On the basis of $N = 1.00$ STB initially, N_p is the fractional recovery r, or N_p/N, and Eq. (3.18) may be written as

OIL SAT

$$S_o = (1 - r)(1 - S_w)\left(\frac{B_o}{B_{oi}}\right) \tag{3.19}$$

where S_w is the connate water, which is assumed to remain constant for volumetric reservoirs. Then at 1600 psig the oil saturation is

$$S_o = (1 - 0.0486)(1 - 0.20)\left(\frac{1.4303}{1.4235}\right)$$

$$= 0.765$$

$$S_g = \frac{V_{fg}}{V_{pi}}$$

The gas saturation is $(1 - S_o - S_w)$, or

$$S_g = 1 - 0.765 - 0.200 = 0.035$$

Figure 3.9 shows the calculated performance of the Kelly-Snyder Field

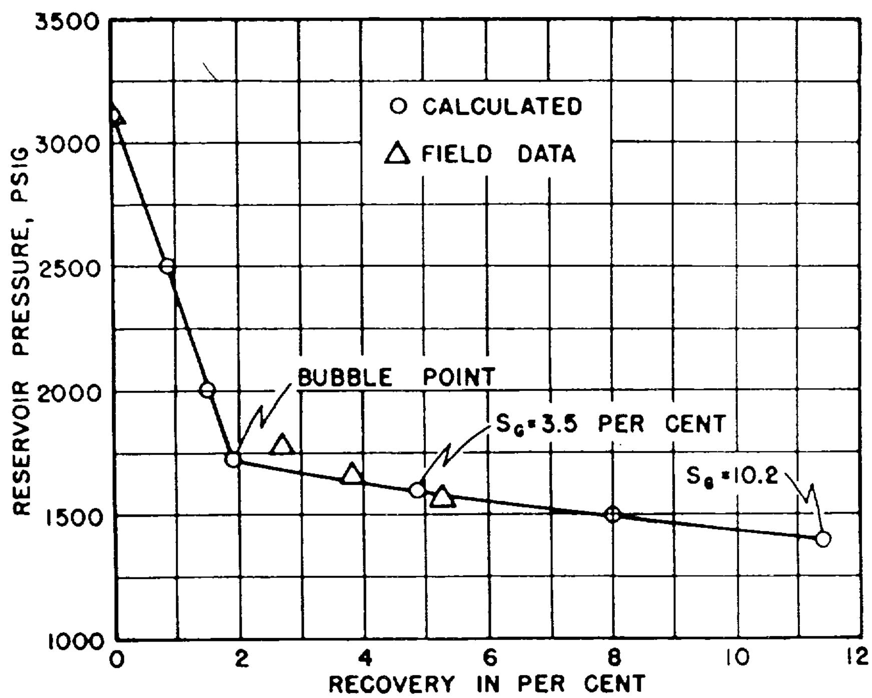


Fig. 3.9. Material balance calculations and performance, Canyon Reef reservoir, Kelly-Snyder Field.

down to a pressure of 1400 psig. Calculations were not continued beyond this point because the free gas saturation had reached approximately 10 per cent, the estimated critical gas saturation for the reservoir. The graph shows the rapid pressure decline above the bubble point and the predicted flattening below the bubble point. The predictions are in good agreement with the field performance which is calculated in Table 3.4 using field pressures and production data, and a value of 2.25MMM STB for the initial oil in place. The producing gas-oil ratio, Col. (2), increases instead of decreas-

Table 3.4. RECOVERY FROM KELLY-SNYDER CANYON REEF RESERVOIR BASED ON PRODUCTION DATA AND MEASURED AVERAGE RESERVOIR PRESSURES, AND ASSUMING AN INITIAL OIL CONTENT OF 2.25MMM STB

(1) *Pressure Interval, psig*	(2) *Avg. Producing Gas-Oil Ratio, SCF/STB*	(3) *Incremental Oil Production, MM STB*	(4) *Cumulative Oil Production, MM STB*	(5) *Per Cent Recovery (N = 2.25MMM STB)*
3312 to 1771	896	60.421	60.421	2.69
1771 to 1713	934	11.958	72.379	3.22
1713 to 1662	971	13.320	85.699	3.81
1662 to 1570	1023	20.009	105.708	4.70
1570 to 1561	1045	11.864	117.572	5.23

ing as predicted by the previous theory. This is due to the more rapid depletion of some portions of the reservoir, for example those drilled first, those of low net productive thickness, and those in the vicinity of the well bores. This is discussed further in Chapter 7, Sec. 5. For the present predictions it is pointed out that the previous calculations would not be altered greatly if a constant producing gas-oil ratio of 885 SCF/STB, i.e., the initial dissolved ratio, had been assumed throughout the entire calculation.

