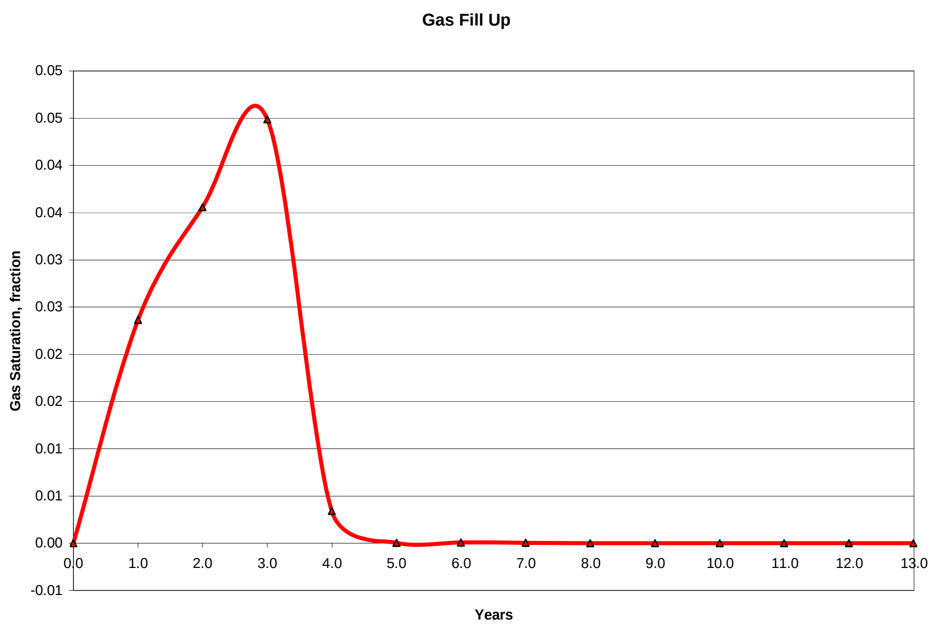


Fig. 3.12—Peak in gas saturation for Case 3 Pattern 1 clearly identifies gas fill-up time.

As we can see from Fig. 3.12, the gas fill-up process ends by the end of Year 6 and is practically no free gas remains in the reservoir. With this information, we calculated ROS.

TABLE 3.9—FINAL CALCULATION RESULTS FOR CASE 3 PATTERN 1

$_o$	μ_w	B_w	B_o	W_l @ 13	W_r @ FU	V_w	V_{wi}	W_{ps}	ΔV_w
0.7cp	12.58cp	1.06	1.268	-684455.1	445101.3	2155742.3	778494	981238.9	1377248.3
Data Obtained Using Areal Distribution Technique									
$N_{ps}+W_{ps}$	$N_{pp}+W_{pp}$	N_{ps}	W_{ps}	W_r	W_l	V_w	S_w	S_w	ROS
RB	RB	RB	RB	RB	RB			%	%
0.0	0.0	0	0						
0.0	*84330.0*	*0*	*0*						
0.0	*111647.2*	*0*	*0*						
0.0	*128703.0*	*0*	*0*						
24724.7	*0.0*	*24722.9*	*1.8*	*222545.5*	*-28168.2*	*210543.7*	*0.1*	*0.25*	*0.75*
264434.9	*0.0*	*264411.0*	*23.9*	*445101.3*	*-60338.3*	*425077.4*	*0.1*	*0.31*	*0.69*
526973.8	*0.0*	*526927.8*	*46.0*	*707640.2*	*-125489.4*	*672594.2*	*0.2*	*0.37*	*0.63*
789406.7	*0.0*	*789276.5*	*130.2*	*970073.1*	*-190538.7*	*919942.9*	*0.2*	*0.43*	*0.57*
1043534.5	*0.0*	*1013686.1*	*29848.4*	*1224200.8*	*-242272.2*	*1124352.4*	*0.3*	*0.48*	*0.52*
1299321.6	*0.0*	*1131895.6*	*167426.0*	*1479988.0*	*-285644.0*	*1212561.9*	*0.3*	*0.50*	*0.50*
1557228.0	*0.0*	*1207099.3*	*350128.7*	*1737894.4*	*-351129.7*	*1277765.7*	*0.3*	*0.52*	*0.48*
1814424.8	*0.0*	*1263124.1*	*551300.8*	*1995091.2*	*-405905.8*	*1313790.4*	*0.3*	*0.53*	*0.47*
2071245.4	*0.0*	*1308442.9*	*762802.6*	*2251911.8*	*-460300.4*	*1339109.2*	*0.3*	*0.53*	*0.47*
2327820.8	*0.0*	*1346581.9*	*981238.9*	*2508487.2*	*-534455.1*	*1377248.3*	*0.3*	*0.54*	*0.46*

Table 3.9 presents the results obtained from areal distribution calculations. By the end of the first year of waterflooding. over 28,000 RB of water was gained from adjacent Pattern 2, and by the end of Year 13 over 534,000 RB of water was gained. A logical assumption is that there are no other sources of water supply to the reservoir other than water injected and that the only open-flow boundary is the front line between patterns. As a result, we can say that Pattern 1 lost the same amount of water.

Fig. 3.13 compares the results for Pattern 1 and shows that the two models match well under the circumstances of water loss and gain. The results show that the Pattern 1 ROS values matched with the data provided by our simulator.

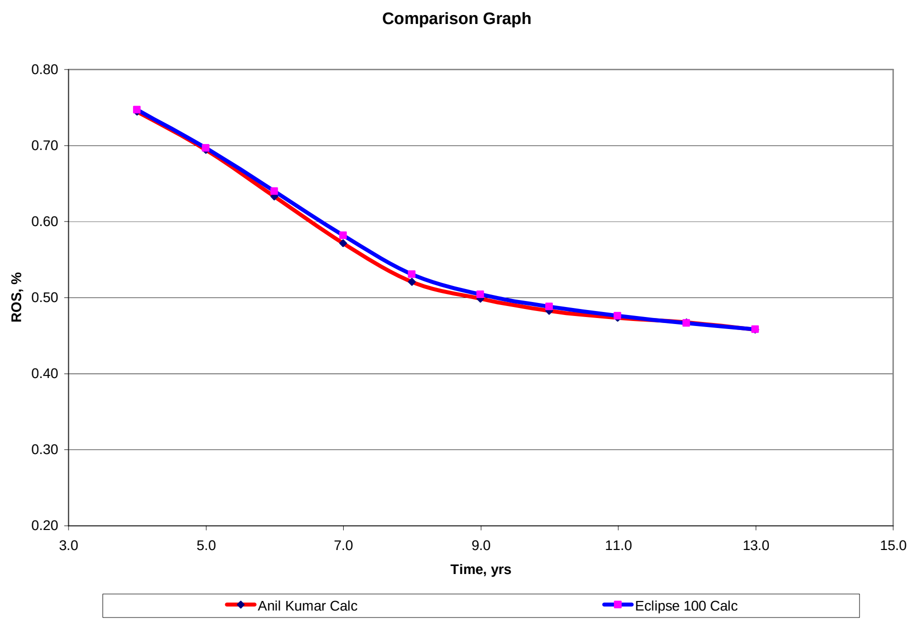


Fig. 3.13—Areal distribution and simulation match closely for Case 3 Pattern 1.

Pattern 2. The same procedures as used for Pattern 1 were used to estimate the ROS in Pattern 2 **(Fig. 3.14);** the only difference is that in this case Pattern 2 is losing the water.

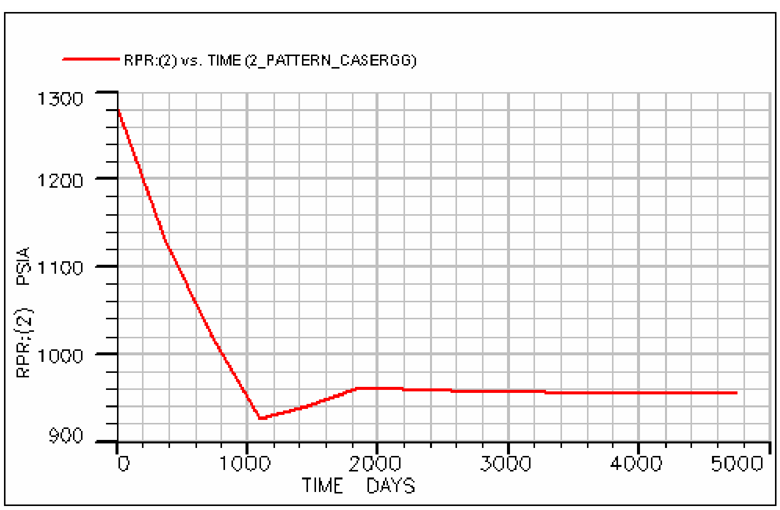


Fig. 3.14—Reservoir pressure rose after the onset of waterflooding in Case 3 Pattern 2 but tapered off as the pattern lost fluid to the formation.

We used the data in **Table 3.10** to model Case 3 Pattern 2..

TABLE 3.10—DATA PROVIDED BY SIMULATOR FOR CASE 3 PATTERN 2

S_{wi}	S_{oi}	B_{oi}	N_{ps} + W_{ps}	V_p	OOIP	N_{pp}
0.2	0.8	1.3174	1004259.6	4026781	2445289	46206.8
			Simulator Data			
YEARS	**FOSAT**	**FGSAT**	**FWSAT**	**FWPT**	**FOPT**	**FWIT**
YEARS	**fraction**	**fraction**	**Fraction**	**RB**	**RB**	**RB**
0.0	0.80	0.00	0.20	0.0	0.0	0.0
1.0	*0.78*	*0.02*	*0.20*	*0.9*	*40574.9*	*0.0*
2.0	*0.76*	*0.04*	*0.20*	*1.5*	*52930.2*	*0.0*
3.0	*0.75*	*0.04*	*0.20*	*2.0*	*60872.8*	*0.0*
4.0	*0.75*	*0.01*	*0.24*	*2.9*	*73022.7*	*182377.2*
5.0	*0.72*	*0.00*	*0.28*	*9.2*	*165250.2*	*364763.0*
6.0	*0.69*	*0.00*	*0.31*	*16.7*	*277951.8*	*547150.8*
7.0	*0.66*	*0.00*	*0.34*	*23.9*	*390552.6*	*729534.4*
8.0	*0.63*	*0.00*	*0.37*	*30.7*	*503286.1*	*911928.6*
9.0	*0.59*	*0.00*	*0.41*	*36.2*	*616225.3*	*1094344.0*
10.0	*0.57*	*0.00*	*0.43*	*2136.0*	*727006.3*	*1276764.7*
11.0	*0.54*	*0.00*	*0.46*	*15033.0*	*826669.8*	*1459185.4*
12.0	*0.52*	*0.00*	*0.48*	*43895.3*	*909885.5*	*1641611.4*
13.0	*0.50*	*0.00*	*0.50*	*95332.2*	*969802.3*	*1824032.1*

Parameters such as pore volume, original oil in place, original water in place, initial formation volume factor, and initial oil and water saturations are equal for both Patterns 1 and 2. The difference is in the formation volume factors after the waterflood initiation, the amount of fluid produced, and the oil and water saturations at every time step after waterflood initiation.

We used Fig. **3.15** to estimate the gas fill-up time and volume.

