CHAPTER III

RESERVOIR SIMULATION

A two-dimensional, two-phase, finite difference reservoir simulator was used to generate rate-production data for a solution-gas drive reservoir. The simulator utilized was ECLIPSE which was commercialized by GeoQuest Schlumberger. The simulator has the ability to simulate production and injection from a single or multiple vertical, deviated, or horizontal well.

The data were generated under the following assumptions: (1) the well is located at the center of a rectangular block of reservoir; (2) the well fully penetrates the reservoir in the vertical direction; (3) the reservoir is initially above the bubble point pressure with no free gas; (4) the initial water saturation is only connate water; (5) isothermal reservoir condition exists; (6) there is no reaction between the reservoir rock and reservoir fluids; (7) there is no gas solubility in the water phase, and (8) capillary pressures are negligible.

Eighty-one different reservoir cases covering a wide range of reservoir rock and fluid conditions were simulated to study their performances. Modified isochronal tests were simulated in these simulations. The data from the modified isochronal tests were then used to predict current and future IPR's. Three basic sets of reservoir properties, relative permeability, and reservoir fluid data were studied. Table 3.1 shows the range of reservoir properties used to develop the performance data. Figures 3.1, 3.2, and 3.3 show the relationship of relative permeability and saturation at the minimum, intermediate, and maximum range, respectively.

The model of reservoir is rectangular block which has 1 layer of 150 ft in height. The numbers of grid cells are $25\times25\times1$ in the x, y, and z directions. The size of drainage area equals to 22,500 ft^3 for minimum case, 62,500 ft^3 for intermediate case, and 122,500 ft^3 for maximum case. The depth of top face equals to 6,000 ft.

Table 3.1: Reservoir data properties.

Properties	minimum	intermediate	maximum
Bubble point pressure, psia	1500	2000	2500
Drainage area, ft^2	150×150	250×250	350×350
Residual oil saturation, S_{or} Critical gas saturation, S_{gc}	0.50 0.00	0.40 0.10	0.30 0.20
Permeability, md	50	250	1000
Porosity, %	10	15	20

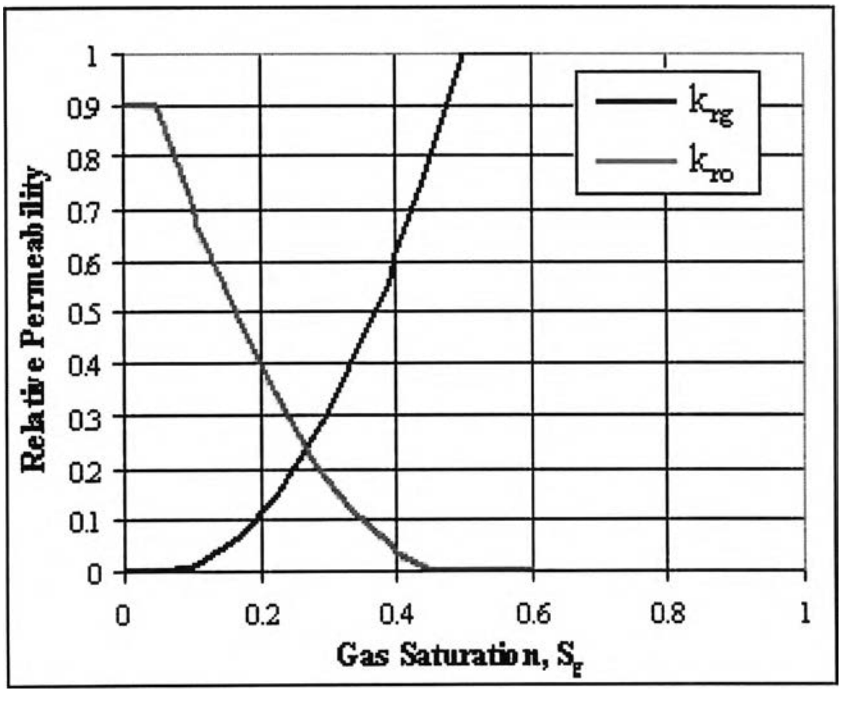

Figure 3.1: Oil and gas relative permeability for minimum case.

