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# PAST PERFORMANCE ANALYSIS PROCEDURES AND PERFORMANCE PREDICTION METHODS IN THE DRAGON TRAIL GAS FIELD



by

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## ABSTRACT

Various past performance analysis techniques and performance prediction methods are evaluated with special emphasis on their applicability in the Dragon Trail gas field. The most dominating characteristic of the Dragon Trail field is the low permeability (0.3 to 1.0 md) of the producing formation which causes unstabilized flow conditions for most of the time.

Due to the shortage of core data, capillary pressure data and geophysical logs, it is necessary to assume average initial water saturation values. Average porosity values can be calculated from bulk density logs and vary between 8% and 14%. Drainage barriers can be found from a consideration of structural factors, relative well positions and relative stabilized production rates of the producing wells. Provisional gas-in-place values can be calculated with the volumetric method.

Permeability values can be found by using approximate stabilized drawdown data. The error introduced by using unstabilized drawdown data (instead of buildup data obtained over a long, unproductive shut-in period) to determine average reservoir pressure is also quantitatively evaluated and found to be relatively small. Final

gas-in-place values can be determined with the material balance method.

A recovery formula defines the fraction of initial gas-in-place that can be recovered ($G_p/G_{wi}$) as a function of stabilized flow rate ($Q_{gs}$) - M SCF/day) and backpressure applied to the formation ($P_{wf}$ - psia). The recovery formula for the Dragon Trail field for average field conditions is as follows:

$$G_p/G_{wi} = 1 - 0.00214 \left(253\, Q_{gs} + P_{wf}^2\right)^{\frac{1}{2}}$$

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# INTRODUCTION

This study is concerned with the production performance of Dragon Trail Unit (DTU) wells that are connected to Cascade Natural Gas Corporation's pipeline. The wells belong to Continental Oil Company (Conoco) and are in Rio Blanco County, Colorado.

Gas is being produced from a low-permeability shale-laminated sandstone ("B" zone of the Mancos Formation). Average depth of the approximately 350-foot-thick payzone is 2,400 feet. Production for commercial purposes was commenced in March, 1968. Gas compressor stations are part of the gathering system and were required in order to increase "line pressure," especially for peak consumption periods.

Although the volume of the initial gas-in-place is fairly high, ultimate economic fractional recovery may be much lower than normal due to the low permeability of the Mancos "B" zone.

It is the purpose of this study to evaluate past performance analysis methods and techniques for predicting future performance.

More emphasis is placed on analytical procedures and techniques, illustrated by a few examples, than on detailed analysis of all the well data in order to arrive at a recovery figure for the complete Dragon Trail Unit. The reasons for following this policy are (1) the absence of critical data in some wells, (2) the early stage of depletion which degrades the reliability of certain calculations, (3) the inhomogeneous nature of the formation which adversely affects averaging and interpolation techniques, and (4) the unknown position of drainage boundaries.

Basic data (logs, backpressure, build-up, and production-history data) have been provided by Continental Oil Company. It is impossible to include all these data in this study. In spite of this difficulty it will be attempted to make the study understandable to the casual reader by including certain extracts of the basic data (appropriate build-up curves, decline curves, etc.).

## PAST PERFORMANCE ANALYSIS

Studies of past performance are usually made with reference to a complete reservoir. However, this particular study will try to solve the problem with reference to the drainage areas of individual wells. The reasons for this approach are as follows:

(1) Since unitization is not in effect in this gas field, only a limited amount of production data are available. It will be impossible, therefore, to solve the problem with reference to the complete reservoir.

(2) Many of the DTU wells are located fairly close to the boundaries of the lease (Figure 1). This is a perfectly legal way of trying to extend the subsurface drainage boundaries beyond the surface lease boundaries. The position of the wells also attempts to offset the effect of neighboring boundary wells. However, the stabilized production rates of competitive neighboring producing wells which partially determine the location of the drainage boundaries, are not known. Inasmuch as the actual drainage boundaries cannot be determined, it is not possible to solve the problem with reference to the DTU drainage area (see also later section on radius of drainage).

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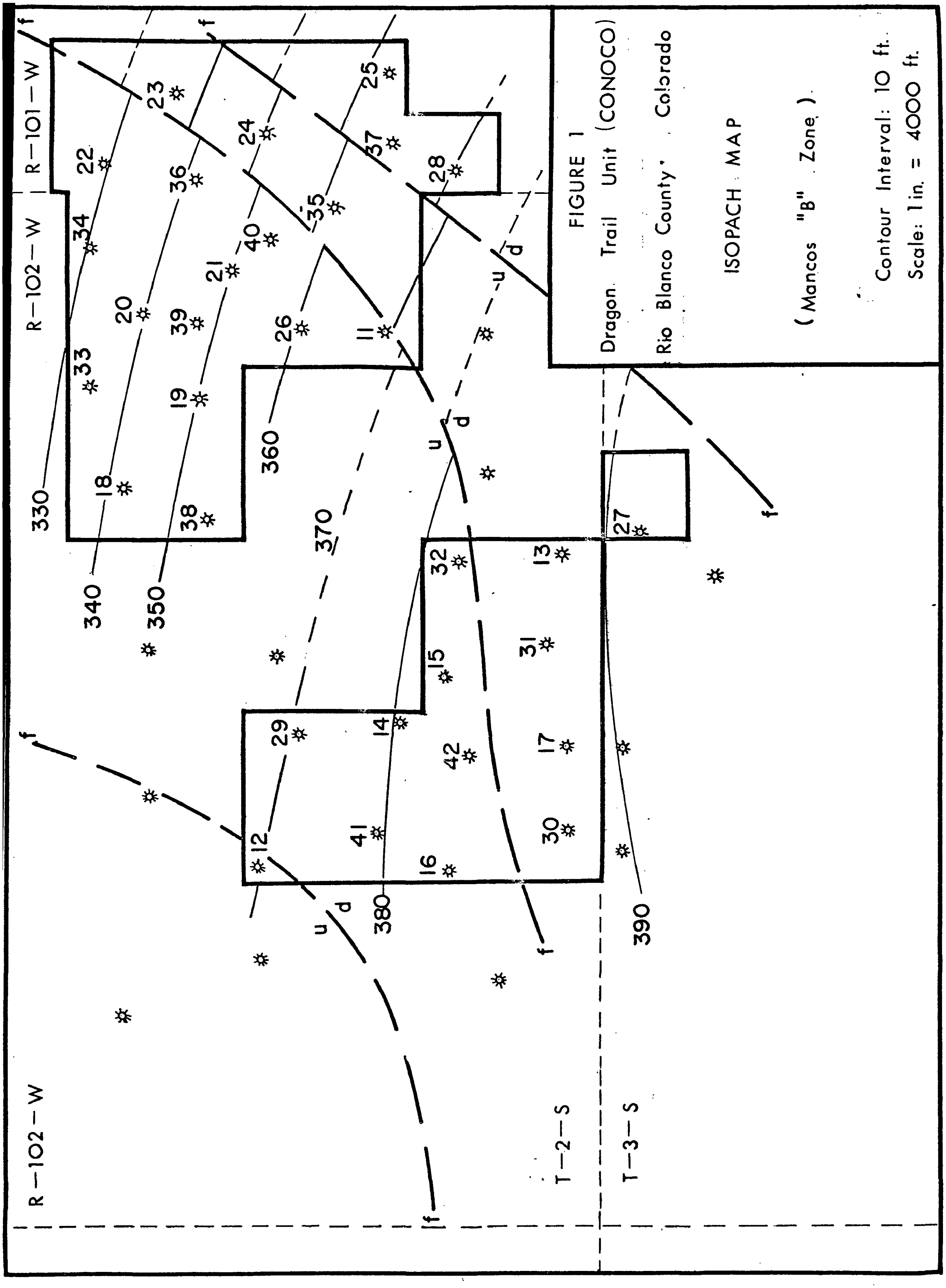

FIGURE 1
Dragon Trail Unit (CONOCO)
Rio Blanco County, Colorado
ISOPACH MAP
(Mancos "B" Zone)
Contour Interval: 10 ft.
Scale: 1 in. = 4000 ft.
R-101-W
R-102-W
T-2-S
T-3-S
330
340
350
360
370
380
390

(3) It is believed that in very low permeability formations the behavior of individual wells is little influenced by the behavior of neighboring producers. The error introduced in the final solution by regarding each well as producing from an isolated volumetric reservoir, will be relatively small. This argument will be further substantiated later.

## Homogeneity and Thickness of the Producing Formation

Homogeneity and constancy of thickness of the producing formation are important factors to consider because most of the classical fluid-flow and well-testing theories have been developed for "homogeneous formations of constant thickness."

Evaluation of available data indicates that the Mancos "B" zone is not only inhomogeneous on a micro-scale but also on a mega-scale. In addition, the formation thickness varies from well to well and the presence of several faults have been established.