The initial oil under the 40-acre units of the Canyon Reef reservoir for a net formation thickness of 200 feet is

$$N = \frac{7758 \times 40 \times 200 \times 0.077 \times (1 - 0.20)}{1.4235}$$
$$= 2.69\text{MM STB}$$

Then at the average daily well rate of 92 BOPD in 1950, the time to produce 11.35 per cent of the initial oil, i.e., at 1400 psig when the gas saturation is calculated to be near 10 per cent, is

$$t = \frac{0.1135 \times 2.69 \times 10^6}{92 \times 365} \cong 9.1 \text{ years}$$

By means of this calculation the reservoir engineers were able to show that there was no immediate need for a curtailment of production, and that there was plenty of time in which to make further reservoir studies and carefully considered plans for the optimum pressure maintenance program. Following comprehensive and exhaustive studies by engineers, the field was unitized in March of 1953 and placed under the management of an operating committee. This group proceeded to put into operation a pressure maintenance program consisting of (a) water injection into wells located along the longitudinal axis of the field, and (b) shutting in the high gas-oil ratio wells and transferring their allowables to low gas-oil ratio wells. The high ratio wells were shut in as soon as the field was unitized, and water injection was started in 1954. Today the operation is going as planned and it appears that approximately 50 per cent of the initial oil in place will be recovered, in contrast to approximately 25 per cent by primary depletion, an increase of approximately 600MM STB of recoverable oil.

7. The Gloyd-Mitchell Zone of the Rodessa Field. Many reservoirs have been discovered which are of the volumetric undersaturated type and whose production, therefore, is controlled largely by the solution gas-drive mechanism. In many cases the mechanism is altered to a greater or lesser extent by gravitational segregation of the gas and oil, by small water drives, and by pressure maintenance, all of which improve recovery. The important characteristics of this type of production may be summarized as follows and observed in the graph of Fig. 3.11 for the Gloyd-Mitchell zone of the Rodessa Field. Above the bubble point the reservoir is produced by *liquid expansion* and there is a rapid decline in reservoir pressure which accompanies the recovery of a fraction of one per cent to a few per cent of the initial oil in place. The gas-oil ratios remain low, and generally near the value of the initial solution gas-oil ratio. Below the bubble point, a gas phase develops, which in most cases is immobile until the gas saturation reaches the critical gas saturation in the range of a few per cent to 20 per cent. During this period the reservoir produces by *gas expansion*, which is characterized by a much slower decline in pressure and gas-oil ratios near, or in some cases even below the initial solution gas-oil ratio. After the critical gas saturation is reached, free gas begins to flow. This reduces the oil flow rate, and depletes the reservoir of its main source of energy. By the time the gas saturation reaches a value usually in the range of 15 to 30 per cent, the flow of oil is small compared with the gas (high gas-oil ratios) and the reservoir gas is rapidly depleted. At abandonment the recoveries are usually in the range of 10 to 25 per cent by the solution gas-drive mechanism alone, but may be improved by gravitational segregation and the control of high gas-oil ratio wells.

The production of the Gloyd-Mitchell zone of the Rodessa Field,[16] Louisiana is a good example of a reservoir which produced during the major portion of its life by the dissolved gas drive mechanism. The availability of reasonably accurate data on this reservoir relating to oil and gas production, reservoir pressure decline, sand thickness, and the number of producing wells, provide an excellent example of the theoretical features of the dissolved gas drive mechanism. The Gloyd-Mitchell zone is practically flat and produced an oil of 42.8° API gravity which, under the original bottom-hole pressure of 2700 psig, had a solution gas-oil ratio of 627 SCF/STB. There was no free gas originally present and there is no evidence of an active water drive. The wells were produced at high rates and had a rapid decline in production. The behavior of the gas-oil ratios, reservoir pressures, and oil production, had the characteristics expected of a dissolved gas drive, although there is some evidence that there was a modification of the recovery mechanism in the later stages of depletion. The ultimate recovery was estimated at 20 per cent of the initial oil in place.

Many unsuccessful attempts were made to decrease the gas-oil ratios, by shutting in the wells, by blanking off upper portions of the formation in producing wells, and by perforating only the lowest sand members. The failure to reduce the gas-oil ratios is typical of the dissolved gas drive mechanism, because when the critical gas saturation is reached, the gas-oil ratio is a function of the decline in reservoir pressure or depletion, and is not materially changed by production rate or completion methods. Evidently there was negligible gravitational segregation by which an artificial gas cap develops and causes abnormally high gas-oil ratios in wells completed high on the structure or in the upper portion of the formation.

