Physical Principles of Oil Production

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CHAPTER 13

CONDENSATE RESERVOIRS

13.1. Introduction.—The primary problem involved in the study of the various type of oil-producing reservoirs discussed in previous chapters has been the dynamical interaction between the fluids and their porous-media carriers. The physical and thermodynamic properties of the fluids have mainly played the role of parameters affecting only the details of the performance. Condensate-producing reservoirs are unique in that it is the thermodynamic behavior of the petroleum fluids that is the controlling factor in their performance and economic evaluation. It is for this reason that they will be given here a separate treatment, although their dynamical aspects are controlled by the same basic laws of fluid flow through porous media[1] as govern the production of crude oil and natural gas.

13.2. General Considerations Regarding Condensate-reservoir Fluids.—Condensate reservoirs produce a liquid phase commonly called "condensate" or "distillate." In contrast to crude oil it is usually a colorless or straw-colored[2] liquid and generally has an API gravity of 48° or higher. As compared with crude-oil production, it is associated with high gas-oil ratios, of the order of 10,000 ft^3/bbl or greater. From a physical point of view the most important characteristic of the condensate is that it is not necessarily a liquid in the reservoir from which it is produced. In most cases it is a liquid phase developed from a hydrocarbon mixture that is in a single or dew-point gas phase under the reservoir conditions. Such a phase transformation may take place within the reservoir as the result of pressure decline, by a process of isothermal retrograde condensation (cf. Sec. 2.5), although the liquid so formed in the producing formation will generally remain trapped and provide only a negligible part of the liquid product recovered at the surface. The major part of the condensate actually produced at the surface is that condensing from the gas by more

[1] Except for the correction of the wet-gas permeability due to the presence of the connate water the homogeneous-fluid theory will govern the dynamics of condensate reservoirs when the pressure is maintained by "cycling" (cf. Sec. 13.4). And even when produced by pressure depletion the homogeneous-fluid representation should still provide a satisfactory approximation from a practical standpoint.

[2] The dark coloration sometimes observed in condensate liquids is probably due in most cases to contamination with slight amounts of crude oil or fine dispersions of dark bituminous material picked up by the petroleum fluids from the reservoir rock on their passage toward the producing wells.

general retrograde-phase transformations during the simultaneous decline in pressure and temperature as the reservoir fluid rises up the flow string. This liquid-phase recovery is often supplemented to an important extent by various methods of processing the gas arriving at the wellhead or passing through the separators so as to extract additional liquefiable hydrocarbons that are still in the gas phase on reaching the surface.

Although condensate-producing fields are usually considered as being

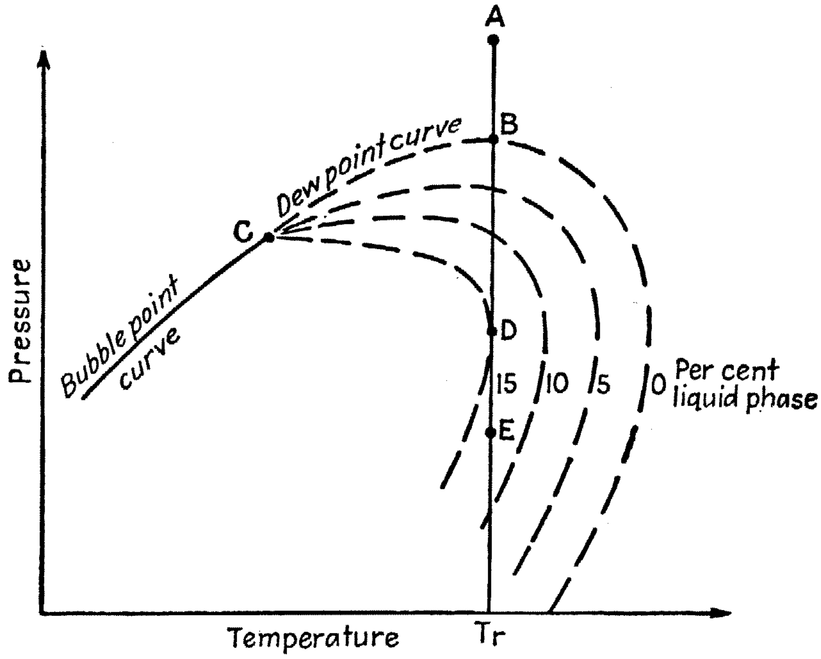


FIG. 13.1. A diagrammatic representation of the gross phase behavior of the reservoir fluid from a condensate-producing formation. T_r denotes the reservoir temperature and C the critical point.

comprised simply of gas-phase reservoirs, the universality of such conditions is neither observed nor to be expected. If the condensate-bearing reservoir fluid is an undersaturated gas, *i.e.*, a single phase above the dew point, as indicated by A in Fig. 13.1, it cannot be in equilibrium with a liquid phase and no liquid phase will be present if equilibrium obtains. If, however, it is a saturated vapor,[1] at its dew-point pressure, as at B, it *may* coexist with a liquid phase and the composite liquid and gas will then be essentially equivalent to a normal segregated two-phase system. If, as is usually the case, the gas phase may be visualized as simply the excess beyond that which will go into solution in the liquid, the latter will be a "crude" oil with its characteristic dark color and relatively low API gravity. Under equilibrium conditions the composition of this "black" oil will be the same as that of the first liquid phase condensing from the gas if its temperature

[1] In most condensate-producing reservoirs the dew-point pressure, at the reservoir temperature, of the initially produced fluids has been found to be the same as the reservoir pressure, within the uncertainties of the experimental determinations.

or pressure were lowered. Except for the special retrograde-condensation property of the gas the reservoir as a whole could be considered as a normal crude-oil reservoir overlain by a gas cap.

As would be expected from these considerations, there is no thermodynamic limitation to the relative amounts of the liquid (crude-oil) phase and the condensate-bearing gas phase that may initially comprise the composite reservoir. Crude-oil rims have been found underlying most condensate-bearing gas reservoirs. In some, such as the *D* Sand of the Benton field, Bossier Parish, La., oil zones definitely appear to be absent. On the other hand, where they are present their size and content may be so small as to be of entirely negligible significance, or they may be large enough far to exceed in value the gas-cap contents.

An understanding of the unique properties of condensate-producing gases is facilitated by reference to their composition, as compared with crude-oil and natural-gas mixtures. Such comparative analyses (in mole per cent) for typical hydrocarbon systems of both types are given in Table 1.

TABLE 1.—TYPICAL COMPOSITIONS OF A CONDENSATE-PRODUCING GAS AND A CRUDE-OIL–GAS MIXTURE

	Saturated vapor			Crude-oil–gas mixture		
	Gas	Condensate	Reservoir fluid	Gas	Oil	Reservoir fluid
Methane.......	85.69	—	82.38	80.53	0.31	45.26
Ethane........	4.45	—	4.28	5.37	0.14	3.07
Propane.......	3.64	0.19	3.51	3.85	0.33	2.30
Iso-butane.....	1.57	2.53	1.61	3.70	0.97	2.50
n-Butane......	3.06	2.22	3.03			
Iso-pentane....	0.35	6.77	0.60	2.09	1.97	2.04
n-Pentane.....	0.45	6.37	0.68			
Hexanes.......	0.34	17.36	0.99	1.17	2.49	1.75
Heptanes and heavier......	0.45	64.56	2.92	3.29	93.79	43.08
Total......	100.00	100.00	100.00	100.00	100.00	100.00
Mol. wt. of heptanes and heavier......	.....	.....	133	.....	200	

It will be seen that, while the separated gas phases in each case are not greatly different in composition,[1] the liquid condensate has a decidedly

[1] The gas phase of the crude-oil–gas mixture of Table 1 is considerably richer in the heavier liquefiable components than the reported compositions of natural gases usually indicate. The latter, however, generally refer to separator-gas samples, whereas that of Table 1 refers to the stock-tank gas obtained by direct flashing of the bubble-point reservoir liquid.

lower content of heptanes and heavier than the oil, and moreover the average molecular weight of these components is considerably lower for the condensate. But more important still is the fact that, whereas in the crude-oil–natural-gas mixture there are 1.27 moles of gas per mole of liquid, the corresponding ratio for the condensate system is 25. It is these composition characteristics that give the condensate-bearing reservoir fluid its unique properties.

Condensate reservoirs were not discovered, or at least recognized as such, until the early thirties. They have since been found with increasing frequency, especially in the Gulf Coast area. This is undoubtedly to be associated with the increasingly deep drilling of the last 10 years.[1] While this is usually attributed simply to the higher pressures and temperatures prevailing at the greater depths, it is the pressure and the composition of the hydrocarbon mixtures, rather than the temperature, that are the controlling factors. As indicated in Fig. 13.1 and noted in Sec. 2.5 isothermal retrograde condensation on pressure decline from the dew point will occur only at temperatures above the critical and at pressures near[2] the critical pressure. Since the critical temperatures of condensate-producing fluids correspond to some type of average[3] of the individual components, they will be exceeded by the reservoir temperatures even at very shallow depths, and hence the factor of temperature would not alone limit the occurrence of condensate fields to the greater depths. On the other hand their critical pressures will generally be considerably greater than those of the separate constituents and will be approached or exceeded by the reservoir pressure only in the deeper fields. Of course the probability of occurrence of condensate *types* of hydrocarbon mixtures may also be inherently greater at the higher pressures and temperatures found in the deeper horizons. However, the relationship between the nature of the petroleum fluids and depth, and general reservoir conditions and sedimentary history, is only one of the

[1] A rough statistical analysis of condensate fields discovered to 1945, based on a survey of 224 fields by J. O. Sue and J. Miller, *API Drilling and Production Practice*, 1945, p. 117, shows that about 88 per cent of these were found at depths exceeding 5,000 ft and that the average depths of about 60 per cent were greater than 7,000 ft.

[2] The range of pressures over which isothermal retrograde condensation may occur, in relation to the critical, depends on whether the pressure-temperature phase diagram is of the type of Fig. 2.8*a* or 2.8*c*. The pressures must be less than the critical for Fig. 2.8*a*, and they may be either greater or less for Fig. 2.8*c*. Most condensate-fluid systems that have been studied appear to follow the latter, as indicated also by Fig. 13.1, so that the pressures must be only in the "range" of the critical.

[3] While such averaging appears to obtain in the case of binary hydrocarbon mixtures (cf. Fig. 2.16), the critical temperatures of more complex systems often deviate sharply from molar averages and may even be completely outside the range of the critical temperatures of the individual components [cf. C. K. Eilerts, V. L. Barr, N. B. Mullens, and B. Hanna, *Petroleum Eng.*, **19**, 154 (February, 1948)].

problems of the origin of oil whose solutions are still hardly beyond the state of nebulous speculation.

As the dew-point pressure is the natural starting point for the consideration of the phase behavior of condensate-reservoir fluids, it is instructive to see how the dew-point pressure[1] may vary with the temperature and gross composition of the hydrocarbon mixture. Expressing the latter in terms of the API gravity of the stock-tank oil (condensate) and the gas-oil ratio of the composite system, a correlation of data obtained in a study of fluids from five San Joaquin Valley (California) fields is reproduced in Table 2.[2]

TABLE 2.—DEW-POINT PRESSURES OF VARIOUS HYDROCARBON MIXTURES AT THREE TEMPERATURES

(In psia)

Temperature	Oil gravity, °API	Gas-oil ratio, ft³/bbl					
		15,000	20,000	25,000	30,000	35,000	40,000
100°F	52	4,440	4,140	3,880	3,680	3,530	3,420
	54	4,190	3,920	3,710	3,540	3,410	3,310
	56	3,970	3,730	3,540	3,390	3,280	3,180
	58	3,720	3,540	3,380	3,250	3,140	3,060
	60	3,460	3,340	3,220	3,100	3,010	2,930
	62	3,290	3,190	3,070	2,970	2,880	2,800
	64	3,080	3,010	2,920	2,840	2,770	2,700
160°F	52	4,760	4,530	4,270	4,060	3,890	3,650
	54	4,400	4,170	3,950	3,760	3,610	3,490
	56	4,090	3,890	3,690	3,520	3,380	3,270
	58	3,840	3,650	3,470	3,320	3,200	3,110
	60	3,610	3,430	3,280	3,150	3,040	2,960
	62	3,390	3,240	3,100	2,990	2,890	2,810
	64	3,190	3,060	2,930	2,820	2,740	2,670
220°F	54	4,410	4,230	4,050	3,890	3,750	3,620
	56	3,990	3,780	3,600	3,440	3,300	3,180
	58	3,700	3,480	3,280	3,110	2,970	2,850
	60	3,430	3,210	3,030	2,880	2,760	2,660
	62	3,150	2,970	2,800	2,670	2,570	2,480
	64	2,900	2,740	2,590	2,470	2,380	2,300

[1] Here, as well as in all the discussion in this chapter with respect to condensate reservoirs and cycling, the dew-point pressure refers only to the upper branch of the dew-point curve between the critical and cricondentherm temperatures; these are sometimes termed "retrograde" dew points.

[2] This is taken from B. H. Sage and R. H. Olds, *AIME Trans.*, **170,** 156 (1947). The gases used in the experiments were separator samples. Their methane content ranged from 82.5 to 89.5 per cent for the mixtures from the five fields studied. The heptanes and heavier content of the separator-liquid samples varied from 48.97 to

It will be seen that in all cases, for fixed temperature and gas-oil ratio, the dew-point pressure decreases with increasing oil gravity, the rate of variation being greatest at low gas-oil ratios and the higher temperatures. In the range of the high gas-oil ratios listed in the table[1] the dew-point pressure increases monotonically with decreasing gas-oil ratio, for fixed oil gravity and temperature. Its sensitivity to the gas-oil ratio is greatest for the lower gravity oils. Its variation with the temperature is not monotonic, and for the systems to which Table 2 refers it is greater in most cases at 160°F than at either 100 or 220°F.

13.3. The Depletion History of Condensate-producing Reservoirs.—If it were not for the retrograde phenomenon, a condensate-bearing single-phase reservoir would perform simply as a gas field. The recovery of condensate would be proportional to the amount of gas produced. And except for possible reservoir shrinkage by water intrusion and the slow variation of the deviation factor of the gas with pressure, the reservoir pressure would decrease linearly with increasing cumulative recovery. It is the potential loss of the liquid content of the gas phase due to retrograde condensation as the pressure declines that is the crux of the problem of evaluating and predicting the performance of a condensate-producing field.

As in the case of crude-oil–natural-gas mixtures the phase relations can be determined for either of two types of process, flash and differential. The former, in which the composition and total mass of the mixture are held fixed while the pressure and volume are varied, corresponds to a simple path as *BDE* in Fig. 13.1, if the process is isothermal. The variation in the amount of liquid phase forming during such paths is illustrated by the curves of Fig. 13.2[2] for mixtures of condensate and gas from the Paloma field, Kern County, Calif. For three of the curves the temperature was 250°F and the gas-oil ratios were 5,361, 7,393, and 14,439 ft^3/bbl. For the fourth the temperature was 190°F, and the gas-oil ratio was 7,393 ft^3/bbl. It will be seen that the volume of liquid has a maximum in all cases, except for curve III, for which the maximum apparently lies below 1,000 psi.

73.11 per cent. The precise determination of dew-point pressures is a rather difficult problem. It is often chosen simply as the pressure-axis intercept of liquid-condensation curves such as those of Figs. 13.2 and 13.3 but can also be established by visual observations on the vanishing or first appearance of the liquid phase in glass-capillary or variable-volume cells fitted with suitable windows [cf. H. T. Kennedy, *Petroleum Eng.*, **11,** 77 (July, 1940); W. F. Fulton, *API Drilling and Production Practice*, 1939, p. 354; and J. P. Sloan, API meetings, Shreveport, La., May, 1946, and *Oil and Gas Jour.*, **46,** 158 (Mar. 25, 1948)].

[1] At lower gas-oil ratios the dew-point pressures may develop a maximum and then decline (cf. Fig. 13.2 below).

[2] These are plotted from tabulations of R. H. Olds, B. H. Sage, and W. N. Lacey, *AIME Trans.*, **160,** 77 (1945).

These maxima of retrograde condensation correspond to the point D in Fig. 13.1. The decline in liquid content at lower pressures simply represents the normal vaporization process. This dividing point recedes to higher pressures at the lower gas-oil ratios,[1] *i.e.*, for the fluids richer in condensate content. And as would be expected, the total liquid condensation increases with decreasing gas-oil ratio. Moreover a comparison of curves II

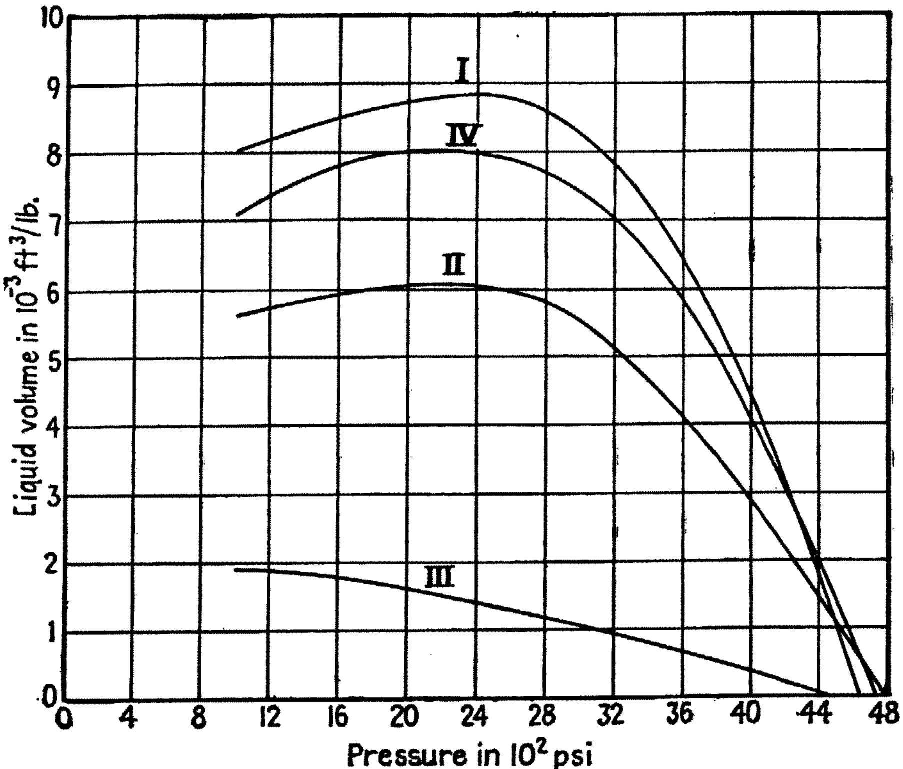


FIG. 13.2. The liquid-condensation curves for combined gas and condensate samples from the Paloma field, for fixed temperatures T and gas-oil ratios R. For curves I, II, and III, $T = 250°F$, R = 5,361, 7,393, and 14,439 ft³/bbl. For curve IV, $T = 190°F$, R = 7,393 ft³/bbl. The volume units refer to 1 lb of total mixture.

and IV, as well as reference to Fig. 13.1, shows that the retrograde liquid accumulation decreases with increasing reservoir temperature.

Although the fixed-composition pressure decline does not correspond to the process occurring in practice, it serves to illustrate one of the basic problems of operating a condensate reservoir by pressure depletion. Thus, on noting that the specific volumes of the single-phase dew-point fluids for curves I, II, III, and IV are 0.04909, 0.05450, 0.06901, and 0.04888 ft³/lb, it follows that the maximum condensation volumes will represent, respectively, 18.1, 11.2, 2.75, and 16.4 per cent of the original hydrocarbon

[1] The maximum condensation pressures are rather high in Fig. 13.2 because of the relatively low gas-oil ratios of the mixtures. They decrease with increasing gas-oil ratios or with decreasing composite reservoir fluid density and often lie in the range of 1,000 to 1,500 psi for actual systems.

volume or pore space. If ρ_l are these values expressed as fractions and the connate-water saturation is ρ_w, the maximum possible total average liquid saturation that could develop by this process would be $\rho_w + \rho_l(1 - \rho_w)$. Even if the condensate is added to the water as a continuous liquid phase, its permeability would evidently be extremely low. It is more probable, however, that the condensate would be distributed as a dispersed phase and have no permeability whatever except possibly under the very high pressure gradients near a well bore.[1] The condensate will therefore remain trapped and lost until partial revaporization sets in after the pressures fall below the point of maximum condensation. It is this potential loss of the liquid content of the reservoir fluids that plays a major role in evaluating the reservoir and in determining the method of development and operation.

While the curves of Fig. 13.2 demonstrate the basic retrograde characteristics of condensate-reservoir fluids and the resulting danger of loss in condensate recovery, they are not of quantitative significance for two reasons. Even if the pressure decline in practice followed the flash process, the total liquid-phase separation plotted in Fig. 13.2 would not represent actual volumes of stock-tank liquid product. For this liquid phase will contain appreciable concentrations of the lighter hydrocarbons, which would separate as a gas at atmospheric conditions. More fundamental is the fact that if the pressure declines at all, it is the result of a removal of part of the reservoir fluids. As only the gas phase will be produced, because of the lack of mobility of the condensed-liquid phase, the composition of the system will constantly change. The reservoir will therefore undergo a differential process of pressure decline and depletion. The amount of liquid condensation under such conditions will evidently be lower than when all the gas phase is maintained in contact with the liquid. It is from experiments in which the pressure decline in the sample container is caused by gas-phase withdrawal that the phase and volumetric data simulating the depletion performance of an actual condensate reservoir can be obtained.

The gross phase and composition characteristics of a condensate-producing reservoir undergoing pressure depletion are illustrated in Fig. 13.3,[2] obtained by a combination of experimental data and calculated analyses for a gas-cap fluid having a dew point of 2,960 psi at a reservoir temperature of 195°F. It will be noted that here the maximum liquid condensation represents only 8.2 per cent of the hydrocarbon pore space. Moreover the volume that the C_4+ fraction would occupy at 60°F is only about 70 per cent of the total at the maximum retrograde point. The C_4+ content of

[1] This situation is entirely analogous to the immobility of a low-saturation distributed gas phase until it builds up to the "equilibrium saturation" (cf. Sec. 7.6).

[2] Figure 13.3, as well as Figs. 13.4 and 13.5, are taken from M. B. Standing, E. W. Lindblad, and R. L. Parsons, *AIME Trans.*, **174,** 165 (1948).

the produced gas, *i.e.*, the gas phase in equilibrium with the reservoir liquid, declines from its initial value of 5.4 gal/10^3 ft^3 to a value of 3.2 gal/10^3 ft^3 as the liquid condensation increases in the reservoir. Shortly after normal vaporization sets in, the C_4+ content of the gas rises sharply, while the

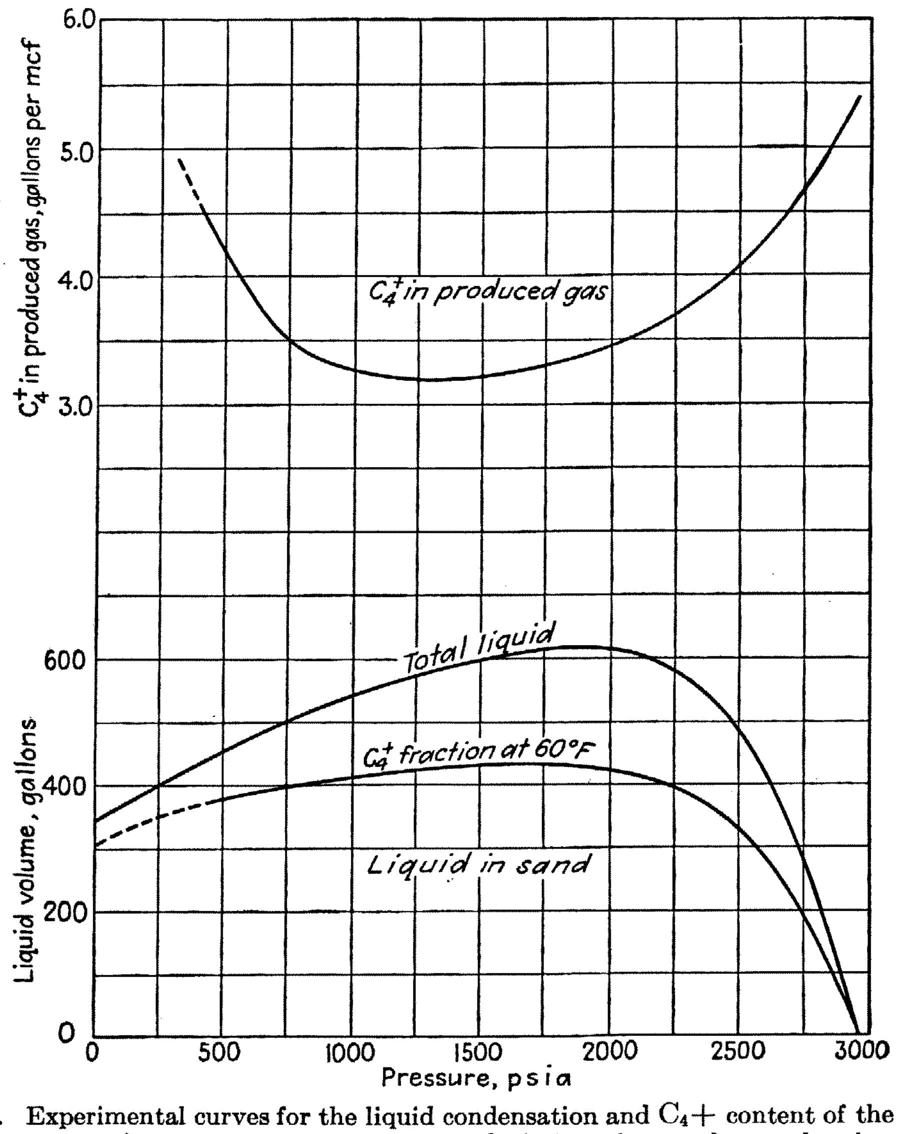


FIG. 13.3. Experimental curves for the liquid condensation and C_4+ content of the produced gas, as a function of pressure, resulting from the depletion of a condensate-bearing reservoir. Liquid volumes refer to an initial hydrocarbon space volume of 10^3 ft^3. (*After Standing, Lindblad, and Parsons, AIME Trans., 1948.*)

reservoir liquid volume declines on further pressure reduction. If all the C_4+ in the produced gas were converted to a liquid phase, the upper curve of Fig. 13.3 would also give the variation in the effective gas-liquid ratio of the composite well stream during the producing life.