Sand-shale laminations cause vertical variations on a micro-scale and the widely different producing characteristics of the wells are evidence (in addition to log evidence) of lateral variations in sand-shale characteristics and formation thickness on a mega-scale. The vertical variations in physical properties, excluding formation thickness, are not so serious since they only result in an "averaging effect," but the lateral inhomogeneities and changes in thickness may introduce serious errors in the calculations. One method to "solve" this problem is by interpolation of formation characteristics and solving with computer techniques. However, such a project would be a major undertaking and would require more data than are available in this area. It is also difficult to establish whether a fault acts as a sealing barrier or a permeable zone.

The following assumption, therefore, has to be made: The producing formation is laterally homogeneous and of constant thickness within the area drained by any particular well.

Figure 1 is an isopach map of the Mancos "B" zone in the area under discussion. The average thickness of any particular drainage area can be estimated from the isopach map.

## Interstitial Water Saturation

Three methods are normally available for obtaining interstitial water saturation ($S_w$) values:

(1) Analyses of cores obtained by using an oil-base mud,

(2) derivation of $S_w$ values from capillary pressure

data, and

(3) calculation of $S_w$ values from geophysical logs.

No core data on the DTU wells are available.

Geophysical logs cannot be used because log interpretation in shaly sandstones is notoriously unreliable due to difficulty in obtaining (1) water salinity or resistivity values (self potential logs, the major source for this type of information, are severely influenced by the presence of shale) and (2) unaffected true resistivity ($R_t$) values (shale also affects the $R_t$-readings).

It is, therefore, not possible to calculate $S_w$ values and the following assumption is based on the very general correlation between connate water and permeability of Welge and Bruce [1]: It is assumed that an average connate water saturation of 60% exists in the producing formations of all the wells. Assuming zero oil saturation, this value implies an average gas saturation ($\overline{S}_g$) of 40%.

It is obvious that any volumetric calculation of initial gas-in-place will use this assumption, and the accuracy of such a calculation will depend on the validity of the assumption.

## Porosity

Production data are available for wells 11 through 42 but Compensated Density Logs are only available for wells 22 through 42.

No core data were available in the DTU wells and grain density ($\rho_{gr}$) values have to be taken from adjacent wells. Work done by Conoco suggests that a $\rho_{gr}$ value of 2.70 gm/cc should be used and this value will be used in any porosity computation.

Once the question of $\rho_{gr}$ has been settled, determination of porosity values is relatively easy through use of the following equation:

$$\phi = ( \rho_{gr} - \rho_b ) / ( \rho_{gr} - \rho_L S_{wi} - \rho_g S_g ) \qquad (1)$$

where

$\phi$ = porosity (fraction),

$\rho_b$ = formation bulk density (given by the Compensated Density Log in gm/cc),

$\rho_L$ = formation liquid density (usually assumed equal to 1.0 gm/cc),

$S_{wi}$ = initial water saturation (fraction),

$\rho_g$ = gas density (gm/cc)

and $S_g$ = gas saturation (fraction).

The gas density can be calculated by using the ideal gas law. The initial gas density in the DTU field was found to be approximately 0.03 gm/cc. It will be clear from an evaluation of equation 1 that the gas density term ($\rho_g$ $S_g$) is very small in comparison to the other terms and, therefore, may be ignored without significantly reducing the accuracy of the porosity values.

To determine the average porosity ( $\bar{\phi}$, see also the nomenclature list) in any particular well, an average bulk density ($\bar{\rho}_b$) value is obtained from the Density Log and the $\bar{\phi}$ is calculated through equation 1. The calculation procedure is illustrated in the following example:

Dragon Trail Well No. 25:

Producing Interval = 1906' - 2263',

$\bar{\rho}_{gr}$ = 2.70 gm/cc,

$\rho_L$ = 1.0 gm/cc,

$\bar{\rho}_b$ = 2.50 gm/cc

and $S_{wi}$ = 0.60

From equation 1 it follows:

$\bar{\phi}$ = 9.5%.

Average porosities for wells in the DTU field vary between 8% and 14%. The average porosities of the various wells are indicated in Figure 2.

## Radius of Drainage

Under normal high-permeability conditions it is possible to determine radius of drainage ($r_e$) values from build-up or draw-down test data. However, these techniques are not applicable in this field since it will be proven later that

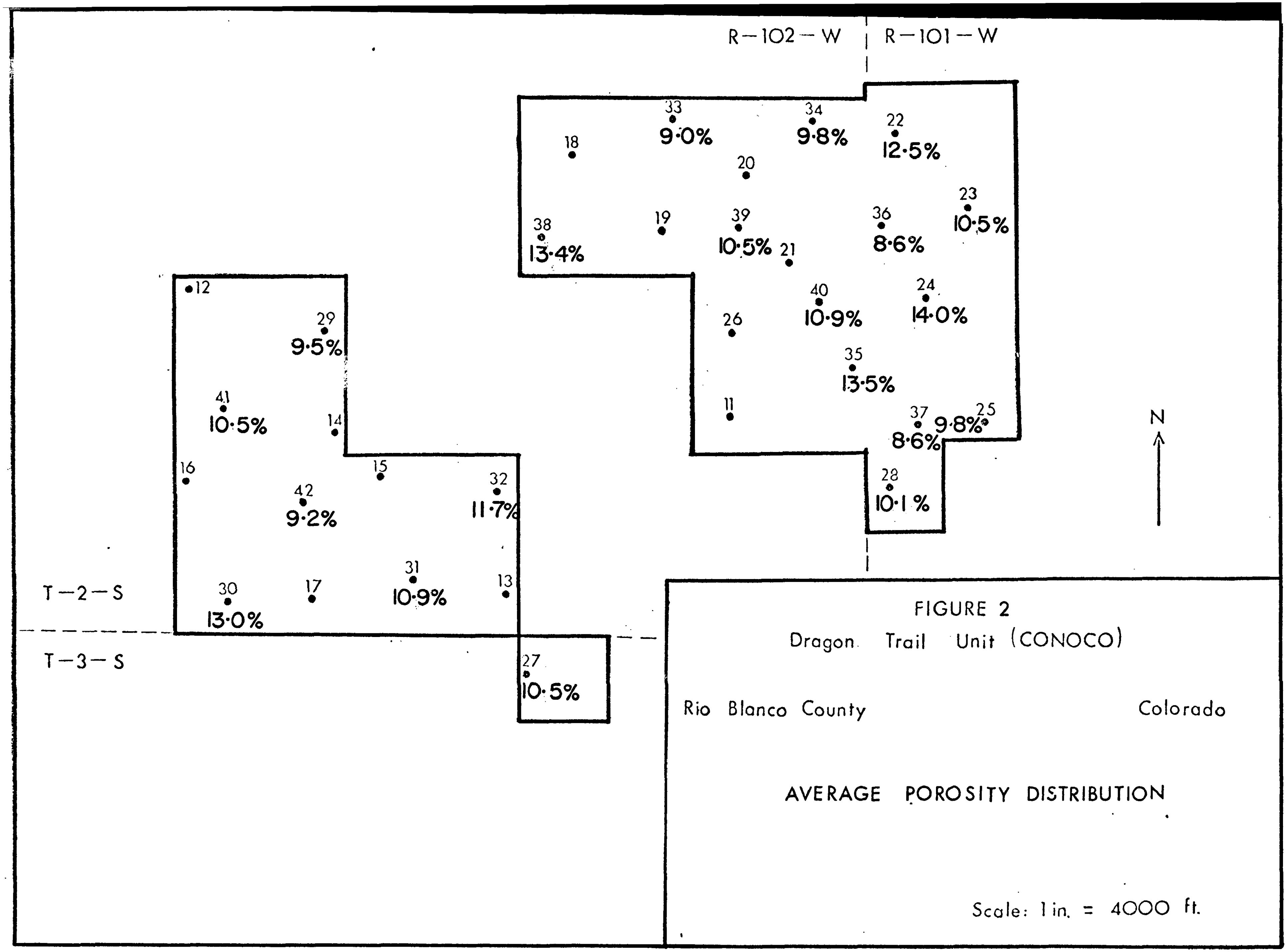


FIGURE 2

Dragon Trail Unit (CONOCO)

Rio Blanco County Colorado

AVERAGE POROSITY DISTRIBUTION

Scale: 1 in. = 4000 ft.

it will theoretically take approximately 400 days to conduct conclusive tests. It is not economical to conduct tests over such a long period.

Determination of drainage boundaries is also possible by considering relative production rates, natural permeability barriers and position of wells. Muskat[2] showed that under pseudo-steady-state or stabilized flow conditions, each well in a reservoir drains a volume proportional to its production rate. (A pseudo-steady-state or stabilized flow condition is a condition in which the pressure at every point about the well is decreasing at very nearly the same rate, during a flow period. The stabilized flow concept will be discussed in greater detail in a later section.) Stewart[3] has presented field data for gas wells which confirm this theory. Matthews and Russel[4] give an adequate description of this technique and it will not be repeated here.

Once the effect of all the faults in the DTU field, as well as the relative stabilized production rates ($Q_{gs}$) of the neighboring producers, are known, it would be easy to determine the drainage boundaries and $r_e$ of any particular well.