Table 3.5 gives the number of producing wells, average daily production, average gas-oil ratio, and average pressure for the Gloyd-Mitchell zone. The daily oil production per well, monthly oil production, cumulative oil production, monthly gas production, cumulative gas production, and cumulative gas-oil ratios have been calculated from these figures. The source of data is of interest. The number of producing wells at the end of any time period is obtained either from the operators in the field, from the completion records as filed with the state regulatory body, or from the periodic potential tests. The average daily oil production is available from the monthly production reports filed with the state regulatory commission. Accurate values for the average daily gas-oil ratios can be obtained only where all of the produced gas is metered. Alternatively this information is obtained from the potential tests. To obtain the average daily gas-oil ratio from potential tests during any month, the gas-oil ratio for each well is multiplied by the daily oil allowable or daily production rate for the same well, giving the total daily gas production. The average daily gas-oil ratio for any month is the total daily gas production from all producing wells divided by the total daily oil production from all the wells involved. For example, if the gas-oil ratio of well A is 1000 SCF/STB and the daily rate is 100 bbl/day, and the ratio of well B is 4000 SCF/STB and the daily rate is 50 bbl/day, then the average daily gas-oil ratio R of the two wells is

AVG DAILY GAS-OIL RATIO

$$R = \frac{1000 \times 100 + 4000 \times 50}{150} = 2000 \text{ SCF/STB}$$

This figure is lower than the arithmetic average ratio of 2500 SCF/STB. The average gas-oil ratio of a large number of wells, then, can be expressed by

$$R_{\text{avg}} = \frac{\Sigma R \times q_o}{\Sigma q_o} \tag{3.20}$$

where R and q_o are the individual gas-oil ratios and stock tank oil production rates.

Figure 3.10 shows plotted in block diagram the number of producing wells, the daily gas-oil ratio, and the daily oil production per well. Also in a

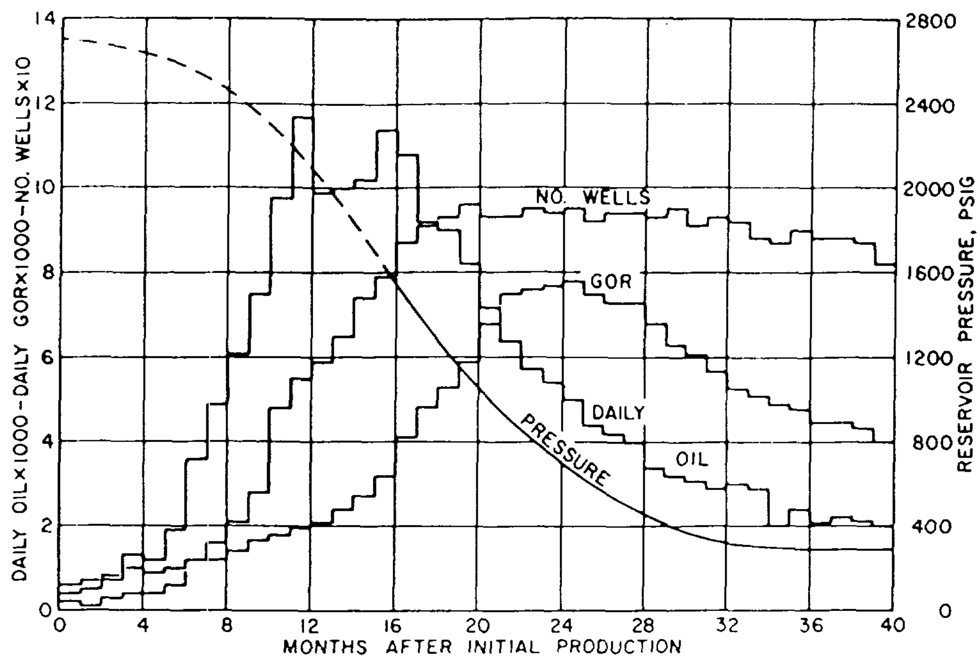


Fig. 3.10. Development, production, and reservoir pressure curves for the Gloyd-Mitchell Zone, Rodessa Field, Louisiana.

smooth curve pressure is plotted against time. The initial increase in daily oil production is due to the increase in the number of producing wells, and not to the improvement in individual well rates. If all the wells had been completed and put on production at the same time, the daily production rate would have been a plateau during the time all the wells could make their allowables, followed by an exponential decline, which is shown beginning at sixteen months after the start of production. Since the daily oil allowable and daily production of a well are dependent on the bottom-hole pressure and gas-oil ratio, the oil recovery is larger for wells completed early in the life of a field. As the controlling factor in this type of mechanism is gas flow in the reservoir, the rate of production will have no material effect on the ultimate recovery, unless some gravity drainage occurs. Likewise well spacing has no proven effect on recovery; however, well spacing and production rate directly affect the economic return.

The rapid increase in gas-oil ratios in the Rodessa Field led to the enactment of a gas-conservation order. In this order, oil and gas production were allocated partly on a volumetric basis, to restrict production from wells with high gas-oil ratios. The basic ratio for oil wells was set at 2000 SCF/bbl. For leases on which the wells produced more than 2000 SCF/STB, the allowable in barrels per day per well, based on acreage and pressure, was multiplied by 2000 and divided by the gas-oil ratio of the well. This cut in production produced a double hump in the daily production curve.