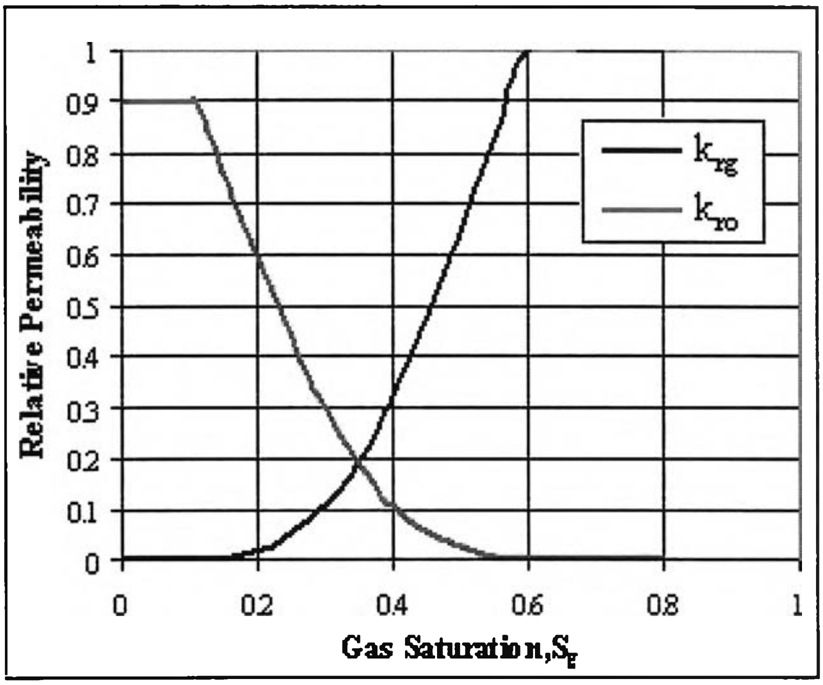

Figure 3.2: Oil and gas relative permeability for intermediate case.

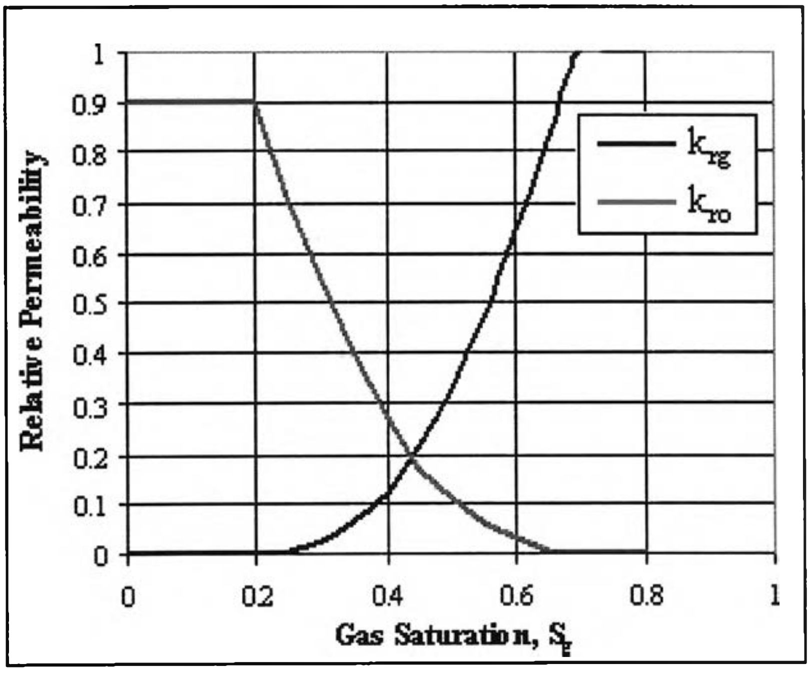

Figure 3.3: Oil and gas relative permeability for maximum case.