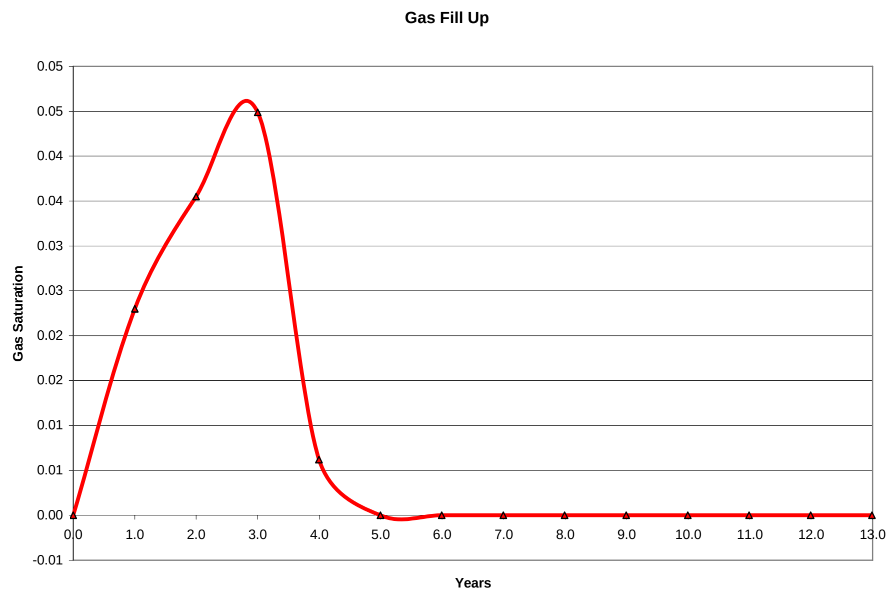


Fig. 3.15—Case 3 Pattern 2 reached gas fill-up at the end of Year 6.

Fig. 3.15 shows that the gas fill-up process ends by the end of Year 6, which we can also estimate from the material balance graph. We can also use material balance graph to estimate the volume of free gas in the reservoir at the waterflood initiation, which would be gas fill-up volume, or we can use Eq. 3.7. Using Eq. 3.7 we get the gas fill-up volume value equal to 180,786 RB, which is shown in **Table 3.11**. As we can see from the table, the amount of water lost to Pattern 1 by the end of the first year of waterflooding is over 28,000 RB, and by the end of Year 13 it is 539,000 RB. These values are very close to those gained by Pattern 1, which shows that the technique works precisely.

TABLE 3.11—FINAL CALCULATION RESULTS FOR CASE 3 PATTERN 2

G_f	μ_w	B_w	B_o	W_l @ 13	W_r @ FU	V_w	V_{wi}	W_{ps}	ΔV_w
180686	12.58cp	1.06	1.273	639096.4	285060.6	1949563.5	759958	95330.1	1189605
Data Obtained Using Areal Distribution Technique									
N_{ps}+W_{ps}	N_{pp}+W_{pp}	N_{ps}	W_{ps}	W_r	W_l	ΔV_w	ΔS_w	S_w	ROS
RB	RB	RB	RB	RB	RB			frac	frac
0.0	0.0	0	0						
0.0	*40575.7*	*0*	*0*						
0.0	*52931.7*	*0*	*0*						
0.0	*60874.8*	*0*	*0*						
12150.7	*0.0*	*12149.9*	*0.8*	*142527.0*	*28350.2*	*154026.2*	*0.0*	*0.24*	*0.76*
104384.6	*0.0*	*104377.4*	*7.2*	*285060.6*	*59702.3*	*305053.4*	*0.1*	*0.28*	*0.72*
217093.6	*0.0*	*217079.0*	*14.6*	*397769.7*	*124381.1*	*422755.0*	*0.1*	*0.30*	*0.70*
329701.6	*0.0*	*329679.8*	*21.8*	*510377.6*	*190156.8*	*539355.8*	*0.1*	*0.33*	*0.67*
442442.0	*0.0*	*442413.3*	*28.7*	*623118.0*	*242810.6*	*669089.4*	*0.2*	*0.37*	*0.63*
555386.7	*0.0*	*555352.5*	*34.2*	*736062.7*	*285281.3*	*809028.5*	*0.2*	*0.40*	*0.60*
668267.5	*0.0*	*666133.5*	*2134.0*	*848943.5*	*350821.2*	*923809.5*	*0.2*	*0.43*	*0.57*
780828.0	*0.0*	*765797.0*	*15031.0*	*961504.0*	*405981.4*	*1038173.0*	*0.3*	*0.46*	*0.54*
892906.0	*0.0*	*849012.7*	*43893.3*	*1073582.0*	*460029.4*	*1137688.7*	*0.3*	*0.48*	*0.52*
1004259.6	*0.0*	*908929.5*	*95330.1*	*1184935.7*	*539096.4*	*1189605.5*	*0.3*	*0.50*	*0.50*

Fig. 3.16 shows the difference between the two models.

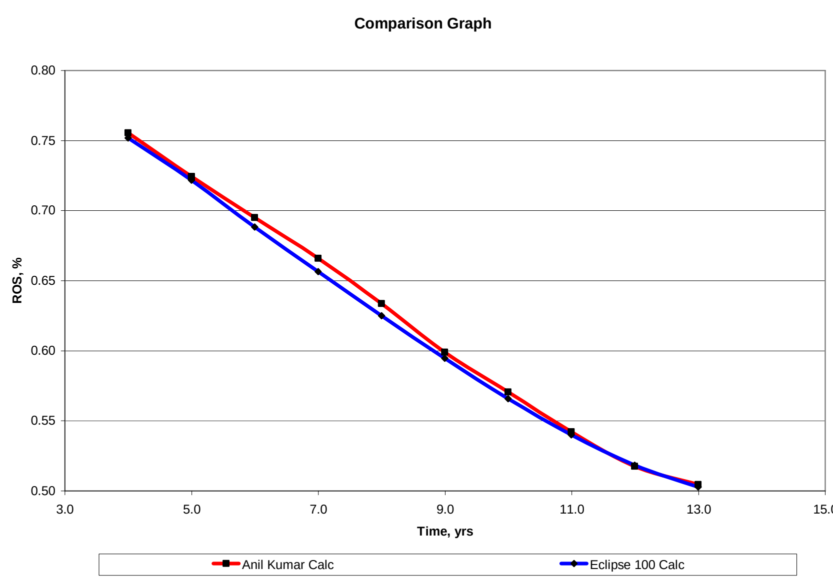


Fig. 3.16—Areal distribution matches simulation for Case 3 Pattern 2.

According to the results obtained from the calculations in both cases for Pattern 1 and Pattern 2, the error factor does not exceed 1%, and the amount of water lost by Pattern 2 is very close to the value of water gained by Pattern 1. This shows that the areal distribution technique is applicable for reservoirs with water loss and/or gain.

3.5 Case 4 – Heterogeneous Scenario

All the previous cases described above represented the homogeneous reservoir with constant permeability values throughout the reservoir. Case 4 **(Table 3.8)** represents the same model of the reservoir as in Cases 1 and 2 with only difference of various permeability factors within each layer.

TABLE 3.12—RESERVOIR PROPERTIES FOR CASE 4

Reservoir properties	**Value**
Reservoir length, L	660, ft
Reservoir width, w	660, ft
Reservoir height, h	200, ft
Reservoir porosity, ϕ *	28 %
Horizontal permeability layer 1 10, k *	1, 10, 50, 100, 150, 200, 250, 300, 350, 400
Vertical permeability layer 1 to 10, k *	0.1, 1, 5, 10, 15, 20, 25, 30, 35, 40, md
Initial oil saturation, S_{oi}	80%
Connate water saturation, S_{wc}	20%
Oil viscosity, μ_o	18.58, cp
Water viscosity, μ_w *	0.7, cp
Water injection rate, i_{wt} *	500, STB/D
Production Rate *	500, STB/D
Initial oil formation volume factor, B_{oi} *	1.277, RB/STB
Oil formation volume factor, B_o *	1.24, RB/STB
Water formation volume factor, B_w	1.06, RB/STB

The applicability of areal distribution technique for homogenous reservoirs was as expected; the heterogeneous reservoir is a greater challenge for this case.

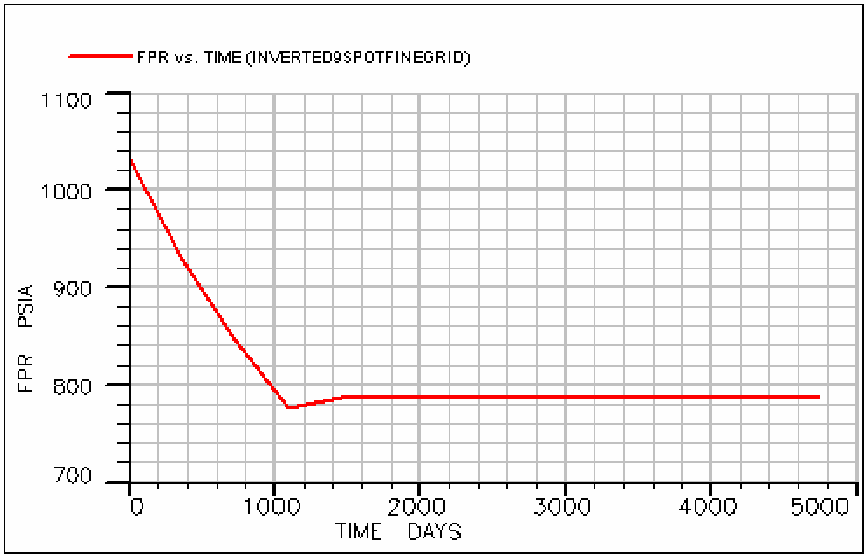


Fig. 3.17—Reservoir pressure for Case 4 closely resembled Case 1, although Case 4 is a heterogeneous reservoir.

As we can see from **Fig. 3.17,** the average reservoir pressure remains constant at 780 psia after water injection. **Tables 3.13** and **3.14** provide the simulator data and final calculations for Case 4.

TABLE 3.13—DATA PROVIDED BY SIMULATOR FOR CASE 4

S_{wi}	S_{oi}	B_{oi}	N_{ps} + W_{ps}	V_p	OOIP	N_{pp}
0.2	0.8	1.277	1617681.9	3921079	2454917	111676.0
			Simulator Data			
YEARS	**FOSAT**	**FGSAT**	**FWSAT**	**FWPT**	**FOPT**	**FWIT**
YEARS	**fraction**	**Fraction**	**fraction**	**RB**	**RB**	**RB**
0.0	0.80	0.00	0.20	0.0	0.0	0.0
1.0	*0.77*	*0.03*	*0.20*	*3.5*	*73779.1*	*0.0*
2.0	*0.76*	*0.04*	*0.20*	*6.2*	*112186.6*	*0.0*
3.0	*0.74*	*0.06*	*0.20*	*8.6*	*138366.6*	*0.0*
4.0	*0.73*	*0.02*	*0.25*	*12.2*	*178451.9*	*182364.5*
5.0	*0.70*	*0.01*	*0.29*	*26.4*	*311068.3*	*364739.6*
6.0	*0.65*	*0.01*	*0.34*	*6087.7*	*476943.1*	*547112.6*
7.0	*0.62*	*0.01*	*0.37*	*68965.1*	*593421.5*	*729484.6*
8.0	*0.61*	*0.01*	*0.39*	*174379.5*	*669704.3*	*911852.3*
9.0	*0.59*	*0.01*	*0.40*	*299421.4*	*727050.2*	*1094216.8*
10.0	*0.58*	*0.01*	*0.41*	*438515.6*	*770380.5*	*1276579.2*
11.0	*0.57*	*0.01*	*0.42*	*584724.6*	*806579.1*	*1458941.6*
12.0	*0.56*	*0.01*	*0.43*	*736314.2*	*837378.2*	*1641314.6*
13.0	*0.56*	*0.01*	*0.44*	*891977.3*	*864079.8*	*1823677.0*