In addition to a graph showing the production history versus *time,* it is usually desirable to have a graph which shows the production history plotted versus the *cumulative produced oil.* Figure 3.11 is such a plot for the

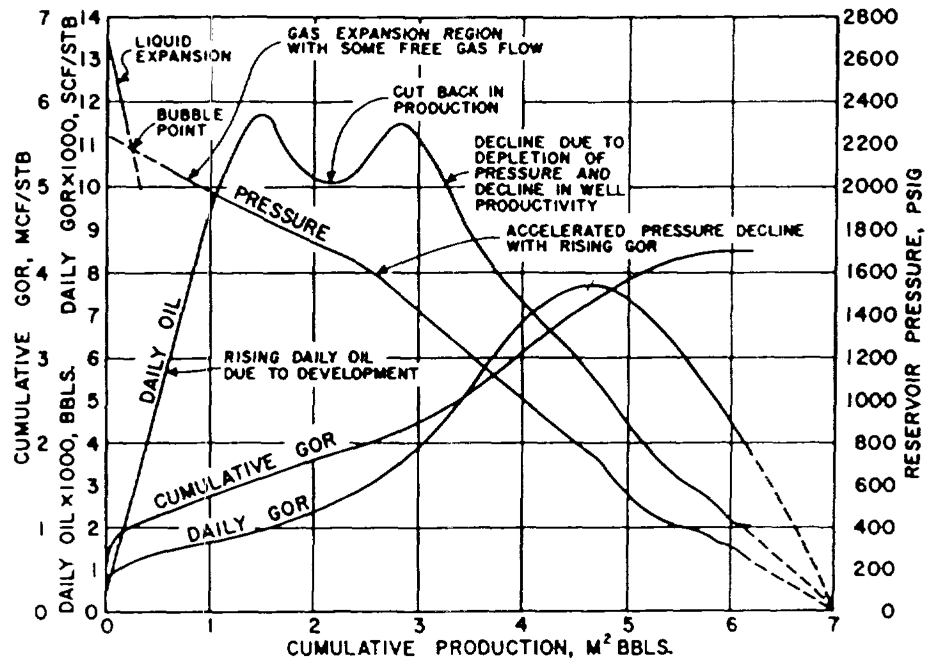


Fig. 3.11. History of the Gloyd-Mitchell Zone of the Rodessa Field plotted versus cumulative recovery.

Gloyd-Mitchell zone data, and is also obtained from Table 3.5. This graph shows some features which do not appear in the time graph. For example, a study of the reservoir pressure curve shows the Gloyd-Mitchell zone was producing by liquid expansion until approximately 200,000 barrels were produced. This was followed by a period of production by gas expansion with a limited amount of free gas flow. When approximately three million barrels had been produced, the gas began to flow much more rapidly than the oil, resulting in a rapid increase in the gas-oil ratio. In the course of this trend, the gas-oil ratio curve reached a maximum, then declined as the gas was depleted and the reservoir pressure approached zero. The decline in gas-oil ratio beginning after approximately four and one-half million barrels were produced is due mainly to the expansion of the flowing reservoir gas as pressure declines. Thus the same gas-oil ratio in standard cubic feet per day gives approximately twice the reservoir flow rate at 400 psig as at 800 psig; hence the surface gas-oil ratio may decline and yet the ratio of the rate of flow of gas to the rate of flow of oil *under reservoir conditions* continues to increase. It may also be reduced by the occurrence of some gravitational segregation, and also, from a quite practical point of view, by the failure of operators to measure or report gas production on wells producing fairly low volumes of low pressure gas.

The results of a differential gas-liberation test[17] on a bottom-hole sample from the Gloyd zone show that the solution gas-oil ratio was 624 SCF/STB, which is in excellent agreement with the initial producing gas-oil ratio of 625 SCF/STB. In the absence of gas-liberation tests on a bottom-hole sample, the initial gas-oil ratio of a properly completed well in either a dissolved gas drive, gas cap drive, or water drive reservoir, is usually a reliable value to use for the initial solution gas-oil ratio of the reservoir. The extrapolations of the pressure, oil rate, and producing gas-oil ratio curves on the cumulative oil plot all indicate an ultimate recovery of about seven million barrels; however, no such extrapolation can be made on the time plot. It is also of interest that whereas the daily producing rate is exponential on the time plot, it is close to a straight line on the cumulative oil plot.

The average gas-oil ratio during any production interval and the cumulative gas-oil ratio may be indicated by integrals and shaded areas on a typical daily gas-oil ratio versus cumulative stock tank oil production curve as shown in Fig. 3.12. If R represents the daily gas-oil ratio at any time, and N_p the cumulative stock tank production at the same time, then the production during a short interval of time is dN_p and the total volume of gas produced during that production interval is $R\,dN_p$. The gas produced over a longer period where the gas-oil ratio is changing is given by

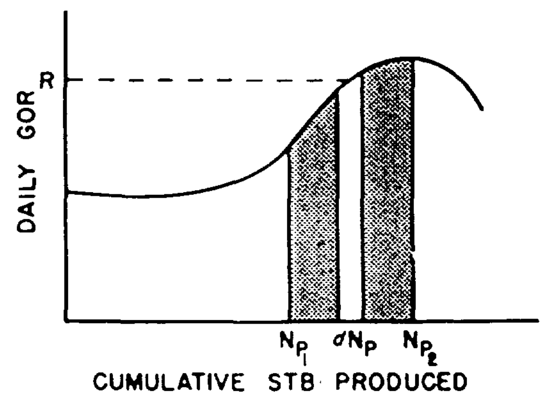


Fig. 3.12. Typical daily gas-oil ratio curve for a dissolved gas drive reservoir.