Simulator results were obtained for solution-gas drive reservoir at constant liquid production rate of 1000 BPD. For each case, modified-isochronal test was simulated at thirteen depletion stages. The flowing bottom pressure and reservoir pressure were estimated at each stage of depletion until the minimum flowing bottomhole pressure was reached at 250 psia. If the flowing bottomhole pressure did not reach this minimum and modified-isochronal test was not taken at bubble point during the simulation, then the simulation was rerun.

3.1 Properties of fluid

Properties of water: water in the reservoir is initial connate water.

Water formation volume factor	1.02174	rb/stb
Water compressibility	3.0998×10^{-6}	1/psi
Water viscosity	0.301328	cp
Water viscosibility	3.3623	1/psi

Properties of fluid density at surface conditions:

Oil density	52.21804	lb/ft^3
Water density	62.42797	lb/ft^3
Gas density	0.04369	lb/ft^3

Rock property:

Rock compressibility	1.52989×10^{-6}	1/psi

3.2 Production plan

The reservoir was produced from the initial pressure of 3,000 psi which is above the bubble point pressure. As the reservoir pressure declined, a series of modified isochronal flow test was performed as illustrated in Fig 3.4. Before starting each test, we need to shut in the well until stabilization was reached in order to determine the average reservoir pressure. After the well flowing pressure equaled to the average reservoir pressure, the test was started with the first flow rate of 300 STB/d for a period of 12 hours. The well flowing pressure at the end of the period was recorded as p_{wf1}. Then, the well was shut in for the same period, and the shut in pressure at the end of the period was recorded as p_{ws2}. The same procedure was repeated with the flow rate 600, 900 and 1200 STB/d. After that, the well was flowed for an extended period until the well pressure stabilized. Finally, the well was shut in until the average reservoir pressure was determined. After the test was finished, the well was open for production at the rate of 1,000 BOPD, and then deliverability test was repeated in the next depletion stage throughout the well life approximately 13 times until the reservoir pressure was below 250 psi.

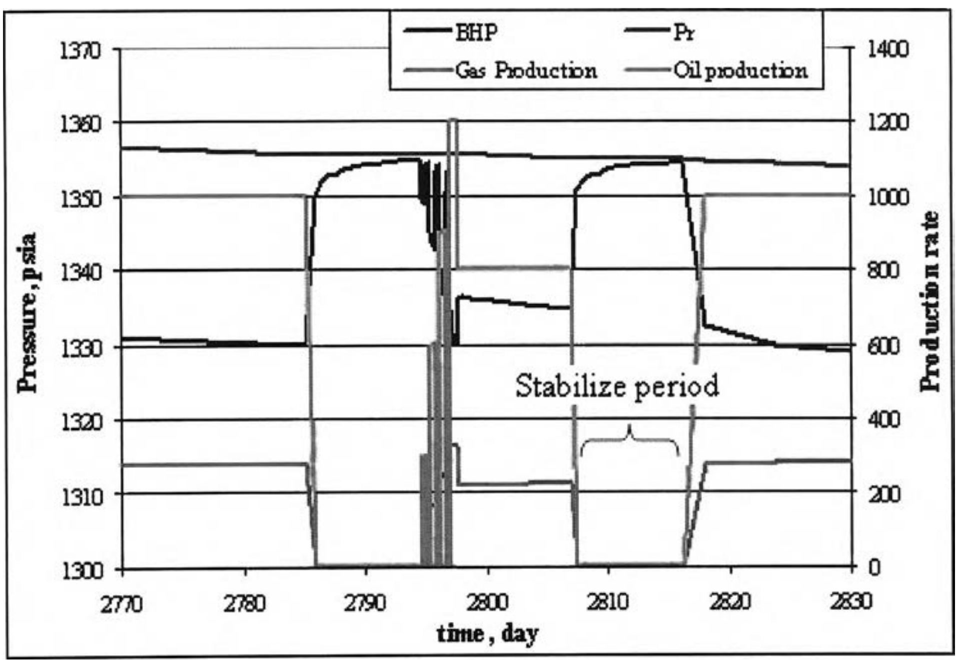

Figure 3.4: Schematic of flowing and shut-in plan of modified isochronal test.