It has been stated previously that it is impossible to determine accurately the drainage boundaries with the available data. However, it is necessary to use $r_e$ values in certain computations and it is proposed that an average radius of drainage ($\bar{r}_e$) be calculated using the following formula:

$$\bar{r}_e = (A/\pi N)^{\frac{1}{2}} \qquad (2)$$

where

$\bar{r}_e$ = average radius of drainage (ft),

$A$ = DTU lease area (sq ft)

and $N$ = number of producing wells in DTU lease area.

If the applicable values are substituted, a value of 1430 ft is calculated for $\bar{r}_e$. This value correlates with a drainage area of 147 acres per well.

## Initial Gas-in-place

Initial gas-in-place (G) can be calculated on a volumetric basis. The accuracy of this calculated value can be improved at a later stage in the production life of the reservoir by material balance considerations.

The volumetric formula for a circular disc-shaped reservoir states:

$$G_{wi} = \pi r_e^2 h \phi S_g/B_{gi} \qquad (3)$$

where

$G_{wi}$ = initial gas-in-place of the drainage system of a well (SCF),

$h$ = thickness of producing formation (ft) and $B_{gi} = z_{P_i} T_f P_{sc} / T_{sc} P_i$ (cu ft/SCF)

where

$T_f$ = formation temperature ($^oR$),

$z_{P_i}$ = gas deviation factor at $T_f$ and $P_i$,

$P_i$ = initial static reservoir pressure (psia),

$P_{sc}$ = standardised pressure (12.5 psia)

and $T_{sc}$ = standardised temperature ($520^o$ R).

To determine an approximate value of $G_{wi}$ the following average values can be used:

Specific gravity of gas (SG) = 0.66 (from production history file),

$\bar{r}_e$ = 1,430 ft,

$\bar{h}$ = 350 ft,

$\bar{\phi}$ = 12%,

$\bar{S}_g$ = 40%,

$P_i$ = 447 psia (see later section on $P_i$),

$T_f$ = $560^o$ R (assuming a mean surface temperature of $64^o$ F, a temperature gradient of $1.5^o$ F/100 ft, and an average formation depth of 2,400 ft)

and $z_{P_i}$ = 0.94 (using pseudo-reduced properties and correlation of Brown et al(5)).

Hence,

$G_{wi} = 3.8 \times 10^9$ SCF.

A very rough approximation of the initial gas-in-place in the total DTU Unit ($G_{ti}$) can be obtained by multiplying this value by 32:

$$G_{ti} = 120 \times 10^9 \text{ SCF.}$$

## Effective Permeability-to-gas

Under normal high-permeability conditions, there are three methods for determining effective permeability-to-gas ($k_g$): (1) core analysis, (2) build-up-test analysis, and (3) backpressure-test analysis. In this study, "stabilized" production performance data were available in addition to build-up and backpressure test data and could also be used for $k_g$ determination. However, the validity of most of these methods is dependent on the degree of stability obtained during the test, which is partially a function of the effective permeability. It is therefore necessary to determine an approximate $k_g$ value to evaluate the validity of the various methods, and, hence, arrive at reliable values of $k_g$.

The build-up test and stabilized production-rate methods will be used to determine approximate $k_g$ values.

Approximate Effective Permeabilities from Build-up Tests ($k_g'$). Build-up data from wells 13 and 20 will be analysed.

Assuming a single constant production rate before shut-in, $k_g$ can approximately be determined according to Aronofsky et al[6,7] and Matthews[8] by plotting $P_w$ vs. log $((t + \Delta t)/ \Delta t)$, setting the slope (m) equal to $2.898 \times 10^4$ $Q_g \mu_g B_g / k_g h$ and solving for $k_g$ where

$k_g$ = effective permeability to gas (md),

$P_w$ = well pressure (shut-in) (psia),

$t$ = apparent total production time at rate $Q_g$, before shut-in (hours),

$\Delta t$ = shut-in time (hours),

$Q_g$ = gas production rate (M SCF/day)

and $\mu_g$ = gas viscosity (cp).

$B_g$ and $\mu_g$ are evaluated at the average reservoir pressure ($\bar{P}$) where $\bar{P}$ is defined as the pressure which would be found if flow at the well were stopped and the pressure in the reservoir were allowed to equalize. $\bar{P}$ is often approximated by the arithmetic mean of the pressure at $r_e$ ($P_e$) and the flowing pressure in the well ($P_{wf}$).

The solution for $k_g$ is the following equation:

$$k_g = 2.898 \times 10^4 \; Q_g \mu_g z_{\bar{P}} T_f P_{sc} / m h T_{sc} \bar{P} \quad (4)$$

Data for Well No. 13 are the following:

SG = 0.66,

m = 54 psia/cycle (see Figure 3),

$Q_g$ = 517.4 M SCF/day (from production history file),

$T_f$ = 560° R,

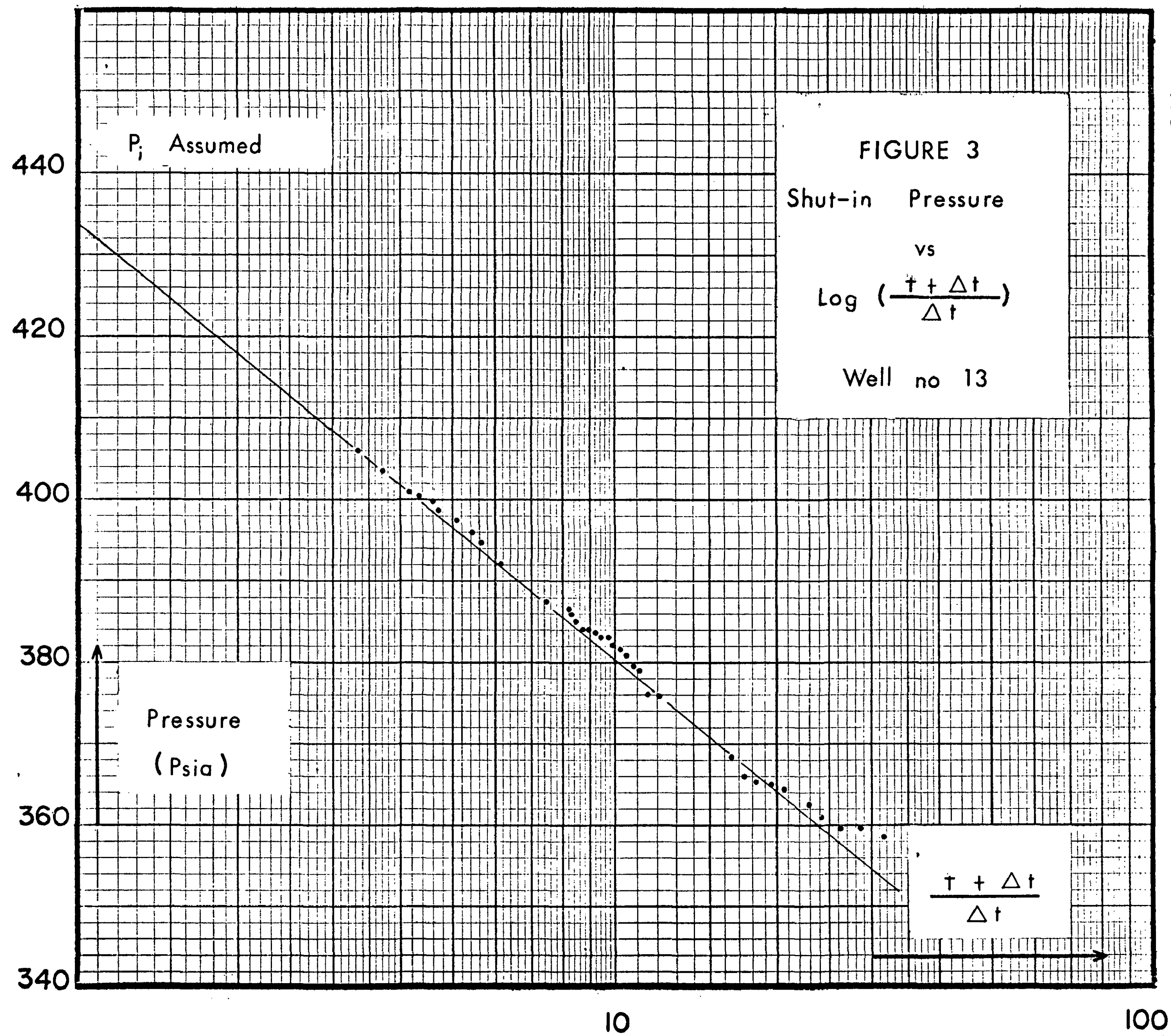
FIGURE 3
Shut-in Pressure
vs
Log ( $\frac{t + \Delta t}{\Delta t}$ )
Well no 13
$P_i$ Assumed
Pressure
( Psia )
$\frac{t + \Delta t}{\Delta t}$
440
420
400
380
360
340
10
100

$\mu_g$ = 0.0125 cp (from viscosity correlation of Bicher and Katz[9]),

$z_{\overline{P}}$ = 0.94,

$\overline{P}$ = (436 + 200)/2 = 31.8 psia (from production history file)

and h = 380 ft (from Density Log).