$$\Delta G_p = \int_{N_{p1}}^{N_{p2}} R\,dN_p \tag{3.21}$$

The shaded area between N_{p1} and N_{p2} is proportional to the gas produced during the interval. The average daily gas-oil ratio during the production interval equals the area under the gas-oil ratio curve between N_{p1} and N_{p2} in units given by the co-ordinate scales, divided by the oil produced in the interval $(N_{p2} - N_{p1})$, and

$$R_{avg} = \frac{\int_{N_{p1}}^{N_{p2}} R\,dN_p}{(N_{p2} - N_{p1})} \tag{3.22}$$

The cumulative gas-oil ratio, R_p, is the total net gas produced up to any

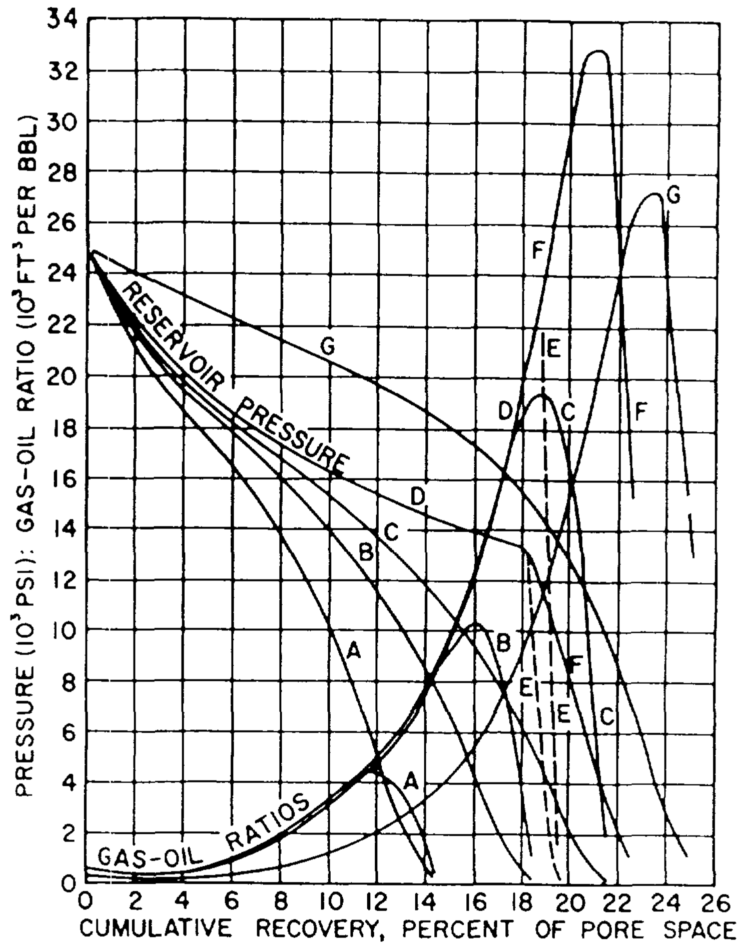


Fig. 7.17. Theoretical pressure and gas-oil ratio histories of gas drive reservoirs subjected to various gas return programs. (A) r = 0, m = 0; (B) r = 0.66, m = 0; (C) r = 0.80, m = 0; (D) r = 1.00 up to R = 20,000 SCF/STB, m = 0; (E) Continuation of D with r = 0; (F) Continuation of D with r = 0.80; (G) Initial gas cap, m = 0.50, r = 0.80. (*After* Muskat, *Oil and Gas Journal*, Vol. 47, No. 48, p. 89.)

Studies by Loper and Calhoun[15] and Miller, Brownscombe, and Kieschnick[16] indicate that recoveries from depletion-drive reservoirs are almost independent of well spacing, pressure drawdowns, and production rate. Reudelhuber and Hinds[17] and Jacoby and Berry[18] have described the modifications necessary in applying the prediction equations to the volatile-type oil depletion reservoirs. Jacoby and Berry[19] have also extended the prediction equations to pressure maintenance by gas injection in volatile-type oil reservoirs.