The time required for stabilization can be estimated from Eq. 2.18 such as in the base case in which $\phi = 0.15$, $\mu_o = 0.69$ cp, $c_t = c_oS_o + c_wS_{wc} + c_gS_g = 10*10^{-6}*0.53 + 3.0998\times10^{-6}\times0.3 + 500\times10^{-5}\times0.17 = 85.6229\times10^{-5}$ psi^{-1}, $A = 122{,}500$ ft^2, $k_o = kk_{ro} = 50*0.55 = 27.5$. The time for stabilization is then.

$$t_s = \frac{380\phi\mu_o c_t A}{k_o} = \frac{380\times0.15\times0.69\times85.6229\times10^{-5}\times122500}{27.5} = 150 hrs.$$

3.3 Evaluation method

When the modified isochronal test was performed in each stage, the well flowing pressure and the reservoir pressure were recorded and analyzed. Fig 3.5 depicts a sample deliverability plot obtained from one of the tests simulated by reservoir simulation. In this plot, the flow exponent, *n*, can be evaluated from 1/slope of the transient line and the PI coefficient, *J*, can be evaluated from the intercept of the stabilized line when the time equals to 1.

The values of *n* and *J* from all the tests were converted into dimensionless variables n/n_b and J/J_b and plotted as a function of dimensionless p/p_b as shown in Fig 3.6 and Fig. 3.7.

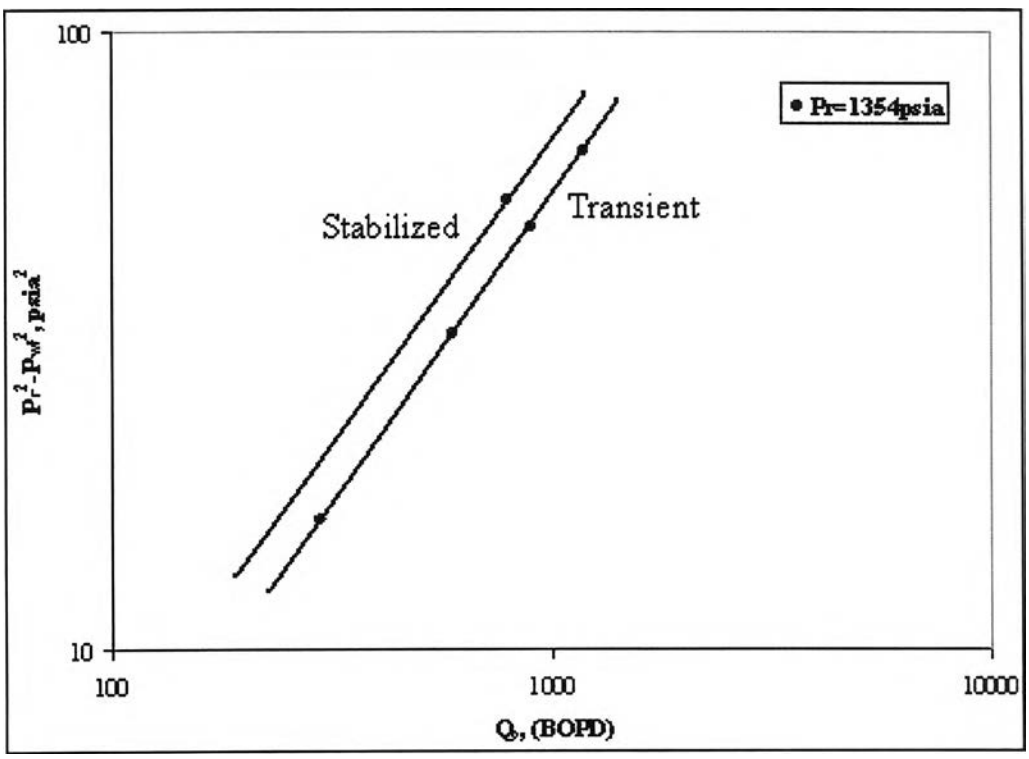

Figure 3.5: Log-log deliverability plots at reservoir pressure 1354 psi.