TABLE 3.14—FINAL CALCULATION RESULTS FOR CASE 4

G_f	B_w	B_o	W_l @ 13	W_r @ FU	V_w	V_{wi}	W_{ps}	ΔV_w
225757.3	1.06	1.24	-19762.2	398476.8	1691477.6	740007	891968.7	951470
			Data Obtained Using Areal Distribution Technique					
N_{ps}+W_{ps}	**N_{ps}**	**W_{ps}**	**W_r**	**W_l**	**ΔV_w**	**ΔS_w**	**S_w**	**ROS**
RB	**RB**	**RB**	**RB**	**RB**			**frac**	**frac**
0.0	0	0						
0.0	*0*	*0*						
0.0	*0*	*0*						
0.0	*0*	*0*						
40089.0	*40085.4*	*3.6*	*199232.6*	*-16868.1*	*199229.0*	*0.1*	*0.25*	*0.73*
172719.5	*172701.7*	*17.8*	*398476.8*	*-33737.2*	*398459.0*	*0.1*	*0.30*	*0.69*
344655.6	*338576.6*	*6079.0*	*570412.9*	*-23300.3*	*564333.9*	*0.1*	*0.34*	*0.65*
524011.4	*455055.0*	*68956.5*	*749768.7*	*-20284.1*	*680812.3*	*0.2*	*0.37*	*0.62*
705708.6	*531337.7*	*174370.9*	*931465.9*	*-19613.7*	*757095.0*	*0.2*	*0.39*	*0.60*
888096.3	*588683.6*	*299412.8*	*1113853.6*	*-19636.8*	*814440.9*	*0.2*	*0.41*	*0.59*
1070520.9	*632013.9*	*438507.0*	*1296278.2*	*-19699.0*	*857771.2*	*0.2*	*0.42*	*0.58*
1252928.5	*668212.5*	*584716.0*	*1478685.8*	*-19744.2*	*893969.8*	*0.2*	*0.43*	*0.57*
1435317.1	*699011.6*	*736305.5*	*1661074.4*	*-19759.8*	*924768.9*	*0.2*	*0.44*	*0.56*
1617681.9	*725713.3*	*891968.7*	*1843439.2*	*-19762.2*	*951470.6*	*0.2*	*0.44*	*0.55*

For Case 2, we estimated the original oil in place value, *N*, using data provided by our simulator for the homogeneous reservoir model. **Fig. 3.18** presents the OOIP calculations for the heterogeneous reservoir model, Case 4. The OOIP provided by our simulator is 2.4 million STB, and oil in place evaluated using the plot is 2.5 million STB, which gives an error factor under 3%.

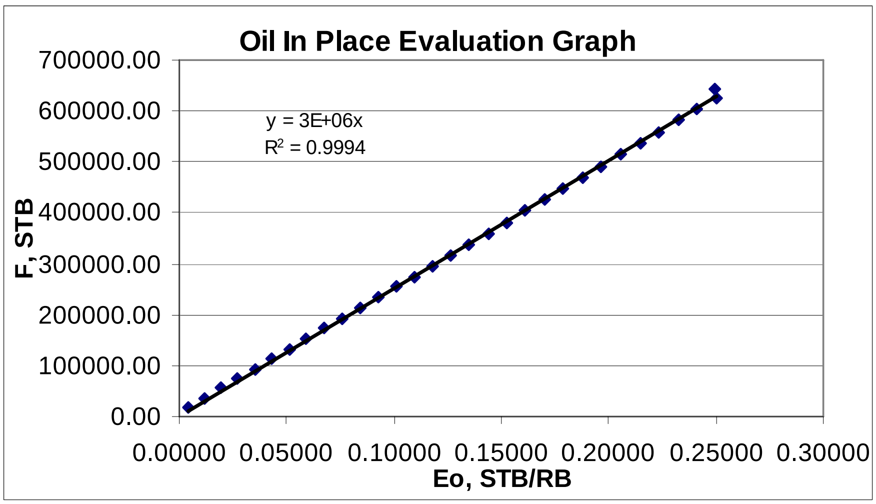


Fig. 3.18—The methods produce similar OOIP estimates for Case 4.

As Case 3 Pattern 2, the material balance graph **(Fig. 3.19)** fails to estimate gas fill-up volume and the end of gas fill-up time, which is very important for water required calculations presented in technique. However, we used calculations to find the necessary values.

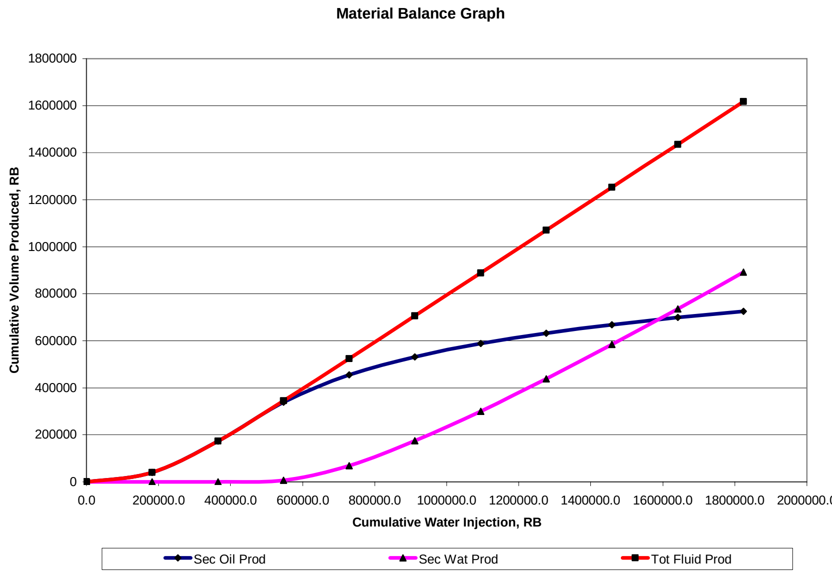


Fig. 3.19—Material balance graph for Case 4 fails to clearly identify gas fill-up time.

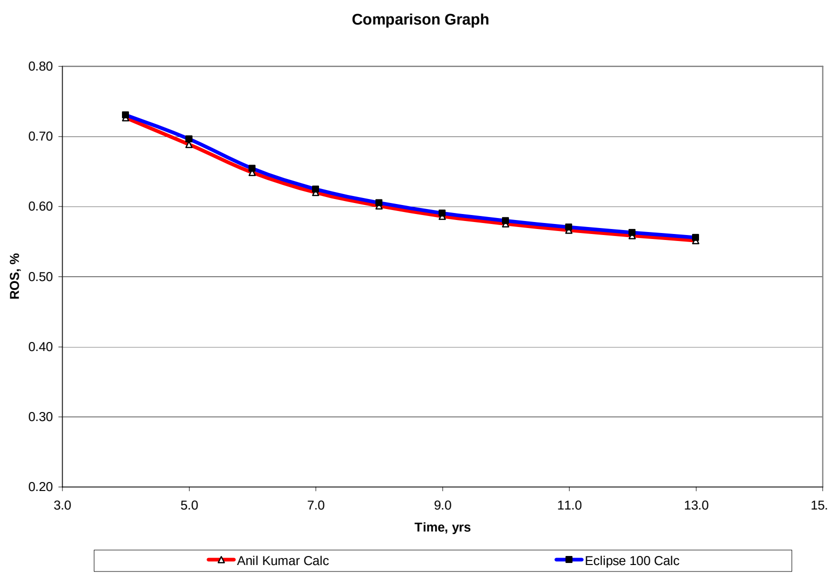


Fig. 3.20—Both methods identify the same ROS for Case 4.

The plot presented in **Fig. 3.20** reveals the applicability of the technique for both homogeneous and heterogeneous reservoirs. As the plot shows, the technique's results for Case 4, heterogeneous reservoirs, are quite precise with average error factor less than 2%.

Cases 2 and 4 are very similar by pattern structure, injection/production rate, and many other input parameters. The only difference is that Case 2 represents a homogeneous reservoir and Case 4 a heterogeneous model. As the heterogeneous case has a very wide range of permeability factors (and has lower permeability values than in Case 2), we should assume that Case 4 would have higher water production values **(Fig. 3.21).**

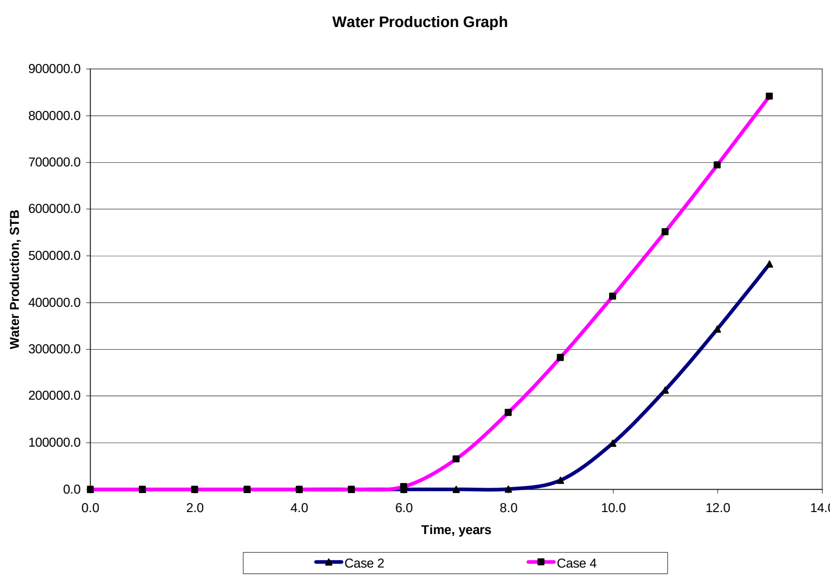


Fig. 3.21—Water production is much higher for Case 4 than for Case 2.

As expected, the heterogeneous case shows more water produced and possibly a sooner breakthrough time. In the material balance procedure, the oil production values would be higher in the homogeneous reservoir model, Case 2, than in the heterogeneous case.

CHAPTER IV

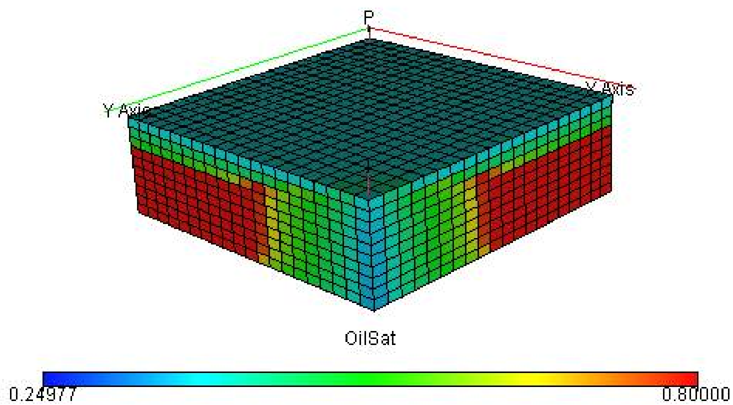
SIMULATION MODEL OVERVIEW

With no real data provided for the research, we created a 40-acre, five-spot pattern representing a homogenous reservoir model with 10 layers with an Eclipse 100 simulator. For Case 1 and 2 models, the grids consisted of 4,000 blocks, but for some sensitivity analysis cases, the number of grid blocks was increased to 32,000. The length and the width of the model is 660 ft divided into 20 grid blocks, which makes the length and width of the single grid block of 33 ft, and the height of the model is 200 ft divided into 10 grid blocks, which makes the height of the single block 20 ft. In more refined cases the measurement parameters were changed to fit the area of 40 acres. Such parameters as porosity, permeability, water viscosity, and injection and production rates were subject to change according to the case to reveal the effect of such parameters at the compatibility of the technique. Different pattern structures were used as well, such as a1D pattern or five-spot, nine-spot, or line drive. As expected, the results appeared to show the reservoir parameters, grid refinement, and pattern structure did not in any way affect the precision of the technique.