The detailed composition history of the condensed-liquid phase in the reservoir is shown in Fig. 13.4. It will be seen that the concentrations of the lighter and more volatile components, methane, ethane, and propane, decrease continuously with declining pressure.[1] At the same time the heaviest component, C_7+, increases monotonically in concentration. The intermediate constituents tend to fall somewhat in concentration at first,

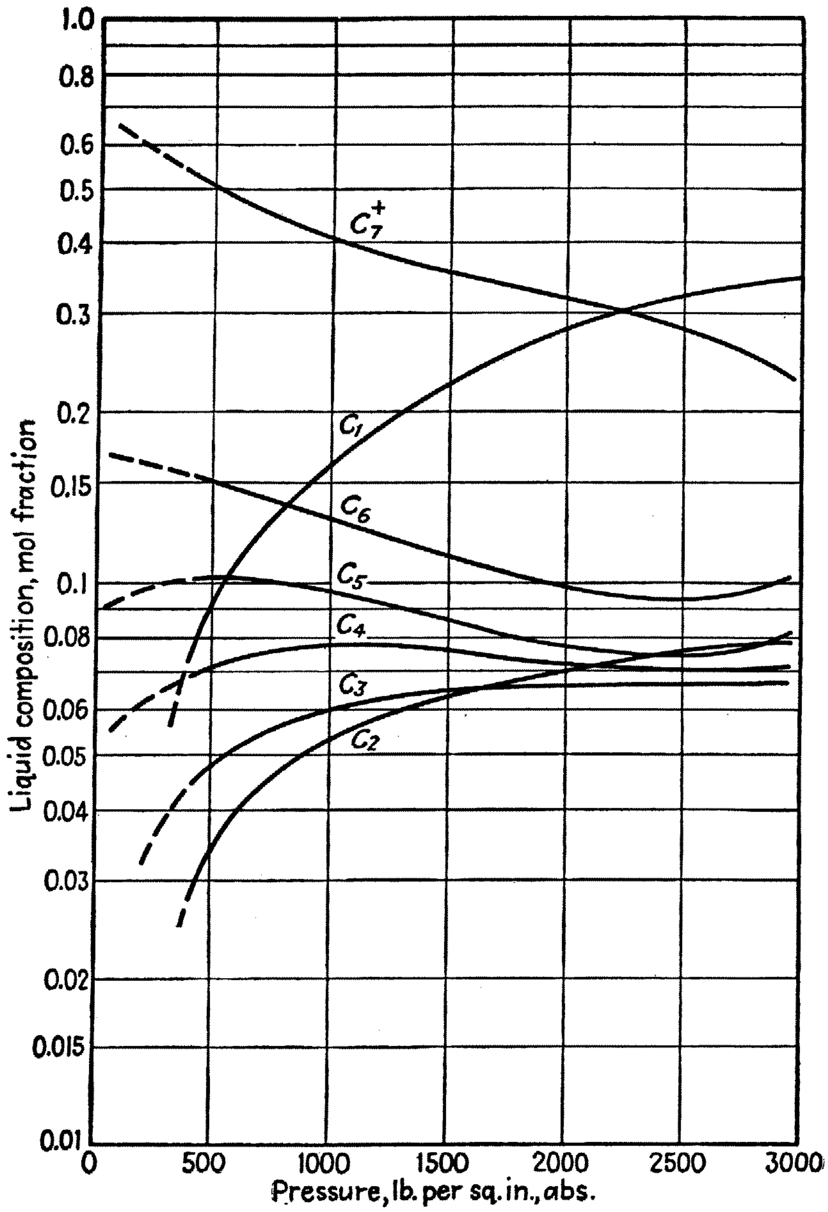


FIG. 13.4. Experimental curves for the composition history of the reservoir liquid phase for the system described by Fig. 13.3. (*After Standing, Lindblad, and Parsons, AIME Trans., 1948.*)

then rise for varying pressure intervals and, in the case of C_4 and C_5, begin another decline in the lower pressure range. The API gravity of the reservoir liquid phase will evidently show a continual decrease as the pressure declines.

[1] The composition of the first liquid phase formed on pressure decline should be identical with that of any reservoir liquid or gas-saturated crude oil lying below and in equilibrium with the condensate-reservoir dew-point gas.

The composition of the gas phase or produced gas corresponding to Figs. 13.3 and 13.4 is plotted vs. the pressure in Fig. 13.5. The general behavior of the liquefiable components, C_4 and heavier, simulates that of

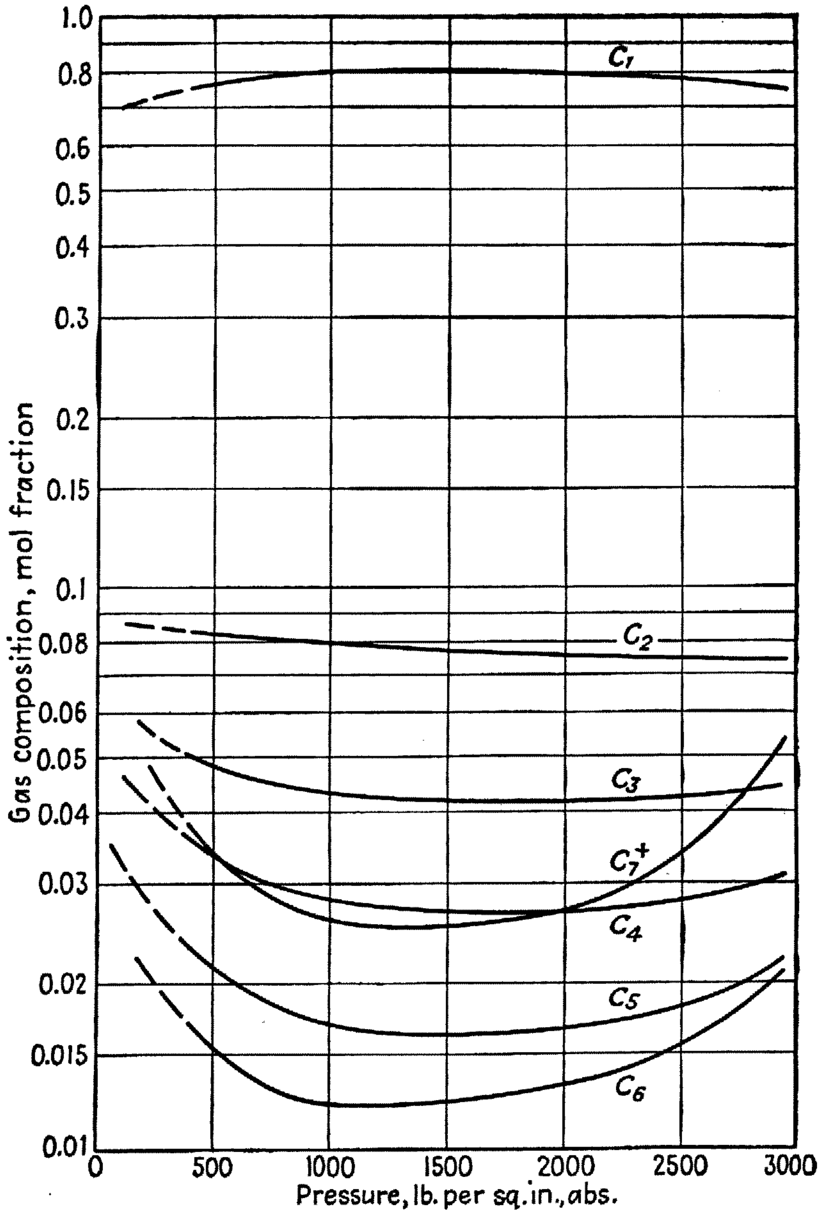


FIG. 13.5. Experimental curves for the composition history of the produced fluids for the system described by Fig. 13.3. (*After Standing, Lindblad, and Parsons, AIME Trans., 1948.*)

the composite C_4+ curve of Fig. 13.3. The concentrations of the volatile constituents, C_1 to C_3, do not change greatly from their initial values in the dew-point fluid. Such curves are of particular value in predicting the nature of the product to be recovered from the reservoir at any state of depletion, as well as the cumulative recoveries. Thus, the cumulative number of moles of the ith component, N_i, per unit volume of hydrocarbon reservoir space, recovered by the time the pressure has declined from its initial value p_i to p is

$$N_i = \frac{1}{RT} \int_p^{p_i} \frac{n_i \, dp}{Z}, \tag{1}$$

where n_i is the current mole fraction concentration, as given by Fig. 13.5, R is the gas constant per mole, T the reservoir temperature, and Z is the deviation factor of the gas, which usually can be calculated with satisfactory accuracy from the composition (cf. Sec. 2.7). The assumption of a slow variation of Z and neglect of the liquid-phase volume, implied by the form of Eq. (1), should not involve serious errors from a practical standpoint. From the cumulative molar recovery, as calculated by Eq. (1), the total liquid-phase recoveries of various heavy-component groupings can be computed. Moreover by application of the equilibrium ratios (cf. Sec. 2.10) the separation of all the components at the surface between the gas and liquid phases can be calculated, and their individual contributions to the cumulative recoveries can be determined as a function of the pressure. The cumulative recoveries computed in this manner for another condensate-producing reservoir are plotted in Fig. 13.6.[1] The curve indicated as "stable condensate" represents the total liquid phase produced in the stock tank through the separators.

The original hydrocarbon contents of the reservoir fluids to which Fig. 13.6 refer were, per 10^6 ft^3 of pore space, 17,490, 18,710, 21,220, and 23,650 bbl of n-C_5+, i-C_5+, n-C_4+, and i-C_4+, respectively. From Fig. 13.6 it is seen that, if the reservoir were produced by simple depletion to a pressure of 500 psi, the cumulative production will contain 8,600 bbl of n-C_5+, 9,770 bbl of i-C_5+, 11,380* bbl of n-C_4+, and 13,680 bbl of i-C_4+, per 10^6 ft^3 of pore space. These represent 49.2, 52.2, 53.6, and 57.8 per cent of the original content, respectively. Conversely, 50.8, 47.8, 46.4, and 42.2 per cent of these components, respectively, would be lost in the reservoir if it were produced to 500 psi by pressure depletion.

It should be noted that the curves of Fig. 13.6, as derived by an integration of composition curves such as those of Fig. 13.5, on applying Eq. (1),† refer to the total recoverable liquid products from the well stream. This implies that the well fluids are processed by a hydrocarbon-extraction plant, so as to remove the condensable components from the separator gases. If only the stable liquid components of the stock-tank condensate were recovered without processing of the gas, a considerably lower part of the

[1] This is taken from E. W. McAllister, *California Oil World*, **38** (No. 20), 19 (1945).

* This is not indicated on Fig. 13.6 but is tabulated separately by McAllister (*ibid.*).

† Usually, however, the variation of Z is neglected, and the areas under the curves of Fig. 13.5 are taken as equivalents of the integral of Eq. (1)

original condensable hydrocarbon content would be recovered. The difference will generally be of increasing importance as the gas-oil ratio increases, since the greater volumes of gas phase can carry off correspondingly higher fractions of the total condensable product. In some cases as much

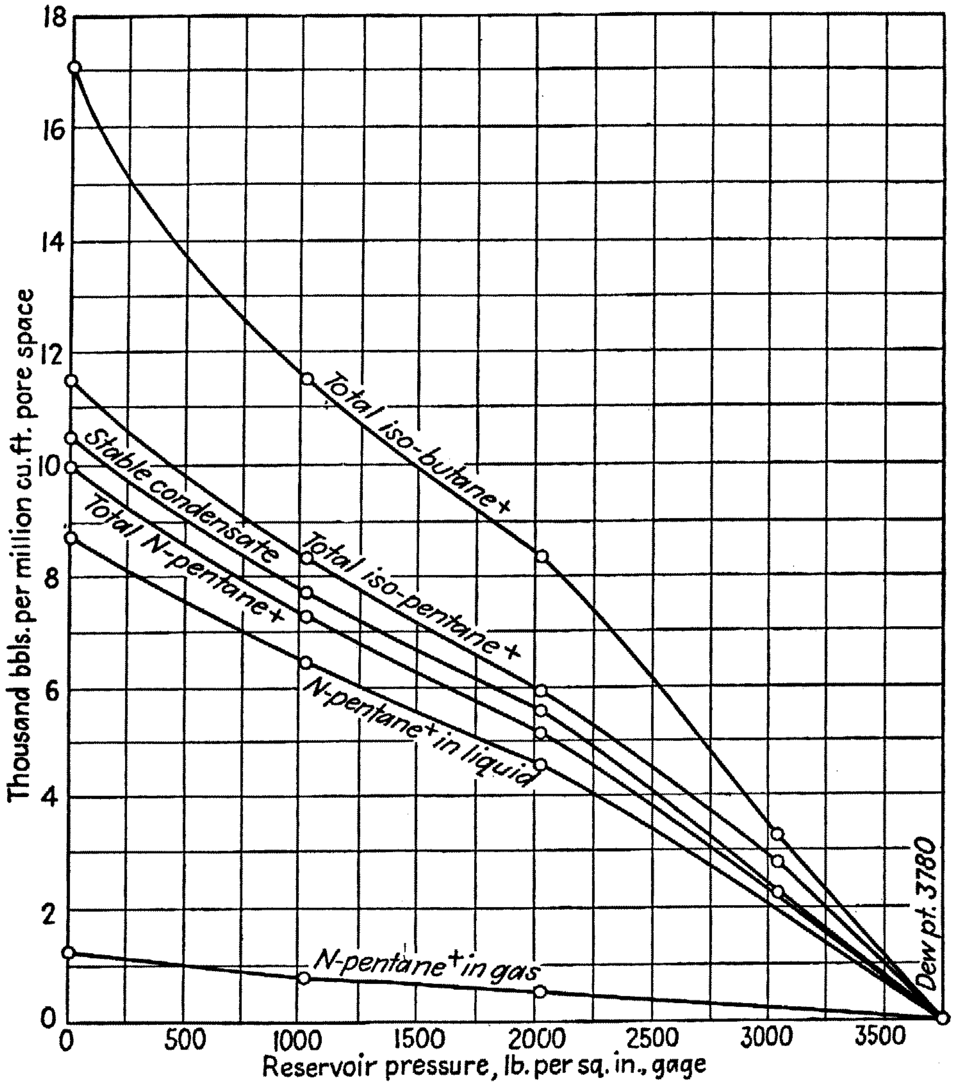


FIG. 13.6. Experimental curves for the cumulative recoveries of the heavier components of a condensate-bearing fluid obtained by reservoir pressure depletion. (*After McAllister, California Oil World, 1945.*)

condensable liquid product will be lost in the gas phase as is recovered directly, so that the recoveries of the C_4+ components without plant extraction or multiple stage separation might be half of that indicated by such curves as Fig. 13.6. The magnitude of the recovery without gas processing can be determined by calculating the current gas-liquid-phase separation, by whatever separator system is used, from the composition of the produced fluid, as given by curves such as those of Fig. 13.5, and integrating over the pressure decline by means of Eq. (1).

Additional numerical illustrations of the gross performance of actual condensate reservoirs under normal depletion, as predicted by experimental studies on a set of six condensate-bearing fluids, are reproduced in Table 3.[1] While no systematic correlations can be derived from the six examples of Table 3, since they vary so widely in the controlling conditions, the order of magnitude of the general numerical features of the performance is clearly indicated. Thus the stable-condensate recoveries by pressure depletion for the six samples fall in the range of 44.5 to 65.8 per cent of the initial contents. The corresponding reservoir losses range from 55.5 to 34.2 per cent. It will be noted, too, that, whereas all the produced stable condensate will be recovered by three-stage separation, the pentanes plus recoveries from the produced wet gas will be of the order of 70 to 80 per cent. And from 75 to 90 per cent of the produced butanes will be lost in the separator gas if it is not further processed.

In contrast to crude-oil-producing reservoirs the gross depletion history of condensate systems is substantially independent of the dynamical characteristics of the reservoir, it being assumed that it is not subject to significant water intrusion. The relation between the cumulative recovery and the average pressure may be constructed similarly to Eq. (1) and may be verified to be

$$\overline{P} = \int_{p}^{p_i} \frac{dp/p_i}{Z/Z_i}, \tag{2}^*$$

where $\overline{P}$ is the cumulative recovery expressed as a fraction of the total initial molar content and p_i, Z_i are the initial pressure and deviation factor of the reservoir gas. The liquid condensation has been neglected, in constructing Eq. (2), both with respect to its volumetric displacement of reservoir gas-phase volume and its hydrocarbon content. It has already been noted that the volume occupied by the reservoir condensate will generally be small. And while a substantial part of the total condensable component of the hydrocarbon mixture may be retained in the reservoir liquid phase, this will still represent but a small part of the total molar content of the reservoir.

As Z is a slowly varying function of the pressure, Eq. (2) implies an approximately linear decline of the pressure with the cumulative molar recovery. In terms of the condensate recovery the pressure will decline more rapidly than linearly,[2] up to the pressure of maximum retrograde

[1] This table is a composite of those given by B. W. Whiteley, AIME meetings, College Station, Tex., December, 1947.

* Equation (2) will be quantitatively accurate in "dry-" gas fields, where there is no reservoir condensation, either because the state of the reservoir gas lies on the lower dew-point-curve segment, or because its cricondentherm temperature is lower than the reservoir temperature (cf. Sec. 13.10).

[2] This will be partly compensated by the decrease in Z as the pressure declines.

TABLE 3.—THE PRESSURE-DEPLETION PERFORMANCE OF CONDENSATE RESERVOIRS AS DETERMINED BY THE ANALYSIS OF VARIOUS RESERVOIR-FLUID SAMPLES

Sample	(1)		(2)		(3)		(4)		(5)		(6)	
	Bbl/10^6 ft^3	%	Bbl/10^6 ft^3	%	Bbl/10^6 ft^3	%	Bbl/10^6 ft^3	%	Bbl/10^6 ft^3	%	Bbl/10^6 ft^3	%
Original content:												
Butanes	33.8	100	7.9	100	17.2	100	24.0	100	14.1	100	12.6	100
Pentanes plus	64.5	100	26.6	100	53.0	100	85.3	100	55.9	100	94.0	100
Hexanes plus	—	—	23.5	100	42.5	100	—	—	46.3	100	83.3	100
Stable condensate	60.1	100	22.5	100	45.4	100	85.1	100	44.0	100	93.5	100
Produced in wet gas:												
Butanes	33.4	98.8	6.8	86.0	15.0	87.2	23.6	98.3	13.3	94.3	12.4	98.4
Pentanes plus	32.4	50.2	17.0	63.9	32.7	61.6	55.9	65.5	29.5	52.8	51.7	55.1
Hexanes plus	—	—	14.0	59.5	24.8	58.4	—	—	23.5	50.7	42.9	51.5
Stable condensate	26.7	44.5	13.0	57.8	29.9	65.8	51.1	60.1	21.8	49.5	44.7	47.8
Retrograde loss in reservoir:												
Butanes	0.4	1.2	1.1	14.0	2.2	12.8	0.4	1.7	0.8	5.7	0.2	1.6
Pentanes plus	32.1	49.8	9.6	36.1	20.3	38.4	29.4	34.5	26.4	47.2	42.3	44.9
Hexanes plus	—	—	9.5	40.5	17.7	41.6	—	—	22.8	49.3	40.4	48.5
Stable condensate	33.4	55.5	9.5	42.2	15.5	34.2	34.0	39.9	22.2	50.5	48.8	52.2
Stock-tank liquid recovery by three-stage separation:												
Butanes	3.2	9.5	—	—	—	—	4.2	17.5	1.6	11.3	3.1	24.6
Pentanes plus	23.8	36.9	—	—	—	—	45.4	53.2	21.4	38.3	41.6	44.4
Hexanes plus	—	—	—	—	—	—	—	—	20.6	44.5	37.2	44.6
Stable condensate	26.7	44.5	13.0	57.8	29.9	65.8	51.1	60.1	21.8	49.5	44.7	47.8
Loss in separator gas:												
Butanes	30.2	89.3	—	—	—	—	19.4	80.8	11.7	83.0	9.3	73.8
Pentanes plus	8.6	13.3	—	—	—	—	10.5	12.3	8.1	14.5	10.1	10.7
Hexanes plus	—	—	—	—	—	—	—	—	2.9	6.2	5.7	6.9
Stable condensate	0	0	0	0	0	0	0	0	0	0	0	0
Reservoir pressure, psia	5,670		4,965		3,765		3,780		4,267		4,595	
Reservoir temp., °F	124		207		228		247		197		265	

condensation, because of the increasing gas-oil ratios (cf. Fig. 13.3). At still lower pressures the slope of the pressure vs. oil-recovery curve should decrease somewhat as the gas-oil ratios decrease.

As a gross index of the "richness" of condensate-reservoir gases and of their changes during the producing life it is convenient to use the terms "gas-liquid," "gas-oil," or "gas-condensate ratios,"[1] although values of these ratios are, of course, of significance only if the separator conditions are fixed. For the initial characterization of a condensate reservoir the gas-condensate ratio may serve to indicate whether it is "rich" or "lean." While these terms do not have precise definitions, it is generally agreed that a gas-condensate ratio of 15,000 ft^3/bbl or less implies a rich gas and that if the ratio exceeds 40,000 ft^3/bbl the reservoir gas is lean.

It should be noted, however, that for the strict evaluation of condensate-producing reservoirs the terms "gas" and "liquid" no longer have quantitative significance. As shown by Fig. 13.5 the "gas" entering the well bores will vary considerably in composition during the producing life. It is, indeed, just this variation that reflects the basic phenomenon of retrograde condensation in the reservoir, and the trapping of the condensed-liquid phase in the producing formation, if the latter is operated by simple pressure depletion. And as indicated in Fig. 13.4 the composition of the reservoir liquid phase may vary during the producing life even more than the composite produced fluids.

The alternative to the fluid phase as a basis for the identification of the hydrocarbons produced from a condensate reservoir is evidently a composition grouping. A procedure sometimes used is that of classifying the total C_4+ content of the reservoir or produced fluids as "plant product" and the remainder as gas. The plant product, so defined, corresponds to the total stable liquid phase that is usually extracted by gas-processing plants. In making detailed economic appraisals of condensate-reservoir-development programs it may be necessary further to subdivide the produced fluids into components such as "stable condensate," gasoline fractions, "liquefied gases," etc., which are individually specified by composition. However, an accounting in terms of the i-C_4+ and C_7+ constituents will often suffice for preliminary economic-evaluation purposes.

It is possible to develop a material-balance equation for condensate reservoirs generalizing Eq. 9.5(6) for crude-oil fields, and also free of the assumptions underlying Eq. (2). However, in place of the usual p-V-T characteristics of the reservoir fluids it involves such empirical properties of the gas and liquid phases that their determination would be almost as

[1] An equivalent representation often used is the C_5+ or C_4+ content of the gas in gallons per 10^3 ft^3, since 1 gal/10^3 ft^3 corresponds to a gas-liquid ratio of 42,000 ft^3/bbl if all the heavier components were transformed to the liquid phase.

involved as the experimentation required to establish Figs. 13.3 to 13.6. Because of this severe limitation on its applicability it will not be considered further here. Equation (2) and simple modifications for the cases of gas injection or water intrusion should suffice for most practical purposes as far as the condensate reservoir itself is concerned.

13.4. Cycling—General Considerations.—As implied by Eq. 13.3(2) the fractional recovery of the molar hydrocarbon content of a condensate-producing reservoir will be approximately equal to the fractional decline in pressure. Hence, if the initial pressure is 4,000 psi, approximately 87½ per cent of the original hydrocarbon content will be recovered by the time the pressure declines to 500 psi. On the other hand, as was noted in Sec. 13.3, in some cases about half of the heavy components (C_5+) may still be left in the reservoir owing to retrograde condensation. Because of the considerably greater market value of the liquid hydrocarbon products the loss of the heavy fractions will represent a substantial part of the total value of the initial hydrocarbon mixture. Thus, if the latter corresponds to a gas-liquid ratio of 10,000 ft^3/bbl, if the market price of the dry gas is \$0.10 per thousand cubic feet, and if the average of that of the liquid products is \$2.50 per barrel, a recovery of 87½ per cent of the gas and 60 per cent of the liquid products would be equivalent to only 67.9 per cent of the initial value of the hydrocarbon reserves. And the 40 per cent of the condensable hydrocarbons left in the reservoir would represent 28.6 per cent of the gross initial value. The economic significance of the liquid products lost by condensation within the reservoir will, of course, depend on the inherent richness of the reservoir fluid, or the initial gas-oil ratio, and the actual magnitudes of the retrograde losses. In principle, however, it is generally possible to prevent at least a large part of this loss by operations termed "cycling," which will now be considered.

Cycling is simply the process of injecting "dry" gas into a condensate-producing reservoir to replace the reservoir fluid withdrawals—the "wet" gas—so as to maintain the reservoir pressure[1] and prevent retrograde condensation of a liquid phase within the porous medium. Cycling is sound from a physical point of view. Its practical value in specific cases is determined entirely by the economic balance[2] between the cost of the operations and the gain in recovery as compared with pressure depletion. The former depends mainly on the additional well-development cost required

[1] This could also be accomplished by water injection, although the economics of water injection except as a supplementary measure for pressure maintenance will usually compare unfavorably with gas injection.