Hence,

$k_g{}''$ = 0.37 md.

Data for Well No. 20 are the same except for the following:

m = 76 psia/cycle,

$Q_g$ = 555.0 M SCF/day

and h = 330 ft.

Hence,

$k_g{}'$ = 0.39 md.

Approximate Effective Permeability from Stabilized Flow Rates ($k_g{}''$). It is also possible to determine an approximate $k_g$ from flow rates measured during long-term commercial production periods, assuming the following:

(1) Production rates were obtained under stabilized flow conditions.

(2) $\overline{P}$ is slightly less than $P_i$.

(3) The drainage radius is equal to $\overline{r}_e$ as previously calculated.

Craft et al[10] have shown, on the basis of work done by Aronofsky and Jenkins[7], that the following equation can be used:

$$k_g' = (Q_{gs}/\mu_g T_f z_{\overline{P}} \text{Ln } (0.472\ r_e/r_w))\ /0.000703h\ (\overline{P}^2 - P_{wf}^2) \tag{5}$$

where

$P_{wf}$ = flowing pressure in the well (backpressure) (psia),

and $r_w$ = well radius (ft).

Gas flow theory states:

$$P_{wf} = P_{tf} + \Delta P_L \tag{6}$$

where

$P_{tf}$ = tubing flowing pressure at the surface (psia)

and $\Delta P_L$ = the pressure due to the column of flowing gas (psia).

Data for Well No. 13 are the following:

$Q_{gs}$ = 750 M SCF/day,

$\overline{r}_e$ = 1,430 ft,

$r_w$ = 0.25 ft,

$\overline{P}$ = 430 psia,

$P_{tf}$ = 76 psia

and $\Delta P_L$ = 10 psia (estimated).

Hence,

$k_g''$ = 0.82 md.

Data for Well No. 20 are the following:

$Q_{gs}$ = 420 M SCF/day,

$\overline{P}$ = 443 psia,

$P_{tf}$ = 80 psia

and $\Delta P$ = 10 psia.

Hence,

$k_g''$ = 0.50 md.

Comparison of the $k_g'$ values with the $k_g''$ values indicate fairly good agreement. A value of 0.5 md will be used in the later discussions as the approximate $\bar{k}_g$ value of this field.

Stabilization Time. It is necessary to define certain complex theoretical concepts which are commonly used in pressure drawdown and build-up analysis to avoid any misunderstanding or confusion. These concepts will be defined with reference to a compressible liquid system. However, Craft et al[11] state that the derived formulae (e.g. stabilization time formula) can be used for gas systems with relatively small errors.

Figure 4 is a plot of dimensionless pressure drop ($\Delta P_D$) versus dimensionless time ($t_{Dw}$) on a log scale and represents a solution to the well known diffusivity equation for compressible fluids (see Appendix I) for the following boundary conditions:

(1) At t = 0, P = $P_i$ everywhere.

(2) At r = $r_w$, Q is constant for all time.

(3) At r = $r_e$, $Q_{r_e}$ = 0 for all time.

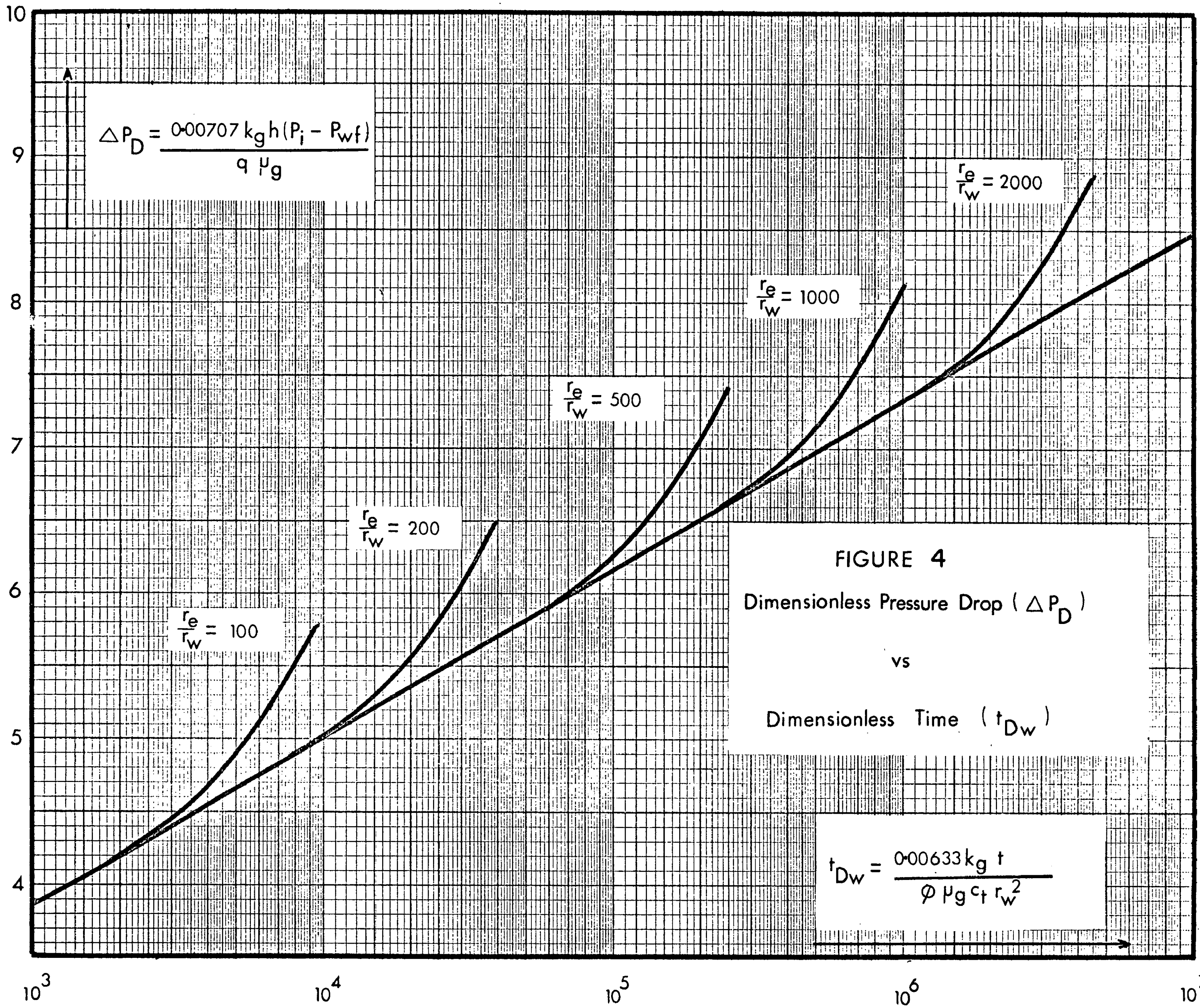


FIGURE 4

Dimensionless Pressure Drop ( $\Delta P_D$ )

vs

Dimensionless Time ( $t_{Dw}$ )

In other words, it represents the constant rate solution to the diffusivity equation for the finite reservoir case.

Dimensionless pressure drop is defined as

$$\Delta P_D = 0.00707 \; k_g \; h \; (P_i - P_{wf}) \; / \; q \; \mu_g \qquad (7)$$

where

q = production rate (subsurface bbl/day),

Dimensionless time is defined as

$$t_{Dw} = 0.00633 \; k_g \; t \; / \; \phi \; \mu_g \; c_t \; r_w^2 \qquad (8)$$

where

t = flowing time (days)

and $c_t$ = total compressibility (vol/vol/psi).

Note that $t_{Dw}$ is defined with reference to $r_w$.

Examination of Figure 4 shows that a family of curves is presented for various-sized reservoirs. It is also obvious that curves for the various sizes of finite reservoirs all branch from a common curve and that the "departure" of the individual curves from the common curve is displaced in time according to the size of the reservoir. It can be proved that the common curve really represents the "Horner solution"[12] to the diffusivity equation for the infinite reservoir case. It is therefore possible to say that the solution for finite reservoirs approximates the solution for the infinite reservoir case for a period of time before it departs. The time of departure of finite reservoir behavior from infinite reservoir behavior increases with increasing size of the reservoir.

However, careful analysis will prove that the finite-reservoir solution and infinite-reservoir solution only approach each other asymptotically but are nowhere truly equal (except for $t = 0$). Therefore, the point of departure depends on the difference between the two solutions which the analyst chooses as his criterion for a departure point. The criterion of departure used, determines the constant C, in the formula

$$0.00633\, k_g\, t / \phi \mu_g\, c_t\, r_e^2 = C \tag{9}$$

which is usually solved either for $r_e$, the effective drainage radius, or t, the time necessary to "initiate" departure from infinite-reservoir behavior. Various analysts have used different criteria of departure and this situation has led to the publication of numerous different "radius of drainage" formulae.