The reservoir model we created has been exploited for 13 years, the first 3 years of which was primary production. The areal distribution technique requires the primary production profile data to calculate ROS during secondary production. The amount of water injected was always equal to the amount of fluid produced to keep the material balance; that is, production rate is equal to injection rate. Pressure data are not required in the calculations, yet if the reservoir is not operating under the low pressure, the method requires the pressure profile to determine the formation volume factors for more precise results.

Throughout the simulation, the 365-day interval was accepted as a single time step. The results provided reflect the values at the end of every time step. **Figs. 4.1 and 4.2** show significant results for Cases 1, 2, and 3.

Case 1—1,825 days



Case 2—1,825 days

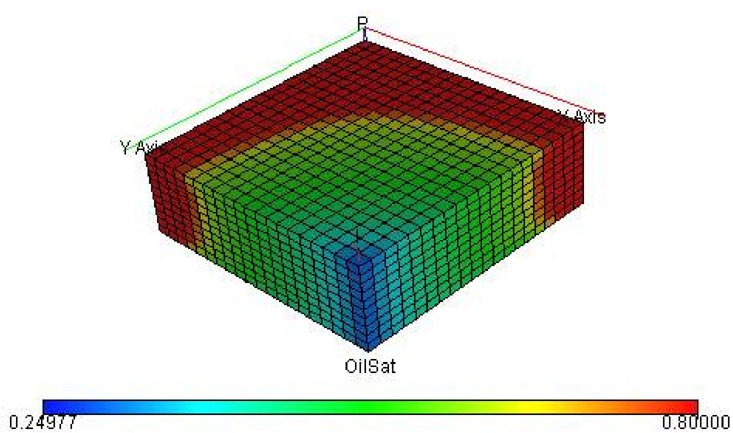


Fig 4.1—Oil saturation at the end of 1,825 days is clearly still much higher in Case 2 than the same time in Case 1.

Case 3—4745 days

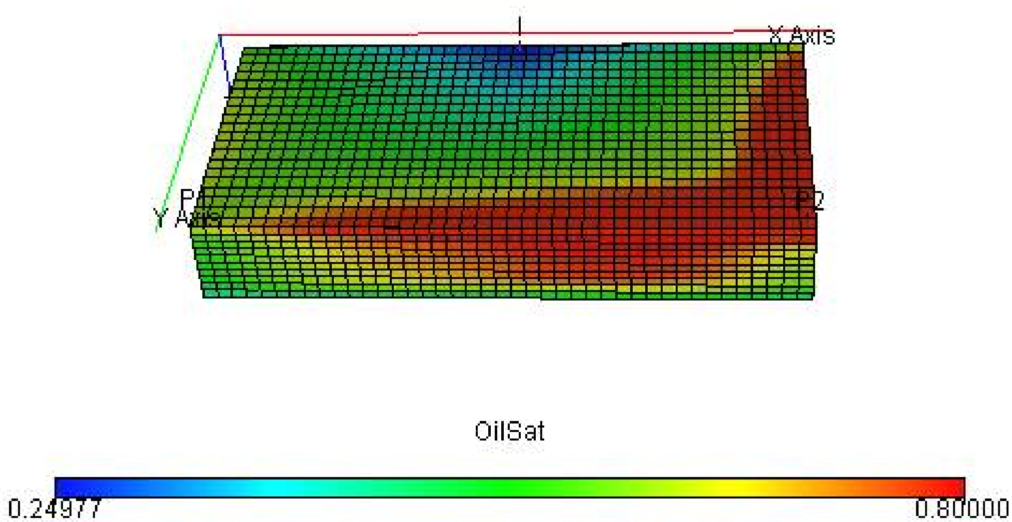


Fig 4.2—For Case 3, waterflooding had clearly swept most of the oil toward the producers by the end of 4,745 days.

We can clearly see from Fig. 4.1 that oil saturation in Pattern 2 is much higher than in Pattern 1. As the water injected in the center between two patterns is distributed to both patterns, it is restricted by lower production rate at the production Well 2 and finds its way to displace more oil by migrating to Pattern 1.

The size of the grid in Case 3 (Fig. 4.2) is 41:20:10—essentially the two five-spot patterns described in Cases 1 and 2 put together with a difference of one more grid block layer in x-direction. Combining the patterns helps us effectively place injection well and make sure that the area and parameters of two patterns are equal.

Case 4—1,825 days

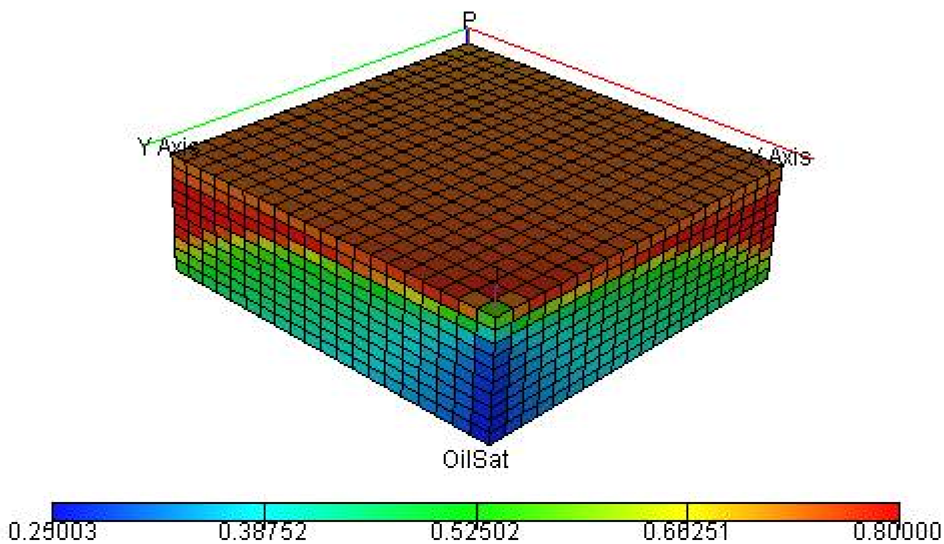


Fig 4.3—In Case 4, low permeability in the heterogeneous reservoir left oil saturation quite high at the end of 1,825 days.

In Case 4 (**Fig. 4.3),** the oil saturation in the reservoir was still quite high at the end of the 13-year trial, which is what we might expect in conditions of a heterogeneous reservoir with low permeability.

CHAPTER V

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

5.1 Summary

Sharma and Kumar[1] presented an areal distribution technique that enables us to calculate the ROS in the low-pressure reservoirs using injection and production profile data only. The main advantages of the technique are the simplicity of the material balance calculations, little computational time, and availability of the data required. To verify whether the technique is accurate in these reservoirs and applicable to higher pressure conditions, we generated data including all the required information such as production and injection data and water, oil, and gas saturations. We studied three main cases: a low-pressure reservoir model, an average-pressure reservoir model, a scenario with water loss and/or gain, and a heterogeneous reservoir.

The sensitivity analysis studied over 40 cases with different input parameters such as different water injection rates maintaining different pressure profiles, different porosity and permeability values, different water viscosity values to create a pseudo polymer-injection situation, and different pattern structures. All the calculations were conducted using a Microsoft Excel spreadsheet. One of the assumptions throughout the calculations was that injection and production rates were equal.

5.2 Conclusions

The main conclusions from the cases studies follow:

1. As the model in the Sharma and Kumar[1] paper was operated under low pressure, the first step was to find the precision of the technique for these cases. The results of Case 1 revealed a very close match between the ROS provided by technique and our simulator.

2. Because in many cases pressure is higher than in Case 1, we applied the technique to average- and high-pressure reservoirs. The results appear to show very close matches with simulator results, with an average error factor between the two models being less than 1%.
3. Cases 3 and 4 represent more real-life case scenarios, so the match of the technique's results with those of our simulator was very important. The match is very close and the average error factor does not exceed 2%.
4. The initial objective of my research was to prove the applicability of the areal distribution technique for the different cases and scenarios. The results provided by this research reveal that technique is capable of very precise estimation of ROS from simple material balance equations.
5. Originally Sharma and Kumar suggested that their technique is a close approximation of the actual value. We confirmed that, with the correction on gas fill-up calculations, the results appeared to be quite precise and almost identical.
6. The areal distribution technique is precise and might be used to evaluate the average ROS values in waterflood reservoirs, but it requires pressure data along with injection and production data. The main concept of the technique, which is that ROS can be evaluated from only injection and production data, did not prove to be accurate.

5.3 Recommendations

For future research, we recommend avoiding the use of production and injection values in stock-tank-barrel measurement units because they do not reflect the true values of the reservoir. Furthermore, reservoir barrels are more accurate as all the processes described for the ROS evaluation are occurring in the reservoir. The only situation where the research can be conducted using stock- tank-barrel units is when the formation volume factor for oil and water is equal to 1.0 RB/STB.

The gas fill-up volume should not be calculated using Sharma and Kumar's[1] method as presented in Eq. 3.1, as it is not correct because gas production values are not incorporated into the equation. Instead, Eq. 3.7 should be used for more precise free-gas-volume estimation, which represents the gas fill-up volume at a given time. Alternatively, free-gas volume can be evaluated from the material balance graph.

After further testing, the areal distribution technique might be checked for applicability for thermal recovery scenarios, such as steam-injection cases.

NOMENCLATURE

B_g = gas formation volume factor, Rcf/scf
B_o = oil formation volume factor, RB/STB
B_{oi} = oil formation volume factor at waterflood initiation, RB/STB
B_w = water formation volume factor, RB/STB
E_o = expansion of oil and its originally dissolved gas, RB/STB
F = total underground withdrawal, RB
G_f = fill-up gas volume, RB
G_p = gas production, Mscf
G_{pf} = partial fill-up gas volume, RB
h = height, ft
i_w = water injected, STB/D
k = permeability, md
L = length, ft
n = number of time steps
N = original oil in place, STB
N_p = cumulative oil produced, RB
N_{pp} = cumulative oil produced during primary recovery, RB
N_{ps} = cumulative oil produced during secondary recovery, RB
R_p = production from the reservoir, RB
R_s = solution-gas/oil ratio, Mscf/STB
R_{si} = initial solution/gas/oil ratio, Mscf/STB
S_g = gas saturation, fraction
S_o = oil saturation, fraction
S_w = water saturation, fraction
S_g = gas saturation, fraction
S_{oi} = initial oil saturation, fraction
S_{wc} = connate water saturation, fraction
S_{wi} = initial water saturation, fraction
S_{gi} = initial gas saturation, fraction
t = time
t_f = time of complete fill up
V_p = pore volume, RB
V_w = water volume, RB
V_{wi} = initial water volume in reservoir, RB
w = width, ft
W_i = cumulative water injected, RB
W_{if} = cumulative water injected at fill up, RB
W_l = water lost from the pattern, RB
W_{ps} = cumulative water produced during secondary production, RB
W_r = volume of net water required at time t, RB
W_{rf} = volume of net water required at time of fill-up, RB

Δp = pressure change, fraction
ϕ = porosity, %
μ_o = oil viscosity, cp
μ_w = water viscosity, cp