[2] For a general discussion of the economic aspects of cycling cf. W. H. Woods, *Oil and Gas Jour.*, **46**, 89, 99 (Aug. 16, 23, 1947); cf. also E. Kaye, *AIME Trans.*, **146**, 22 (1942); E. O. Bennett, R. C. Williams, and G. O. Kimmell, *Petroleum Eng.*, **13** (No. 10), 99 (1942).

for the cycling program, the amount of compression needed to bring the processed[1] gas to the injection-wellhead pressures, and the volume of gas to be handled to ensure a reasonable operating life. The latter is given essentially[2] by the product of the fractional initial-oil content, per unit hydrocarbon pore volume, which would be left in the reservoir by pressure depletion, times the total hydrocarbon pore volume swept out by the injected gas during the life of the operations, if equivalent gas-processing plants be assumed available with and without cycling. The retrograde-condensation losses, which are the basic reason for considering cycling at all, have been discussed in the preceding section and, as noted there (cf. Table 3), can be determined by suitable experimentation with and analysis of the original reservoir fluids. The reservoir volume swept out by the injected dry gas is largely controlled by the geometry of the injection- and producing-well pattern and the uniformity of the reservoir formation. These will be discussed in the next several sections.

13.5. Analytical Determinations of the Sweep Efficiencies of Cycling Patterns.—The basic method of calculation of sweep efficiencies for cycling patterns is the same as that outlined in Sec. 12.6 for the steady-state homogeneous-fluid treatment of secondary-recovery operations. Since the dry-gas-injection rates in cycling are frequently substantially equal to those of the wet-gas withdrawals, the steady-state representation should provide a practical and reasonably accurate approximation. The assumption of equal viscosities and deviation factors for the dry and wet gases will also involve errors of negligible significance, compared with the basic idealization of reservoir uniformity that underlies virtually all analytical treatments.[3] And for purposes of simplicity the sweep-efficiency analysis will be carried through as if the fluid were an incompressible liquid. Although the sweep efficiencies, flow pattern, and injection fronts for gas flow will not be strictly identical to those for liquids, the differences will not be of importance unless the total pressure differential between the injection and producing wells is very large (cf. Sec. 13.6).

In contrast to the areal interlaced distribution of injection and producing wells commonly used in secondary-recovery operations, cycling patterns are generally developed by segregating the injection and pro-

[1] In all cycling operations the separator gas is passed through extraction plants to remove the condensable hydrocarbons before returning the stripped gas to the formation. In fact this additional liquid-product recovery itself often represents a large part of the total gain from the cycling operations.

[2] A more detailed discussion of the comparative recoveries and economics of cycling and pressure-depletion operations will be given in Sec. 13.10.

[3] In Sec. 13.8 the theory will be given of the effect of permeability stratification. However, lateral and areal variations in permeability and thickness are, for practical purposes, beyond the scope of tractable analysis.

ducing wells. Because of the smaller potential value of the recoverable reserves in condensate-bearing reservoirs[1] and their greater average depths it is necessary to minimize the well investment. In fact, average well spacings of 320 acres per well are often used in condensate fields. While higher well densities would shorten the operating life, the increased cost of the wells and of the larger capacity gas-processing and compression plants severely limits the total well density. Moreover the number of injection wells often is considerably smaller than the number of producing wells.

To make most efficient use of the rather small number of wells drilled for cycling programs the injection and producing wells are generally located along the reservoir boundaries. If the reservoir area is approximately rectangular, the injection wells may be placed along one side and the producing wells along the opposite side, so as to give an "end-to-end" sweep. The injection wells may also be distributed at the center of the reservoir and the producing wells along the whole peripheral productive boundary. Or they can be inverted, with the injection wells placed at the boundary. The particular pattern to be used must, of course, be fitted to the gross geometry of the reservoir in question.

While an interior well distribution for the same total well density would permit more flexible control over the operations, a more complete accumulation of reservoir information, and the earlier detection of the development of channeling or the effects of reservoir inhomogeneities, the over-all sweep efficiencies in uniform formations will be greater for greater average separations between the injection and producing wells. The "dead" areas in sweep patterns are often concentrated about the producing wells, owing to the cusping of the injection fluid as it enters the region of the local pressure distributions created by the producing wells. These dead areas will be rather insensitive to the nature of the injection-well distribution and their location, provided that the relative production and injection rates are kept fixed, and as long as the average separation between wells of the same kind is appreciably less than the average separation of wells of different kind. Hence the fractional loss in sweep area represented by these unswept regions will decrease as the total area to be swept, or the distance between the injection and producing wells, increases.

The simple case of an end-to-end sweep between parallel single lines of injection and producing wells can be easily treated analytically.[2] Upon

[1] Even a "rich" reservoir gas, which would produce at a ratio of 10,000 ft^3/bbl of condensate, would have a total condensate content of only 215 bbl/acre-ft of reservoir volume, if the pressure is 300 atm., temperature is 200°F, deviation factor is 0.9, and the porosity and connate-water saturations are each 25 per cent.

[2] Since this treatment is given only to illustrate the basic features of cycling patterns in which the injection and producing wells lie oppositely along the actual reservoir

placing for convenience the x axis parallel to and midway between the injection and producing wells (cf. Fig. 13.7), the pressure distribution will be

$$p(x,y) = \frac{Q\mu}{4\pi kh} \log \frac{\cosh 2\pi(y-d)/a - \cos 2\pi x/a}{\cosh 2\pi(y+d)/a - \cos 2\pi x/a}, \tag{1}$$

where Q is the common injection and producing rate, in reservoir measure, of the wells in the two lines, μ the gas viscosity, k the permeability, h the pay thickness, a the well separation within the lines, and $2d$ the distance between the lines. Equation (1) evidently is a simple superposition of the pressure distributions for the individual lines as given by Eq. 12.2(1).

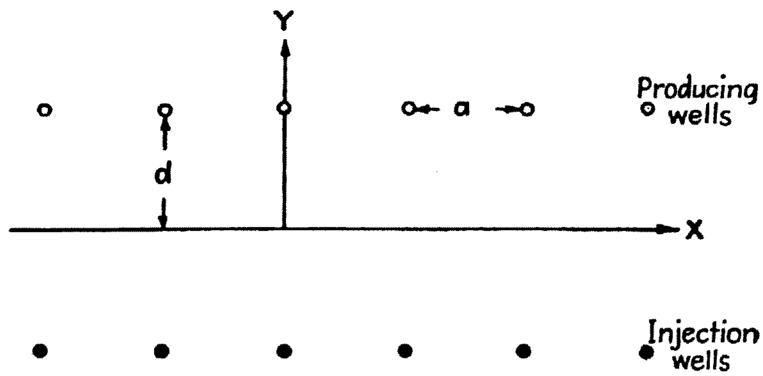


FIG. 13.7. A diagrammatic representation of a parallel-line cycling pattern.

The fluid velocity between the injection and producing wells along the y axis is therefore

$$v_y = -\frac{k}{\mu \bar{f}} \frac{\partial p}{\partial y}\bigg|_{x=0} = -\frac{Q}{2a\bar{f}h} \frac{\sinh 2\pi d/a}{\sinh \pi(y-d)/a \sinh \pi(y+d)/a}, \tag{2}$$

where $\bar{f}$ is the displacement porosity, *i.e.*, the porosity times the fraction of the pore space occupied by the dry gas.

The shortest time of travel between the injection and producing wells will therefore be

$$t = 2\int_0^d \frac{dy}{v_y} = \frac{2\bar{f}a^2h}{Q}\left(\frac{d}{a}\coth\frac{2\pi d}{a} - \frac{1}{2\pi}\right), \tag{3}$$

implying a sweep efficiency E given by

$$E = \frac{Qt}{2adh\bar{f}} = \coth\frac{2\pi d}{a} - \frac{a}{2\pi d}. \tag{4}$$

As is to be expected, E increases uniformly from 0 at $d/a \ll 1$, to 1 at $d/a \gg 1$. Thus for $d/a = 0.1$, 1, and 5, E will be 0.204, 0.841, and 0.968,

boundaries, the analysis is based on the simplifying assumption of an infinite-reservoir area. The infinite-medium assumption will also be made in the discussion of the circular cycling pattern, although it is possible to treat in both cases also the finite-reservoir systems.

respectively. The unswept area per unit injection- and producing-well pair is readily seen to be

$$A = 2ad\left(1 - \coth\frac{2\pi d}{a}\right) + \frac{a^2}{\pi}. \tag{5}$$

Hence for $d/a \geqslant 1$ the unswept area at the time of first dry-gas entry into the producing wells has the constant value a^2/π, independent of the exact value of d. Equations (4) and (5) verify the previously outlined qualitative

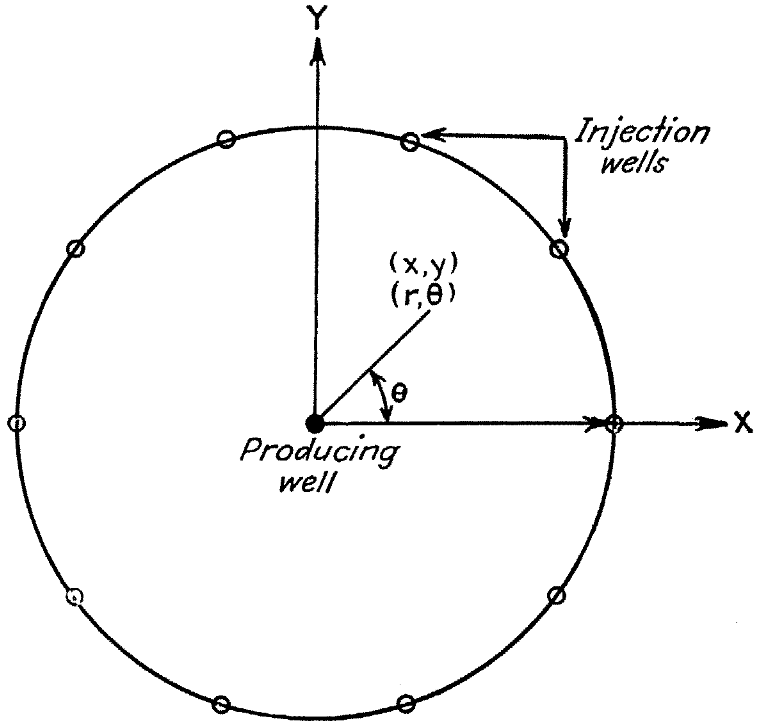


FIG. 13.8. A diagrammatic representation of a circular cycling pattern.

considerations indicating the increasing sweep efficiency with increasing separations between the injection and producing wells.[1]

Equation (1) also describes the pressure distribution between a continuous line drive at $y = 0$ and the line of producing wells along $y = d$. The sweep efficiency will be given by Eq. (4) also for this case, although the shapes of the injection-fluid fronts will be quite different. The dead areas per producing well will be half of those of Eq. (5) for the end-to-end sweep pattern.

Peripheral injection into a circular ring of wells, in an infinite area, and production from the center (cf. Fig. 13.8), or the same basic pattern with the injection and producing wells reversed can also be treated analytically. Thus it may be verified that the pressure distribution and stream functions,

[1] This principle is also well illustrated and demonstrated by the curves of Fig. 12.8, which show that in infinite line-drive networks the sweep efficiency also increases as the separation between the injection and producing lines increases.

p and Ψ, are given by the real and imaginary parts, respectively, of the complex potential function

$$p + i\Psi = \frac{Q\mu}{2\pi kh}\left[\log z - \frac{1}{n}\log(z^n - R^n)\right], \tag{6}$$

where R is the radius of the circular ring, Q is the injection or producing rate of the central well, and z is the complex coordinate variable $x + iy$, or $re^{i\theta}$ (cf. Fig. 13.8). It follows from Eq. (6) that

$$p(r,\theta) = \frac{Q\mu}{2\pi kh}\left[\log r - \frac{1}{2n}\log(r^{2n} + R^{2n} - 2r^nR^n\cos n\theta)\right] + \text{const.} \tag{7}$$

The fluid velocity between the injection and producing well along $\theta = 0$ is, then,

$$v_r = -\frac{k}{\mu\bar{f}}\left(\frac{\partial p}{\partial r}\right)_{\theta=0} = -\frac{Q}{2\pi h\bar{f}r}\cdot\frac{R^n}{R^n - r^n}. \tag{8}$$

The time of travel between the injection and producing wells is therefore

$$t = \int_R^0 \frac{dr}{v_r} = \frac{\pi h\bar{f}nR^2}{Q(n+2)}, \tag{9}$$

and the sweep efficiency for the area enclosed by the circular ring of wells will be

$$E = \frac{n}{n+2}. \tag{10}^*$$

For a single injection- and producing-well pair ($n = 1$), Eq. (10) gives $E = \frac{1}{3}$, which agrees, as it should, with that found in Sec. 12.10 [cf. Eq. 12.10(12)]. Equation (10) also shows that the sweep efficiency rapidly approaches unity as n increases and that the gain resulting from additional wells decreases as $2/(2 + n)^2$.

By exactly the same method it may be shown that if the injection and producing wells are both equally spaced at angles $2\pi m/n$, $m < n$, on concentric rings of radii with a ratio R, the sweep efficiency will be

$$E = \frac{n}{R^2(R^n - 1)}\left(\frac{R^{n+2} - 1}{n+2} - \frac{R^n - R^2}{n-2}\right), \quad n \neq 2. \tag{11}\dagger$$

* Equation (10) has also been derived by a somewhat different procedure by B. D. Lee, *AIME Trans.*, **174**, 41(1948).

† For $n = 2$ the equation involves a logarithmic term. For $n = 1$, however, it becomes equivalent to $E = \frac{1}{3}$, as it should when properly interpreted. For the similar problem of a continuous circular line drive of radius r_e into a concentric circular ring of radius R, of n producing wells, which is of interest in the development of complete-water-drive reservoirs, the sweep efficiency may be shown to be

$$1 - \frac{2R^2}{n-2}\left\{\frac{1 - (R/r_e)^{n-2}}{r_e^2 - R^2}\right\}, \quad \text{for} \quad r_e \gg R.$$

It will be clear that, when $R \gg 1$, Eq. (11) reduces to Eq. (10). But at moderate values of R and n there will be an appreciable difference between the sweep efficiency for the concentric rings and a single central well. Thus if $R = 5$ and $n = 3$, Eq. (11) gives $E = 0.508$, whereas Eq. (10) gives $E = 0.60$. And for $R = 10$, $n = 3$, Eq. (11) gives $E = 0.574$. This, too, implies greater sweep efficiencies as the injection- and producing-well separations are increased.

By using potential-theory methods, such as applied in Sec. 12.6 for the calculation of sweep efficiencies in regular well networks, the characteristics

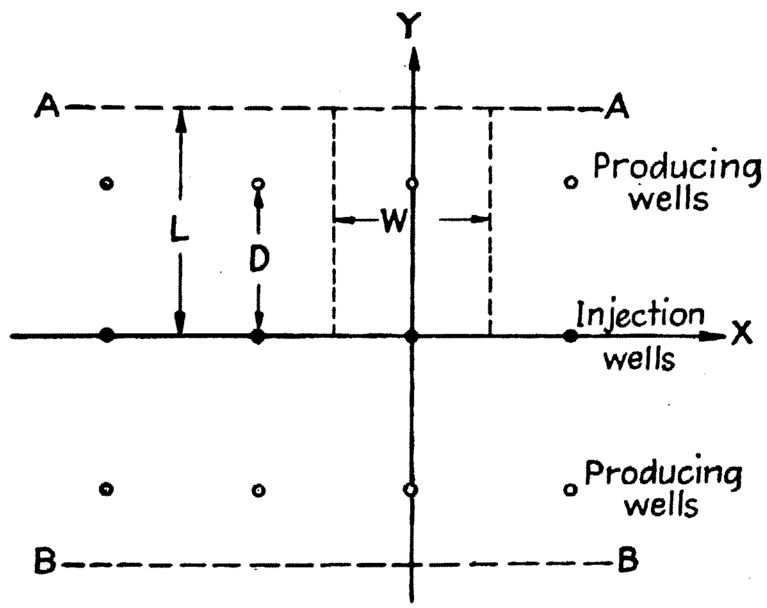


FIG. 13.9. A diagrammatic representation of a bilateral cycling pattern.

of bilateral cycling patterns have also been determined[1] analytically. Here, as seen in Fig. 13.9, the injection wells are placed along the central axis of the reservoir and the producing wells on either side—or conversely—the field boundaries being represented by AA, BB. The geometry of this system is determined by the length-to-width ratio of the basic rectangle, L/W, and the ratio of the separation between the injection and producing lines to the spacing within the lines, D/W (cf. Fig. 13.9). Typical results[2] of the analysis are illustrated by Figs. 13.10 and 13.11 for $D/W = 1.25$ and 1.75, respectively, L/W being 1.75 in each case. To the left of Figs. 13.10 and 13.11 are the equipressure contours (p = const) and streamline (Ψ = const) distributions. To the right are injection-fluid fronts, on each of which are indicated the fraction of wet gas in the production, the fraction

[1] Cf. W. Hurst and A. F. Van Everdingen, *AIME Trans.*, **165**, 36 (1946).

[2] Only the upper halves of the pressure and streamline distributions and fluid fronts in a bilateral system are plotted in Figs. 13.10 and 13.11, since by symmetry those in the lower halves will simply be their reflections in the X axis.

of total wet gas displaced, and the total gas processed, or throughflow, divided by the gas originally in place.

Figures 13.10 and 13.11, as well as calculations for other cases, show again the increasing sweep efficiency as the distance between the injection and producing wells is increased. Thus, for Fig. 13.10, $E = 0.492$, whereas

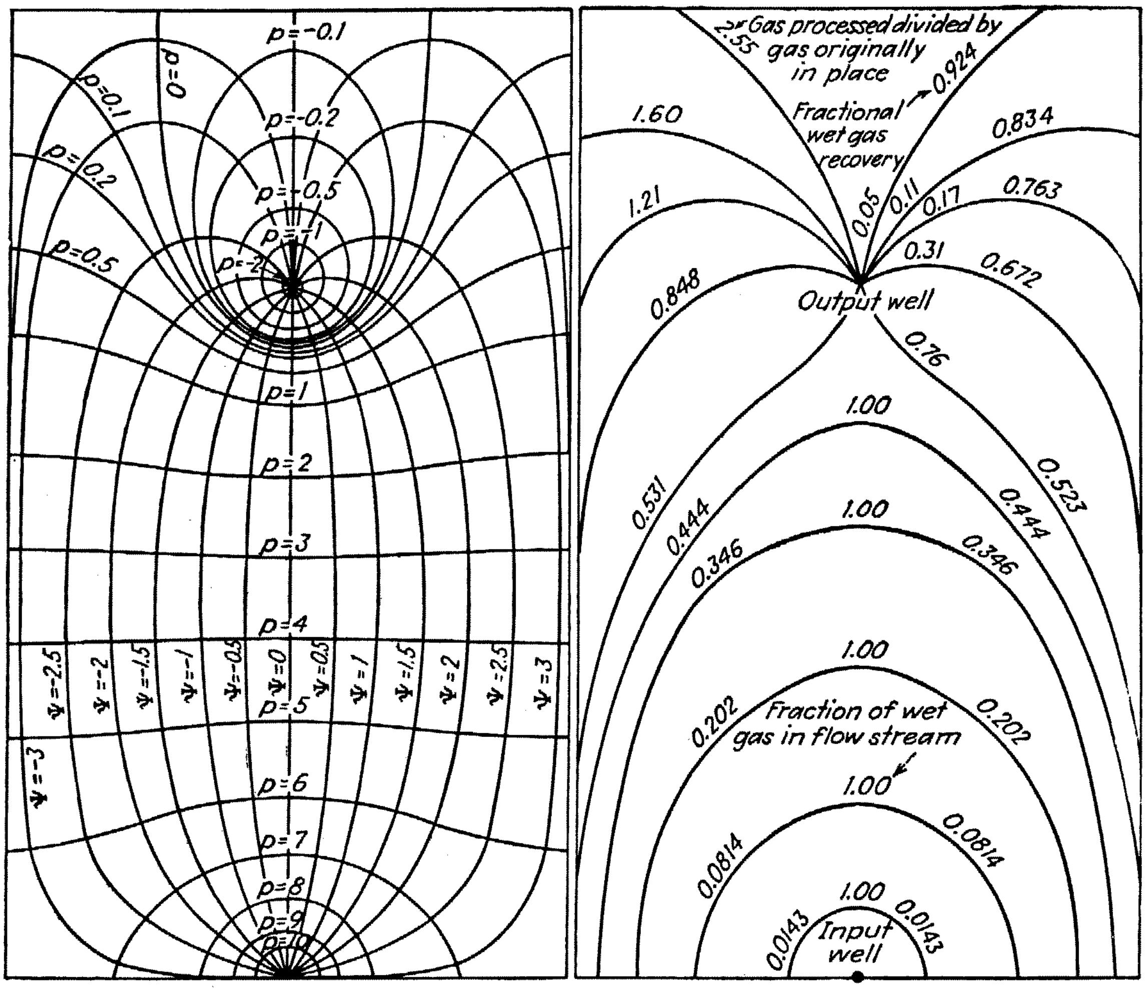


FIG. 13.10. The calculated pressure (p) and streamline (Ψ) distributions and injection-fluid fronts in a bilateral cycling pattern in which $L/W = 1.75$ and $D/W = 1.25$. L = half width of field; W = well spacing within the injection and producing lines; D = separation between the injection and producing lines. (*After Hurst and Van Everdingen, AIME Trans., 1946.*)

for Fig. 13.11, in which the producing wells are placed at the very limits of the reservoir,[1] $E = 0.741$. If D/W were 1.00, with $L/W = 1.75$, E would fall to 0.369, or only half of that for $D/W = 1.75$. It should be noted, however, that here by far the greater part of the gain due to the increased separation between the injection and producing lines results from the improved sweep behind the producing wells, in the area between them and the assumed reservoir boundaries AA, BB. Whereas as fractions of the

[1] This special case also gives the sweep efficiency in an end-to-end sweep in a finite reservoir with the wells located along the actual boundaries, with $d/a = 0.875$.

total reservoir area the sweep efficiencies vary as 0.369, 0.492, 0.633, and 0.741 as D/W is changed from 1.00, 1.25, 1.50 to 1.75, in terms of the areas only between the injection and producing lines they are 0.646, 0.689, 0.738, and 0.741, respectively.

The composition of the produced gas, expressed as the fractional wet-gas

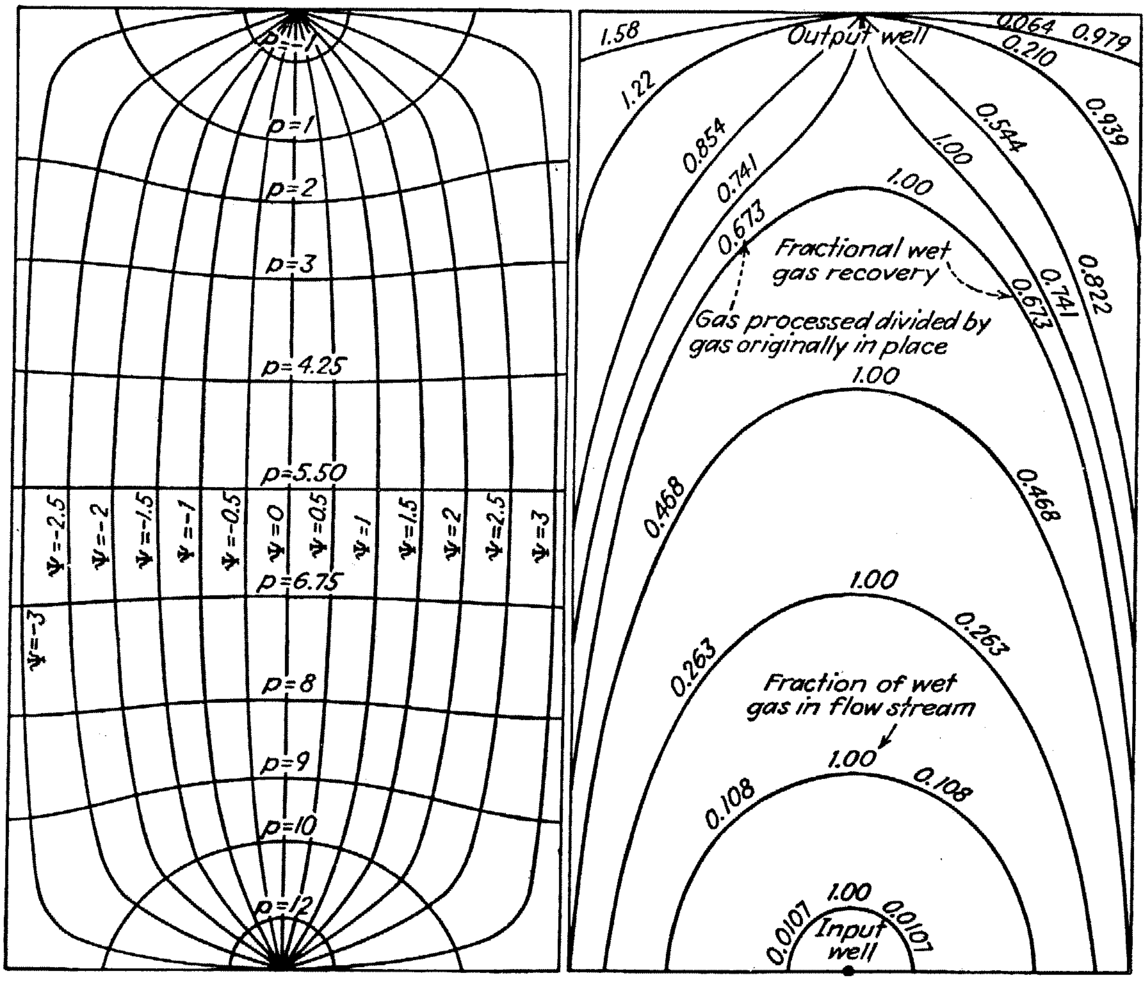


FIG. 13.11. The calculated pressure (p) and streamline (Ψ) distributions and injection-fluid fronts in a bilateral cycling pattern in which $L/W = 1.75 = D/W$. L = half width of field; W = well spacing within the injection and producing lines; D = separation between the injection and producing lines. (*After Hurst and Van Everdingen, AIME Trans., 1946.*)

content, for a bilateral drive is plotted in Fig. 13.12, for the cases shown in Figs. 13.10 and 13.11 and also for $D/W = 1.00$ and $D/W = 1.50$. Thus after a throughflow equal to the original gas volume the wet-gas contents of the produced gas for the four systems will range from 19 to 36 per cent, the latter referring to the case of maximum separation between the injection and producing wells. The total gas processed, or throughflow, by the time the wet-gas content falls to 15 per cent will be, for the four cases, 1.26, 1.33, 1.46, and 1.35, respectively, times the original reservoir gas content. These are evidently proportional to the total operating lives, for equal throughflow rates. While the differences are rather small and would appear to favor the pattern with the shortest distance between the producing and injection lines and the lowest sweep efficiency, the total wet-gas recoveries are quite appreciably affected by the line separations and sweep efficiencies. The total wet-gas recoveries vs. the gas throughflow, corresponding to Fig. 13.12, are plotted in Fig. 13.13. From this figure and reference to Fig. 13.12, it will be seen that at the 15 per cent limit of wet-gas content the total wet-gas recoveries will be 64, 78, 90, and 96 per cent, respectively, of the original wet-gas content of the reservoir.