It is also possible to plot dimensionless pressure drop ($\triangle P_D$) versus dimensionless time ($t_{De}$) on a linear scale (Figure 5) where $t_{De}$ is defined as

$$t_{De} = 0.00633\, k_g\, t / \phi \mu_g\, c_t\, r_e^2 \tag{10}$$

Note that $t_{De}$ is defined with reference to $r_e$. The $t_{Dw}$ values are converted to $t_{De}$ values by picking several points

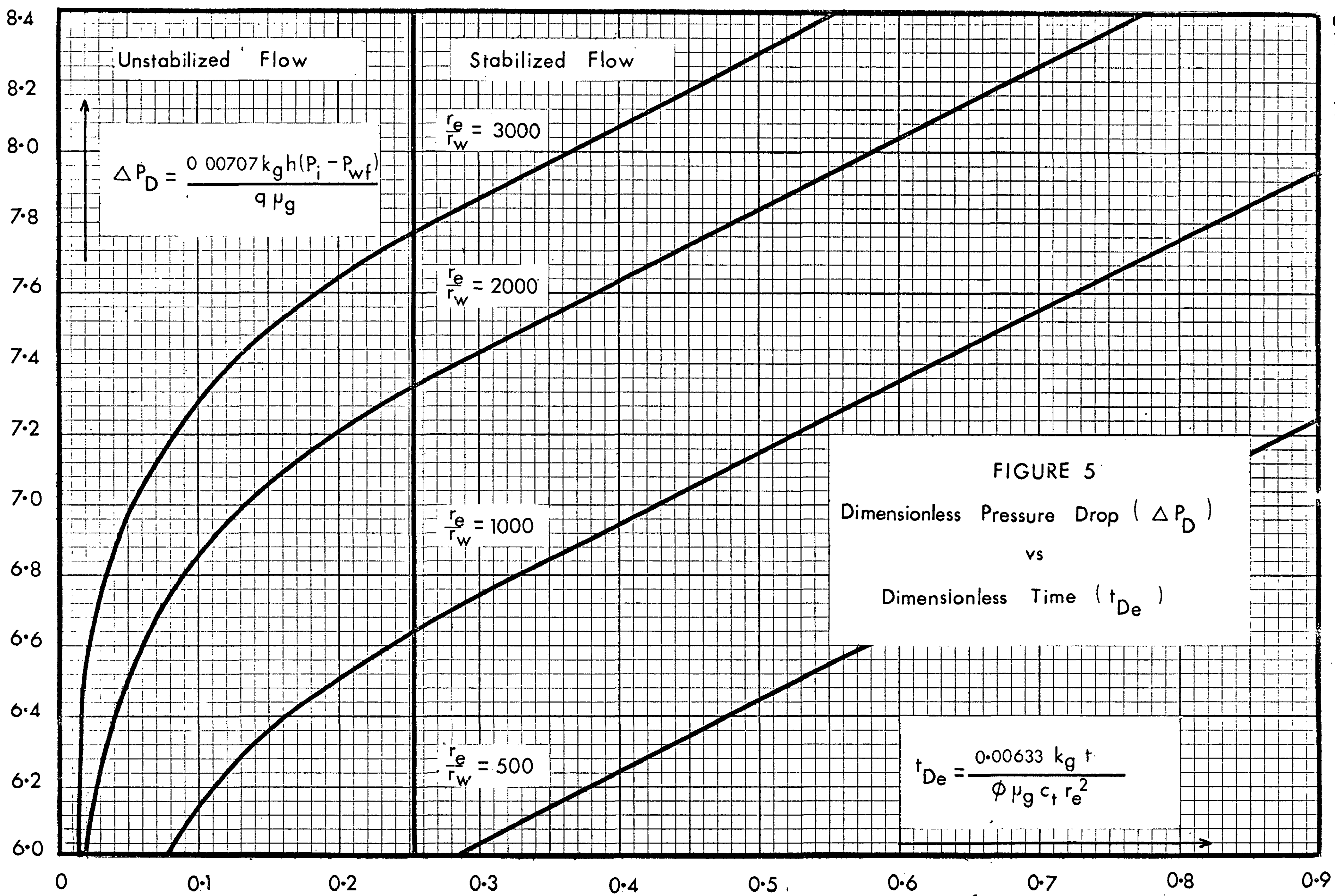


FIGURE 5

Dimensionless Pressure Drop ( $\Delta P_D$ )

vs

Dimensionless Time ( $t_{De}$ )

from the respective curves on Figure 4, reading $\triangle P_D$ and $t_{Dw}$ values and dividing the $t_{Dw}$ values by $(r_e/r_w)^2$.

Examination of Figure 5 shows that during the later parts of the curves, the curves are approximately straight lines or $\frac{\partial P}{\partial t}$ is approximately constant. This characteristic satisfies the definition of stabilized flow conditions.

It is noted that if the points of departure from the straight-line portions of the curves are consistently picked relative to each curve, each curve will have the same value of $t_{De}$ at the point of departure. Careful evaluation will show again that the solution to the finite reservoir case is nowhere truly equal to the equation of the straight line and the curve approaches the straight line asymptotically. Again the selection of the criterion of departure is quite arbitrary and depends on the analyst. After the departure point has been established by using a specific criterion of departure, it is possible to determine a stabilization time ($t_s$) formula where stabilization time is defined as the time required to obtain stabilized flow conditions, i.e. the "time required to reach the departure point '' on the above mentioned plot.

Van Poollen[13] has suggested that the criterion of departure be selected in such a way that the radius-of-drainage formula will be identical with the stabilization-time formula. In essence this means that there is no transition period between the infinite reservoir behavior period and the finite reservoir stabilized flow period. Since the selection of the criterion of departure is arbitrary, the suggestion of Van Poollen seems to be a useful simplification and may prevent confusion. Van Poollen's stabilization time formula (which is identical to the formula of Craft et al[14]) will be used in this study and can be stated as follows:

$$t_s = 40\ \phi\ \mu_g\ c_t\ r_e^2 / k_g \qquad (11)$$

It is emphasized that the stabilization time is inversely proportional to the permeability but independent of the flow rate. The corresponding radius-of-drainage formula is simply:

$$r_e = (k_g\ t / 40\ \phi\ \mu_g\ c_t)^{\frac{1}{2}} \qquad (12)$$

It can be seen that in the unstabilized flow period, $r_e$ is effectively a function of time.

The stabilization time can now be calculated for the average drainage system in the DTU Unit:

$\bar{k}_g$ = 0.5 md,
$\bar{\phi}$ = 14%,
$\bar{r}_e$ = 1430 ft,
$\mu_g$ = 0.0125 cp,
$\bar{S}_w$ = 60%,
$\bar{S}_g$ = 40%,

$c_w = 3.3 \times 10^{-6}$ vol/vol/psi (normal average value),

$c_f = 7 \times 10^{-6}$ vol/vol/psi (normal average value),

$$c_g = (1/P)(1/z)\ \partial z/\partial P$$

$$= 1/400\ (1/0.94)\ (-190 \times 10^{-6})$$

$$= 2.7 \times 10^{-3} \text{ vol/vol/psi}$$

and $c_t = c_w S_w + c_g S_g + c_f$

$$= 1.09 \times 10^{-3} \text{ vol/vol/psi.}$$

From equation 11:

$$\overline{t}_s = 299 \text{ days.}$$

Thus it can be stated that under the given conditions, it will take approximately 300 days to obtain stabilized flow conditions or 150 days for a $k_g$ of 1.0 md. (Inasmuch as the diffusivity equation was solved for the constant rate case, stabilized flow conditions or stabilized flow rates implies that the flow rate was held constant and that the well pressure was allowed to "stabilize" over a period of 300 days.) Alternatively, it can be stated that if a well is shut in after a stabilized flow period, it will take approximately 300 days before the reservoir pressure will have stabilized and the average reservoir pressure can be measured directly.

Initial Reservoir Pressure. There is some doubt about the reliability of $P_i$ measurements on account of the long stabilization times required. The $P_i$ distribution will therefore be investigated.

Table 1 summarizes the available $P_i$ data. Column 4 contains the measured $P_i$ at mid-perforation depth. Column 5 contains the pressure values adjusted to a reference level of 4100 ft. (The pressure gradient was calculated using the non-ideal gas law and averaged values.)

Figure 6 shows the reduced values plotted (in brackets) on a plan according to their relative positions. Examination of this map will show that many of the values are much lower than the maximum values shown. Ignoring these lower values, it can be seen that there is a slight decrease in the maximum values from north to south (wells 20, 19, 12, 14, 26, 11, and 15).

The lower values will be ignored and a regional $P_i$ gradient of 1 psia per 2,000 ft. in a north-south direction will be assumed, based on the following arguments:

(1) A fairly "smooth" or regular $P_i$ distribution is expected in a zone like the Mancos "B."

(2) Maximum pressure values indicate that stabilized pressures were measured, but lower values can be due to non-stabilized pressures or uncorrected surface pressure measurements.

(3) Due to the small diffusivity ($k_g$ / $\phi \mu_g c_t$) of the formation, it is unlikely that pressure measurements were affected by production in neighboring wells.