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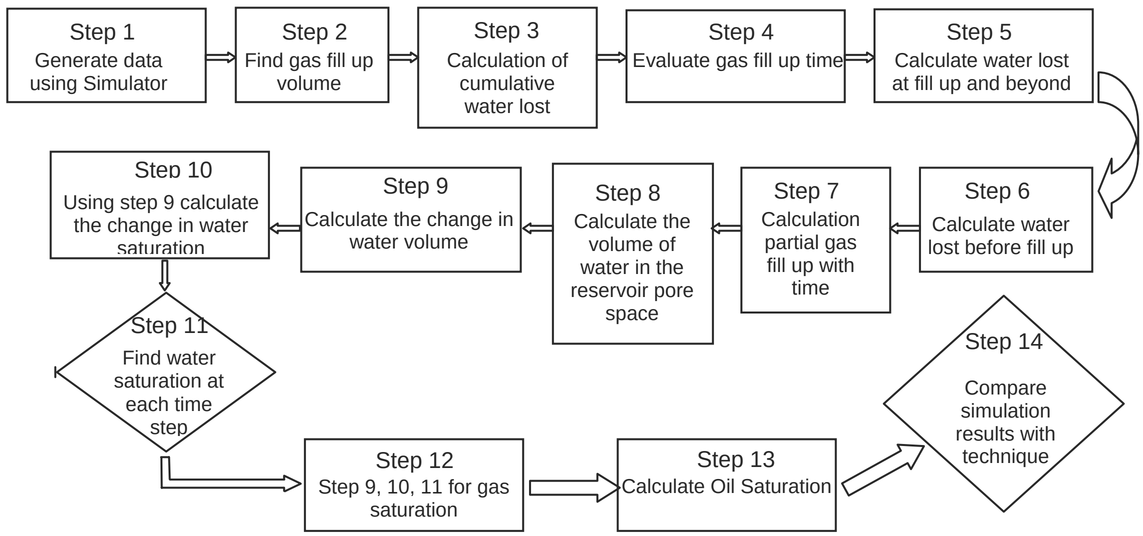
APPENDIX A

Calculation Procedure Flowchart



APPENDIX B

Simulator Input Data File for Case 1

```
-- Case1

-- Area of the pattern is 40 acres. Quarter of 5-spot represents 10 acres.
-- Grid dimensions are 660 ft  by 660 ft by 200 ft
-- Grid represents a 20x20x10 Cartesian model of a quarter of a 40 acre 5-spot

RUNSPEC

-- Specifies the dimensions of the grid: 20x20x10
DIMENS
20    20    10  /


-- Specifies phases present: oil, water, gas and dissolved gas
OIL

WATER

GAS

DISGAS

-- Field units to be used
FIELD

-- Specifies dimensions of saturation and PVT tables
TABDIMS
1    1   30    30    1   30 /

-- Specifies maximum number of well and groups of wells
WELLDIMS
2    50    2    5 /

-- Specifies start of simulation
START
1 'JAN' 1983  /



-- Specifies the size of the stack for Newton iterations
```

```
NSTACK
50 /


GRID
=================================================================

-- Specifies the length of the cell in the X direction
DY
4000*33 /

-- Specifies the length of the cell in the Y direction
DX
4000*33 /

-- Specifies the length of the cell in the Z direction
DZ
4000*20 /

-- Specifies absolute permeability in the X direction: 430 mD


BOX

2 19 1 20 1 10 /
PERMX
3600*430


/

BOX

20 20 1 20 1 10 /
PERMX
200*215

/




BOX
```

```
1 1 1 20 1 10 /
PERMX
200*215

/

ENDBOX


BOX

1 20 2 19 1 10 /
PERMY
3600*430

/

BOX
1 20 20 20 1 10 /
PERMY
200*215

/

BOX

1 20 1 1 1 10 /
PERMY
200*215

/

ENDBOX


-- Specifies absolute permeability in the Z direction

BOX

2 19 2 19 1 10 /
PERMZ
3240*43
/
```

```
BOX

1 1 20 20 1 10 /
PERMZ
10*10.75
/
BOX

1 1 1 1 1 10 /
PERMZ
10*10.75
/

BOX

20 20 20 20 1 10 /
PERMZ
10*10.75
/

BOX

20 20 1 1 1 10 /
PERMZ
10*10.75
/

BOX

2 19 20 20 1 10 /
PERMZ
180*21.5
/

BOX

2 19 1 1 1 10 /
PERMZ
180*21.5
/

BOX
```

```
1 1 2 19 1 10 /
PERMZ
180*21.5
/

BOX

20 20 2 19 1 10 /
PERMZ
180*21.5
/

ENDBOX


BOX

2 19 2 19 1 10 /
PORO
3240*0.28
/


BOX

1 1 20 20 1 10 /
PORO
10*0.07
/

BOX

1 1 1 1 1 10 /
PORO
10*0.07
/

BOX

20 20 20 20 1 10 /
PORO
10*0.07
/
```

```
BOX

20 20 1 1 1 10 /
PORO
10*0.07
/

BOX

2 19 20 20 1 10 /
PORO
180*0.14
/

BOX

2 19 1 1 1 10 /
PORO
180*0.14
/

BOX

1 1 2 19 1 10 /
PORO
180*0.14
/

BOX

20 20 2 19 1 10 /
PORO
180*0.14
/

ENDBOX
-- Specifies the depth of the top cells: 8000 ft
TOPS
400*8000.0
/

-- Specifies porosity: 28%
```

```
-- Specifies what is to be written in the GRID output file
RPTGRID
1 1 1 1 1 0 0 0 /

-- DEBUG
--  0 0 1 0 1 0 1  /

-- Allows for creating a GRID output file
GRIDFILE
2 1 /

-- Allows for creating an INIT output file
INIT



PROPS
=============================================================

-- Specifies water saturation tables: Water saturation, Water relative permeability, Oil
relative permeability
-- and Oil-Water capillary pressure

SWOF

-- Sw     krw           kro              Pcow

0.20    0.000000       0.900000        0
0.25    0.000364       0.709187        0
0.30    0.002536       0.544963        0
0.35    0.007892       0.405962        0
0.40    0.017660       0.290741        0
0.45    0.032987       0.197760        0
0.50    0.054960       0.125368        0
0.55    0.084625       0.071765        0
0.60    0.122991       0.034959        0
0.65    0.171041       0.012686        0
0.70    0.229732       0.002243        0
0.75    0.300000       0.000000        0

/
```

```
-- Specifies gas saturation tables: Gas saturation, Gas relative permeability, Oil relative
permeability when only
-- gas and connate water are present and Oil-gas capillary pressure

SGOF

-- Sg    krg         kro         Pcog
0.00   0.000000    0.900000     0
0.05   0.004389    0.724054     0
0.10   0.016608    0.570544     0
0.15   0.036175    0.438425     0
0.20   0.062847    0.326599     0
0.25   0.096462    0.233902     0
0.30   0.136893    0.159099     0
0.35   0.184043    0.100859     0
0.40   0.237829    0.057735     0
0.45   0.298179    0.028125     0
0.50   0.365033    0.010206     0
0.55   0.438335    0.001804     0
0.60   0.518036    0.000000     0
0.65   0.604092    0.000000     0
0.70   0.696463    0.000000     0
0.75   0.795110    0.000000     0
0.80   0.900000    0.000000     0
/


-- Specifies PVT properties
PVTW
525  1.06  3.03E-06  .7  0.0 /


-- Specifies PVT properties of the oil: Rs, pressure, Bo and oil viscosity
PVTO

-- Rs     Pressure        Bo     Oil visc
0.001     14.7   1.01     20           /
0.0467     158    1.034 18.5800        /
0.09       288    1.08  15.6800        /
0.154      525    1.199 14.3200        /
0.223      750    1.239 13.3200        /
0.29      1025    1.277 12.5200        /
0.356     1250    1.313 11.9000        /
0.424     1500    1.353 11.3200        /
```

```
0.493     1750    1.391 10.8100          /
0.568     2000    1.432 10.3500          /
0.648     2250    1.477  9.9700          /
0.735     2500    1.526  9.5500          /
0.768     2600    1.545  9.4200
          2700    1.54   9.4945
          2800    1.535  9.5585
          2900    1.532  9.6225
          3000    1.526  9.7100
          3100    1.524  9.7505
          3500    1.511 10.000
          4000    1.496 10.3200
          4500    1.483 10.6500
          5000    1.477 10.9700          /
/


-- Specifies PVT properties of gas: Pressure, Bg and gasvisc
PVDG

-- Pressure  Bg (RB/MSCF) Gas visc, cP
178    18.69991095  0.0118
288    11.72751558  0.0119
525    6.747996438  0.0137
750    4.464826358  0.0145
1025   3.317898486  0.0153
1250   2.632235085  0.0158
1500   2.181656278  0.0168
1750   1.857524488  0.0176
2000   1.620658949  0.0184
2250   1.442564559  0.0193
2500   1.296527159  0.0203
/

-- Specifies surface densities: Oil API: 34.2; Water spec. gravity: 1.07; Gas spec.
gravity: 0.7

GRAVITY
34.2  1.07  0.7  /

-- Specifies rock compressibility

ROCK
525.0  5.0E-06 /
```

```
REGIONS
==============================================================

-- Specifies the number of saturation regions (only one for this case)
SATNUM
4000*1 /


SOLUTION
==============================================================

-- Specifies initial equilibration conditions. Datum depth = 8000 ft; Reference pressure at
datum = 525 psia
EQUIL
--DATUM  PR
8000  525  15000  0   0   0   1   0   0  /

-- Specifies Rs versus depth tables. At initial conditions, Rsi = .154 throughout the whole
reservoir depth interval
RSVD
-- Depth  Rsi
8000  .154
8200  .154
/

-- Specifies parameters to be written in the SOLUTION section of the RESTART file:
pressure, water saturation
-- gas saturation and oil saturation

RPTSOL
PRESSURE  SWAT  SGAS SOIL FIP RPORV /

-- Specifies that RESTART files are to written every time step
RPTRST
SWAT SOIL
BASIC=2 /


SUMMARY
============================================================
```

-- Specifies that a SUMMARY file with neat tables is to be written in text format
RUNSUM

-- Specifies that the SUMMARY file is to be created as a separate file in addition from the text file with neat tables
SEPARATE

-- Specifies that reports are to be written only at the timesteps specified in the DATA file. Avoids reports to
-- be created at chopped timesteps (to avoid excessive data and clutter).
RPTONLY

-- Specifies that a group of parameters specific to ECLIPSE are going to be written in the SUMMARY files.
-- ALL

FOPR

FWPR

FOPT

FWPT

FPR

FOSAT

FGSAT

FWSAT

FGPR

FWIT

FWIR

FVIR

FVIT

FRS

```
FGOR

FGPT

WPI1
/


-- EXCEL

-- Specifies that the Field Liquid Production Rate has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FLPR

-- Specifies that the Field Liquid Production Total has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FLPT

-- Specifies that the Field Volume Production Rate (reservoir voidage) has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FVPR

-- Specifies that the Field Volume Production Total (reservoir voidage) has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FVPT



SCHEDULE
=====================================================

-- Specifies what is to written to the SCHEDULE file
RPTSCHED                              FIELD   16:55 18 APR 86
  1  0  1  0  0  0  2  0  0  0  0  2  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  /
```

```
-- Define well specifications:
WELSPECS
'P'  'G'    1   1  8100  'OIL'  /
-- 'I'  'G'    50  1  8100  'WAT'  /
/

-- Specifies completion data
-- Well name: I for injector and P for producer;
-- I location of the well completion: 1-11 for injector and 1-11 for producer;
-- J location of the well completion: 31 for injector and 1 for producer;
-- K location for the top limit of the completion interval: 2 for both wells
-- K location for the bottom limit of the completion interval: 2 for both wells
-- This means that the wells are completed from layer 1 to layer 2

COMPDAT
'P'    1       1   1   10 'OPEN'   1  0   .27 3* X /
/

-- Specifies well controls for the producer
-- Name of the well: P
-- Status of the well: open to production
-- Well control mode: reservoir voidage rate


WCONPROD
'P' 'OPEN' 'RESV' 4* 3000  100/
/

-- Specifies well controls for the injector
-- Name of the well: I
-- Status of the well: open to injection
-- Well control mode: reservoir injection rate



WECON
P  0  0  .8 /
/

-- Specifies the number and length of the timesteps required:

TSTEP
```

```
3*365
/

WCONPROD
'P' 'OPEN' 'RESV' 4* 100  100/
/

WELSPECS
'I'  'G'    20  20  8100  'WAT'  /
/


COMPDAT
'I'    20    20   1   10 'OPEN'   1  0   .27 3* X /
/



WCONINJE
'I' 'WAT' OPEN RESV 1* 100 500/
/

TSTEP
10*365
/


END
```