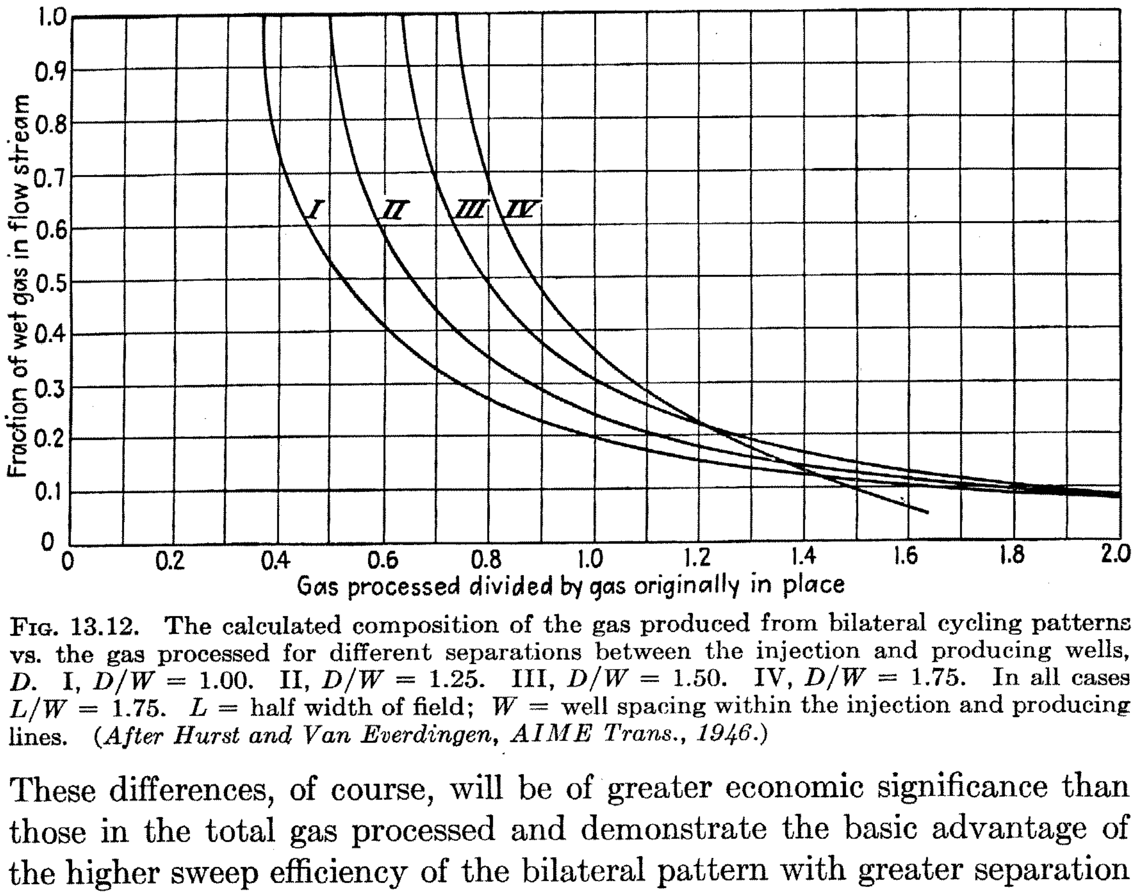


FIG. 13.12. The calculated composition of the gas produced from bilateral cycling patterns vs. the gas processed for different separations between the injection and producing wells, D. I, $D/W = 1.00$. II, $D/W = 1.25$. III, $D/W = 1.50$. IV, $D/W = 1.75$. In all cases $L/W = 1.75$. L = half width of field; W = well spacing within the injection and producing lines. (*After Hurst and Van Everdingen, AIME Trans., 1946.*)

These differences, of course, will be of greater economic significance than those in the total gas processed and demonstrate the basic advantage of the higher sweep efficiency of the bilateral pattern with greater separation between the injection and producing lines.

It should be emphasized that all the considerations of this section refer to reservoirs of uniform permeability and thickness. The study of cycling systems by electrical models, as will be discussed in the following two sections, are also primarily limited to single-zone reservoirs, although the variations of permeability and thickness within a single stratum can be treated by the potentiometric model. On the other hand, when the formation is known to be comprised of substantially distinct layers of different permeability, the study of the composite motion of the injection fluid will require a supplementary analysis of the superposed histories of the individual zones. This will generally imply an appreciable lowering of the resultant sweep efficiency. The theory of multilayer systems will be given in Sec. 13.8.

It should be noted that theoretically the times of injection-fluid breakthrough, areas swept out, and sweep efficiency will be the same if the injection and producing wells are interchanged, provided that the pressures at all injection wells are the same and all the producing well pressures are equal. The choice among the two possibilities will depend on practical

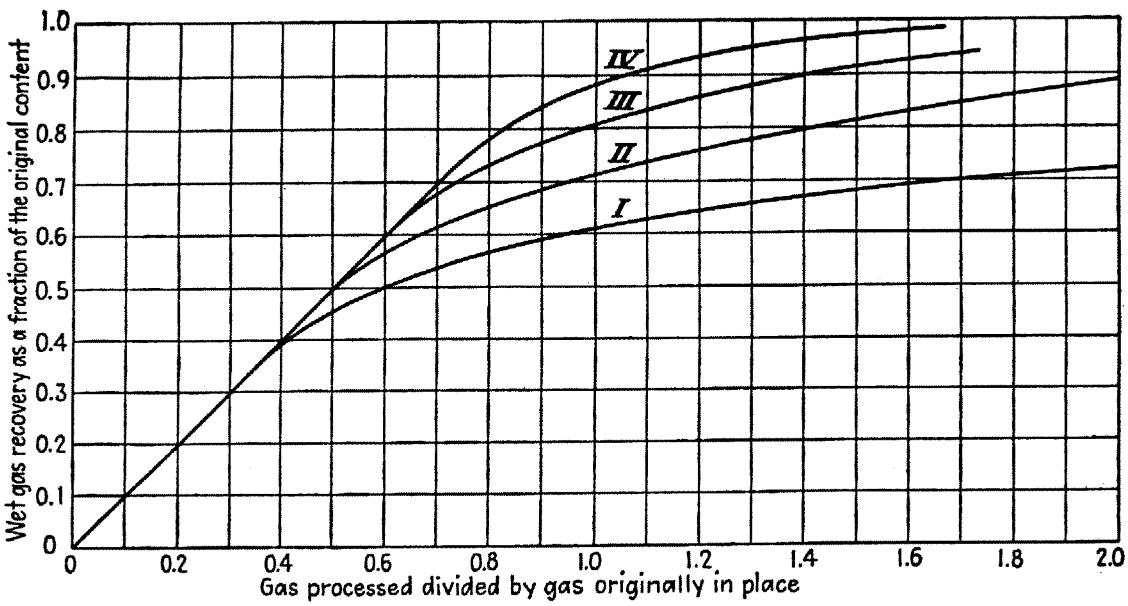


FIG. 13.13. The calculated variation of the total wet-gas recovery in bilateral cycling systems vs. the volume of gas processed for different separations between the injection and producing wells, D. I, $D/W = 1.00$. II, $D/W = 1.25$. III, $D/W = 1.50$. IV, $D/W = 1.75$. In all cases $L/W = 1.75$. L = half width of field; W = well spacing within the injection and producing lines. (*After Hurst and Van Everdingen, AIME Trans., 1946.*)

considerations, such as the relative cost of injection and producing wells, the presence of bounding oil rims, the mobility of underlying waters, etc.

13.6. The Theory of Potentiometric Models.—Although the sweep efficiencies of general well patterns in two-dimensional uniform media can be determined by use of the electrolytic gelatin model described in Sec. 12.11, the potentiometric model is basically more accurate. Moreover it is more flexible in making it possible to treat systems of variable permeability and porosity, which, for practical purposes, are beyond the scope of the gelatin model, and variable-thickness formations can be studied with it much more conveniently than with gelatin models. The general principle of operation of the potentiometric model, when the four-electrode probe is used, has been outlined in Sec. 12.10.[1] For homogeneous two-

[1] The technique of operating electrolytic potentiometric models in which the fluid motion is calculated directly from the pressure or potential distributions is described by W. Hurst and S. N. McCarty, *API Drilling and Production Practice*, 1941, p. 228. The construction and operation of the four-electrode-probe models, which are much

dimensional systems, of constant thickness, the basic analogy between the electrical model and the flow system simply rests on the observation that the electrical potential corresponds to the pressure and the current density to the fluid flux. While this analogy still obtains in more complex systems of variable thickness and permeability, the construction of the electrical model to give an accurate analogue requires more detailed consideration.[1]

The equations of continuity for steady-state current flow in an electrolytic medium and fluid flow in a porous body are

$$\nabla \cdot \bar{i} = \nabla \cdot \bar{v} = 0, \tag{1}$$

where $\bar{i}$, $\bar{v}$ are the vector current density and mass flux, respectively. Since all model studies of the type considered here are based on a two-dimensional idealization in both the electrical- and porous-media-flow systems, Eqs. (1) may be expressed, by virtue of Ohm's and Darcy's law, as

$$\nabla \cdot \sigma \nabla V = 0 = \nabla \cdot \frac{\gamma k h}{\mu} \nabla p, \tag{2}$$

where σ is the equivalent electrical conductivity, V the voltage, γ the gas density, k the permeability[2] to the gas, μ its viscosity, h the local effective pay thickness, and p the pressure. As γ, μ are, in principle, functions only of the pressure, the second half of Eqs. (2) can be formally simplified to

$$\nabla \cdot kh \nabla \Phi = 0, \tag{3}$$

where:

$$\Phi = \int \frac{\gamma}{\mu} dp. \tag{4}$$

If there is areal geometrical similarity between the reservoir in question and the model and if both have the same source and sink distributions, corresponding to the injection and producing wells, the electrical model will have a voltage distribution identical, except for scale, with that for Φ,

---

more convenient and determine simultaneously the streamline distributions and the potential gradients along the streamlines, have been reported by Lee, *loc. cit.* It may be noted also that the basic principle of determining the shapes of fluid-injection fronts from the potential distributions had been stated and applied to a five-spot well network by R. D. Wyckoff, H. G. Botset, and M. Muskat, *AIME Trans.*, **103**, 219 (1932), using a conducting metallic sheet to establish the equipotential contours.

[1] The discussions of the analogy in the literature are restricted to systems of uniform thickness and permeability, except for the treatment of transient-water-drive reservoir histories by the electrical analyzer (cf. Sec. 11.8). The detailed analysis given here follows that of M. Muskat, *Petroleum Technology*, **11**, 1 (November, 1948).

[2] This should be the *effective* permeability in the presence of the connate water.

provided σ is made everywhere proportional to kh. The variability of σ is obtained by varying the depth h_e of the layer of electrolyte, so that

$$\sigma = \sigma_o h_e = akh \tag{5}$$

where σ_o is the specific conductivity of the electrolyte and a is a scale factor. Thus gross geometrical similarity and a variation of the electrolyte thickness in proportion to the millidarcy-feet of the formation will ensure formal equivalence between the voltage and Φ distributions. If the reservoir formation is to be approximated as one of uniform permeability, the electrolytic bath is to be made geometrically similar to an isopach map of the section.

It should be noted that the porosity does not enter in the construction of the electrolytic-model analogue,[1] although, as will be seen presently, it is involved in the derivation of the fluid-front contours from the pressure distributions. The primary criterion for equivalence between the model and the actual reservoir is the creation of geometrically similar *potential* fields, which are determined only by the thickness, permeability, and boundary conditions. The basic function of the model is to give an empirically measurable solution of Eq. (2) for the pressure distribution. The determinations of injection-fluid fronts is essentially nothing more than an interpretation of the pressure distribution, as may be obtained by suitable numerical, graphical, or electrical manipulation of its characteristics.

To derive the character of the fluid motion it is noted that the rate of local fluid advance along the streamlines will be given by

$$\frac{ds}{dt} = \frac{v}{\bar{f}} = \frac{k}{\mu\bar{f}}|\nabla p| = \frac{k}{\bar{f}\gamma}|\nabla \Phi|, \tag{6}$$

where v is the local volumetric flux along the streamline and $\bar{f}$ is the displacement porosity, *i.e.*, the actual porosity times the fraction of the pore space displaced by the invading fluid.[2] The time of travel over an element of length ds along a streamline will therefore be

$$dt = \frac{\bar{f}\gamma\, ds}{k|\nabla \Phi|}. \tag{7}$$

Hence, if the potential[3] distribution represented by Φ is known, Eq. (7) will permit the stepwise integration of the time of advance of the fluid

[1] "Iso-vol" or constant-pore-volume analogues, which have been used in some model studies, will not give correct potential distributions, except when both the net hydrocarbon porosity and effective permeabilities are constant.

[2] It is intuitively probable, and it has been essentially confirmed experimentally, that in cycling operations there is no appreciable mixing between the injected dry and displaced wet gas. Under such conditions $\bar{f}$ is the total hydrocarbon porosity.

[3] Φ may be conveniently considered here as a potential function, although it does not satisfy the simple Laplace equation.

front. To carry through this procedure with the aid of the voltage distribution in the potentiometric model, the scale factors L, M may be introduced as

$$\begin{aligned} ds_M &= L\, ds_R \\ V &= M\Phi \end{aligned} \tag{8}$$

where ds_M is a linear distance in the model and ds_R the corresponding distance in the reservoir and M is, in effect, the ratio of the total voltage between two points in the model to the corresponding difference in Φ in the reservoir. It then follows that Eq. (7) can be rewritten as

$$dt = \frac{Ma}{\sigma_o L^2} \frac{\gamma h \bar{f}}{h_e} \frac{ds_M}{|\nabla V|}. \tag{9}$$

If, as in the use of the four-probe electrodes, the potential drop ΔV is measured along the streamlines over the fixed electrode separation Δs_m, the corresponding fluid-travel-time increments will be

$$\Delta t = \frac{Ma}{\sigma_o L^2} \frac{\gamma h \bar{f}}{h_e} \frac{\Delta s_m^2}{\Delta V}. \tag{10}$$

By summing such increments along the individual streamlines the constant-time surfaces can be plotted. These evidently correspond to the various fluid-injection fronts, or interfaces between the injection and displaced fluids.

It is to be noted that, if the coefficient $\gamma h \bar{f}/h_e$ is variable, the sum of the reciprocals of ΔV will not alone suffice to determine quantitatively the shapes of the injection-fluid fronts. On the other hand, in most practical applications it will be necessary to make such approximations as will permit simplifications of Eq. (10). Thus, if permeability variations are neglected, Eq. (10) reduces to

$$\Delta t = \frac{M}{kL^2} \gamma \bar{f} \frac{\Delta s_m^2}{\Delta V}, \tag{11}$$

where k is the assumed uniform permeability to the fluids involved. If $\bar{f}$ is also considered as constant, the only remaining variable in Eq. (11), except for ΔV, will be γ. Since γ does not vary rapidly in cycling systems except near the injection and producing wells, it should suffice to neglect its variation outside of these regions, if average values are used, in actual field studies. In fact such approximations would appear to be inherently reasonable if the variations in $\bar{f}$ and k are also neglected.

As indicated by Eqs. (6) the velocity of advance of the fluid front will be proportional to the pressure gradient whether the fluids involved are gases or liquids. The pressure distributions, however, will be quite different in the two cases. On the other hand, since the distributions in the function

Φ will be the same for gases and liquids for a given reservoir formation, the shapes of the injection-fluid fronts will be different for gases only because of the factor γ in Eq. (7). The assumed equivalence in these fronts between liquids and gas thus implies the neglect of the variation of the gas density γ.

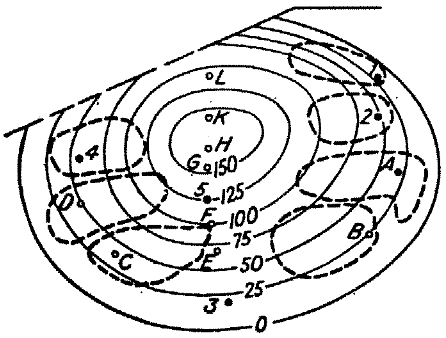
Although the shapes of injection-fluid fronts will be independent of the fluid viscosities, the absolute times of travel will be proportional to the viscosity. Moreover, even aside from the effect of the viscosity, the sweep rates will be different for gases and liquids, for the same terminal pressures.

While the density factor in Eq. (7) makes almost impossible a strict analytical treatment of the motion of gas injection-fluid fronts, it does not present unsurmountable difficulties in using the potentiometric model if it is felt desirable to take it into account. For it is only necessary that the density distribution be calculated from the potential distribution, and its local value be multiplied into the reciprocals of the gradients, according to Eq. (7) or (10), to obtain the time increments. Such a stepwise evaluation of the latter would in any case be required if the permeability or displacement porosity is variable. Actually, however, even the effects of the latter are usually neglected in practical applications, and the travel times are determined simply by summing the reciprocals of the potential increments, ΔV. From a practical standpoint, attempts to take into account the refinements associated with the variations in permeability and displacement porosity usually will not be warranted, since it will be very seldom that their variation will be known with any certainty. When these effects must be neglected of necessity, it is doubtful that the corrections due to the density variations would be justified except in the immediate vicinities of the individual wells. It is for this reason that no attempt has been made in the theoretical analyses of Sec. 13.5 to treat the problem of sweep efficiency as if the fluids involved actually had variable density.[1] Nor will consideration be given to this effect in the next section, where an illustrative example of cycling studies by use of the potentiometric model will be discussed, although the model experiments were made without correcting for the gas-density variation.

13.7. An Illustrative Application of the Potentiometric Model to Cycling Systems.—An instructive example of the way in which the potentiometric model has been applied in planning cycling operations is shown in Fig. 13.14.[2] The reservoir in question had a continuous water-gas contact around the boundary of the structure, except at the north, where it was

[1] A calculation carried through for a circular injection ring with a central producer, taking into account the variable gas density, gave sweep efficiencies that were higher than Eq. 13.5(10), corrected for an average density, for $n < 5$, and lower for $n > 5$.

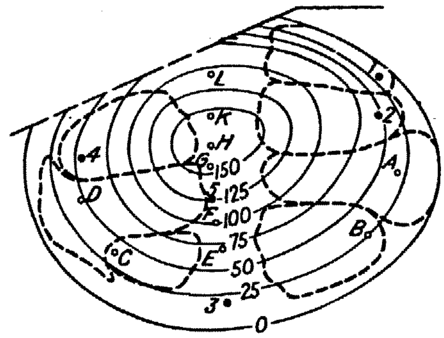
[2] This is taken from D. L. Marshall and L. R. Oliver, *AIME Trans.*, **174**, 67 (1948).



(a)

OPERATING PLAN

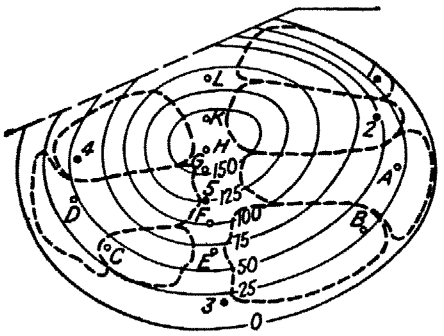
INJECTION		PRODUCTION	
WELL	CAP.	WELL	CAP.
1	17.8	L	15.6
2	17.8	K	15.6
4	17.8	H	15.6
A	17.9	G	15.6
B	17.9	F	15.6
C	17.9	E	15.6
D	17.9	3	15.7
		5	15.7



(b)

OPERATING PLAN

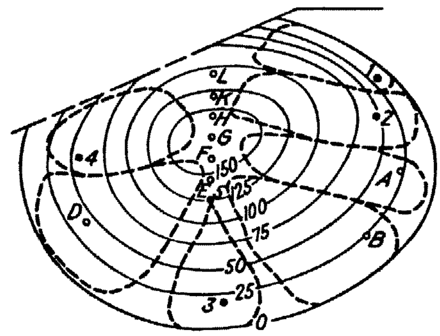
INJECTION		PRODUCTION	
WELL	CAP.	WELL	CAP.
1	9.0	L	25.0
2	25.0	K	25.0
4	25.0	H	18.7
A	20.0	G	18.8
B	14.0	F	10.0
C	7.0	E	10.0
D	25.0	3	5.0
		5	12.5



(c)

OPERATING PLAN

INJECTION		PRODUCTION	
WELL	CAP.	WELL	CAP.
1	10.2	L	23.8
2	28.3	K	17.5
4	21.1	H	17.5
A	22.6	G	18.7
B	15.9	F	12.6
C	5.9	E	12.5
D	21.1	3	6.1
		5	16.3



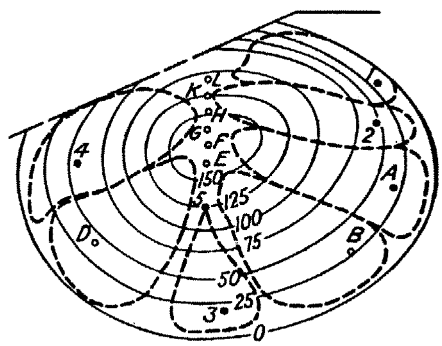
(d)

OPERATING PLAN

INJECTION		PRODUCTION	
WELL	CAP.	WELL	CAP.
1	7.0	L	17.8
2	22.0	K	17.8
3	8.0	H	17.8
4	22.0	G	17.9
A	22.0	F	17.9
B	22.0	E	17.9
D	22.0	5	17.9

OPERATING PLAN

INJECTION		PRODUCTION	
WELL	CAP.	WELL	CAP.
1	9.0	L	17.8
2	22.0	K	17.8
3	6.0	H	17.8
4	22.0	G	17.9
A	22.0	F	17.9
B	22.0	E	17.9
D	22.0	5	17.9



(e)

FIG. 13.14. Dry-gas invasion fronts, as determined by a potentiometric model, for various plans for cycling a condensate reservoir. Contours indicate sand thickness. Operating plans indicate assumed injection and production rates of individual wells in 10^6 ft^3/day. Measured sweep efficiencies for plans *a*, *b*, *c*, *d*, and *e* are 27, 63, 72, 67, and 76 per cent respectively. (*After Marshall and Oliver. AIME Trans., 1948.*)

limited by a fault. Five wells had already been completed in the reservoir, and the cycling patterns studied were chosen so as to use as many of these wells as possible. The net thickness variation of the condensate-bearing sand is indicated by the isopach contours in Fig. 13.14.

In order to prevent water entry into the reservoir and producing wells the latter were located on the crest of the structure, and the injection wells were distributed along the flanks on both sides of the line of producing wells. The wells already drilled are designated by numbers and the suggested new locations by letters.

In the first pattern tried the injection rates were made the same for all the injection wells, and the producing wells were produced at equal rates, with a total withdrawal rate equal to the total injection rate of 125 million cubic feet per day. The dry-gas invasion pattern at the time of first break-through into producing well F is shown in Fig. 13.14a. It will be seen that at the time of break-through the dry gas injected to the east of the producing wells still had far to go before reaching the latter. The total invaded area covered by the dry-gas contours represented only 27 per cent of the reservoir volume.

By using the same well locations but changing the individual injection and producing rates as indicated in the operating plan, the predicted dry-gas boundary at the time of first break-through, in well #5, as determined by the potentiometric model, is plotted in Fig. 13.14b. The increased injection rates in wells #2, #4, A, and D, heavier withdrawals from wells L and K, and restricted injection and producing rates from wells C and #3 have evidently led to a greatly improved sweep efficiency, namely, 63 per cent of the reservoir volume at the time of break-through. This pattern, however, was nevertheless unsatisfactory, because of the large unswept area east of the producing wells, and some of the required producing rates exceeded the actual capacities of the wells. A further readjustment of the injection and producing rates improved the sweep efficiency to 72 per cent (cf. Fig. 13.14c) but still left a considerable unswept area in the central thicker part of the reservoir.

A basic rearrangement of the well distribution was then tried, as shown in Fig. 13.14d. Well C was omitted, and D was moved farther south. E and F were shifted north of #5, and #3 was converted to an injection well. The individual injection and producing rates are indicated in the operating plan in the figure. The resulting sweep efficiency was found to be 67 per cent. A final modification, in which the proposed producing-well locations F, G, H, K, and L were moved still farther north and undrilled injection wells A, B, D were shifted to the south, gave a dry-gas-invasion pattern at first break-through as shown in Fig. 13.14e and a sweep efficiency of 76 per cent.