Using the assumed regional gradient, initial reservoir pressure now can be calculated for each well (Columns 6 and

TABLE 1.

| Well No. | (1) G. L. Elevation | (2) Depth to Mid-Perforation | (3) Mid-Perforation Elevation | (4) Measured Initial Pressure ($P_i$') at M-P Depth (psia) | (5) $P_i$' reduced to 4100' (psia) | (6) $P_i$ at 4100 from assumed regional gradient (psia) | (7) $P_i$ at M-P Elevation (psia) |
|---|---|---|---|---|---|---|---|
| 11 | 6443 | 2126 | 4317 | 447 | 445 | 445.4 | 447.6 |
| 12 | 6810 | 2604 | 4206 | 448 | 447 | 447.5 | 448.6 |
| 13 | 6366 | 2120 | 4246 | 447 | 445 | 442.7 | 444.1 |
| 14 | 7010 | 2840 | 4170 | 445 | 444 | 445.2 | 445.9 |
| 15 | 7102 | 2729 | 4374 | 445 | 442 | 444.5 | 447.2 |
| 16 | 7176 | 3146 | 4030 | 435.5 | 436 | 444.5 | 443.8 |
| 17 | 7120 | 3310 | 3810 | 418 | 421 | 442.6 | 439.7 |
| 18 | | | | 444 | | 449.3 | |
| 19 | 6588 | 2505 | 4083 | 448 | 448 | 448.2 | 448.0 |
| 20 | 6292 | 2308 | 3984 | 448 | 449 | 449.0 | 447.8 |
| 21 | | | | 428 | | 447.7 | |
| 22 | 6230 | 2300 | 3930 | 410 | 412 | 449.6 | 447.9 |
| 23 | 6399 | 2400 | 3999 | 387 | 388 | 448.5 | 447.5 |
| 24 | 6439 | 2230 | 4209 | 424 | 423 | 447.3 | 448.4 |
| 25 | 6298 | 2050 | 4248 | 406 | 406 | 445.3 | 446.8 |
| 26 | 6828 | 2660 | 4168 | 445 | 444 | 446.8 | 447.5 |
| 27 | 6709 | 2483 | 4226 | 427 | 426 | 441.5 | 442.8 |
| 28 | 6355 | 2020 | 4355 | 386 | 384 | 444.3 | 446.7 |
| 29 | 7224 | 3230 | 3994 | 407 | 408 | 446.8 | 445.8 |
| 30 | 7287 | 3640 | 3647 | 392 | 397 | 442.6 | 438.1 |
| 31 | 6465 | 2430 | 4035 | 409 | 410 | 443.0 | 442.4 |
| 32 | 6500 | 2110 | 4390 | 418 | 415 | 444.4 | 447.3 |
| 33 | 6494 | 2570 | 3924 | 411 | 413 | 449.9 | 448.1 |
| 34 | 6220 | 2290 | 3930 | 409 | 411 | 449.9 | 448.2 |
| 35 | 6753 | 2540 | 4213 | 411 | 410 | 446.0 | 447.1 |
| 36 | 6581 | 2520 | 4061 | 385 | 385 | 448.3 | 447.9 |
| 37 | 6397 | 2160 | 4237 | 386 | 385 | 445.3 | 444.0 |
| 38 | 6657 | 2530 | 4127 | 409 | 409 | 449.1 | 448.4 |
| 39 | -- | 2310 | | 389 | | 448.3 | |
| 40 | -- | 2370 | | 408 | | 447.2 | |
| 41 | 7264 | 3280 | 3984 | 371 | 372 | 445.6 | 444.4 |
| 42 | 6949 | 2720 | 4229 | 389 | 388 | 444.2 | 445.5 |

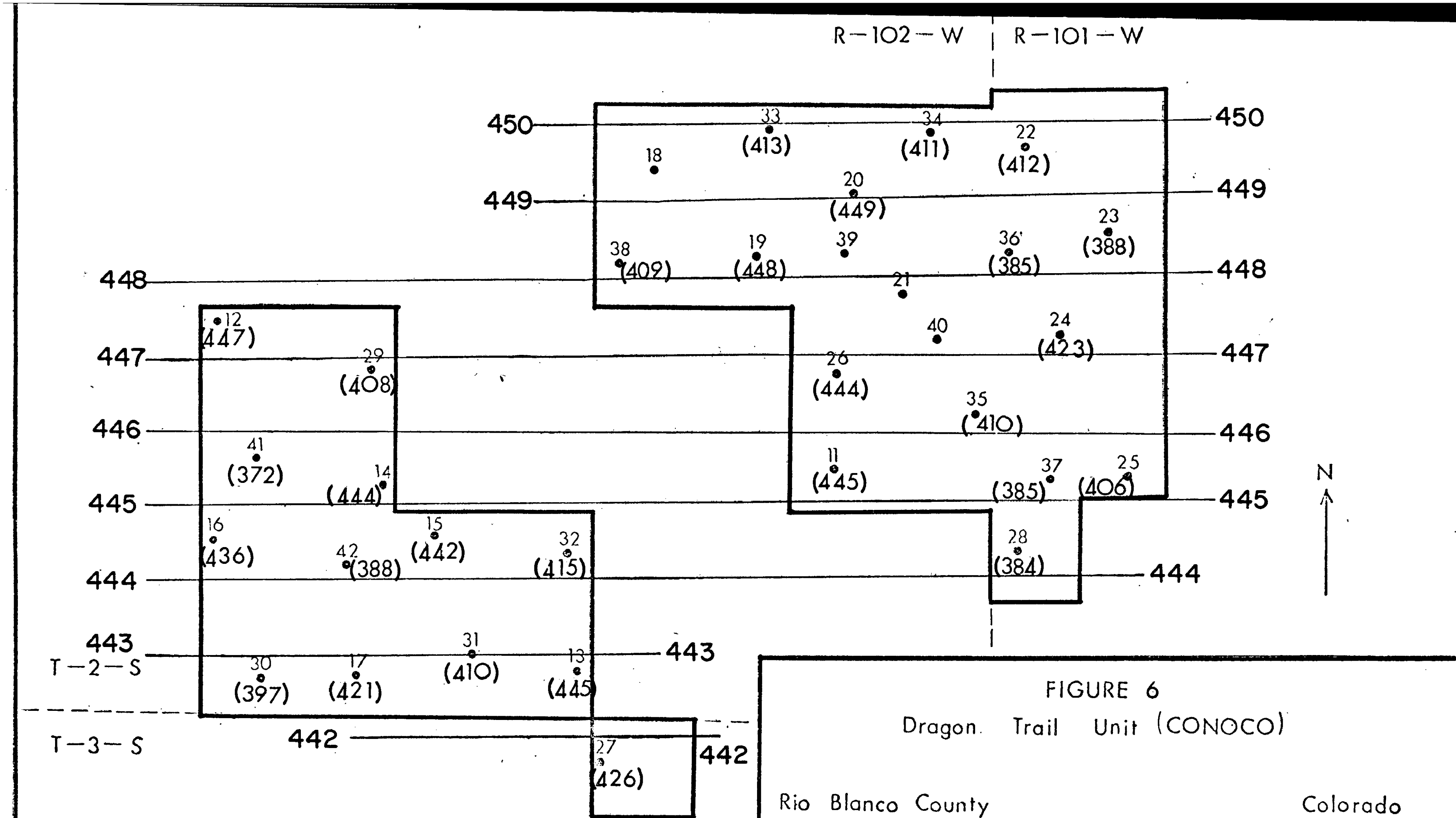


FIGURE 6

Dragon Trail Unit (CONOCO)

Rio Blanco County Colorado

INITIAL RESERVOIR PRESSURE DISTRIBUTION

( $P_i$ reduced to a base elevation )

Pressure:. Psia

Scale: 1 in. = 4000 ft.

7, Table 1). The $P_i$ values in Column 7 will be used in any later calculations.

It is possible that other data which are not available to this analyst may indicate or prove that an irregular $P_i$ distribution is more realistic.

Validity of Backpressure Analysis. Rawlins and Schelhardt[15] developed the basic method for gas-well testing and their backpressure testing method is still used today under certain optimum conditions. The method consists of obtaining backpressure values at various stabilized flow rates, after letting the shut-in pressures stabilize after each flow period. The performance curve is given by

$$\text{Log } Q_{gs} = \log C + n \log (P_e^2 - P_{wf}^2) \qquad (13)$$

where

$Q_{gs}$ = stabilized gas flow rate (M SCF/day),

$P_e$ = pressure at external radius-of-drainage boundary (psia)

and $n$ = constant, which is close to 1, depending on the turbulency of the gas flow.

The performance coefficient C is defined from Darcy's Law as

$$C = 0.000703\, k_g\, h \,/\, \mu_g\, T_f\, z_{\bar{P}} \,\text{Ln}\, (r_e/r_w) \qquad (14)$$

and is usually obtained from the relation

$$C = Q_{gs} \,/\, (P_e^2 - P_{wf}^2)^n \qquad (15)$$

If the performance curve is plotted on a log-log scale with $(P_e^2 - P_{wf}^2)$ on the ordinate and $Q_{gs}$ on the abscissa, the inverse slope is equal to the constant n.