5. Relative Permeability Ratios from Field Data. Relative permeabilities and relative permeability ratios are usually measured in the laboratory on core samples. The relative permeability *ratio* may also be calculated from field data in volumetric, undersaturated reservoirs. The fractional recovery at any pressure is calculated from material balance using

$$\frac{N_p}{N} = \frac{B_o - B_{oi} + B_g(R_{si} - R_s)}{B_o + B_g(R_p - R_s)} \tag{7.49}$$

Then the average oil saturation is calculated using

$$\boxed{S_o = \left(1 - \frac{N_p}{N}\right)\frac{B_o}{B_{oi}}(1 - S_w)} \tag{7.50}$$

From the measured field producing gas-oil ratio at the same pressure of Eq. (7.49), the k_g/k_o value corresponding to an oil saturation of S_o, or a total liquid saturation $(S_o + S_w)$, is found using the producing gas-oil ratio equation, Eq. (7.34), or

$$\frac{k_g}{k_o} = \frac{(R - R_s)}{B_o B_g} \times \frac{\mu_g}{\mu_o} \tag{7.51}$$

Suppose in the field whose data is given in Fig. 7.12 and Table 7.4, the observed net, cumulative, produced gas-oil ratio, R_p, at 1300 psia was 1500 SCF/STB and the producing gas-oil ratio at 1300 psia was 2500 SCF/STB. Then by Eq. (7.49) the fractional oil recovery at 1300 psia is

$$\frac{N_p}{N} = \frac{1.233 - 1.315 + 0.001616(650 - 450)}{1.233 + 0.001616(1500 - 450)} = 0.0823$$

The corresponding oil saturation at 1300 psia then is

$$S_o = (1 - 0.0823) \times \frac{1.233}{1.315} \times (1 - 0.22) = 0.671$$

and the corresponding relative permeability ratio is

$$\frac{k_g}{k_o} = \frac{(2500 - 450)}{1.233 \times 619} \times \frac{1}{102.61} = 0.0262$$

This value of k_g/k_o at a total liquid saturation of 89.1 per cent (S_w = 22 per cent) is shown plotted in the relative permeability ratio curve of Fig. 7.12. Continued plotting of these values of k_g/k_o versus S_o from field data gives a curve which may be extrapolated to predict future reservoir performance. Mueller, Warren, and West[20] have shown that one of the main reasons for the discrepancy between laboratory k_g/k_o values and field-measured values can be explained by the unequal stages of depletion in the reservoir. For the same reason, field gas-oil ratios will seldom show the slight decline predicted in the early stages of depletion, and conversely will usually show a rise in gas-oil ratio at an earlier stage of depletion than the prediction. Whereas the theoretical predictions assume a negligible (actually zero) pressure drawdown, so that the saturations are therefore uniform throughout the reservoir, actual well pressure drawdowns will deplete the reservoir in the vicinity of the well bore in advance of areas further removed. In development programs, too, some wells are completed often years before other wells, and depletion is naturally further advanced in the area of the older wells, which will have gas-oil ratios considerably higher than the newer wells. And even when all wells are completed within a short period, when the formation thickness varies, and all wells produce at the same rate (allowable), the reservoir will be depleted faster where the formation is thinner. Finally, when the reservoir comprises two or more strata of different specific permeabilities, even if their relative permeability characteristics are the same, the stratum with the higher permeability will be depleted before those with lower permeabilities. Since all of these effects are minimized in high *capacity* formations, closer agreement between field and laboratory data might be expected for higher capacity formations. On the other hand, high capacity formations tend to favor gravity segregation. Where gravity segregation occurs and advantage is taken of it by shutting in the high ratio wells, or working over wells to reduce their ratios, the field-measured k_g/k_o values will be lower than the laboratory values. Thus the laboratory k_g/k_o values may apply at every point in a reservoir without gravity segregation, and yet the field k_g/k_o values will be higher owing to the unequal depletion of the various portions of the reservoir.

6. Productivity Index Decline in Depletion Reservoirs. The productivity index of a well may be expressed using the radial flow equation as

$$J = \frac{q}{(p_e - p_w)} = \frac{7.08\ k_o h}{\mu_o B_o \ln (r_e/r_w)} \tag{7.52}$$

Where the drawdown is appreciable, the values of k_o, μ_o, and B_o change appreciably about the well bore. Evinger and Muskat[21] have shown that these changing values must be integrated to give

$$J = \frac{7.08\ kh}{(p_e - p_w) \ln (r_e/r_w)} \int_{p_w}^{p_e} \frac{k_{ro}}{\mu_o B_o}\, dp \tag{7.53}$$

This equation may be integrated graphically as shown in detail by Calhoun;[22] however, it is quite complex because the relative permeability to oil is only indirectly related to the pressure.

The PI decline relative to the initial $(\text{PI})_i$ may be approximated using Eq. (7.52) to give

$$\frac{J}{J_i} = \frac{(k_o/\mu_o B_o)}{(k_o/\mu_o B_o)_i} \tag{7.54}$$

Figure 7.18 gives the relative permeabilities to oil and gas for the same reservoir data of Fig. 7.12 and Table 7.4. At 1500 psia the oil saturation