Simulator Input Data File for Case 2

```
-- Case2

-- Area of the pattern is 40 acres. Quarter of 5-spot represents 10 acres.
-- Grid dimensions are 660 ft  by 660 ft by 200 ft
-- Grid represents a 20x20x10 Cartesian model of a quarter of a 40 acre 5-spot

RUNSPEC


-- Specifies the dimensions of the grid: 20x20x10
DIMENS
20    20    10  /



-- Specifies phases present: oil, water, gas and dissolved gas
OIL

WATER

GAS

DISGAS

-- Field units to be used
FIELD


-- Specifies dimensions of saturation and PVT tables
TABDIMS
1    1   30    30    1   30 /

-- Specifies maximum number of well and groups of wells
WELLDIMS
2    50    2    5 /

-- Specifies start of simulation
START
1 'JAN' 1983  /
```

```
-- Specifies the size of the stack for Newton iterations
NSTACK
50 /



GRID
==============================================================

-- Specifies the length of the cell in the X direction
DY
4000*33 /

-- Specifies the length of the cell in the Y direction
DX
4000*33 /



-- Specifies the length of the cell in the Z direction
DZ
4000*20 /

-- Specifies absolute permeability in the X direction: 430 mD
BOX

BOX

2 19 1 20 1 10 /
PERMX
3600*430


/

BOX

20 20 1 20 1 10 /
PERMX
200*215

/
```

```
BOX

1 1 1 20 1 10 /
PERMX
200*215

/

ENDBOX


BOX

1 20 2 19 1 10 /
PERMY
3600*430

/

BOX
1 20 20 20 1 10 /
PERMY
200*215

/

BOX

1 20 1 1 1 10 /
PERMY
200*215

/

ENDBOX


-- Specifies absolute permeability in the Z direction

BOX

2 19 2 19 1 10 /
PERMZ
3240*43
```

```
/

BOX

1 1 20 20 1 10 /
PERMZ
10*10.75
/
BOX

1 1 1 1 1 10 /
PERMZ
10*10.75
/

BOX

20 20 20 20 1 10 /
PERMZ
10*10.75
/

BOX

20 20 1 1 1 10 /
PERMZ
10*10.75
/

BOX

2 19 20 20 1 10 /
PERMZ
180*21.5
/

BOX

2 19 1 1 1 10 /
PERMZ
180*21.5
/
```

```
BOX

1 1 2 19 1 10 /
PERMZ
180*21.5
/

BOX

20 20 2 19 1 10 /
PERMZ
180*21.5
/

ENDBOX


BOX

2 19 2 19 1 10 /
PORO
3240*0.28
/


BOX

1 1 20 20 1 10 /
PORO
10*0.07
/

BOX

1 1 1 1 1 10 /
PORO
10*0.07
/

BOX

20 20 20 20 1 10 /
PORO
10*0.07
```

```
/

BOX

20 20 1 1 1 10 /
PORO
10*0.07
/

BOX

2 19 20 20 1 10 /
PORO
180*0.14
/

BOX

2 19 1 1 1 10 /
PORO
180*0.14
/

BOX

1 1 2 19 1 10 /
PORO
180*0.14
/

BOX

20 20 2 19 1 10 /
PORO
180*0.14
/

ENDBOX

-- Specifies the depth of the top cells: 8000 ft
TOPS
400*8000.0
/
```

```
-- Specifies porosity: 28%


-- Specifies what is to be written in the GRID output file
RPTGRID
1 1 1 1 1 0 0 0 /

-- DEBUG
--  0 0 1 0 1 0 1  /

-- Allows for creating a GRID output file
GRIDFILE
2 1 /

-- Allows for creating an INIT output file
INIT

PROPS
===============================================================

-- Specifies water saturation tables: Water saturation, Water relative permeability, Oil relative permeability
-- and Oil-Water capillary pressure

SWOF

-- Sw     krw          kro           Pcow

0.20    0.000000     0.900000     0
0.25    0.000364     0.709187     0
0.30    0.002536     0.544963     0
0.35    0.007892     0.405962     0
0.40    0.017660     0.290741     0
0.45    0.032987     0.197760     0
0.50    0.054960     0.125368     0
0.55    0.084625     0.071765     0
0.60    0.122991     0.034959     0
0.65    0.171041     0.012686     0
0.70    0.229732     0.002243     0
0.75    0.300000     0.000000     0
/
```

-- Specifies gas saturation tables: Gas saturation, Gas relative permeability, Oil relative permeability when only
-- gas and connate water are present and Oil-gas capillary pressure

```
SGOF

-- Sg     krg          kro           Pcog
0.00    0.000000     0.900000       0
0.05    0.004389     0.724054       0
0.10    0.016608     0.570544       0
0.15    0.036175     0.438425       0
0.20    0.062847     0.326599       0
0.25    0.096462     0.233902       0
0.30    0.136893     0.159099       0
0.35    0.184043     0.100859       0
0.40    0.237829     0.057735       0
0.45    0.298179     0.028125       0
0.50    0.365033     0.010206       0
0.55    0.438335     0.001804       0
0.60    0.518036     0.000000       0
0.65    0.604092     0.000000       0
0.70    0.696463     0.000000       0
0.75    0.795110     0.000000       0
0.80    0.900000     0.000000       0
/
```

-- Specifies PVT properties of water: Bw = 1.063; Cw = 3.03E-06; watervisc = .7

```
PVTW
1025  1.06  3.03E-06  .7  0.0 /
```

-- Specifies PVT properties of the oil: Rs, pressure, Bo and oilvisc

```
PVTO

-- Rs     Pressure        Bo     Oil visc

0.0467    178    1.119 18.5800       /
0.09      288    1.153 15.6800       /
0.154     525    1.199 14.3200       /
0.223     750    1.239 13.3200       /
0.29     1025    1.277 12.5200       /
0.356    1250    1.313 11.9000       /
0.424    1500    1.353 11.3200       /
```

```
0.493     1750    1.391 10.8100          /
0.568     2000    1.432 10.3500          /
0.648     2250    1.477  9.9700          /
0.735     2500    1.526  9.5500          /
0.768     2600    1.545  9.4200
          2700    1.54   9.4945
          2800    1.535  9.5585
          2900    1.532  9.6225
          3000    1.526  9.7100
          3100    1.524  9.7505
          3500    1.511 10.000
          4000    1.496 10.3200
          4500    1.483 10.6500
          5000    1.477 10.9700          /
   /


-- Specifies PVT properties of gas: Pressure, Bg and gasvisc
PVDG

-- Pressure  Bg (RB/MSCF) Gas visc, cP
178    18.69991095  0.0118
288    11.72751558  0.0119
525    6.747996438  0.0137
750    4.464826358  0.0145
1025   3.317898486  0.0153
1250   2.632235085  0.0158
1500   2.181656278  0.0168
1750   1.857524488  0.0176
2000   1.620658949  0.0184
2250   1.442564559  0.0193
2500   1.296527159  0.0203

/

-- Specifies surface densities: Oil API: 34.2; Water spec. gravity: 1.07; Gas spec.
gravity: 0.7

GRAVITY
34.2  1.07  0.7  /

-- Specifies rock compressibility: 5.0E-06 psi -1 @ 1025 psia
ROCK
1025.0  5.0E-06 /
```

REGIONS
==

-- Specifies the number of saturation regions (only one for this case)
SATNUM
4000*1 /

SOLUTION
==

-- Specifies initial equilibration conditions. Datum depth = 8000 ft; Reference pressure at datum = 1025 psia

EQUIL
--DATUM PR
8000 1025 15000 0   0   0   1   0   0 /

-- Specifies Rs versus depth tables. At initial conditions, Rsi = .29 throughout the whole reservoir depth interval
RSVD

-- Depth Rsi
8000 .29
8200 .29
/

-- Specifies parameters to be written in the SOLUTION section of the RESTART file: pressure, water saturation
-- gas saturation and oil saturation
RPTSOL
PRESSURE SWAT SGAS SOIL FIP RPORV /

-- Specifies that RESTART files are to written every time step
RPTRST
SWAT SOIL
BASIC=2 /

SUMMARY
==

-- Specifies that a SUMMARY file with neat tables is to be written in text format
RUNSUM

-- Specifies that the SUMMARY file is to be created as a separate file in addition from the text file with neat tables
SEPARATE

-- Specifies that reports are to be written only at the timesteps specified in the DATA file. Avoids reports to
-- be created at chopped timesteps (to avoid excessive data and clutter).
RPTONLY

-- Specifies that a group of parameters specific to ECLIPSE are going to be written in the SUMMARY files.
-- ALL

FOPR

FWPR

FOPT

FWPT

FPR

FRS

FOSAT

FGSAT

FWSAT

FGPR

FGPT

FWIT

FWIR

FVIR

FVIT

FGOR

WPI1
/

-- EXCEL

-- Specifies that the Field Liquid Production Rate has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FLPR

-- Specifies that the Field Liquid Production Total has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FLPT

-- Specifies that the Field Volume Production Rate (reservoir voidage) has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FVPR

-- Specifies that the Field Volume Production Total (reservoir voidage) has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FVPT

SCHEDULE
==

-- Specifies what is to written to the SCHEDULE file

```
RPTSCHED                              FIELD   16:55 18 APR 86
  1  0  1  0  0  0  2  0  0  0  0  2  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  /


-- Define well specifications:
WELSPECS
'P'  'G'    1   1  8100  'OIL'  /
-- 'I'  'G'    50  1  8100  'WAT'  /
/

-- Specifies completion data
-- Well name: I for injector and P for producer;
-- I location of the well completion: 1-11 for injector and 1-11 for producer;
-- J location of the well completion: 31 for injector and 1 for producer;
-- K location for the top limit of the completion interval: 2 for both wells
-- K location for the bottom limit of the completion interval: 2 for both wells
-- This means that the wells are completed from layer 1 to layer 2
-- The final record specifies well radius: 0.27 ft for both wells

COMPDAT
'P'    1       1   1   10 'OPEN'   1  0   .27 3* X /


/

-- Specifies well controls for the producer
-- Name of the well: P
-- Status of the well: open to production

ls

WCONPROD
'P' 'OPEN' 'RESV' 4* 500  100/
/

-- Specifies well controls for the injector
-- Name of the well: I
-- Status of the well: open to injection
-- Well control mode: reservoir injection rate
```

```
WECON
P  0  0  .8 /
/

-- Specifies the number and length of the timesteps required

TSTEP
1*365
/
TSTEP
1*365
/
TSTEP
1*365
/


WELSPECS
'I'  'G'    20  20  8100  'WAT'  /
/


COMPDAT
'I'    20    20   1   10 'OPEN'   1  0   .27 3* X /
/


WCONINJE
'I' 'WAT' OPEN RESV 1* 500 5000/
/

TSTEP
10*365
/


END
```