The Rawlins-Schelhardt[15] test method can be used where $t_s$ is short, but is uneconomical where $t_s$ is long.

Cullender[16] proposed the isochronal backpressure testing technique for use in situations where stabilization times are long. This technique utilizes short, unsteady-state flow periods of the same length of time, but pressures still had to be equalized to static conditions between flow periods. It can be proved that the slope n of the performance curve is independent of stabilized flow conditions as long as isochronal flow periods are used. However, at least one stabilized flow rate is required if a performance curve comparable to the Rawlins-Schelhardt performance curve is to be obtained, i.e., if a stabilized performance coefficient is required as well.

Various modifications of the Cullender isochronal testing method have been suggested on the basis of slightly different assumptions. Tek et al[17] described a technique for calculating the performance coefficient without obtaining a stabilized flow rate, but this technique assumes the availability of a reliable build-up curve. Carter et al[18] described a technique utilizing "short flow periods" but also required "equilibrium (shut-in) conditions" after the well has been flowed for a specific period.

Backpressure tests in the DTU Unit were obtained in wells 22 through 42. Backpressure tests usually consisted of taking 3 or 4 consecutive values of isochronal flow rates and backpressures without shutting the well in. Flow periods were 1- or 2-hour periods. Approximate n values can be obtained from these data but the absence of a stabilized performance coefficient prevents the reliable prediction of performance. Any prediction of performance or calculation of $k_g$ will depend on an unstabilized performance coefficient and values for both parameters will be unrealistically high. The available backpressure data will therefore not be used to calculate effective permeabilities.

It is also known that the n values obtained with this type of isochronal testing method are too low (since the wells were not shut in between the flow rates). In view of the relatively low production rates used in the tests (and in the commercial producing periods), it is believed that an n value of 1.0 would be more valid instead of the 0.81 (average) value obtained in the tests.

Validity of Stabilized Drawdown Analysis. Equations 14 and 15 can be solved for $k_g$ by equating them:

$$k_g = Q_{gs} / u_g \; T_f \; z_{\overline{P}} \; \mathrm{Ln} \; (r_e/r_w) / .000703 \; h \; (P_e^2 - P_{wf}^2)^n \qquad (16)$$

This equation is similar to equation 5 previously used. In equation 5, n was equal to 1.0 and $\bar{P}$ was used instead of $P_e$.

It is known now that stabilized flow rates are obtained after approximately 300 days of production. Theoretically $P_e$ is still the same as $P_i$ at the instant stabilized flow is obtained and $k_g$ can be solved for that particular flow rate and backpressure. If the calculated value of $k_g$ is much different from 0.5, a new $t_s$ can be determined and the computation can be repeated.

The backpressure can be calculated using the non-ideal gas law and averaged properties (it is assumed that friction losses are zero):

$$P_{wf} = P_{tf} + 0.01875 \text{ SG } \bar{P} \text{ D} / z_{\bar{P}} \bar{T} \qquad (17)$$

where D = mid-perforation depth from surface (ft).

As an example, the effective permeabilities will again be calculated for wells 13 and 20.

Well No. 13:

$Q_{gs}$ = 750 M SCF/day,

$P_{wf}$ = 89 psia,

$P_e$ = 444.1 psia

and n = 1.0.

Hence, $k_g$ = 0.95 md.

Well No. 20:

$Q_{gs}$ = 420 M SCF/day,

$P_{wf}$ = 93 psia

and $P_e' = 447.8$ psia.

Hence,

$$k_g = 0.61 \text{ md.}$$

However, the above method assumes that the production rate is allowed to stabilize. Very often this is not the case in practice since the wells are sometimes shut-in to allow line repairs, or production rates change due to seasonal demand variations. If this is the case, equation 5 should be used. $\overline{P}$ can be calculated using the non-ideal gas law and remaining gas-in-place. This calculation should be done for an apparent stabilized production rate, which may be obtained at the end of the summer or winter season. This technique is illustrated in a later section.

Validity of Build-up Test Analysis. Build-up test analysis is not considered an important method in this study for the following reasons:

(1) A more reliable method (stabilized drawdown analysis) is available for determining effective permeabilities in all the wells.

(2) Useful build-up data are only available for a few wells.

(3) The assumption concerning a single constant production rate before shut-in (see page 14) is not a very good assumption for the available data and can cause serious errors.

If it is essential that a $k_g$ value be obtained from a build-up test, a more reliable value can be obtained if the production history prior to shut-in is known. The following multirate build-up equation (unsteady state period) which is based on the superposition principle, can be analyzed:

$$P_w = P_i - (2.898 \times 10^4 / u_g B_g / k_g h)(Q_{g1} \log(t_m + \triangle t - t_1)/(t_m + \triangle t)$$
$$+ Q_{g2} \log(t_m + \triangle t - t_2)/(t_m + \triangle t - t_1) - - -$$
$$+ Q_{gm} \log(\triangle t)/(t_m + \triangle 5 - t_{m-1})) \qquad (18)$$

where

$P_w$ = shut-in pressure in well (psia),

$Q_{g1}$ = first production rate (M SCF/day),

$Q_{g2}$ = second production rate (M SCF/day),

$Q_{gm}$ = mth production rate (M SCF/day),

$\triangle t$ = shut-in time (hours),

$t_1$ = period from time zero to end of first production period (hours)

and $t_m$ = period from time zero to end of the mth production period (hours).

The above equation is only valid for the unsteady-state period. $P_w$ can be plotted on the ordinate and the term inside the second brackets can be evaluated for various values of t and plotted on the abscissa. The effective permeability can then be determined from the slope of the curve.

It is also possible to assume $P_i$ values for extrapolation purposes (as previously discussed) and this will probably improve the reliability of the $k_g$ values, as long as the well is being produced in the initial unstabilized period.

Average Reservoir Pressure

The discussion of average reservoir pressure will be fairly theoretical since most of the DTU build-up data available were obtained during the unsteady-state period and extrapolation for obtaining $\overline{P}$ should only give the same value as $P_i$.

There are 3 normal methods for obtaining average reservoir pressures in a finite system from build-up data, namely (1) the Matthews et al[18] method, (2) the Miller et al[19] method and (3) the Dietz[20] method. The methods are briefly reviewed by Matthews and Russel[21].

All these methods require reliable values of $r_e$ and $k_g$. Fairly long shut-in periods (50 to 150 days) will be required if accurate values are wanted. Long shut-in periods are required to decrease the effects of afterflow and permeability irregularities near the borehole.

It is also possible to obtain $\overline{P}$ values from stabilized drawdown data (backpressure and flow rate) if $k_g$ and $r_e$ are known. Re-arranging equation 5 gives:

$$\overline{P} = \left( \left(Q_{gs}/u_g T_f z_{\overline{P}} Ln(0.472 r_e/r_w)/0.000703 h k_g\right) + P_{wf}^2\right)^{\frac{1}{2}} \qquad (19)$$

(It is assumed that n = 1.0.)

This method of obtaining average reservoir pressure in the DTU field is considered the most practical by this author. It is therefore necessary to determine reliable values of $k_g$ and $r_e$ as early as possible in the life of the producing reservoir in order that later production data can be used to determine $\overline{P}$.

## Error Introduced by Using Unstabilized Flow Data

It has been pointed out previously that $t_s$ is independent of the production rate or change in production rate. Thus if $t_s$ is 300 days and the production rate is changed after 150 days of stabilization by any amount (large or small) it will theoretically take another 300 days before the flow rate is stabilized. It is obvious that the error introduced in calculating $\overline{P}$ by using unsteady flow data ($e_u$) is a function of the fraction of $t_s$ applied. It can be shown by qualitative reasoning that $e_u$ is also dependent upon the production rate change: Consider a well that is being stabilized at a flow rate of 1000 M SCF/day. After 150 days of stabilization, if the flow rate is decreased from 1000 M SCF/day to 999 M SCF/day and the well is then allowed to stabilize for another 150 days, $e_u$ will not be too large if the flow data after 300 days of production are being used as stabilized flow data. On the other hand, if the flow rate is decreased to 0.001 M SCF/day after 150 days of stabilization, $e_u$ will be much larger than in the previous case if the flow data after another 150 days of production are being used as stabilized flow data. Thus $e_u$ is a function of the change in production rate.

It is also possible to evaluate $e_u$ quantitatively and this will be done with special reference to the DTU flow data. This evaluation is again based on theory developed for slightly compressible fluids while in practice it will be applied to gas flow data.

First, $e_u$ as a function of $t_s$ applied, will be investigated.

Figure 7 is a plot of $\triangle P_D$ vs. $t_{De}$ for the case of $r_e/r_w = 5000$. (In the case of the DTU field, $r_e/r_w \simeq 5700$.) It can be seen that unstabilized flow changes into stabilized flow at $t_{De} = 0.253$ (due to the definition of $t_s$, i.e., $t_{De} = 40 \times 0.00633 = 0.253$).