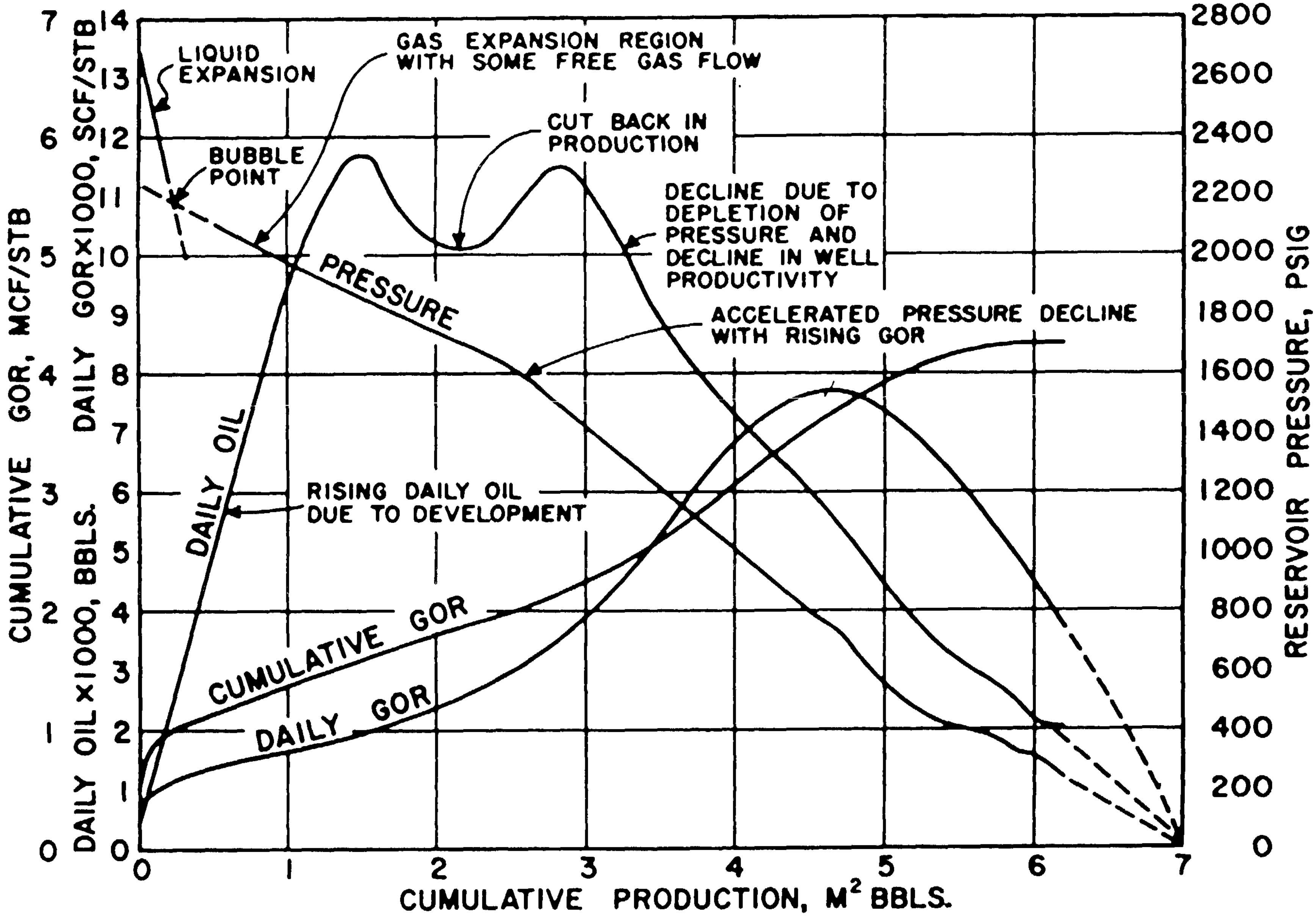


Fig. 3.11. History of the Gloyd-Mitchell Zone of the Rodessa Field plotted versus cumulative recovery.