Simulator Input Data File for Case 3

```
-- Case 3

-- Area of the pattern is 80 acres. Quarter of 5-spot represents 20 acres.
-- Grid dimensions are 1353 ft  by 660 ft by 200 ft
-- Grid represents a 41x20x10 Cartesian model of a quarter of an 80 acre 5-spot

RUNSPEC


-- Specifies the dimensions of the grid: 41x20x10
DIMENS
41    20    10  /



-- Specifies phases present: oil, water, gas and dissolved gas
OIL

WATER

GAS

DISGAS

-- Field units to be used
FIELD


-- Specifies dimensions of saturation and PVT tables
TABDIMS
2    1   30    30    2   30 /

-- Specifies maximum number of well and groups of wells
WELLDIMS
3    50    3
    5 /

-- Specifies start of simulation
START
1 'JAN' 1983  /
```

```
-- Specifies the size of the stack for Newton iterations
NSTACK
50 /



GRID
==============================================================

-- Specifies the length of the cell in the X direction:
DY
8200*33 /

-- Specifies the length of the cell in the Y direction

DX

8200*32.19512 /


-- Specifies the length of the cell in the Z direction:
DZ
8200*20 /

-- Specifies absolute permeability in the X direction: 430 mD
BOX

2 40 1 20 1 10 /
PERMX
7800*430


/

BOX

41 41 1 20 1 10 /
PERMX
200*215

/
```

```
BOX

1 1 1 20 1 10 /
PERMX
200*215

/

ENDBOX


BOX

1 41 2 19 1 10 /
PERMY
7380*430

/

BOX
1 41 20 20 1 10 /
PERMY
410*215

/

BOX

1 41 1 1 1 10 /
PERMY
410*215

/

ENDBOX


-- Specifies absolute permeability in the Z direction

BOX

2 40 2 19 1 10 /
PERMZ
7020*43
```

```
/

BOX

1 1 20 20 1 10 /
PERMZ
10*10.75
/
BOX

1 1 1 1 1 10 /
PERMZ
10*10.75
/

BOX

41 41 20 20 1 10 /
PERMZ
10*10.75
/

BOX

41 41 1 1 1 10 /
PERMZ
10*10.75
/

BOX

2 40 20 20 1 10 /
PERMZ
390*21.5
/

BOX

2 40 1 1 1 10 /
PERMZ
390*21.5
/
```

```
BOX

1 1 2 19 1 10 /
PERMZ
180*21.5
/

BOX

41 41 2 19 1 10 /
PERMZ
180*21.5
/

ENDBOX


BOX

2 40 2 19 1 10 /
PORO
7020*0.28
/


BOX

1 1 20 20 1 10 /
PORO
10*0.07
/

BOX

1 1 1 1 1 10 /
PORO
10*0.07
/

BOX

41 41 20 20 1 10 /
PORO
10*0.07
```

```
/

BOX

41 41 1 1 1 10 /
PORO
10*0.07
/

BOX

2 40 20 20 1 10 /
PORO
390*0.14
/

BOX

2 40 1 1 1 10 /
PORO
390*0.14
/

BOX

1 1 2 19 1 10 /
PORO
180*0.14
/

BOX

41 41 2 19 1 10 /
PORO
180*0.14
/


ENDBOX

-- Specifies the depth of the top cells: 8000 ft
TOPS
820*8000.0
/
```

-- Specifies porosity: 28%

-- Specifies what is to be written in the GRID output file
RPTGRID
1 1 1 1 1 0 0 0 /

-- DEBUG
-- 0 0 1 0 1 0 1 /

-- Allows for creating a GRID output file
GRIDFILE
2 1 /

-- Allows for creating an INIT output file
INIT

PROPS
===

-- Specifies water saturation tables: Water saturation, Water relative permeability, Oil relative permeability
-- and Oil-Water capillary pressure

SWOF

```
-- Sw     krw           kro           Pcow

0.20    0.000000    0.900000    0
0.25    0.000364    0.709187    0
0.30    0.002536    0.544963    0
0.35    0.007892    0.405962    0
0.40    0.017660    0.290741    0
0.45    0.032987    0.197760    0
0.50    0.054960    0.125368    0
0.55    0.084625    0.071765    0
0.60    0.122991    0.034959    0
0.65    0.171041    0.012686    0
0.70    0.229732    0.002243    0
0.75    0.300000    0.000000    0       / table 1
```

```
-- Sw     krw         kro          Pcow

0.20    0.000000      0.900000      0
0.25    0.000364      0.709187      0
0.30    0.002536      0.544963      0
0.35    0.007892      0.405962      0
0.40    0.017660      0.290741      0
0.45    0.032987      0.197760      0
0.50    0.054960      0.125368      0
0.55    0.084625      0.071765      0
0.60    0.122991      0.034959      0
0.65    0.171041      0.012686      0
0.70    0.229732      0.002243      0
0.75    0.300000      0.000000      0        / table 2


-- Specifies gas saturation tables: Gas saturation, Gas relative permeability, Oil relative permeability when only
-- gas and connate water are present and Oil-gas capillary pressure

SGOF

-- Sg     krg         kro          Pcog
0.00    0.000000      0.900000      0
0.05    0.004389      0.724054      0
0.10    0.016608      0.570544      0
0.15    0.036175      0.438425      0
0.20    0.062847      0.326599      0
0.25    0.096462      0.233902      0
0.30    0.136893      0.159099      0
0.35    0.184043      0.100859      0
0.40    0.237829      0.057735      0
0.45    0.298179      0.028125      0
0.50    0.365033      0.010206      0
0.55    0.438335      0.001804      0
0.60    0.518036      0.000000      0
0.65    0.604092      0.000000      0
0.70    0.696463      0.000000      0
0.75    0.795110      0.000000      0
0.80    0.900000      0.000000      0        / table 1

-- Sg     krg         kro          Pcog
0.00    0.000000      0.900000      0
0.05    0.004389      0.724054      0
```

```
0.10    0.016608    0.570544    0
0.15    0.036175    0.438425    0
0.20    0.062847    0.326599    0
0.25    0.096462    0.233902    0
0.30    0.136893    0.159099    0
0.35    0.184043    0.100859    0
0.40    0.237829    0.057735    0
0.45    0.298179    0.028125    0
0.50    0.365033    0.010206    0
0.55    0.438335    0.001804    0
0.60    0.518036    0.000000    0
0.65    0.604092    0.000000    0
0.70    0.696463    0.000000    0
0.75    0.795110    0.000000    0
0.80    0.900000    0.000000    0     / table 2


-- Specifies PVT properties of water: Bw = 1.063; Cw = 3.03E-06; watervisc = .7
PVTW
1280  1.06  3.03E-06  .7  0.0 /


-- Specifies PVT properties of the oil: Rs, pressure, Bo and oilvisc
PVTO

-- Rs     Pressure       Bo     Oil visc

0.0467    178    1.119 18.5800       /
0.09      288    1.153 15.6800 /
0.154     525    1.199 14.3200       /
0.223     750    1.239 13.3200       /
0.29      1025   1.277 12.5200       /
0.356     1250   1.313 11.9000       /
0.424     1500   1.353 11.3200       /
0.493     1750   1.391 10.8100       /
0.568     2000   1.432 10.3500       /
0.648     2250   1.477  9.9700       /
0.735     2500   1.526  9.5500       /
0.768     2600   1.545  9.4200
          2700   1.54   9.4945
          2800   1.535  9.5585
          2900   1.532  9.6225
          3000   1.526  9.7100
          3100   1.524  9.7505
```

```
              3500    1.511 10.000
              4000    1.496 10.3200
              4500    1.483 10.6500
              5000    1.477 10.9700          /
/


-- Specifies PVT properties of gas: Pressure, Bg and gasvisc
PVDG

-- Pressure  Bg (RB/MSCF) Gas visc, cP
178    18.69991095  0.0118
288    11.72751558  0.0119
525    6.747996438  0.0137
750    4.464826358  0.0145
1025   3.317898486  0.0153
1250   2.632235085  0.0158
1500   2.181656278  0.0168
1750   1.857524488  0.0176
2000   1.620658949  0.0184
2250   1.442564559  0.0193
2500   1.296527159  0.0203

/

-- Specifies surface densities: Oil API: 34.2; Water spec. gravity: 1.07; Gas spec.
gravity: 0.7
GRAVITY
34.2  1.07  0.7  /

-- Specifies rock compressibility: 5.0E-06 psi -1 @ 1280 psia
ROCK
1280.0  5.0E-06 /



REGIONS
============================================================

-- Specifies the number of saturation regions (only one for this case)


INCLUDE
Regions.dat/
```

SOLUTION
==

-- Specifies initial equilibration conditions. Datum depth = 8000 ft; Reference pressure at datum = 1280 psia

```
EQUIL
--DATUM  PR
8000  1280  15000  0   0   0   1   0   0  /
```

-- Specifies Rs versus depth tables. At initial conditions, Rsi = .357 throughout the whole reservoir depth interval

```
RSVD
-- Depth  Rsi
8000  .357
8200  .357
/
```

-- Specifies parameters to be written in the SOLUTION section of the RESTART file: pressure, water saturation

```
-- gas saturation and oil saturation
RPTSOL
PRESSURE  SWAT  SGAS SOIL FIP RPORV /
```

-- Specifies that RESTART files are to written every time step

```
RPTRST
SWAT SOIL
BASIC=2 /
```

SUMMARY
==

-- Specifies that a SUMMARY file with neat tables is to be written in text format

```
RUNSUM
```

-- Specifies that the SUMMARY file is to be created as a separate file in addition from the text file with neat tables

```
SEPARATE
```

-- Specifies that reports are to be written only at the timesteps specified in the DATA file. Avoids reports to
-- be created at chopped timesteps (to avoid excessive data and clutter).
RPTONLY

-- Specifies that a group of parameters specific to ECLIPSE are going to be written in the SUMMARY files.
-- ALL

FOPR

FWPR

FOPT

FWPT

FPR

FOSAT

FGSAT

FWSAT

FGPR

FWIT

FWIR

FVIR

FVIT

FOIP

FWIP

FLIP

FGIP

FGPT

ROSAT
/
RWSAT
/
RGSAT
/
RGIP
/
ROIP
/
RWIP
/
ROPR
/
ROPT
/
RWPR
/
RWPT
/
RWIR
/
RWIT
/

WPI1
/
WOPR
/
WOPT
/

-- EXCEL

-- Specifies that the Field Liquid Production Rate has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FLPR

-- Specifies that the Field Liquid Production Total has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FLPT

-- Specifies that the Field Volume Production Rate (reservoir voidage) has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FVPR