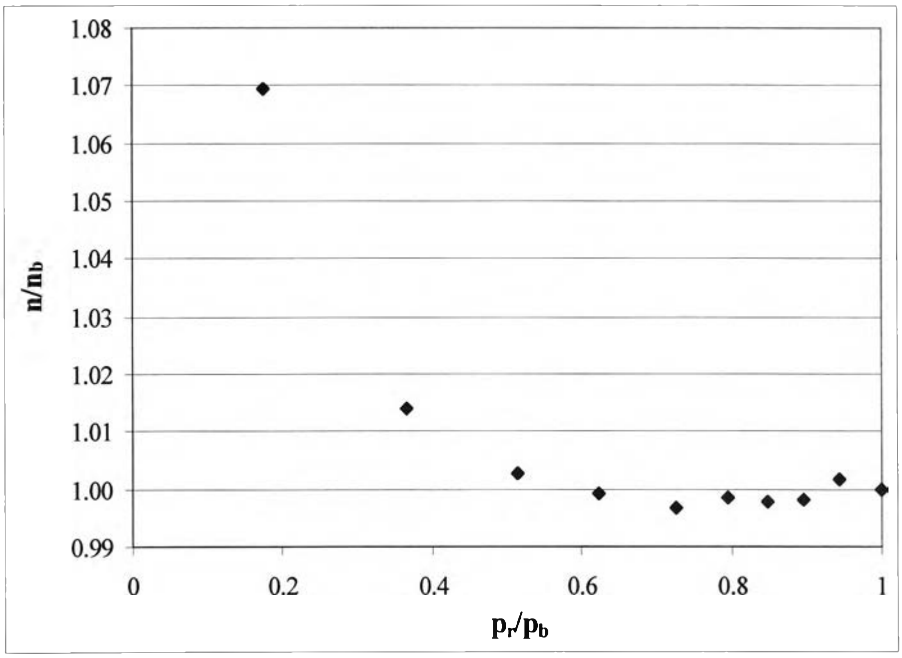

Figure 3.6: Dimensionless flow exponent, n/n_b as a function of dimensionless pressure p_r/p_b.

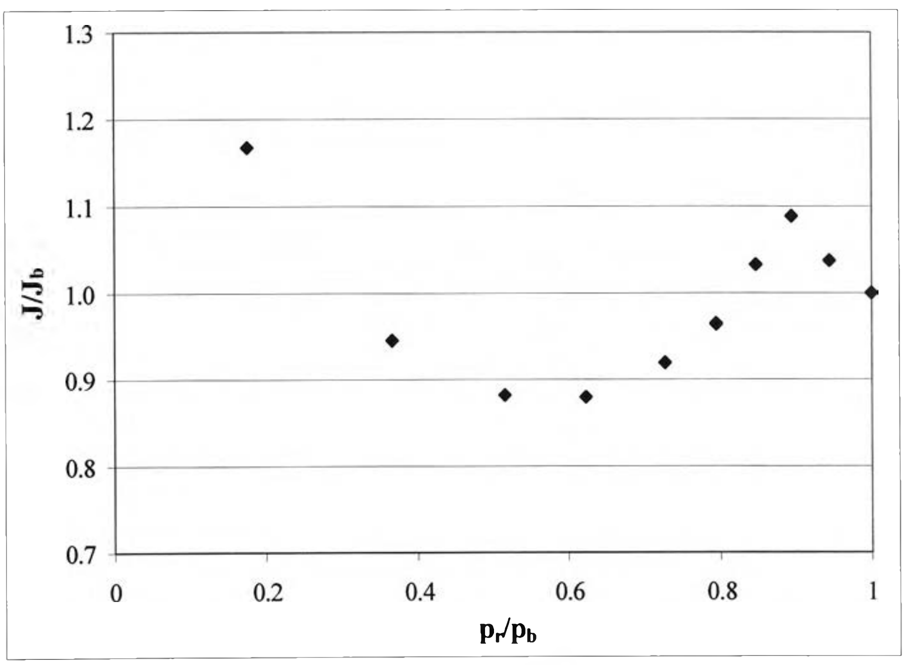

Figure 3.7: Dimensionless flow constant, J/J_b as a function of dimensionless pressure p_r/p_b.