It will be evident from these progressive changes in plans that without further drilling than that involved in the program of Fig. 13.14*e* the latter probably represents a close approximation to the optimum cycling pattern, on the assumption of reservoir permeability uniformity made in the study. In actually carrying out this program additional information was obtained that indicated the reservoir conditions to be somewhat more complex than anticipated, and appropriate changes in the cycling operations were made after further model investigations. However, the preliminary phase of the investigation, as represented by Figs. 13.14*a* to *e*, should suffice to show the flexibility and power of the potentiometric model in studying the effects of both well location and the distribution of the relative injection and production rates on dry-gas-invasion fronts.[1]

13.8. The Effect of Permeability Stratification in Cycling[2] Operations.— One of the basic problems involved in the successful operation of cycling programs is that arising from dry-gas by-passing due to permeability stratification. It has been seen in previous sections that means are available for determining satisfactorily the areal sweep efficiencies and injection-fluid fronts for arbitrary distributions of well locations and injection or producing rates. These are applicable, however, only to individual strata. If the reservoir is comprised of a series of individual layers of substantially different permeabilities, the sweep processes will proceed in each one at rates approximately in proportion to their permeabilities. Hence, if some of the strata have much higher permeabilities than the remainder, the wet-gas displacement and dry-gas break-through will develop in them much sooner than in the remainder, and while an appreciable part of the reservoir as a whole is still unswept. The resultant sweep efficiency, *i.e.*, the total fractional wet-gas displacement at the time of first dry-gas break-through, will thus be reduced in proportion.

[1] Additional examples of applications are given in the paper of Marshall and Oliver (*ibid.*); cf. also the results of a study of the cycling operations in the Grapeland field, Houston County, Tex., by means of an electrolytic gelatin model, reported by F. C. Kelton, *API Proc.*, **24** (IV), 199 (1943). It should be noted, however, that from a practical standpoint the predictions of reservoir performance given by the electrical models cannot be more accurate than the assumed reservoir data. It is the uncertainty in the latter that ultimately limits the quantitative significance of model-study predictions.

[2] The general theory given here is also applicable to the study of stratification effects in water-drive reservoirs or primary-water-injection operations. The numerical results, however, will be modified by the additional factor of the ratio of the mobility (permeability-to-viscosity ratio) of the water to that of the oil. If this ratio exceeds 1, the stratification effects will be accentuated, whereas they will be lessened, as compared to cycling operations, if the water mobility is lower than that of the oil. This type of treatment of water-drive reservoirs with probability distribution of permeability has been developed by H. Dykstra and R. L. Parsons, API meetings, Los Angeles, Calif., May, 1948.

From a physical point of view the problem of permeability stratification can be readily treated without difficulty. If the different-permeability strata are mutually separated by shale breaks or are otherwise free of cross flow, they can be considered simply as a system of parallel reservoirs. But even if there is potential intercommunication normal to the bedding planes, this will not be of significance if the pressure distributions in the individual zones are substantially the same. The latter condition will obtain if the permeabilities and thicknesses of the separate members are uniform over the reservoir area or if the product of the permeability and thickness varies in a parallel manner for the different strata. In general, therefore, unless it is definitely known that appreciable cross flow is taking place or that the various-permeability layers are not continuous over the reservoir, the composite flow history can be approximated by a simple parallel superposition of those of its components.

While the superposition history of multilayer systems can be constructed by obvious graphical procedures, it can be formulated analytically as follows[1]: It will be assumed that the permeability k and displacement porosity $\bar{f}$ are continuous functions of a depth coordinate z along the well bore. The rate of dry-gas inflow[2] per unit thickness in the lamina at depth z may evidently be expressed as

$$Q(z) = ck(z), \tag{1}$$

where c is a constant determined by the areal geometry of the reservoir,[3] the well distribution, and their relative injection and producing rates. For a fixed cycling pattern and operating plan the composition of the produced gas in a uniform zone will be a function only of the total gas throughflow, expressed as a fraction of the hydrocarbon pore volume. The rate of wet-gas production from a unit-thickness lamina at z at the time t will therefore be

$$Q_w(z) = ck(z)F\left[\frac{ctk(z)}{A\bar{f}(z)}\right], \tag{2}$$

where F denotes the functional variation of the wet-gas fraction in the produced gas with the total gas throughflow, as determined by the well distribution and their relative fluxes, and the argument of F represents the

[1] The general theory of cycling with continuous permeability stratification presented here, including applications to probability and linear permeability distributions in addition to the results for the exponential distribution, is taken from M. Muskat, *Petroleum Technology*, **11**, 1 (November, 1948). Studies of discontinuous permeability distributions have been reported by Hurst and Van Everdingen, *op. cit.*, and Standing, Lindblad, and Parsons, *loc cit.*

[2] The rates of flow and volumes of throughflow discussed in this treatment refer to reservoir rather than surface measure.

[3] In addition to lateral uniformity and continuity of all the productive strata it is assumed here that these are all penetrated by each producing and injection well.

cumulative gas throughflow divided by the hydrocarbon volume available at z, A being the reservoir area. The fraction of wet gas in the total effluent from the stratified formation, at the time t, will then be

$$R_w(t) = \frac{\int_0^H k(z)F[ctk(z)/A\bar{f}(z)]dz}{\int_0^H k(z)dz}, \tag{3}$$

where H is the total thickness of permeable pay. Equation (3) defines the composition history as a function of time. This can be related to the total fractional reservoir sweep by noting that the total wet gas produced at time t is

$$\overline{Q_w}(t) = \int_0^t dt \int_0^H Q_w(z)dz = c\int_0^t dt \int_0^H k(z)F\left[\frac{ctk(z)}{A\bar{f}(z)}\right]dz. \tag{4}$$

The fractional reservoir sweep is then simply

$$\overline{V} = \frac{\overline{Q_w}(t)}{A\int_0^H \bar{f}\, dz}. \tag{5}$$

In applying these equations it is convenient to consider the multilayer formation rearranged so that the permeability-to-displacement-porosity ratio $k/\bar{f}$ increases with z. Upon denoting the argument of the function F, $ctk/A\bar{f}$, by u, it follows from the definition of F that

$$\int_0^\infty F(u)du = 1; \qquad \int_S^\infty F(u)du = 1 - S; \qquad F(u) = 1 \quad : \quad u \leqslant S, \tag{6}$$

where S is the geometrical sweep efficiency in a uniform stratum.

Now at such values of t before any break-through has developed, *i.e.*, for

$$t \leqslant \frac{AS}{c}\left(\frac{\bar{f}}{k}\right)_{z=H} \equiv t_b, \quad F = 1,$$

and by Eq. (3),

$$R_w(t) = 1; \qquad \overline{Q_w}(t) = Qt; \qquad \overline{V} = \frac{Qt}{A\int_0^H \bar{f}\, dz}, \tag{7}$$

where

$$Q = c\int_0^H k(z)dz, \tag{8}$$

and is simply the total injection rate.

At times t between t_b and the time for break-through in the tightest zone, *i.e.*, for $t_b \leqslant t \leqslant t_m \equiv (AS/c)(\bar{f}/k)_{z=0}$,

$$R_w(t) = \frac{c\int_0^{z_0} k(z)dz + c\int_{z_0}^H k(z)F(u)dz}{Q}; \qquad u = \frac{ctk(z)}{A\bar{f}(z)}, \tag{9}$$

where z_0 is such that

$$\frac{k(z_0)}{\bar{f}(z_0)} = \frac{AS}{ct}.$$

The cumulative wet-gas recovery will be

$$\overline{Q_w}(t) = ct\int_0^{z_0} k(z)dz + SA\int_{z_0}^{H}\bar{f}\,dz + c\int_{z_0}^{H} k(z)dz\int_{A\bar{f}S/ck(z)}^{t} F\left[\frac{c\tau k(z)}{A\bar{f}(z)}\right]d\tau. \quad (10)$$

After break-through has developed in the tightest zone, *i.e.*, for $t > t_m$,

$$R_w(t) = \frac{c\int_0^H k(z)F(u)dz}{Q}, \quad (11)$$

where now $F(u) < 1$. And the cumulative wet-gas recovery will be given by the general expression of Eq. (4).

To illustrate these relationships it will be assumed that

$$F(u) = 1 \quad : \quad u \leqslant S; \qquad F(u) = e^{(S-u)/(1-S)} \quad : \quad u \geqslant S. \quad (12)$$

This form satisfies Eq. (6) and roughly approximates the calculated variation of F in special cases (cf. Fig. 13.12). It will be further assumed that the permeability distribution is exponential,[1] as defined by

$$k(z) = ae^{bz/H}, \quad (13)$$

and that the displacement porosity $\bar{f}(z)$ is a constant, f.

Upon introducing the notation

$$\bar{t} = \frac{t}{t_b}; \qquad r = \frac{t_m}{t_b}; \qquad b = \log r, \quad (14)$$

where $t_b = AS\bar{f}e^{-b}/ac$, an evaluation of the above general equations, using Eqs. (12) and (13), gives

$$\bar{t} \leqslant 1 \quad : \quad R_w(\bar{t}) = 1; \qquad \overline{Q_w}(\bar{t}) = Qt; \qquad \overline{V}(\bar{t}) = \frac{S(r-1)\bar{t}}{rb}; \quad (15)$$

$$1 \leqslant \bar{t} \leqslant r \ : \ R_w(\bar{t}) = \frac{1}{r-1}\left[\frac{r}{\bar{t}} - 1 + \frac{(1-S)r}{S\bar{t}}\left(1 - e^{[S/(1-S)](1-\bar{t})}\right)\right], \quad (16)$$

$$\overline{V}(\bar{t}) = \frac{1}{b}\log\bar{t} + \frac{S}{b}\left(1 - \frac{\bar{t}}{r}\right) - \frac{(1-S)}{b}e^{S/(1-S)}\left[Ei\left(-\frac{S\bar{t}}{1-S}\right) - Ei\left(-\frac{S}{1-S}\right)\right]; \quad (17)$$

[1] This type of permeability distribution implies a constant percentage change in permeability per unit of depth, and greater thicknesses of the low-permeability layers when the absolute permeability range is fixed. The ratio e^b of the maximum permeability ae^b to the minimum value a provides a convenient index of the exponential distribution and will be termed the "stratification constant" r [cf. Eq. (14)].

$$\bar{t} \geqslant r \quad : \quad R_w(\bar{t}) = \frac{r(1-S)e^{S/(1-S)}}{S\bar{t}(r-1)}\left[e^{-S\bar{t}/(1-S)r} - e^{-S\bar{t}/(1-S)}\right], \tag{18}$$

$$\overline{V}(\bar{t}) = 1 - \frac{1-S}{b}\,e^{S/(1-S)}\left[Ei\left(-\frac{S\bar{t}}{1-S}\right) - Ei\left(\frac{-S\bar{t}}{(1-S)r}\right)\right]. \tag{19}$$

In all cases the total throughput at the time $\bar{t}$, as a fraction of the net reservoir pore volume, is

$$\overline{Q}(\bar{t}) = \frac{S(r-1)\bar{t}}{rb}. \tag{20}$$

It will be readily verified that these expressions are continuous at their mutual contact points. At the time of break-through in the tightest zone ($\bar{t} = r$) these equations imply that

$$R_w(r) = \frac{(1-S)/S}{r-1}\left\{1 - e^{[S/(1-S)](1-r)}\right\}, \tag{21}$$

which reduces to the coefficient for $r \gg 1$. And

$$\overline{V}(\bar{r}) = 1 - \frac{1-S}{b}\,e^{S/(1-S)}\left[Ei\left(\frac{-Sr}{1-S}\right) - Ei\left(\frac{-S}{1-S}\right)\right], \tag{22}$$

which has the asymptotic value for $r \gg 1$

$$V(r) \sim 1 - \frac{(1-S)^2}{Sb}. \tag{23}$$

In the limiting case of a uniform reservoir, $b \to 0$ and $r \to 1$. Equations (15) to (19) then reduce to the following forms:

$$\left.\begin{aligned} &\bar{t} \leqslant 1 \quad : \quad R_w(\bar{t}) = 1; \qquad \overline{Q_w}(\bar{t}) = Qt; \qquad \overline{V}(\bar{t}) = S\bar{t}; \\ &\bar{t} \geqslant 1 \quad : \quad R_w(\bar{t}) = e^{(S-S\bar{t})/(1-S)} = F(S\bar{t}); \\ &V(\bar{t}) = 1 - (1-S)e^{(S-S\bar{t})/(1-S)} = 1 - (1-S)F(S\bar{t}). \end{aligned}\right\} \tag{24}$$

In Eqs. (24), $\bar{t} = t/t_b = Qt/AH\bar{f}S$. Equations (24) can, of course, also be derived from first principles.

In the limit of 100 per cent areal sweep efficiency, that is, $S = 1$, Eqs. (15) to (19) reduce to

$$\left.\begin{aligned} &\bar{t} \leqslant 1 \quad : \quad R_w(\bar{t}) = 1; \qquad \overline{V}(\bar{t}) = \frac{(r-1)\bar{t}}{rb}; \\ &1 \leqslant \bar{t} \leqslant r \quad : \quad R_w(\bar{t}) = \frac{1}{r-1}\left(\frac{r}{\bar{t}} - 1\right); \\ &\overline{V}(\bar{t}) = \frac{1}{b}\left(1 - \frac{\bar{t}}{r} + \log \bar{t}\right); \\ &\bar{t} \geqslant r \quad : \quad R_w(\bar{t}) = 0; \qquad \overline{V}(\bar{t}) = 1. \end{aligned}\right\} \tag{25}$$

For the intermediate time interval, $\bar{V}$ and the total throughflow, $\bar{Q}$, expressed as fractions of the reservoir hydrocarbon pore volume, can be related directly to R_w as

$$\left.\begin{aligned}\bar{V} &= 1 - \frac{1}{b}\left\{\log\left[1 + (r-1)R_w\right] - \frac{(r-1)R_w}{1+(r-1)R_w}\right\},\\ \bar{Q} &= \frac{r-1}{b[1+(r-1)R_w]}.\end{aligned}\right\} \qquad (26)$$

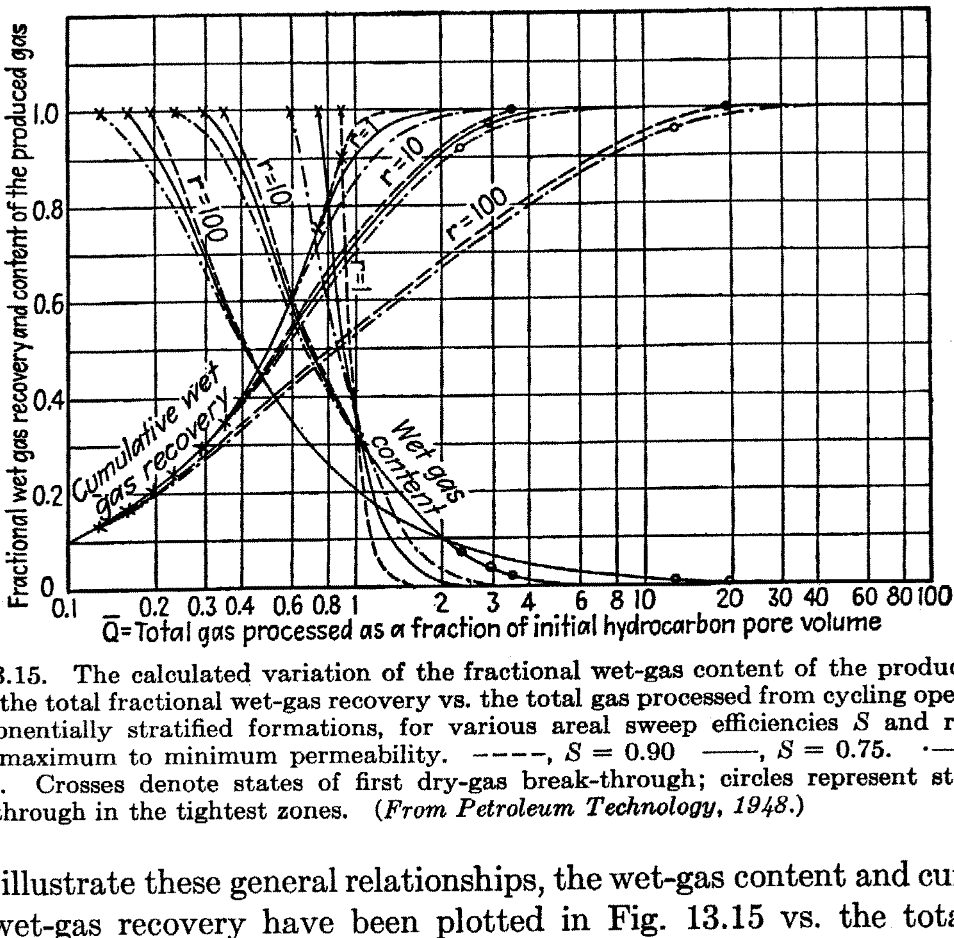


FIG. 13.15. The calculated variation of the fractional wet-gas content of the produced gas and of the total fractional wet-gas recovery vs. the total gas processed from cycling operations in exponentially stratified formations, for various areal sweep efficiencies S and ratios r of the maximum to minimum permeability. ----, $S = 0.90$ ——, $S = 0.75$. ·—·—, $S = 0.60$. Crosses denote states of first dry-gas break-through; circles represent states of break-through in the tightest zones. (*From Petroleum Technology, 1948.*)

To illustrate these general relationships, the wet-gas content and cumulative wet-gas recovery have been plotted in Fig. 13.15 vs. the total gas throughflow for $S = 0.60$, 0.75, 0.90 and for $r = 1$, 10, and 100. $r = 10$ corresponds to a ratio of the maximum to minimum permeability equal to 10, and this ratio is 100 for $r = 100$. $r = 1$ represents the strictly uniform reservoir. The abscissa values $\bar{Q}$ represent the total gas injection or production divided by the total hydrocarbon pore volume. $\bar{Q}$ is related to the argument $\bar{t}$ of Eqs. (14) to (19) as $\bar{Q} = (r-1)S\bar{t}/br$. The crosses in Fig. 13.15 denote the states of first dry-gas break-through in the most permeable zone, and the circles indicate break-through in the tightest layer. The curves for $r = 1$ simply reflect the functional form assumed for F, as required by Eqs. (24).

It will be noted from Fig. 13.15 that, whereas in a uniform formation the dry-gas break-through will develop after a total throughflow equal to the sweep efficiency S, dry gas will first appear in the producing wells for $r = 10$ after a throughflow of only 23.4, 29.3, and 35.2 per cent of the total hydrocarbon pore volume, for $S = 60$, 75, and 90 per cent, respectively. The former will also represent the fraction of total wet-gas content produced by the time of first dry-gas break-through. And for $r = 100$ the corresponding break-through periods will represent recoveries of 12.9, 16.1, and 19.4 per cent of the original wet-gas content.

For dry-gas break-through in the tightest layers, with $r = 10$, the total gas processed will correspond to 2.34, 2.93, and 3.52 times the reservoir hydrocarbon pore volume,[1] for $S = 0.60$, 0.75, and 0.90. By that time the wet-gas content of the produced gas will be 7.41, 3.70, and 1.23 per cent, respectively. And the total wet-gas recovery will be 92.2, 97.2, and 99.56 per cent of the initial reservoir content. For $r = 100$ the volumes of gas processed before break-through in the tightest layer will be 12.90, 16.12, and 19.35 times the reservoir hydrocarbon pore volume, for $S = 0.60$, 0.75, and 0.90. The produced gas will then have wet-gas contents equal to 0.68, 0.33, and 0.11 per cent, respectively. And the total wet-gas recoveries will be 96.1, 98.6, and 99.99 per cent of the initial wet-gas content of the reservoir.

As shown in Fig. 13.15 and implied by Eq. (15) the total gas processed and wet-gas recovery by the time of first dry-gas break-through are directly proportional to the areal sweep efficiency S. And the cumulative wet-gas-recovery curves remain somewhat higher for all values of $\bar{Q}$ after break-through for the higher values of S. The wet-gas-content curves, however, first tend to merge and ultimately cross, although the latter divergence is so slight for $r = 10$ and 100 that it could not be shown on the scale of Fig. 13.15. For $r = 1$ the crossing point lies at $\bar{Q} = 1$, by virtue of the functional form assumed for $F(u)$.

The variation of the total wet-gas recovery vs. r by the time the wet-gas content falls to fixed limits, at which further processing may become unprofitable, is plotted in Fig. 13.16. As is to be expected the recovery curves decrease continually with increasing values of r or degree of stratification. For high values of r the recovery assumes an approximately logarithmic decline with increasing r. Figure 13.16 shows that the effects of stratification may be far more serious in limiting the total condensate recoveries than the areal sweep efficiency. Thus for $r = 100$, which does not represent an abnormally high degree of stratification as compared with

[1] The reservoir hydrocarbon volume used as a base for expressing the abscissa variable in Fig. 13.15 and in these comparisons is the actual net pore volume, or the initial total wet-gas content in reservoir measure.

those values commonly observed, the total recovery at an abandonment limit of 15 per cent wet-gas content will be only 61 per cent even if the areal sweep efficiency is 90 per cent.

The curves in Fig. 13.16 for $R_w = 1$ represent the fractional recoveries

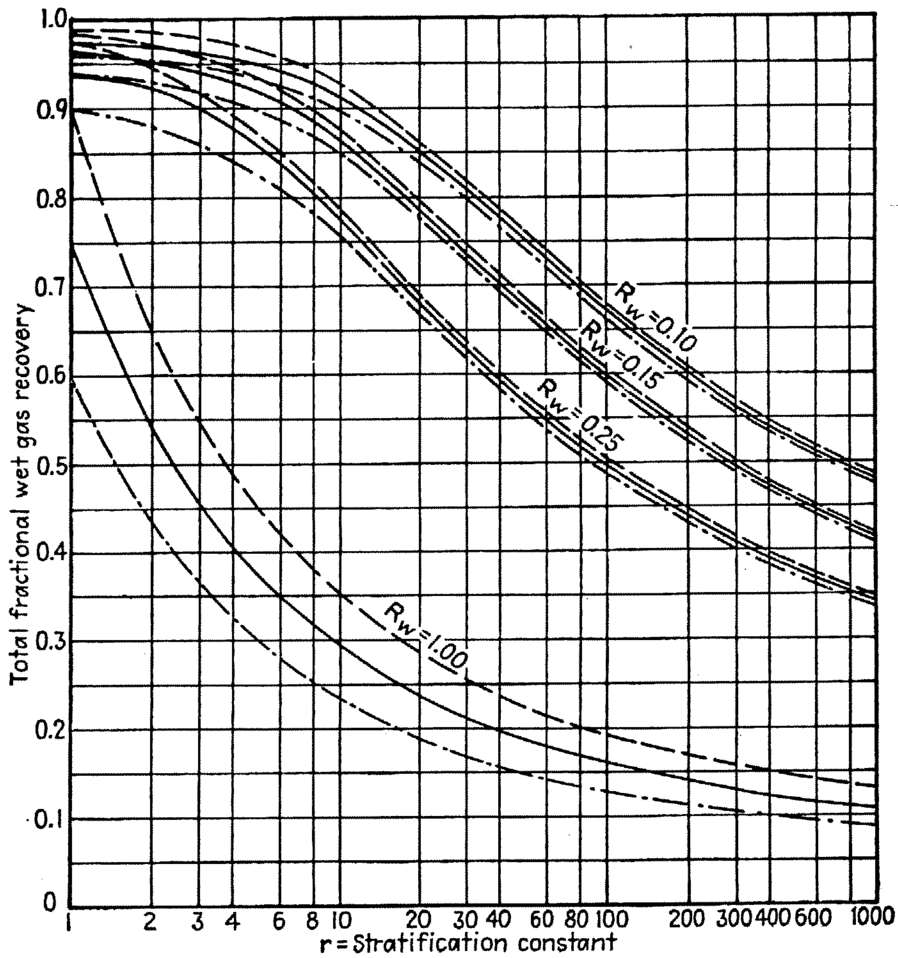


FIG. 13.16. The calculated variation of the total fractional wet-gas recovery in cycling operations vs. the stratification constant, r = ratio of maximum to minimum permeability, in exponentially stratified formations, for fixed fractional wet-gas-content abandonment limits, R_w. ----, $S = 0.90$. ——, $S = 0.75$. -·-·—, $S = 0.60$. S = areal sweep efficiency. (*From Petroleum Technology, 1948.*)

at the time of first dry-gas break-through. They are given by

$$\overline{V}(R_w = 1) = \frac{S(r-1)}{r \log r}, \tag{27}$$

and represent the composite sweep efficiency resulting both from the well pattern and permeability stratification. It will be seen that even for $r = 100$ the permeability stratification will reduce the over-all sweep efficiency almost by a factor of 5 compared with the areal sweep efficiency S. It is evidently because of the continued cycling operation to rather low wet-gas contents (after the initial dry-gas break-through) that the total wet-gas recoveries in practice will represent significant fractions of the original reservoir contents, as indicated by the upper curves of Fig. 13.16.