-- Specifies that the Field Volume Production Total (reservoir voidage) has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FVPT

```
SCHEDULE
=====================================================

-- Specifies what is to written to the SCHEDULE file
RPTSCHED                              FIELD   16:55 18 APR 86
  1  0  1  0  0  0  2  0  0  0  0  2  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  /


-- Define well specifications:
WELSPECS
'P1'  'G'    1   20  8100  'OIL'  /
'P2'  'G'    41   20  8100  'OIL'  /
-- 'I'  'G'    50  1  8100  'WAT'  /
/

-- Specifies completion data
-- Well name: I for injector and P for producer;
-- I location of the well completion: 1-11 for injector and 1-11 for producer;
-- J location of the well completion: 31 for injector and 1 for producer;
```

```
-- K location for the top limit of the completion interval: 2 for both wells
-- K location for the bottom limit of the completion interval: 2 for both wells
-- This means that the wells are completed from layer 1 to layer 2
-- The final record specifies well radius: 0.27 ft for both wells

COMPDAT
'P1'   1      20   1   10 'OPEN'   1  0   .27 3* X /
'P2'   41      20   1   10 'OPEN'   1  0   .27 3* X /

/

-- Specifies well controls for the producer
-- Name of the well: P
-- Status of the well: open to production
-- Well control mode: reservoir voidage rate


WCONPROD
'P1' 'OPEN' 'RESV' 4* 700  100/
'P2' 'OPEN' 'RESV' 4* 300  100/
/

-- Specifies well controls for the injector
-- Name of the well: I
-- Status of the well: open to injection
-- Well control mode: reservoir injection rate



WECON
P1  0  0  .8 /
P2  0  0  .8 /
/

-- Specifies the number and length of the timesteps required
TSTEP
1*365
/
TSTEP
1*365
/
TSTEP
1*365
/
```

```
WELSPECS
'I'  'G'    21  1  8100  'WAT'  /
/


COMPDAT
'I'    21    1   1   10 'OPEN'   1  0   .27 3* X /
/



WCONINJE
'I' 'WAT' OPEN RESV 1* 1000 5000/
/

TSTEP
10*365
/



END
```

Simulator Input Data File for Case 4

```
-- EXAMPLE

-- Area of the pattern is 40 acres. Quarter of 5-spot represents 10 acres.
-- Grid dimensions are 660 ft by 660 ft by 200 ft
-- Grid represents a 20x20x10 Cartesian model of a quarter of a 40 acre 5-spot

RUNSPEC


-- Specifies the dimensions of the grid: 20x20x10
DIMENS
20    20    10  /



-- Specifies phases present: oil, water, gas and dissolved gas
OIL

WATER

GAS

DISGAS

-- Field units to be used
FIELD


-- Specifies dimensions of saturation and PVT tables
TABDIMS
1    1   30    30    1   30 /

-- Specifies maximum number of well and groups of wells
WELLDIMS
2    50    2    5 /

-- Specifies start of simulation
START
1 'JAN' 1983  /

-- Specifies the size of the stack for Newton iterations
```

```
NSTACK
50 /



GRID
==========================================================

-- Specifies the length of the cell in the X direction: 33 ft
DY
4000*33 /

-- Specifies the length of the cell in the Y direction (DY varies)
DX
4000*33 /



-- Specifies the length of the cell in the Z direction: 20 ft
DZ
4000*20 /

-- Specifies absolute permeability in the X direction: 430 mD and 215 in boundary cells
PERMX
400*1.0 400*10.0 400*50 400*100 400*150 400*200 400*250 400*300 400*350
400*400
/

PERMY
400*1.0 400*10.0 400*50 400*100 400*150 400*200 400*250 400*300 400*350
400*400
/

-- Specifies absolute permeability in the Z direction: 30 mD and 215 in boundary cells

PERMZ
400*0.1 400*1.0 400*5 400*10 400*15 400*20 400*25 400*30 400*35 400*40
/

BOX

2 19 2 19 1 10 /
PORO
3240*0.28
```

```
/

BOX

1 1 20 20 1 10 /
PORO
10*0.07
/

BOX

1 1 1 1 1 10 /
PORO
10*0.07
/

BOX

20 20 20 20 1 10 /
PORO
10*0.07
/

BOX

20 20 1 1 1 10 /
PORO
10*0.07
/

BOX

2 19 20 20 1 10 /
PORO
180*0.14
/

BOX

2 19 1 1 1 10 /
PORO
180*0.14
/
```

```
BOX

1 1 2 19 1 10 /
PORO
180*0.14
/

BOX

20 20 2 19 1 10 /
PORO
180*0.14
/

ENDBOX


-- Specifies the depth of the top cells: 8000 ft
TOPS
400*8000.0
/

-- Specifies porosity: 28%


-- Specifies what is to be written in the GRID output file
RPTGRID
1 1 1 1 1 0 0 0 /

-- DEBUG
--  0 0 1 0 1 0 1  /

-- Allows for creating a GRID output file
GRIDFILE
2 1 /

-- Allows for creating an INIT output file
INIT



PROPS
==============================================================
```

```
-- Specifies water saturation tables: Water saturation, Water relative permeability, Oil relative permeability
-- and Oil-Water capillary pressure

SWOF

-- Sw    krw         kro          Pcow

0.20   0.000000    0.900000    0
0.25   0.000364    0.709187    0
0.30   0.002536    0.544963    0
0.35   0.007892    0.405962    0
0.40   0.017660    0.290741    0
0.45   0.032987    0.197760    0
0.50   0.054960    0.125368    0
0.55   0.084625    0.071765    0
0.60   0.122991    0.034959    0
0.65   0.171041    0.012686    0
0.70   0.229732    0.002243    0
0.75   0.300000    0.000000    0

/


-- Specifies gas saturation tables: Gas saturation, Gas relative permeability, Oil relative permeability when only
-- gas and connate water are present and Oil-gas capillary pressure

SGOF

-- Sg    krg         kro          Pcog
0.00   0.000000    0.900000    0
0.05   0.004389    0.724054    0
0.10   0.016608    0.570544    0
0.15   0.036175    0.438425    0
0.20   0.062847    0.326599    0
0.25   0.096462    0.233902    0
0.30   0.136893    0.159099    0
0.35   0.184043    0.100859    0
0.40   0.237829    0.057735    0
0.45   0.298179    0.028125    0
0.50   0.365033    0.010206    0
0.55   0.438335    0.001804    0
```

```
0.60    0.518036        0.000000        0
0.65    0.604092        0.000000        0
0.70    0.696463        0.000000        0
0.75    0.795110        0.000000        0
0.80    0.900000        0.000000        0

/


-- Specifies PVT properties of water: Bw = 1.063; Cw = 3.03E-06; watervisc = .7. All
values at 1025 psia and 280 DegF
PVTW
1025  1.06  3.03E-06  0.7  0.0 /


-- Specifies PVT properties of the oil: Rs, pressure, Bo and oilvisc
PVTO

-- Rs     Pressure          Bo      Oil visc

0.0467     178    1.119 18.5800          /
0.09       288    1.153 15.6800 /
0.154      500    1.199 14.3200          /
0.223      750    1.239 13.3200          /
0.29      1025    1.277 12.5200          /
0.356     1250    1.313 11.9000          /
0.424     1500    1.353 11.3200          /
0.493     1750    1.391 10.8100          /
0.568     2000    1.432 10.3500          /
0.648     2250    1.477  9.9700          /
0.735     2500    1.526  9.5500          /
0.768     2600    1.545  9.4200
          2700    1.54   9.4945
          2800    1.535  9.5585
          2900    1.532  9.6225
          3000    1.526  9.7100
          3100    1.524  9.7505
          3500    1.511 10.000
          4000    1.496 10.3200
          4500    1.483 10.6500
          5000    1.477 10.9700          /
/
```

```
-- Specifies PVT properties of gas: Pressure, Bg and gasvisc
PVDG

-- Pressure  Bg (RB/MSCF) Gas visc, cP
178    18.69991095  0.0118
288    11.72751558  0.0119
500    6.747996438  0.0137
750    4.464826358  0.0145
1025   3.317898486  0.0153
1250   2.632235085  0.0158
1500   2.181656278  0.0168
1750   1.857524488  0.0176
2000   1.620658949  0.0184
2250   1.442564559  0.0193
2500   1.296527159  0.0203

/

-- Specifies surface densities: Oil API: 34.2; Water spec. gravity: 1.07; Gas spec.
gravity: 0.97
GRAVITY
34.2  1.07  0.7  /

-- Specifies rock compressibility: 5.0E-06 psi -1 @ 1025 psia
ROCK
1025.0  5.0E-06 /



REGIONS
============================================================

-- Specifies the number of saturation regions (only one for this case)
SATNUM
4000*1 /


SOLUTION
============================================================

-- Specifies initial equilibration conditions. Datum depth = 8060 ft; Reference pressure at
datum = 3480 psia
-- WOC depth = 15000 ft (out of the reservoir means no initial contact present)
-- GOC depth = 0 ft (out of the reservoir means no initial contact present)
```

```
EQUIL
--DATUM  PR
8000  1025  15000  0   0   0   1   0   0  /

-- Specifies Rs versus depth tables. At initial conditions, Rsi = .768 throughout the whole reservoir depth interval
RSVD
-- Depth  Rsi
8000  .290
8200  .30
/

-- Specifies parameters to be written in the SOLUTION section of the RESTART file: pressure, water saturation
-- gas saturation and oil saturation
RPTSOL
PRESSURE  SWAT  SGAS SOIL FIP RPORV /

-- Specifies that RESTART files are to written every timestep
RPTRST
SWAT SOIL
BASIC=2 /


SUMMARY
===========================================================

-- Specifies that a SUMMARY file with neat tables is to be written in text format
RUNSUM

-- Specifies that the SUMMARY file is to be created as a separate file in addition from the text file with neat tables
SEPARATE

-- Specifies that reports are to be written only at the timesteps specified in the DATA file. Avoids reports to
-- be created at chopped timesteps (to avoid excessive data and clutter).
RPTONLY

-- Specifies that a group of parameters specific to ECLIPSE are going to be written in the SUMMARY files.
-- ALL
```

FOPR

FGPT

FRS

FVOPR

FWPR

FOPT

FLPT

FWPT

FWPT

FPR

FOSAT

FGSAT

FWSAT

FGPR

FWIT

FWIR

FVIR
FVIT

WPI1
/

-- EXCEL

-- Specifies that the Field Liquid Production Rate has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FLPR

-- Specifies that the Field Liquid Production Total has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FLPT

-- Specifies that the Field Volume Production Rate (reservoir voidage) has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FVPR

-- Specifies that the Field Volume Prodction Total (reservoir voidage) has to be written in the SUMMARY file.
-- This parameter is not included in the ALL group, therefore it has to be specified separately.
FVPT

```
SCHEDULE
=====================================================

-- Specifies what is to written to the SCHEDULE file
RPTSCHED                    FIELD   16:55 18 APR 86
  1  0  1  0  0  0  2  0  0  0  0  2  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  /


-- Define well specifications:
WELSPECS
'P'  'G'   1   1  8100  'OIL'  /
-- 'I'  'G'   50  1  8100  'WAT'  /
/
```

```
-- Specifies completion data
-- Well name: I for injector and P for producer;
-- I location of the well completion: 1-11 for injector and 1-11 for producer;
-- J location of the well completion: 31 for injector and 1 for producer;
-- K location for the top limit of the completion interval: 2 for both wells
-- K location for the bottom limit of the completion interval: 2 for both wells
-- This means that the wells are completed from layer 1 to layer 2
-- The final record specifies well radius: 0.27 ft for both wells

COMPDAT
'P'    1       1   1   10 'OPEN'   1  0   .27 3* X /


/

-- Specifies well controls for the producer
-- Name of the well: P
-- Status of the well: open to production
-- Well control mode: reservoir voidage rate
-- The final record specifies target for the control parameter: 250 reservoir barrels

WCONPROD
'P' 'OPEN' 'RESV' 4* 500  100/
/

-- Specifies well controls for the injector
-- Name of the well: I
-- Status of the well: open to injection
-- Well control mode: reservoir injecttion rate
-- The final record specifies target for the control parameter: 250 reservoir barrels


WECON
P  0  0  .8 /
/

-- Specifies the number and lenght of the timesteps required: 40 timesteps of 100 days
each

TSTEP
3*365
/
```

```
WELSPECS
'I'  'G'    20  20  8100  'WAT'  /
/


COMPDAT
'I'    20    20   1   10 'OPEN'   1  0   .27 3* X /
/



WCONINJE
'I' 'WAT' OPEN RESV 1* 500 15000/
/

TSTEP
10*365
/



END
```

VITA

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