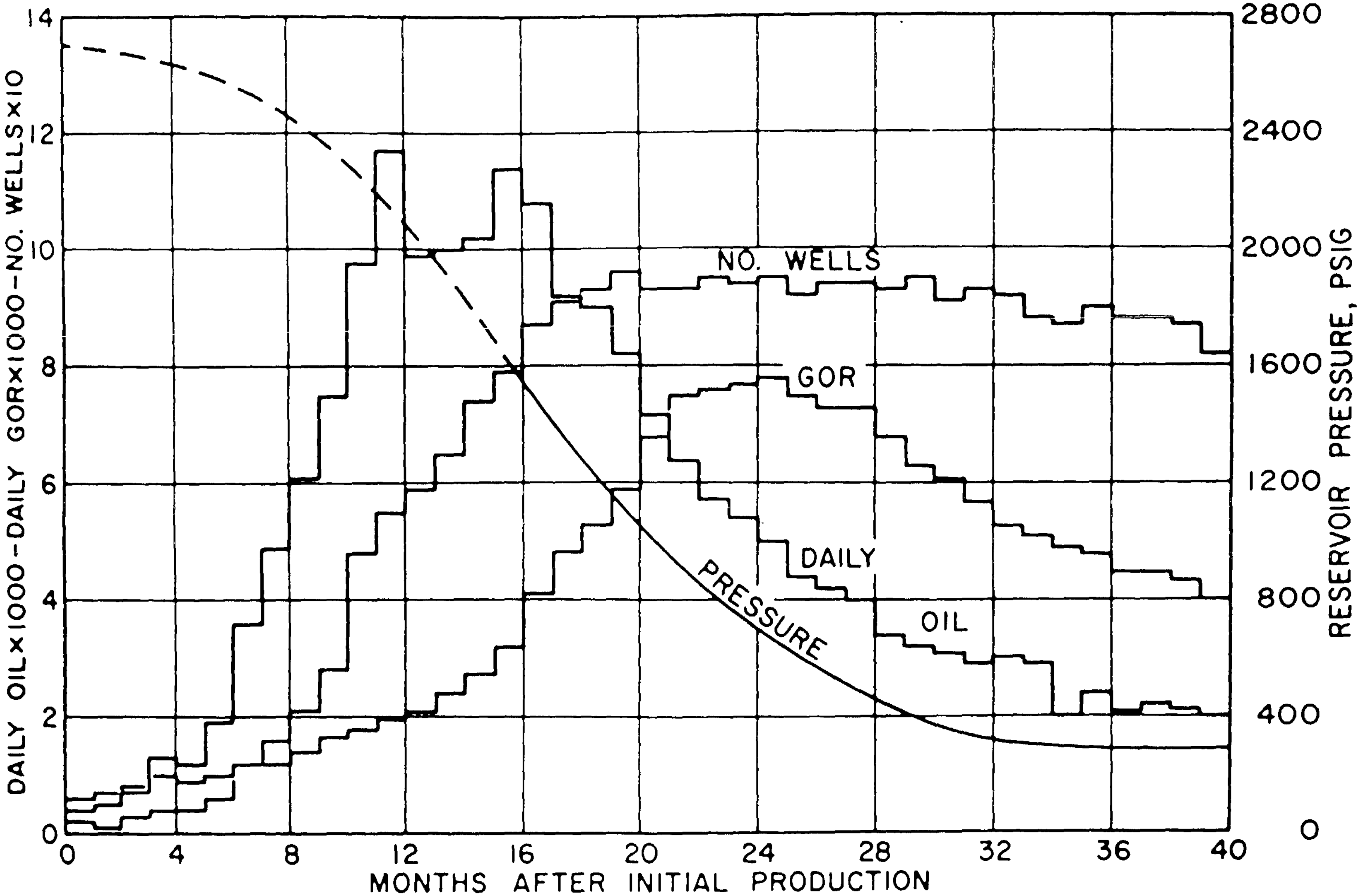
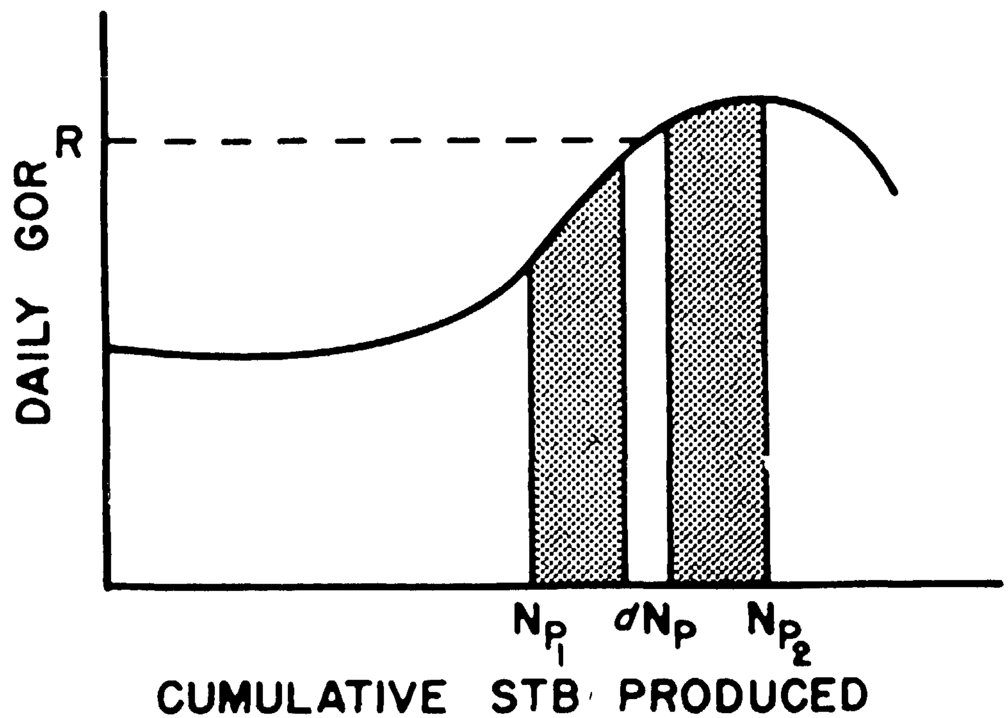


Fig. 3.10. Development, production, and reservoir pressure curves for the Gloyd-Mitchell Zone, Rodessa Field, Louisiana.


DAILY GOR
R
N_{p_1}
dN_p
N_{p_2}
CUMULATIVE STB PRODUCED