The total volumes of gas throughflow or processed, in reservoir measure, and as fractions of the total reservoir hydrocarbon volume, are plotted vs. r in Fig. 13.17, for various abandonment limits for the wet-gas content.[1]

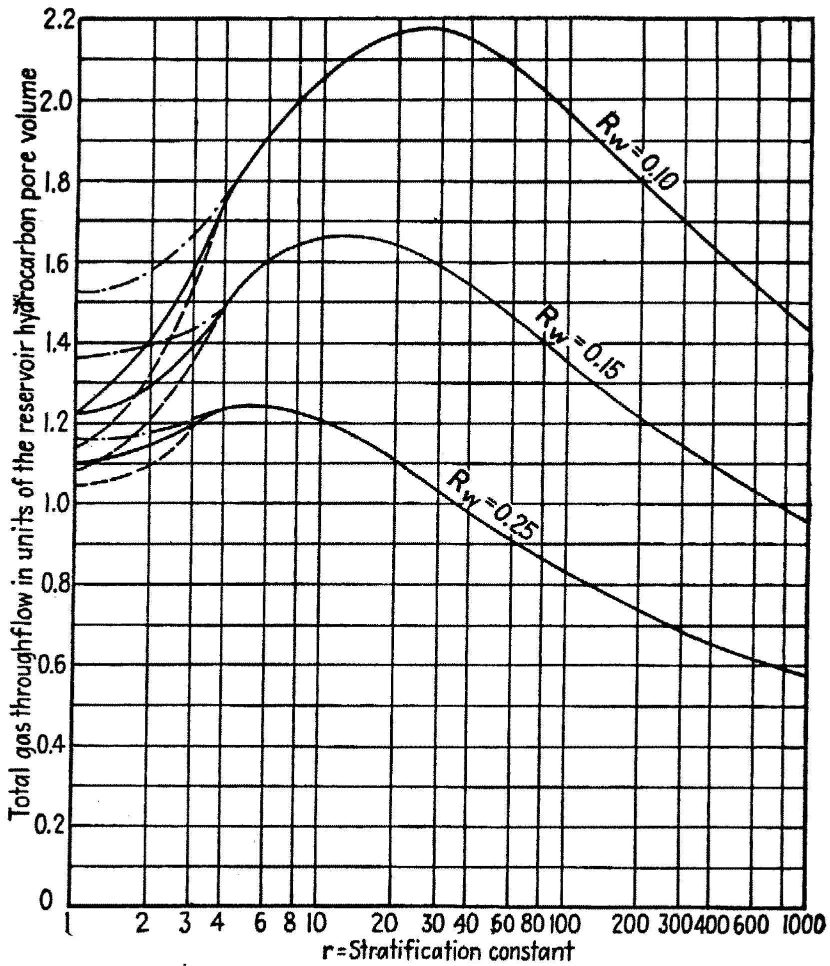


FIG. 13.17. The calculated variation of the total gas throughflow, in units of the reservoir hydrocarbon pore volume, in cycling operations vs. the stratification constant, r = ratio of maximum to minimum permeability, in exponentially stratified formations, for fixed wet-gas-content abandonment limits, R_w. ----, $S = 0.90$. ——, $S = 0.75$. ·—·—, $S = 0.60$. S = areal sweep efficiency. (*From Petroleum Technology, 1948.*)

It will be observed that these are affected by the areal sweep efficiency only at the lower values of r. In fact, for $r > 5$, the total throughflow to abandonment is, for practical purposes, independent of S. Moreover the curves all show maxima in the range of r of 5 to 30 and then decline as r is still further increased. The initial rise in the curves of Fig. 13.17 is due to the increasing throughflow required to give the approximately constant total wet-gas displacements indicated by Fig. 13.16 for low values of r. The ultimate declines reflect the corresponding reductions in

[1] The total gas throughflows for $R_w = 1.00$ are evidently equal to the total wet-gas recoveries for $R_w = 1.00$ plotted in Fig. 13.16.

total wet-gas recovery, shown in Fig. 13.16 at high stratification ratios, which can be swept out by relatively small volumes of injected gas. It will also be noted that the volumes of gas processed will vary more rapidly with the abandonment limit of wet-gas content than the total wet-gas recovery.

If the permeability distribution is not satisfactorily represented by a continuous function, the integral representation used in the above discussion can be transformed into discrete summations by obvious procedures. For a rapid approximate evaluation of the by-passing effects due to permeability stratification a discontinuous permeability distribution may be used, together with the assumption of complete sweeping ($S = 1$) at the time of first dry-gas break-through. This corresponds to a continuous-line-drive representation for both the injection and the producing wells.

The total throughflow rate will then be

$$Q = c \sum_1^N k_n h_n, \tag{28}$$

where N is the total number of layers, k_n is the permeability of the nth layer, h_n is its thickness, and c is a constant proportional to the pressure differential and also gives expression to the geometry of the system. The sweep-out time for the nth layer will then be

$$t_n = \frac{A\overline{f_n}}{ck_n} = \frac{\overline{f_n} T \Sigma k_n h_n}{k_n \Sigma h_n \overline{f_n}}, \tag{29}$$

where $\overline{f_n}$ is the displacement porosity for the nth zone, A is the total sweep area, and T is the time for a complete throughflow of the hydrocarbon reservoir volume. The fractional wet-gas content of the gas at any time t is then

$$R_w(t) = \frac{\sum_1^j k_n h_n}{\sum_1^N k_n h_n}, \tag{30}$$

where j is such that $t_j > t > t_{j+1}$, and it is assumed that the various layers are numbered in a sequence of decreasing t_n's or increasing $k_n/\overline{f_n}$'s. The fractional sweep of the total reservoir wet-gas content at the time t is

$$\overline{V}(t) = \frac{ct \sum_1^j k_n h_n + A \sum_{j+1}^N \overline{f_n} h_n}{A \sum_1^N \overline{f_n} h_n} = \frac{t \sum_1^j k_n h_n}{T \sum_1^N k_n h_n} + \frac{\sum_{j+1}^N \overline{f_n} h_n}{\sum_1^N \overline{f_n} h_n}. \tag{31}$$

When $t = t_j$, the time for break-through in the jth layer,

$$\bar{V}_j(t) = \frac{\dfrac{\bar{f}_j}{k_j}\sum_{1}^{j} k_n h_n + \sum_{j+1}^{N} \bar{f}_n h_n}{\sum_{1}^{N} \bar{f}_n h_n}. \tag{32}$$

Equation (32) is evidently the summation equivalent of the integral representation obtained by appropriately simplifying Eq. (10), namely,

$$\bar{V}(t) = \frac{\dfrac{\bar{f}(z_0)}{k(z_0)}\displaystyle\int_0^{z_0} k(z)dz + \int_{z_0}^{H} \bar{f}\, dz}{\displaystyle\int_0^{H} \bar{f}\, dz} \tag{33}$$

where z_0 is the depth at which break-through first develops at the time t.

As an example of the application of Eqs. (30) to (32) it may be noted that for a simple hypothetical case of four layers of equal thickness and displacement porosity, but permeabilities in the ratio of 1:5:10:25, the sequence of break-throughs will come at values of 100, 80, 65, and 41 per cent of the total wet-gas content. The wet-gas contents of the produced gas after these break-throughs in the three most permeable strata will be 2.44, 14.63, and 39.02 per cent, respectively.

It should be noted that even the generalized treatment giving rise to Figs. 13.16 and 13.17 is based on the assumptions of an exponential permeability distribution [cf. Eq. (13)], the neglect of the variation of the connate-water saturation with the permeability, and the functional form of the function F represented by Eq. (12). Recent statistical studies of permeability distributions[1] of formation samples taken from well bores indicate that Gaussian distributions often represent a closer approximation to those occurring in actual reservoirs than exponential distributions. While the analysis similar to that given here for the exponential distribution has also been carried through[2] for the probability distribution, it is somewhat more complex and has been limited to 100 per cent areal sweep efficiencies ($S = 1$). However, the general results are quite similar to those of Figs. 13.16 and 13.17, although the stratification index is different from that defining the exponential distribution. Since the actual permeability variation will seldom be known with precision, the exponential approximation may suffice for most practical applications.[3] Similar con-

[1] Cf. J. Law, *AIME Trans.*, **155**, 202 (1944).

[2] Muskat, *loc. cit.* The corresponding results for linear permeability distributions are also given in this work.

[3] If the actual distribution cannot be approximated satisfactorily by a single exponential function, it may be possible to resolve the composite section into segments

siderations apply with respect to the function F. While Figs. 13.16 and 13.17 will not be quantitatively valid in practice, they should provide reasonable estimates of the effect of permeability inhomogeneities even when applied to specific reservoirs.[1] In any case they serve to show that an efficient areal well pattern will not alone ensure high cycling recoveries and that the variations in zonal permeability and the abandonment limit of wet-gas content of the produced gas will ultimately control the effectiveness of cycling operations.

13.9. Field Observations on Condensate-producing Reservoirs.—Although more than 200 condensate reservoirs had been discovered by 1945 and 37 cycling plants had been built by November, 1944, the published data on their performance are extremely meager. And even these are limited mainly to observations that the gas-oil ratios increased during the producing life of reservoirs in which cycling was not undertaken at all or where the pressure was not fully maintained by cycling. No comparisons have been reported of the complete and detailed composition histories of the produced fluids and the reservoir pressure or cumulative production with the predictions from laboratory studies of the original reservoir fluids, such as discussed in Sec. 13.3. On the other hand, as will be seen below, there is good field evidence that the basic features of condensate-reservoir performance are governed by the retrograde-condensation phenomena. Moreover, when substantially complete cycling has been tried, the prevention of retrograde losses has been generally confirmed by the constancy of the composition of the produced gas until the development of dry-gas break-through.

One of the first reports of rising gas-liquid ratios in condensate reservoirs producing by pressure depletion, without cycling, was that on the La Blanca field, Hidalgo County, Tex.[2] The condensate-bearing reservoir in this field was discovered in 1937 at a depth of 7,500 ft in the Frio Sand.

with individual approximating exponential representations. If, however, the probability or linear distributions definitely appear to be indicated by the core-analysis data, the corresponding cycling efficiency curves (Muskat, *loc. cit.*) should, of course, be used. The argument of the Gaussian or probability distribution referred to here and elsewhere in this section is the logarithm of the ratio of the permeability to the median permeability.

[1] It should be noted, however, that the idealized assumptions of perfect stratification and areal continuity underlying the theoretical analysis will tend to accentuate the dry-gas break-through by-passing effects as compared to those which may occur in practice. And the use of a constant porosity $\bar{f}$ also implies an underestimation of the fractional cycling recoveries, since in actual reservoirs the unswept tighter parts of the reservoir may be expected to contain higher connate-water saturations and lower initial hydrocarbon reserves.

[2] F. V. L. Patten and D. C. Ivey, *Oil Weekly*, **92**, 20 (Dec. 12, 1938). Figure 13.18 is taken from this source.

The oil (condensate) gravity was 55°API. The original gas-condensate ratio was approximately 55,500 ft^3/bbl, at the reservoir pressure of 4,200 psi. No attempt was made to cycle the field. By the time the pressure declined to 3,800 psi, the gas-condensate ratio had doubled to 111,000 ft^3/bbl. The subsequent rise to 384,000 ft^3/bbl at 2,180 psi is plotted in Fig. 13.18 as the solid curve. The dashed part of the curve is an extrapolation to indicate the predicted future behavior during the decline in pressure below 2,180 psi. It was estimated that 65 per cent of the liquid content of the

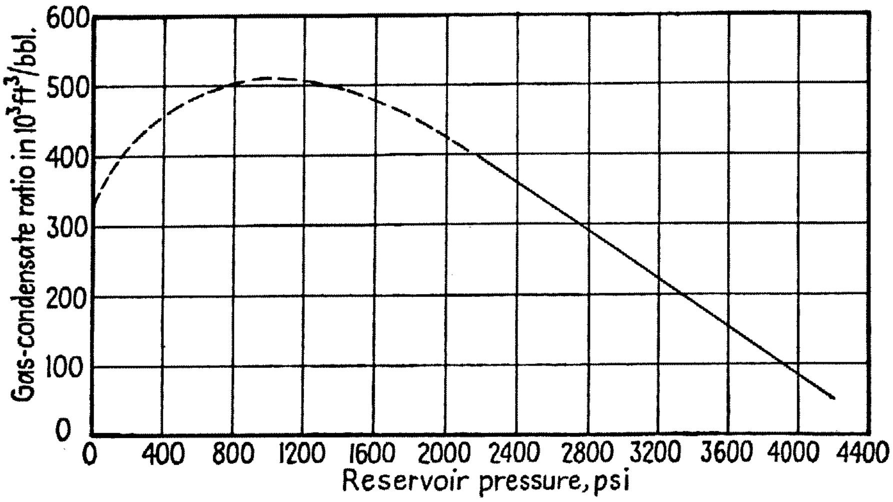


FIG. 13.18. The variation of the gas-condensate ratio observed for the production from the La Blanca field with declining reservoir pressure. Dashed segment represents extrapolation. (*After Patten and Ivey, Oil Weekly, 1938.*)

reservoir gas at 3,800 psi would be lost at ultimate pressure depletion and 82 per cent of the original condensate content at 4,200 psi. While the retrograde characteristics of the La Blanca reservoir fluids are not available for comparison with Fig. 13.18, there can be little doubt that the latter reflects the continued condensation and trapping of the liquid phase in the reservoir formation.

Similar, though not as pronounced, declines in condensate recovery per unit gas volume have been observed[1] in the 8,200-ft horizon of the Big Lake field, Reagan County, Tex. When discovered in 1929 the reservoir pressure was 2,270 psi, and the separator-fluid recoveries were in the ratio of 36 to 38 bbl/10^6 ft^3 of gas. When the last gas well was completed in March, 1933, the reservoir pressure had fallen to 1,225 psi and the rate of condensate recovery to 28 to 30 bbl/10^6 ft^3 of gas. The API gravity of the separator liquid rose from an initial range of 61 to 63° to 73 to 75° in 1938. The latter change also reflects the dropping out and trapping of the heavier wet-gas components in the reservoir, so that the residual-liquid content of the produced gas had an average lower molecular weight.

[1] Cf. E. V. Foran, *AIME Trans.*, **132**, 22 (1939).

The variation of the condensate recovery from 19 wells in the La Gloria field, Jim Wells County, Tex., over a 3-year period is plotted[1] in Fig. 13.19. Although this field was being cycled, the reservoir pressure apparently was not fully maintained. None of the wells in the group had yet been invaded by the dry gas, and in the unswept area the decline in pressure led to liquid condensation in the same manner as in uncycled reservoirs.

Perhaps the most complete reported study of the behavior of an actual condensate reservoir is that of the Bodcaw Sand of the Cotton Valley field,

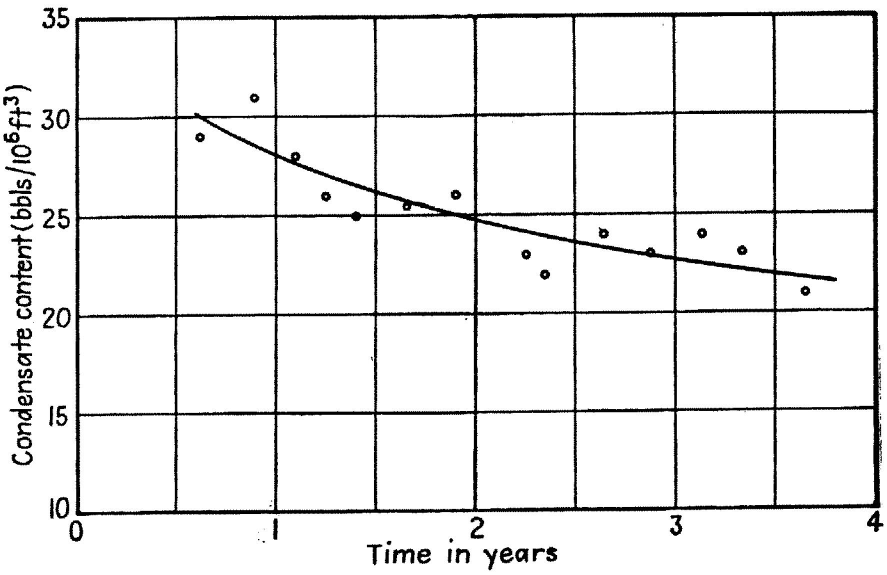


FIG. 13.19. The history of the average condensate content (C_5+) of 19 producing wells in the La Gloria field.

Webster Parish, La. The Bodcaw Sand is the most important member of five condensate-producing strata lying at depths of 8,100 to 8,600 ft and discovered in 1937. A small oil rim underlay the 18,295 acres of the anticlinal gas-cap reservoir. The reservoir temperature was 238°F, and the initial pressure was 4,000 psi gauge. An analysis of recombined separator-gas and -liquid samples showed the fluid to be at the dew-point pressure within the reservoir and to have a condensable liquid (C_4+) content of 113.98 bbl/10^6 ft^3, corresponding to a gas-liquid ratio of about 8,770 ft^3/bbl.

Prior to unitization for cycling and the beginning of gas injection in May, 1941, 81.3×10^9 ft^3 of gas, 5,438,500 bbl of condensate, and 944,800 bbl of oil had been produced. As the water intrusion from the bounding aquifer did not suffice to replace these withdrawals, the pressure declined continuously to approximately 3,220 psi. The volumetric calculation of the original gas content of the condensate reservoir, based on an average porosity of 16.2 per cent, connate-water saturation of 25.4 per cent, and average effective thickness of 23.8 ft, gave 510×10^9 ft^3.

[1] The original data were given by J. O. Lewis, *AIME Trans.*, **170,** 202 (1947).

Although 86 wells had been originally completed in the Bodcaw Sand, many were shut in when cycling was undertaken. In March, 1946, 6 crestal wells were being used for injection, and 30 wells along the flanks and near the lower boundary were maintained on production. Some of the shut-in wells were used for test purposes to study the sweep of the dry-gas downstructure.

The gross compositon history of the produced gas is plotted in Fig. 13.20.[1] It will be seen that the data based on the recoveries from the cycling plant

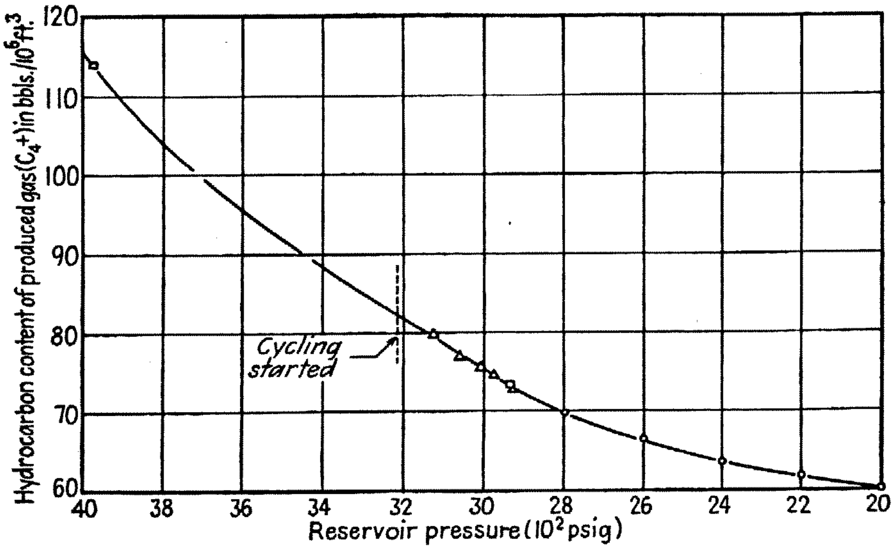


FIG. 13.20. The variation of the hydrocarbon content of the gas produced from the Bodcaw Sand of the Cotton Valley field with the reservoir pressure. □, recombined reservoir-fluid analyses. Δ, plant-yield data. ○, extrapolated predictions based on laboratory analyses. (*After Miller and Lents, API Drilling and Production Practice, 1946.*)

agree closely with those predicted from the laboratory analyses. The continued pressure decline and fall in the condensate content of the produced gas during the cycling operations do not imply a failure of the latter, since less than 80 per cent of the produced gas was returned to the formation. Moreover, whereas the pressure drop of 700 psi to May, 1941, when cycling was begun, resulted from a withdrawal of only 81,300,000,000 ft^3 of gas, the subsequent withdrawal of 206,700,000,000 ft^3 of gas to March, 1946, led to an additional pressure drop of only 360 psi. And the decline in content of condensable product of the produced gas in the latter period was 8.7 per cent, as compared with 28.3 per cent before cycling was started. That the continued decline in the curve after cycling was undertaken was due to retrograde liquid accumulation in the reservoir rather than dilution by dry gas was established by a detailed comparative study of the producing

[1] Figure 13.20, as well as the discussion given here of the Bodcaw Sand cycling operations, is taken from M. G. Miller and M. R. Lents, *API Drilling and Production Practice*, 1946, p. 128: cf. also R. L. Hock, *Oil and Gas Jour.*, **47,** 63 (Nov. 4, 1948).

characteristics of individual wells distributed over the whole producing area.

An interesting feature of the operation of the Bodcaw cycling plan was the periodic testing of the wet-gas content of wells that had been shut in prior to envelopment by dry gas, so as to determine the nature of the wet-gas displacement. The results of these tests are plotted in Fig. 13.21. The cumulative productions for these wells to January, 1946, ranged from 715×10^6 ft^3 for well E to 5.4×10^9 ft^3 for well J. It will be noted that

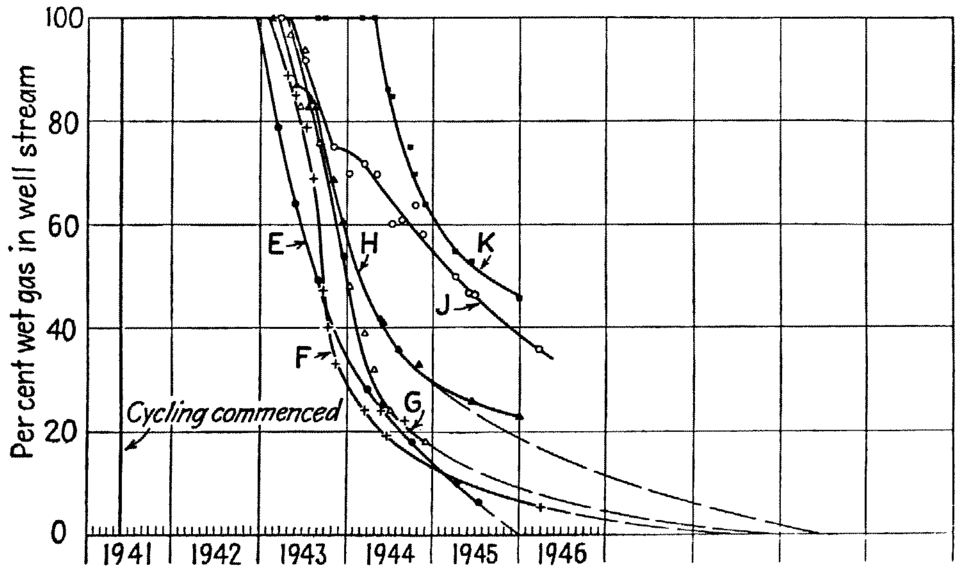


FIG. 13.21. The history of the approach of injection gas at various wells in the Bodcaw Sand of the Cotton Valley field, as obtained by periodic well tests on the wet-gas content of the well fluid. (*After Miller and Lents, API Drilling and Production Practice, 1946.*)

the wet-gas content dropped quite sharply, indicating a rather rapid and uniform sweeping of the dry gas past the test wells. An electrolytic-model study, in which the thickness variations were neglected, indicated that the dry gas should have appeared in wells H, J, and K, within 768, 830, and 1,347 days after cycling was started. The break-through times actually observed were 667, 720, and 1,056 days, respectively, which may be considered as agreeing quite satisfactorily with the predictions, in view of the simplifications made in the model study.

Using an average permeability distribution for the Bodcaw Sand, as based on core-analysis data from a number of wells, predictions were made of the expected dilution history of the producing wells, applying a simplified theory corresponding to Eqs. 13.8(28) to 13.8(32). These showed satisfactory agreement with the observed data plotted in Fig. 13.21. In fact the steep declines in wet-gas content implied by the curves of Fig. 13.21 were thus shown to reflect simply the rather uniform character of the formation and the absence of high degrees of stratification in the productive section. Related calculations of the reservoir volumes swept out by the injected gas, using the field average-permeability profile, also were in reasonable agreement with the implications of individual well tests on the spread of the dry gas.

Because a number of producing wells are spaced closely along the lower boundary of the gas cap, the very high areal sweep efficiency of 95 per cent was indicated by the electrolytic-model investigation. In fact the well distribution roughly simulates the circular cycling patterns discussed in Sec. 13.5 and is inherently susceptible to the achievement of high sweep efficiencies. Moreover there has been some intrusion of edgewaters, which has facilitated the sweep into the producing wells of the gas between the latter and the limits of the gas cap. From the actual reservoir performance to March, 1946, when 49 per cent of the reservoir content had been produced, it was estimated that the ultimate recovery will be 85 per cent of the wet-gas reserves, with a processing of a gas volume equivalent to 115 per cent of the initial-gas content.

13.10. Practical Aspects of Condensate-reservoir Development.—The basic practical problem arising in the exploitation of a condensate-producing reservoir evidently lies in the decision as to whether or not it is to be cycled. This is, of course, little else than an economic problem. Because of the many factors involved no simple formula or rule can express the economic balance between the operating profit under cycling and that under pressure-depletion operations.

It is instructive to illustrate the economic factors by reference to a hypothetical situation. Thus, if the gross condensate-reservoir volume is 200,000 acre-ft and the porosity and connate-water saturations are each 25 per cent, the total hydrocarbon pore volume will be 16.34×10^8 ft^3. If the reservoir pressure is 300 atmo ($\sim$ 4,500 psi), the reservoir temperature is 200°F, and the gas deviation factor is 0.9, the wet-gas content, in surface measure, will be equivalent to 4.29×10^{11} ft^3. If the initial gas-liquid ratio is 40,000 ft^3/bbl, the liquid content of the reservoir gas will be 10,725,000 bbl. Assuming that 80 per cent of this is recoverable by cycling, including subsequent blowdown, and 45 per cent by pressure depletion alone, without a plant, the corresponding recoveries will be 8,580,000 and 4,826,000 bbl, respectively. A plant of 125,000,000 ft^3/day would be required for a cycling life of about 12 years with a throughput of 1.25 reservoir volumes. At a plant cost of \$65,000 per 10^6 ft^3/day capacity this would require an initial plant investment of \$8,125,000. For an average injection capacity of 9,000,000 ft^3/day per well, 14 injection wells would be needed. If their cost is \$125,000 per well, the injection-well investment would be \$1,750,000. When the plant operating expenses and flow-line costs are added and account is taken of the discounted present worth of the deferred income under cycling, it is clear that the value of the increased liquid recovery of 3,754,000 bbl will hardly compensate for the increased cost of the cycling operations over that involved in simple pressure depletion.[1]

If, however, the gas-liquid ratio of the same reservoir were 10,000 ft^3/bbl, the value of the increased recovery would be multiplied approximately[2] by a factor of 4 and the balance in favor of cycling would evidently be substantial. These numerical values are, of course, only of illustrative significance and are not applicable to specific reservoirs. However, they should serve to show the order of magnitude of some of the major economic factors. Much more detailed accounting of all the cost items and a more precise evaluation of the recovered products in terms of the individual major components[3] will be necessary in order to derive a complete economic appraisal of the cycling possibilities in actual reservoirs.

It should be observed that the difference between the initial condensate content times the fractional sweep volume under cycling and the initial content times the pressure-depletion recovery factor is not a complete measure of the potential gain by cycling. For after the cycling itself must be terminated, because of the fall in wet-gas content of the produced gas until it is no longer profitable to reinject it, the reservoir can then be produced by simple pressure depletion. The unswept part of the formation will then provide an additional condensate recovery similar to that which would be obtained by pressure depletion if there had been no cycling. If $\overline{V}$ is the estimated fractional wet-gas recovery during the cycling phase with complete pressure maintenance, such as is indicated by Fig. 13.16, R_d the fractional condensate-recovery factor under pressure depletion, and $\overline{R}$ the total fractional condensate recovery, the latter would thus be

$$\overline{R} = \overline{V} + (1 - \overline{V})R_d. \tag{1}$$

Equation (1) is commonly used in predicting condensate recoveries. If $\overline{V}$ is taken as the resultant sweep efficiency to the cycling abandonment limit, the first term will need correction when applied to practical systems. Because of the shrinkage losses due to liquid extraction, the sale of low-pressure vapors, the use of some of the produced gas for fuel, although compensated in part by the fact that the returned dry gas generally[4] has a

[1] While these comparisons suggest that cycling would not be warranted economically under the assumed conditions if there were a current market for the dry gas, the operation of a gasoline- or liquid-extraction plant with pressure depletion might well be, in this case, the optimum economic-development method.

[2] With the increase in richness of the gas by a factor of 4 there would probably be associated an increased reservoir loss due to retrograde condensation. Moreover the details of the plant design and costs would be different.

[3] Cf., for example, W. H. Woods, *Oil and Gas Jour.*, **46**, 94 (Aug. 23, 1947).

[4] In fact, under certain conditions the deviation factors may increase to such an extent, on passing from the wet to the dry gas, as more than to compensate for the liquid-

higher deviation factor than the reservoir wet gas, the withdrawals will not be fully replaced and there will be some decline in pressure and retrograde loss even during the cycling operations, unless "make-up" gas is purchased. The first term on the right-hand side of Eq. (1) will therefore usually be reduced by a factor of 0.85 to 0.95.

Equation (1) must be supplemented by similar relations applying to the liquefiable products other than the stable condensate. For these the depletion recoveries R_d will generally be higher than for the stable condensate. The corresponding gains over pressure depletion will be lower in proportion. The value of R_d in Eq. (1) for these components will also depend on the manner of treating the wet gas after cycling is discontinued. Moreover, in comparing the relative recoveries of these components by cycling and pressure depletion, consideration should be given to the possibility of operating a gasoline or low-pressure hydrocarbon extraction plant without returning the stripped gas to the formation. On the other hand the dry gas following up the wet gas in the strata that were not completely swept during cycling will partly vaporize the retrograde liquid accumulation and make it available for recovery at the surface. Although it is difficult to evaluate all these factors accurately,[1] they should not be ignored arbitrarily in attempting to make quantitative comparative analyses of different methods of producing condensate reservoirs.

While the immediate purpose of cycling is the displacement of the wet gas at its dew point so as to prevent retrograde losses in the reservoir, the processing of the produced gas itself will generally provide a substantial part of the over-all gain from the cycling method of exploitation. Processing plants of modern design extract 50 to 90 per cent of the propane, 80 to 98 per cent of the butanes, and virtually all the pentanes plus content of the wet gas. As indicated by Table 3 the recovery of the butanes, even by three-stage separation, may be only 10 to 25 per cent of that in the produced gas, if not processed in an extraction plant.

The recovery factors will largely control the gross economics of various development methods. But they do not alone determine the advisability of cycling. If there is no satisfactory market for the gas, cycling may serve as a means of gas storage as well as a method for efficient recovery

extraction shrinkage losses [cf. D. L. Katz and C. M. Sliepcevich, *Oil Weekly*, **116**, 30 (Feb. 26, 1945)].

[1] Still another factor that should be taken into account when possible, although no evaluation of it has been reported, is the assumption that the uniform pressure-depletion and blowdown recovery factors as determined by calculation or laboratory experimentation are applicable to the actual stratified or nonuniform reservoirs. In the latter the depletion recovery factors should be averaged and weighted according to the permeability distribution and corrected, if possible, for cross flow. And the blowdown recovery factors will reflect primarily that associated with the tight parts of the pay and hence will be somewhat lower than that for a uniform depletion throughout the reservoir.

of the condensable-liquid products of the wet-gas reservoir content. For example, the gas content alone of the hypothetical reservoir considered above would be worth roughly 50 million dollars if it were stored at the original reservoir pressure until it could be sold at a price of $0.12 per thousand cubic feet. This is evidently much greater than the value of the liquid content, if the gas-liquid ratio were 40,000 ft^3/bbl. Similar consideration should be given to the gas-storage aspect of cycling if there is a probability that the market value of the gas will rise, even if it could be sold immediately. On the other hand, if the sale price of the gas were to remain constant, its storage until completion of the cycling would represent a loss in present worth due to the interest discount. In addition the slower recovery of the condensate under cycling than would be possible under unrestricted pressure depletion will lead to a reduced present worth of the liquid recovery. This time factor will also be of importance in determining the size or capacity of the cycling plant. Still other factors are the tightness of the formation, which will determine the number of injection wells required, the well costs, which will be controlled largely by the depth, the reservoir uniformity, possibilities of faulting, and the areal sweep efficiency. Each reservoir must be evaluated separately in the light of its unique characteristics.[1]

Although the primary emphasis of the discussion of this chapter has been on the exploitation of the condensate reservoir itself, such reservoirs often are underlain by crude-oil zones of sufficient size so that the development of the latter must be made an integral part of the program for producing the gas cap. Among the various possible methods of operation the most efficient, from the point of view of recovery, will be that in which the fluid withdrawals are limited to the crude-oil zone while pressure is maintained in the condensate reservoir by gas injection. The injection wells are then to be so located as to sweep the wet gas into the oil zone. In this manner the retrograde losses in the gas cap will be prevented, and the oil-recovery efficiency will be enhanced by virtue of the general pressure-maintenance effect and the contribution of the gravity-drainage mechanism. Moreover the condensate accumulation that may develop in the swept part of the black-oil zone, owing to the lower pressures in the withdrawal area, will be recoverable because it will add to the residual-oil saturation and have a nonvanishing permeability. In fact the mixing of the condensate with the crude oil and the lowering of its viscosity will tend to increase the black-oil recovery factor. The sweep efficiency of the gas

[1] Examples of studies made in planning cycling operations in actual fields are the reports of N. Williams, *Oil and Gas Jour.*, **46**, 99 (Dec. 6, 1947), on the Lake St. John field, Concordia and Tensas Parishes, La., and of W. L. Horner and E. G. Trostel, *Oil and Gas Jour.*, **46**, 77 (Mar. 4, 1948), on the Benton field, Bossier Parish, La.

cap will also be high, since the "dead" areas usually left behind the peripheral producing wells in the simple gas-cap cycling will be eliminated. If it is not feasible to confine the withdrawals entirely to black-oil wells and shut them in progressively as they become enveloped by the displaced wet gas until the oil zone is depleted, the recovery efficiency will not be seriously impaired as long as the production in the original oil reservoir is so controlled that there is a net downflank migration of the oil.

Simultaneous black-oil production and cycling of the gas cap, as is common practice, should lead to high recovery efficiency provided that a net pressure gradient is maintained from the gas cap toward the oil zone. If the gradients are reversed, there may be serious losses in crude-oil recovery due to oil migration into the gas cap. And if the wet-gas-oil contact is held fixed, the black-oil zone will become depleted as if there were no gas cap and no pressure maintenance, although it may still be subject to the favorable effects of gravity drainage. If a potentially active water drive is available, the necessity for maintaining pressure in the gas cap and downdip gradients near the gas-oil contact will be even more imperative.

Production of only the crude-oil zone, with no gas return to the gas cap, will lead to pressure decline and retrograde liquid accumulation in the latter. Cycling of the gas cap following the depletion of the oil reservoir could theoretically lead to complete condensate recovery as the combined result of residual-wet-gas displacement and revaporization of the liquid phase. However, the crude-oil recovery may be appreciably lower than under simultaneous cycling and oil production because of the reduced effectiveness of the gravity-drainage recovery mechanism and the lack of pressure maintenance. Moreover, if a gas-processing plant is not installed until cycling is undertaken, much of the intermediate condensable-liquid content of the separator gases produced during the oil-zone depletion will be lost. Such operations will also defer the income from the gas-cap production and reduce its present worth.

Shutting in the oil zone until the gas cap is completely cycled will evidently ensure high condensate recovery. Subsequent production of the oil reservoir before blowdown of the gas cap will lead to substantially the same recovery as when the oil-zone depletion precedes the gas-cap cycling. Analogous to the latter, there will be involved here a deferment of the income from the black-oil reservoir if its depletion is delayed until after the cycling is completed.

These general observations do not represent universal comparative evaluations of the various possible methods of exploiting composite crude-oil and condensate reservoirs. In considering a specific reservoir all its individual characteristics and the practical and economic aspects of its development must be taken into account. What may appear to be the most efficient operating plan theoretically may be entirely impractical in a particular situation because of unique practical conditions involved in actual operation. The market demand for the gas, condensate, or oil, state regulations, the richness of the wet gas, the cost of the wells, the presence or absence of water drives, the relative size of the oil zone, the faulting of the reservoir, the reservoir pressure, and other related factors may singly or in combination virtually force the adoption of one method of operation in one field, whereas a different method may be necessary in another reservoir that is apparently similar in some respects.

When the condensate reservoir is bounded directly by edgewater rather than an oil rim, the operating problems are simplified. If the edgewaters can provide a sufficiently active water drive to maintain the pressure near the dew point, without prohibitively restricting the withdrawal rates, gas return will evidently be unnecessary.[1] However, such active water drives are very unlikely except in highly fractured limestones, although it is conceivable that by supplementary water injection a practical degree of pressure maintenance could be achieved in some cases. Moreover the development of appreciable rates of natural water intrusion will require that some pressure decline take place in the condensate reservoir. On the other hand, if the edgewaters have any mobility whatever, the location of the producing wells near the water-gas contact will induce the entry of water, due to the superposition of the local pressure drawdowns and the slow pressure decline in the gas cap associated with the incompleteness of the gas-withdrawal replacement. By placing the producing wells at the crest of the structure not only will the production be water-free,[2] but it will be possible to achieve high areal sweep efficiencies by completing the injection wells below the edge of the gas cap and into the water-bearing formation. In this way a driving pressure toward the producing wells will be exerted on the gas even at the very limits of the condensate reservoir, and the development of dead spaces that would be left behind the injection wells if completed within the gas-bearing formation will be prevented. This increase in areal sweep efficiency should more than counterbalance the higher flow resistance in the water zone above the injection wells. While some of the water will be displaced into the gas cap, it will be gradually dispersed and should become trapped before reaching the producing wells. Aside from the achievement of increased sweep efficiency

[1] While an equilibrium gas saturation, of the order of 5 to 15 per cent, might be trapped in the water-invaded zone, the loss of this gas would probably not be serious as compared with the savings in the cost of the gas-injection facilities of a cycling program.

[2] This refers to the entry of edgewater into the producing wells. The production of condensate is always accompanied by fresh water, which had been held in the vapor phase in the reservoir and drops out, together with the condensate, as the temperature and pressure are reduced from those in the reservoir.

the location of the injection wells below the water-gas contact affords the possibility of using dry holes that may have been drilled in delineating the reservoir boundaries and that would otherwise be abandoned as useless. Although this procedure seems rather unorthodox, it has been successfully applied in several fields in the Gulf Coast area.[1]

It has already been noted that in cycling operations there is usually an incomplete replacement of the total fluid withdrawals. This results in a slow pressure decline and some liquid condensation. There is another cause of retrograde liquid accumulation during cycling operations. This is the pressure drawdown about the producing wells. Because all the production must pass through the annular ring immediately bounding the well bore, the retrograde condensation will quickly build up the pore saturation near the well bore until it becomes mobile and is swept into the well with the gas phase. The area in which the limiting saturation has been built up will gradually expand outward from the producing well as production continues. The dew-point pressure of the well effluent will correspond to that at the limit of the area of condensate mobility and should theoretically increase as the region of mobility expands, provided that the reservoir pressure as a whole remains fixed.

An estimate of the rate of build-up of the liquid-phase saturation can be made by evaluating the equation

$$\frac{d\rho}{dt} = \frac{Q}{2\pi rhf}\frac{dp}{dr}\frac{dC}{dp}, \tag{2}$$

where Q is the production rate, h the formation thickness, f its porosity, dp/dr the pressure gradient at the radius r, and C the liquid content of the wet gas per unit volume, in surface measure. By assuming a steady-state radial pressure distribution, a reservoir pressure of 4,000 psi, and a drawdown of 500 psi, the pressure gradient at a radius of 1 ft will be approximately 50 psi/ft. For $h = 50$ ft, $f = 0.25$, and $Q = 5 \times 10^6$ ft³/day, the factor of dC/dp becomes 3.18×10^6 psi/day. The value of dC/dp near the dew point of some of the condensate-reservoir fluids for which data have been obtained is of the order of magnitude of $10^{-6} - 10^{-7}$ cc/cc/(psi). It thus follows that the area within a radius of 1 ft about the well bore will be filled up with liquid phase to the point of mobility within a few hours or several days at the most. As the rate of fill-up will vary inversely as the square of the radius, it will take about 1.7 years for a condensate saturation of 20 per cent to develop at 100 ft from the well bore even if dC/dp is 10^{-6} cc/cc/(psi).* The rate of condensate-saturation build-up is also

[1] H. L. Hensley, *Oil and Gas Jour.*, **45**, 84 (May 3, 1947).

* If the effect of the liquid accumulation on the pressure distribution is neglected, the history of the liquid-saturation build-up as a function of both time and the radial distance can be readily calculated by applying Eq. (2). Results of this type have been

essentially proportional to the square of the drawdown or the square of the production rate. While this continued accumulation may become of serious magnitude in tight formations producing a very rich gas, it will probably not represent a major loss factor in most cycling operations. Moreover by the time the cycling is completed at least a part of the liquid phase will be revaporized as the dry gas sweeps through the area about the well bore.

Although the basic premise underlying the previous discussion of the operation of condensate reservoirs has been that the liquid-phase accumulation in the formation resulting from retrograde condensation is essentially irrecoverable, this is not strictly correct from a physical standpoint. It is true that except near the producing well bores the pore saturation of condensate liquid will generally be too low to have any mobility and will remain trapped as the residual wet gas is produced. This is confirmed by such observations as are recorded in Figs. 13.18 to 13.20, which show the condensate content of the well fluid to decrease with declining pressure in the same manner as the content of the reservoir gas phase alone. However, it is, in principle, possible to vaporize or "dry up" the condensed-liquid phase on exposing it to a sweep of dry gas. It may readily be shown that under equilibrium conditions the number of moles of dry gas, N, of mole fraction composition represented by n_{id}, required completely to vaporize a mole of liquid of molar composition n_{io} is given by

$$N = \frac{\Sigma(n_{io}/K_i) - 1}{1 - \Sigma(n_{id}/K_i)}, \tag{3}$$

where the K_i's are the equilibrium ratios at the reservoir temperature and pressure. Thus, for example, on assuming the reservoir liquid-phase composition to be that plotted in Fig. 13.4 and the dry gas to be comprised of 88.14 per cent methane, 8.46 per cent ethane, 2.94 per cent propane, 0.18 per cent butanes, 0.08 per cent pentanes, 0.09 per cent hexanes, and 0.11 per cent heptanes +, it is found that it[1] would take 20.8, 46.8, 56.9, and 55.4 moles of dry gas to vaporize one mole of the retrograde liquid formed by pressure depletion to 2,500, 1,500, 1,000, and 500 psi, respectively.

This possibility of revaporizing the condensed liquid phase by contact with dry gas raises the question whether dew-point cycling is inherently necessary and whether dry-gas sweeping at lower pressures may not suffice

reported by M. G. Arthur, API meetings, Los Angeles, Calif., May, 1948. In this work it is also shown that the condensate accumulation near the well bore should have only a negligible effect on the well productivity.

[1] A reservoir temperature of 200°F was assumed, and the equilibrium ratios were taken from C. H. Roland, D. E. Smith, and H. H. Kaveler, *Oil and Gas Jour.*, **39,** 128 (Mar. 27, 1941).

to recover the original reservoir condensate content. As a strictly physical problem it is evident that such low-pressure cycling can lead to recoveries as high as by dew-point cycling. In fact, a detailed analysis[1] for a hypothetical condensate reservoir containing a wet gas whose depletion history is described by Figs. 13.3 to 13.5 shows this to be the case. Stepwise calculations were made of the pickup of the condensed liquid by dry gas as it passed through a linear column of sand that had been previously produced

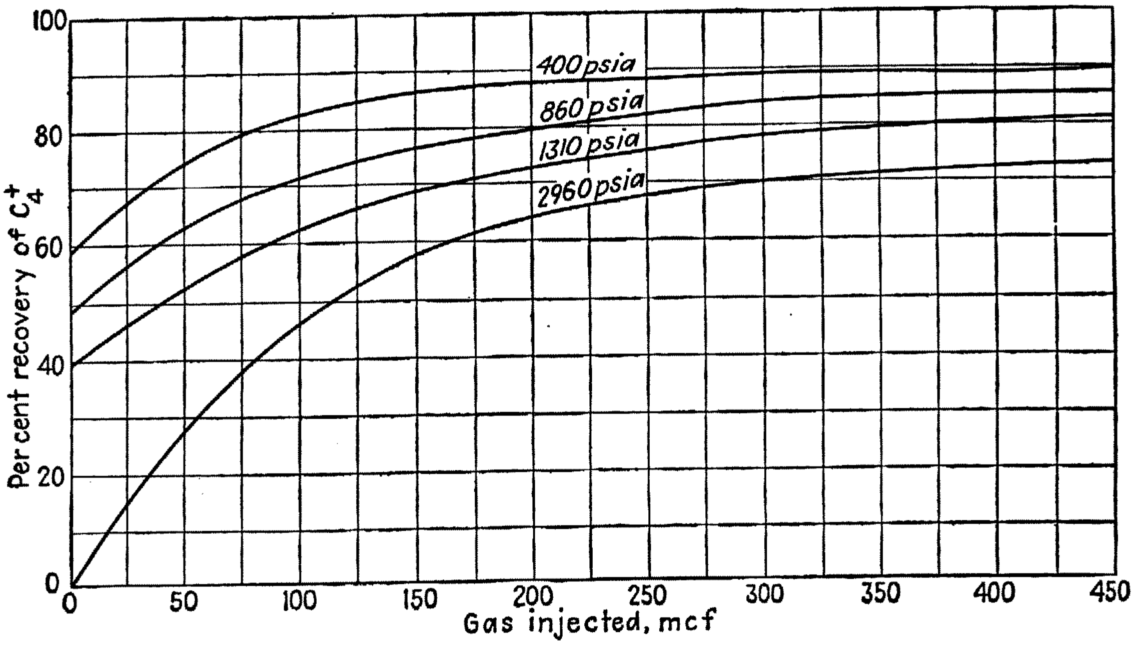


Fig. 13.22. The calculated variation of the total C_4+ recoveries from a hypothetical condensate reservoir vs. the cumulative gas injection, per 1,000 ft^3 of hydrocarbon pore space, during cycling operations at various reservoir pressures. (*After Standing, Lindblad, and Parsons, Petroleum Technology, 1947.*)

by gas withdrawal to various limiting pressures. After so determining the vaporization and sweep history in a uniform-permeability zone the composite behavior was computed for a multilayer system with a Gaussian permeability distribution, with a standard deviation of 0.7985 in the log of the permeability, and a 75 per cent areal sweep efficiency. The per cent C_4+ recoveries as a function of the total gas injected at various pressures, derived in this manner, are plotted in Fig. 13.22.

It will be seen from Fig. 13.22 that whereas the recoveries per unit volume of injected gas, *i.e.*, the slopes of the curves, are greatest for the dew-point cycling (2,960 psia), the total recoveries for given volumes of injected gas increase with decreasing cycling pressure. This, in itself, is not surprising and simply reflects the fact that the multiple throughflows required for effective sweeping through the tighter zones and revaporization of the condensed-liquid phase when injected at low pressure may represent a gas

[1] Cf. Standing, Lindblad, and Parsons, *op. cit.*

volume, in surface- or atmospheric-pressure measure, even lower than the small number of throughflows which would be used at the dew point or high pressure. Thus the pore volumes of injected gas, for 100 per cent sweep efficiency, required to obtain a total recovery of 1,059 gal of C_4+ per 1,000 ft^3 of hydrocarbon pore space were found to be 2.0, 5.1, 5.9, and 7.8 for cycling pressures of 2,960, 1,310, 860, and 400 psi, respectively. But these represented volumes of injected gas, in surface measure, of 364,000, 396,000, 295,000, and 171,000 ft^3, respectively.

These numerical values apply only to the hypothetical system described by Fig. 13.22. For different reservoir fluid and dry-gas compositions the relative volumes involved will be different. If the volume of liquid accumulation on pressure decline is greater or if its heavy-component content is greater and of higher molecular weight than represented by the system of Figs. 13.3 to 13.5, the volume of dry gas required for revaporization will be correspondingly greater and the low-pressure cycling may require more gas injection than dew-point cycling for equivalent recoveries. The degree of permeability stratification and total areal sweep efficiency will also affect the comparative effectiveness of low-pressure and dew-point cycling.

All the calculations for low-pressure cycling on which Fig. 13.22 is based assume complete equilibrium between the injected dry gas and the local liquid phase. This, however, does not seem to be unreasonable, in view of the highly dispersed character of the liquid phase and the long distance of travel and time of exposure of the dry gas before leaving the formation. Moreover, laboratory experiments, in which the dry-gas velocity was considerably greater than that obtaining in actual reservoirs, showed the liquid-phase vaporization to follow the equilibrium predictions.[1]

Even if the actual reservoir conditions should simulate those assumed for the illustrative example discussed above, the curves of Fig. 13.22 in themselves do not prove that low-pressure cycling is desirable from a practical and economic standpoint. An important factor not taken into account at all in Fig. 13.22 is that the completion of the cycling phase does not represent the state of abandonment. As noted previously the dry-gas content alone in a reservoir that has been cycled at the dew point would represent a very substantial economic asset. Moreover the unswept part of the reservoir will still contain all its original condensate content. Evidently in actual operations a reservoir that has been cycled at the dew-point pressure or at any pressure above the final abandonment pressure would be allowed to bleed off its residual dry and wet gas by pressure depletion to abandonment. The recovery of condensate from the previously

[1] Experiments on condensate-fluid depletion in sand-filled vessels also show equilibrium behavior during both the retrograde and normal vaporization phases [cf. C. F. Weinaug and J. C. Cordell, *Petroleum Technology,* **11,** 1 (November, 1948)].

unswept volume should therefore be added to that obtained during cycling to give a proper comparison of the total recovery under dew-point and low-pressure cycling. Since only a small number of pore volumes will be passed through the formation under high-pressure cycling, the unswept volume will be higher than when the cycling is conducted at low pressure. The additional depletion recovery will be correspondingly greater for the former. Supplementary calculations of the amount of this recovery for the reservoir conditions underlying Fig. 13.22 show that the resultant recoveries for dew-point cycling will be substantially the same as for low-pressure cycling, for the same final abandonment pressure. In fact this conclusion appears to be generally applicable to relatively rich reservoir gases.

There are factors other than the total condensate recovery that are of importance in the comparative values of cycling at different pressures.[1] For the same plant capacity the total operating life would be shorter under low-pressure cycling. However, to maintain such plant capacities during a low-pressure cycling the number of wells would be considerably greater than during cycling at the dew point, since for a fixed pressure differential the injection- and producing-well capacities will be proportional to the mean reservoir pressure. This can be partly compensated by using higher pressure differentials. But this will require increased compression costs. The cost of the flow lines and much of the plant equipment also will be greater in handling, at low pressure, gas volumes comparable with those processed at high pressure. There is in addition the psychological factor that an operator may be reluctant sharply to cut his current income from gas sales during a preliminary depletion phase and at the same time make the large investments required in starting a gas-return program. Failure for such reasons to undertake the cycling operations would then certainly lead to large losses in liquid recoveries, if the reservoir were inherently susceptible to cycling. It should also be noted that, whereas the total C_4+ recovery from the reservoir may theoretically be as high with low-pressure as dew-point cycling, much of liquefiable material other than the stable condensate recovered may be lost under the former type of operations. Unless an extraction plant were built for operation during the initial pressure-depletion period, a large part of the intermediate hydrocarbons will be lost in the separator gases.

[1] For a more detailed discussion of the practical aspects of the problem cf. E. O. Bennett, *California Oil World*, **40**, 25 [October (2d issue), 1947]. A quantitative analysis by M. G. Arthur (API meetings, Los Angeles, Calif., May, 1948) of the economics of cycling a hypothetical reservoir at various pressures shows that the interest-discount factor and the future prices of the products may ultimately control the present worth of the net profits. For constant prices he finds that cycling at intermediate pressures will give maximum profits, while high-pressure cycling will be somewhat more profitable for increasing price trends, for the particular reservoir and economic conditions investigated.

There is much less question about the relative merits of low-pressure and dew-point cycling when the condensate reservoir is underlain by an oil zone of substantial size. A preliminary depletion phase will then lead to reduced oil recoveries, as well as a loss in the intermediate liquefiable hydrocarbons of both the condensate and solution gases. Moreover, to take advantage of the possibilities of a reduced operating life for the field, assuming there is a market for all available gas, the gas withdrawals during the depletion period will have to be considerably more rapid than would correspond to the normal depletion of the oil zone. It is likely that at best the oil-reservoir depletion could only keep pace with that in the gas cap; but this would nullify any pressure-maintenance and gas-sweep effects on the oil recovery. However, if there were a lag in the depletion of the oil zone, there would be serious danger of its encroachment into the gas cap, which would lead to still greater losses in oil recovery. In such composite reservoirs, high-pressure cycling, while involving longer operating lives, would undoubtedly lead to greater over-all efficiency in recovery, if cycling is basically desirable for the development of the gas cap. Of course, if there is an active water drive in the field, the difficulties of preventing migration of the oil into the gas cap during the depletion phase become greatly aggravated, and high-pressure cycling will be the only safe way to operate the field.

Although not concerned directly with condensate reservoirs, related to them are two other types worthy of brief mention. It will be recalled from Sec. 13.2 that the occurrence of retrograde isothermal condensation is limited by the requirement that the reservoir temperature lie between the critical and cricondentherm temperatures of the hydrocarbon mixture and that the reservoir pressure lie at least in the range of the critical pressure. It follows that if the reservoir temperature exceeds the cricondentherm temperature, the hydrocarbon mixture will be in a single phase regardless of the pressure. Thus there will be no retrograde condensation within the formation,[1] and the reservoir will perform as a gas field even though both condensate and gas will be produced at the surface. There will be no need for cycling or pressure maintenance for the purpose of ensuring the recovery of the condensable hydrocarbon content. Fields of this type have been discovered and developed as gas fields, although the composition of the initial production alone would suggest that they are lean condensate reservoirs.

If a condensate-producing wet gas were carried along its dew-point phase-diagram boundary curve with a continual reduction in temperature past the critical temperature, the saturated vapor would change into a bubble-point liquid (cf. Fig. 13.1). If the latter were now produced through

[1] The reservoir fluid will follow a pressure-temperature phase-diagram path represented by a straight line parallel to *ABDE* in Fig. 13.1 and lying entirely to the right of the dew-point curve.

a well bore, the surface fluids recovered initially would be identical with that which would have been obtained if the production had its origin in a dew-point gas reservoir, since the phase separation at any terminal state, such as atmospheric conditions, is independent of the initial state. Within the bubble-point liquid reservoir, however, a gas phase would develop immediately on pressure decline.[1] Moreover, if considered as the equivalent of a crude-oil system, the reservoir liquid would have an abnormally high formation-volume factor. From the considerations of Sec. 10.4 it is clear that the solution-gas-drive recovery of the heavy-liquid components would be extremely low in spite of the low viscosity of the liquid phase. The produced gas will be rich in condensable-liquid components, and if processed by an extraction plant it will contribute appreciably to the total liquid-phase recovery. Within the reservoir the gas-phase saturations will quickly build up until the gas permeability is very high compared with the liquid, after which the liquid will simply shrink in place by continued gas evolution as the pressure declines owing to flow of the gas phase into the well bore. While a large part of the lighter and intermediate hydrocarbon content of the reservoir will thus be recovered, most of the C_7+'s will probably remain trapped in the formation.

The loss in recovery due to the rapid liquid-phase shrinkage can be prevented in such reservoirs by pressure maintenance. If the reservoir can be produced by gravity drainage, with gas injection into the structural crest, the direct recovery will be given by the difference between the average initial- and residual-liquid-phase saturations. The subsequent pressure depletion should lead to some additional recovery of the intermediate hydrocarbon components in the residual oil. Continued gas injection or cycling may also result in at least partial vaporization of the residual-liquid phase. Natural water drives or water injection will likewise serve to prevent the liquid-phase shrinkage and to reduce the residual-liquid saturation. However the latter will remain essentially unrecoverable even if water injection be discontinued and the pressure be allowed to decline. The methods of field operation must be evaluated separately for each specific reservoir in the light of the economic factors pertinent to the particular reservoir of interest.

While the hypothetical situation considered above would lead to a production with gas-liquid ratios characteristic of condensate reservoirs, fields of this type have been found[2] with substantially lower gas-oil ratios. The

[1] The reservoir fluid will follow a pressure-temperature phase-diagram path represented by a straight line parallel to *ABDE* in Fig. 13.1 and lying to the left of the point *C*.

[2] The Rattlesnake field, San Juan County, N. Mex., appears to have been this type of reservoir, although it was discovered (1924) before means for analyzing the reservoir conditions were developed [cf. A. H. Hinson, *AAPG Bull.*, **31**, 731 (1947)]. A com-

liquid phase itself in such cases is definitely of the condensate type. But the gas content is relatively low, and the critical temperature of the mixture apparently exceeds the reservoir temperature. Instead of leading to complete dew-point vaporization the reservoir temperature and pressure suffice only for the creation of a bubble-point liquid phase.

It will be obvious without detailed discussion that condensate-reservoir cycling cannot be effectively conducted unless the operations are unitized. Competitive pressure depletion in one part of the field and cycling in an adjoining and intercommunicating part of the reservoir will evidently defeat the purposes of the gas injection. Moreover pressure gradients will be developed leading to migration losses of the reservoir fluids from the cycled area.[1] The flexibility of well location for efficient dry-gas sweeping and all the operating economies that would be possible through unitized development will be seriously reduced. In fact the unitized operation may be considered as an axiomatic *sine qua non* for all cycling programs.

13.11. Summary.—Condensate reservoirs are unique because of the special thermodynamic properties of the reservoir fluid. The latter generally constitutes a saturated vapor within the reservoir and suffers retrograde condensation of a liquid phase when the pressure is reduced. Its over-all composition is largely comprised of methane and the intermediate hydrocarbons. The liquid phase formed from the vapor is usually straw-colored and of high API gravity. The critical temperature of the mixture is lower than the reservoir temperature, and the critical pressure must be of the same order of magnitude as the reservoir pressure. The average molecular weight of the heavy components is generally considerably lower than that of crude oils. The gas-liquid ratio of the production from condensate reservoirs is decidedly higher than that commonly associated with crude-oil–natural-gas systems. Reservoir "wet" gases are considered as "rich" if the gas-condensate ratio is of the order of 10,000 ft^3/bbl, but many condensate fields produce with ratios of 50,000 ft^3/bbl or greater.

plete p-v-T analysis of a particular reservoir fluid of this type has been reported by J. P. Sloan (AIME meetings, Dallas, Tex., October, 1948). An approximate treatment of the expected solution-gas-drive performance of a hypothetical reservoir containing this fluid indicates a recovery of 16.0 per cent of the initial "residual" oil content, corresponding to only 2.5 per cent of the pore space, and an almost vertical rise of the gas-oil ratio to 3.4×10^6 ft^3 /bbl after the equilibrium gas saturation has been developed (cf. M. Muskat, *Journal Petroleum Technology*, in press). Still another recent study of bubble-point-liquid reservoirs producing condensate-type fluids is that on the North Lindsay field, McClain County, Okla., reported by A. B. Cook, G. B. Spencer, F. P. Bobrawski, and E. J. Dewees, *Petroleum Eng.*, **19**, 158 (September, 1948).

[1] While regional fluid migration, in itself, is a virtually necessary and desirable feature of cycling operations, especially in composite condensate and oil reservoirs, such migration will lead to an inequitable distribution of the recoveries unless the field is unitized and property lines are ignored in the location of both the injection and producing wells.

As soon as the pressure is reduced below the dew point in a condensate-bearing reservoir, by fluid withdrawal, liquid will condense in the formation. This condensation process (retrograde) will continue until the pressure falls to a value of 1,000 to 2,000 psi, depending on the initial wet-gas composition and reservoir temperature. Beyond this point normal vaporization will develop, and the reservoir liquid volume will decrease (cf. Fig. 13.3). As the total liquefiable components comprise only a small part of the wet gas, even a flash condensation of the whole reservoir wet-gas content would lead to a build-up of the liquid saturation to only 5 to 18 per cent of the pore volume (cf. Fig. 13.2). The accumulation will therefore remain trapped in the formation, and only the gas phase will be produced. Because of this separation of the liquid phase the composition of the produced-gas phase will continually change (cf. Fig. 13.5), and the gas-condensate ratio will rise until the pressure of maximum retrograde condensation is reached. The reservoir liquid-phase composition will also change continuously as increments are added to it from the partly denuded residual gas (cf. Fig. 13.4). The liquid trapped in the reservoir by pressure depletion may amount to 30 to 60 per cent of the original reservoir content. A larger fraction of the heavy components will be lost in this manner than the intermediate constituents, although a large part of the latter that are produced may be carried away by the separator gases if the well fluids are not processed by extraction plants (cf. Table 3). The losses within the reservoir will evidently be greater as the fractional content of the heavy components in the wet gas increases.

While it is convenient to use the terms "gas-oil" and "gas-condensate ratios" in describing the production from condensate reservoirs, by analogy with crude-oil–natural-gas systems, they are not sufficiently precise for purposes of detailed economic evaluation. The compositions of the produced-gas and liquid phases will vary during the producing life and will be sensitive to the separator conditions. A more satisfactory description of the reservoir content and production is one based on the composition of the fluids. The production history under pressure depletion can then be expressed in terms of the cumulative recovery of the individual components or appropriate groupings of them vs. the reservoir pressure (cf. Fig. 13.6).

For practical purposes the dynamical behavior of a condensate reservoir may be considered as identical with that of a normal gas reservoir. The cumulative molar production will therefore decrease approximately linearly with the reservoir pressure [cf. Eq. 13.3(2)].

The obvious solution to the problem of preventing the retrograde losses of the heavier components resulting from reservoir pressure decline is pressure maintenance by fluid injection. When the fluid injected is the produced gas stripped of its liquefiable content, the process is called "cycling."

One of the first steps in planning cycling operations is the choice of the well distribution that will lead to an efficient sweep of the wet reservoir gas by the injected gas. While the well pattern must be adjusted to the basic geometry of the reservoir, the theoretical analysis of the simpler systems suffices to indicate the order of magnitude of the sweep efficiencies that can be achieved and the important factors controlling the sweep efficiency. By analogy to the similar problem in secondary-recovery operations the sweep efficiency is conveniently defined as the fraction of the cycled area swept out by the time of first dry-gas break-through.

When the reservoir can be approximated by a rectangular area, a convenient cycling pattern is the "end-to-end" sweep, in which the injection wells are distributed on one side and the producing wells on the other. For a uniform infinite porous medium the fraction of the area between the wells swept out by the time of first gas entry into the producing wells may be derived analytically in explicit form [cf. Eq. 13.5(4)]. It is found that the unswept area is independent of the separation between the injection and producing wells as long as the separation equals or exceeds half the spacing between wells of the same kind [cf. Eq. 13.5(5)]. It follows that the sweep efficiency increases with the distance between the injection and producing lines, for fixed separations of wells of the same kind. This result has considerable generality and is also verified in the case of the infinite-line-drive networks.

The cycling pattern in which the injection wells are equally spaced over a circular ring and a single producing well is placed at the center, or conversely, has a sweep efficiency given simply by the ratio of the number of wells in the ring to this number plus 2 [cf. Eq. 13.5(10)]. The efficiency thus rapidly approaches unity as the number of wells in the ring increases. Similar though somewhat more complicated results may be derived if both the injection and producing wells are distributed on concentric rings with equal and uniform angular spacing [cf. Eq. 13.5(11)].

Finite rectangular areas cycled with a bilateral pattern, with injection wells along a central line and producing wells along the opposite parallel sides (cf. Fig. 13.9), or conversely, also can be treated analytically. Here, on taking into account the finite-reservoir area the effect of locating the producing wells (or injection wells) at various distances from the boundary is clearly demonstrated. Thus, the over-all sweep efficiency is increased from 36.9 per cent, when the line of producing wells is located at a distance from the central injection line that is 57 per cent of the reservoir half width, to 74.1 per cent, when the producing line is placed along the actual limits of the reservoir. A calculation of the produced-fluid composition after dry-gas break-through shows the wet-gas content to fall sharply and reach a value of 15 per cent of the composite produced fluid by the time the total gas processed is of the order of 1.3 times the reservoir hydrocarbon pore volume (cf. Fig. 13.12). The exact value of the total gas processed by the time an abandonment limit such as 15 per cent wet-gas content is reached does not vary rapidly with the producing-well location. However, the total wet-gas recoveries increase from 64 to 96 per cent as the producing wells are moved to the reservoir boundary from an initial distance from the injection wells that is 57 per cent of the reservoir half width (cf. Fig. 13.13).

Cycling patterns of more complex geometry can be effectively studied only by means of electrolytic models. While gelatin models provide a quick visual record of the history of the injection-fluid motion, they do not have the precision and flexibility of the potentiometric models. With the latter the injection-fluid fronts can be determined for a system of variable thickness and permeability almost as easily as for one of strictly uniform characteristics. Such potentiometric models may be made by adjusting the depth of the electrolyte so as to be proportional to the product of the permeability and effective pay thickness at the corresponding point in the actual reservoir [cf. Eq. 13.6(5)]. On locating in the electrolytic bath a distribution of input- and output-current electrodes which is geometrically similar to that of the injection and producing wells, with respective currents proportional to the injection and producing rates, the voltage distribution in the model will be proportional to an effective potential function given by the pressure integral of the fluid density to viscosity ratio [cf. Eq. 13.6(4)]. The local fluid velocities will be proportional to the voltage gradients along the streamlines. The latter are conveniently measured by a four-probe electrode, two of which are set to lie along an equipotential, so that the other pair, normal to the first, lies along the streamline. The time increments for fluid movement along the streamlines are directly proportional to the product of the gas density and displacement porosity and inversely proportional to the permeability and voltage gradient.

In practical applications, where the permeability variations are neglected, the electrolytic-bath thickness is made geometrically similar to the isopach map of the formation. While in principle the gas-density variation will affect the details of the injection-fluid motion, it will be an important factor mainly near the injection and producing wells and is usually neglected. Models of this type have been successfully applied in the determination of optimum cycling well patterns (cf. Fig. 13.14) as well as in the interpretation of actual field observations.

If there is any flexibility whatever in the choice of the well locations, it is generally possible to find a distribution that will lead to a sweep efficiency of 60 to 80 per cent of the area to be swept, without requiring a prohibitively large number of wells. This, however, does not in itself ensure an effective sweeping of the wet reservoir gas. The areal sweep efficiency of a uniform stratum will generally be reduced materially by the permeability stratification of the formation. Such stratification will lead to a superposition history of the sweep patterns in the individual layers in which dry-gas break-through will develop in sequence according to their permeability. The resultant behavior of the composite system can be readily formulated in general analytical expressions for any type of permeability variation.

A convenient though approximate representation of the permeability stratification in producing formations is given by an exponential variation of the permeability with depth, on assuming that the different strata are arranged in a sequence of increasing permeability with increasing depth [cf. Eq. 13.8(13)]. The ratio of the maximum to minimum effective permeability then provides a simple stratification parameter controlling the behavior of the composite formation. On assuming also the wet-gas content of the effluent from the individual zones after dry-gas break-through to decrease exponentially with the total gas throughflow [cf. Eq. 13.8(12)], the time history of the composition of the production and the total wet-gas recovery can be readily computed for different stratification parameters (cf. Fig. 13.15). The effective resultant sweep efficiency at the time of first dry-gas break-through is then found to decrease approximately as the inverse of the logarithm of the stratification parameter [cf. Eq. 13.8(15) and Fig. 13.16]. Thus, when the latter is 10, the first dry-gas break-through will develop after only 35.2 per cent of the reservoir has been swept, even if the areal sweep efficiency is 90 per cent. And for stratification ratios of 100 the composite sweep efficiency will be only 19.35 and 12.9 per cent for areal sweep efficiencies of 90 and 60 per cent.

The severe reduction in sweep efficiency due to permeability stratification is compensated in practice by the fact that cycling operations are usually continued after the initial dry-gas break-through until the well effluent contains only 10 to 25 per cent of wet gas. The total fractional recoveries of wet gas to such cycling abandonment limits will evidently be much greater than the composite sweep efficiencies (the recoveries at first dry-gas break-through) and will increase as the abandonment limit of wet-gas content is reduced. While these, too, will decline as the stratification parameter increases, this reduction is not serious until the stratification ratio exceeds 10 (cf. Fig. 13.16). For greater values the total cycling wet-gas recovery decreases in an approximately logarithmic manner with the stratification ratio, and the latter will ultimately control the over-all efficiency of the cycling operations. The areal sweep efficiency itself will be of secondary importance except in highly uniform formations.

The total gas throughflow during cycling operations increases at first with increasing stratification parameter, reaches a maximum, and then declines (cf. Fig. 13.17). Over the range of areal sweep efficiencies and cycling abandonment limits usually occurring in practice the total gas throughflow will not exceed about 2.2 times the initial reservoir hydrocarbon volume and may be considerably lower when the small recoveries from highly stratified formations are swept out. The areal sweep efficiency again will affect the volume of total gas throughflow only in the range of low stratification parameters.

While many condensate reservoirs in which the original dew-point pressures have been maintained by cycling have been produced with substantially constant effluent composition until dry-gas break-through, but few detailed reservoir studies have been reported for reservoirs that have been produced by pressure depletion. However, those which have been so produced, such as the La Blanca field in Texas, have shown continually increasing gas-condensate ratios as the pressures have declined (cf. Fig. 13.18). Such observations confirm not only the basic thermodynamic phenomenon of retrograde condensation but also the immobility of the condensed-liquid phase formed in the reservoir. In the case of cycled reservoirs in which the reservoir pressure has not been completely maintained, such as the La Gloria field in Texas and the Cotton Valley field in Louisiana, similar though less rapid rises in the gas-condensate ratio have been observed (cf. Figs. 13.19 and 13.20). Moreover an analysis of the performance of the Bodcaw Sand reservoir of the Cotton Valley field showed the composition history of the produced fluid actually to follow that predicted from laboratory experiments on the phase behavior of the reservoir hydrocarbon mixture. Special tests on shut-in wells in this field gave data on the sweep of the dry gas through the Bodcaw Sand (cf. Fig. 13.21) and indicated close conformance with theoretical predictions based on the measured permeability variation in the formation. As the latter is relatively uniform and the well distribution is favorable for high sweep efficiency, it is anticipated that 85 per cent of the wet-gas reserves will be recovered, with a processing volume equal to 115 per cent of the initial-gas content.

The fact that in principle the hydrocarbon content of condensate reservoirs can be recovered almost completely by cycling does not imply that such cycling is universally desirable. As in the case of all reservoir exploitation the method used must be chosen on the basis of economic considerations. Because of the complexity of the latter the criterion of maximum profit cannot be formulated as simple and universal rules. It is evident, however, that the controlling factors will be the richness of the wet gas, the size of the reservoir, and its uniformity. Lean gases inherently suffer lower retrograde losses on pressure decline, and the total value of such losses will be correspondingly lower. Hence, except when there is no market for the gas, cycling of reservoirs producing at ratios of 50,000 ft^3 of gas per barrel of condensate will usually be undesirable from an economic standpoint. Reservoirs of small volume will also be unfavorable for cycling because of the limited value of the retrograde losses resulting from pressure depletion. The low sweep efficiencies of highly stratified formations will likewise make questionable the economic success of cycling operations.

In estimating the recovery to be expected under cycling one must add to that obtained during the cycling phase the pressure-depletion recovery of the unswept reservoir volume which will be produced during the blowdown of the cycled reservoir. It is the resulting increase in recovery by the composite program of cycling and pressure depletion, as compared with simple pressure depletion, that must be balanced against the investment costs of the gas-processing and compressor plant, the wells required for injection, the gas-injection lines, and the associated operating costs. The deferred income from the dry gas, in case there is an immediate market for it, as well as the reduced present worth of the liquid products, because the operating life of the reservoir will usually be longer under cycling than under pressure depletion, must also be considered.

The retrograde losses of liquefiable hydrocarbons within a reservoir by complete pressure depletion will usually range from 30 to 60 per cent of the initial reservoir content. However, an appreciable part of the corresponding potential hydrocarbon recoveries of 70 to 40 per cent will be carried away by the separator gases, if the latter are not further processed. Successful cycling itself should lead to at least 50 per cent over-all recovery, and the subsequent pressure depletion should yield additional liquefiable products to make the total equal to 60 to 80 per cent of the original reservoir contents of condensable products.

When the condensate reservoir is bounded by a crude-oil zone of appreciable size, the development program must be so chosen as to achieve maximum recovery from both. The most efficient method would be a limitation of withdrawals to the oil zone with sufficient gas return to the gas cap fully to maintain the pressures while sweeping the wet gas into the oil wells. If it is not feasible to defer the recovery of condensate, the gas cap may be cycled simultaneously with the oil withdrawals, provided that a regional pressure gradient is maintained from the gas cap to the oil section so as to prevent migration of oil into the condensate reservoir and induce a pressure-maintenance action on the oil zone. Postponement of oil withdrawals until the gas cap is completely cycled will provide efficient condensate recovery, although the deferment of the oil recovery may not be economically feasible. Moreover the oil recovery, obtained without pressure maintenance, will not be quite so high as under simultaneous complete cycling and oil production. On the other hand a delay in cycling or gas return to the gas cap until the black-oil zone is depleted will lead to pressure decline and retrograde losses in the gas cap, which could be largely prevented by the other development methods. Of course, in practice all the numerous economic and physical factors pertaining to the particular reservoir of interest will have to be evaluated in choosing the operating program.

When edgewaters bound the gas cap, it will be undesirable to place the producing wells near the water-gas contact. The injection wells, however, may be advantageously completed within the water-saturated section, or "dry holes" near the water-gas contact can be used as injection wells. In this way the whole of the gas cap will be susceptible to dry-gas sweeping, and unswept "dead" areas will be kept to a minimum. Dry-gas injection below the gas-water contact has been applied successfully, and no evidence has developed that the water-saturated section above the injection wells offers permanent and serious resistance to the gas flow.

Even under complete pressure maintenance by cycling the drawdown about the producing wells will create local condensation of liquid. As all the produced fluid must pass through the annular zones immediately surrounding the well bore, the liquid will rapidly accumulate there until a saturation for mobility is built up. Thereafter the additional liquid condensation will be swept into the well bore. As production continues, the zone of saturation to the limit of mobility will expand away from the well bore. The rate of growth of the liquid saturation at any point will vary inversely as the square of the distance from the producing well and directly as the square of the producing rate or pressure drawdown. The resulting loss in liquid recovery should not be of serious magnitude except in very tight formations producing exceptionally rich gases.

While the retrograde liquid accumulation is immobile with respect to displacement by the gas flow, except near the well bore where the saturation has been built up to the point of mobility, it is subject to revaporization on exposure to dry gas. This observation raises the question whether dew-point cycling and the complete prevention of retrograde condensation is inherently necessary and whether the liquid phase that would be formed by pressure depletion could not be effectively recovered by low-pressure dry-gas cycling. Here, too, the obvious fact that it is *physically* possible to recover all the hydrocarbons by low-pressure cycling is of little significance except as it may be proved that such recovery is *economically* feasible. And even if the latter be confirmed, its practical value depends on the costs of and profits from such operations as compared with those of high-pressure or dew-point cycling.

A detailed analysis of the recoveries which can be obtained by cycling at various pressures following preliminary pressure depletion, for a particular set of reservoir conditions, showed that for these the total condensable-liquid recoveries to a given uniform abandonment pressure are essentially independent of the sequence of cycling and depletion and will require substantially the same volume of gas processing. The economic factors, however, require special consideration. If the plant capacities for dew-point and low-pressure cycling be the same, the latter will lead to shorter operating lives and increased present-worth values of the recovery. But to operate a low-pressure cycling system at the same throughput rate as at high pressures will require more wells and greater investments in flow lines and plant facilities. Failure to process the produced gas during the initial depletion phase will also lead to substantial losses in the intermediate liquefiable hydrocarbons. No simple rule will indicate the optimum cycling pressure. However, if there should be an increasing price trend for the gas and plant products during the operations, cycling at or near the dew-point pressure should generally lead to maximum present-worth profits. And when the condensate gas cap is underlain by a crude-oil belt of substantial size, the requirement of maximum recovery from the latter will usually leave little question as to the economic advantage of high-pressure cycling over low-pressure gas-return operations. Such advantage will become still more decisive if there should be a strong water-drive action in the field.

Since isothermal retrograde condensation will take place only at temperatures between the critical and cricondentherm temperatures of the hydrocarbon mixture, the same system would behave simply as a normal gas if it should occur in a reservoir with a temperature exceeding the cricondentherm. At the surface temperature and pressures the separation into condensate and gas would be exactly the same as if it were produced from a typical condensate reservoir, but there would be no phase change within the reservoir. Cycling would be entirely unnecessary, and the reservoir could be produced by pressure depletion as a gas field.

If, conversely, the reservoir temperature were below the critical, the reservoir fluid, if in a single saturated phase, will be a bubble-point liquid. Again the initial surface-production stream will appear identical to that which would be produced if the reservoir fluid were a saturated vapor. Within the reservoir, however, rapid gas evolution and liquid-phase shrinkage will develop and will result in a small recovery owing to direct liquid-phase expulsion. Pressure maintenance by gas or water injection and mass displacement of the reservoir liquid will be necessary in order to achieve high recoveries of the heavy hydrocarbon components.

Once it has been determined that cycling is the optimum method for field exploitation, it is necessary to unitize the operations to achieve maximum efficiency. Competitive development will make impossible the control over the well pattern and withdrawals necessary for effective dry-gas sweeping, will induce fluid migration and inequitable distribution of the recovered products between the competitive areas, and may make it impractical to maintain the pressures at the dew point to prevent retrograde losses.