Consider the following theoretical case:

$Q_{gs}$ = 750 M SCF/day

$\therefore$ $q$ = 4275 reservoir bbl/day (using non-ideal gas law and averaged properties),

$k_g$ = 0.5 md,

$h$ = 350 ft,

$P_i$ = 450 psia,

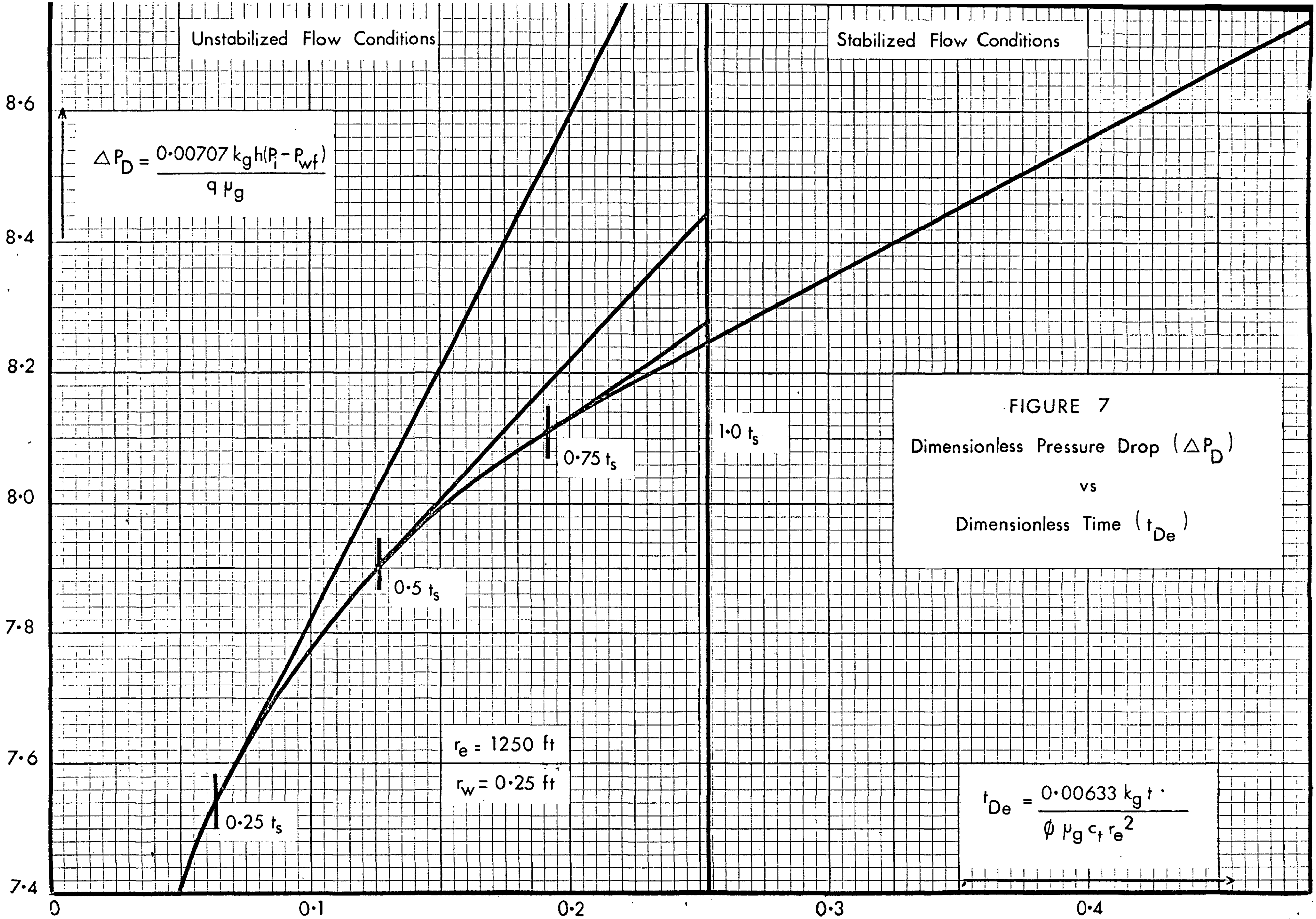


FIGURE 7

Dimensionless Pressure Drop ($\Delta P_D$) vs Dimensionless Time ($t_{De}$)

$\mu_g$ = 0.0125 cp,

$r_e$ = 1250 ft,

$r_w$ = 0.25 ft,

$T_f$ = 560° R

and $z_{\overline{P}}$ = 0.94.

From Figure 7 it can be seen that $\Delta P_D = 8.24$ when $t_{De}$ = 0.253.

By re-arranging equation 7, which defines $\Delta P_D$, $P_{wf}$ can be found for any value of $t_{De}$:

$$P_{wf} = P_i - \Delta P_D \, q \, \mu_g \, / \, 0.00707 \, k_g \, h \tag{20}$$

In particular, $P_{wf}$ can be found for that instant when stabilized flow conditions have been obtained (i.e., when $t_{De} = 0.253$ and $\Delta P_D = 8.24$):

$$P_{wf} = 94 \text{ psia.}$$

The $\overline{P}$ equation for slightly compressible fluids, corresponding to equation 19 (the $\overline{P}$ equation for gases), can be stated as follows:

$$\overline{P} = q \mu \, \text{Ln}(0.472 \, r_e/r_w) \, / \, 0.00708 \, k \, h + P_{wf} \tag{21}$$

$\overline{P}$ can now be found for $t_{De} = 0.253$:

$$\overline{P} = 429 \text{ psia.}$$

An approximate $\overline{P}$ can also be calculated if unsteady flow data is assumed to be stabilized. Consider the case where the flow data were obtained at a time $t = 0.5\ t_s$:

$$\Delta P_D = 7.91,$$

$$P_{wf} = 108 \text{ psia}$$

and $\bar{P} = 443$ psia.

Thus,

$$e_u = \frac{443-429}{429} \times 100$$

$$= 3.3\%.$$

Similarly,

$$(e_u)_{t = 0.75\ t_s} = 1.4\%$$

and $(e_u)_{t = 0.25\ t_s} = 7.0\%$.

It is theoretically possible to reduce $e_u$ by extrapolating the curve to 1.0 $t_s$ ($t_{De} = 0.253$) as indicated in Figure 7.

If the extrapolated values of $\Delta P_D$ are used, $e_u$ values are as follows:

$$(e_u)_{t = 0.5\ t_s} = 2.0\%$$

and $(e_u)_{t = 0.75\ t_s} = 0.4\%$,

but $(e_u)_{t = 0.25\ t_s} > 10\%$.

The effect of the production rate change can easily be evaluated by repeating the above calculation procedure, but for a production rate of 250 M SCF/day which is approximately the production rate change between summer and winter season rates.

For non-extrapolated flow data:

$$(e_u)_{t = 0.5\ t_s} = 1.13\%,$$

$$(e_u)_{t = 0.75\ t_s} = 0.50\%$$

and $$(e_u)_{t = 0.25\ t_s} = 2.4\%.$$

For extrapolated flow data:

$$(e_u)_{t = 0.5\ t_s} = 0.70\%$$

and $$(e_u)_{t = 0.75\ t_s} = 0.15\%.$$

Thus, $e_u$ is very nearly directly proportional to the production rate change.

It is evident that $e_u$ will be quite small in most cases (for $t > 0.5\ t_s$ and $\Delta\ Q_{gs} < 250$ M SCF/day). The errors introduced by other parameters (e.g., $\phi$, $r_e$, etc.) will be much larger. Accuracy of $\overline{P}$ can be improved by extrapolation of the flow data if $t > 0.5\ t_s$.

The fluid-flow theory for slightly compressible fluids was used to evaluate the magnitude of $e_u$ in a gas-flow system. The accuracy of $e_u$ can be improved if necessary by using gas-flow theory developed for ideal or real gases. Aronofsky et al[6,7] have solved the ideal gas flow diffusivity equation using computer techniques. Al-Hussainy et al[22,23] have solved the real gas flow diffusivity equation also using computer techniques. After studying the above-mentioned literature, it is concluded that application of ideal or real gas flow theory will not significantly influence the conclusions reached previously concerning the magnitude of $e_u$ for the given conditions (e.g., the range of production rates found in the DTU field).

## Material Balance Calculations

Initial gas-in-place has been calculated on a volumetric basis. It is possible to confirm this calculated value or to determine the presence of extra energy sources by material balance computations. (In the simplest form, the material balance equation can be written as: initial volume = volume remaining + volume removed).

If successive calculations of initial gas-in-place according to the material balance equation give increasing values, it probably indicates the presence of another source of reservoir energy, e.g. an invading water front. If successive calculations of initial gas-in-place give constant values, there are no extra energy sources present and the initial gas-in-place value can be compared with the volumetric value. If necessary, certain parameters used in the volumetric calculation can be adjusted.

According to Craft et al[25], a material balance equation for gas reservoirs can be stated as follows:

$$G_p = P_i V_i T_{sc}/z_{Pi} P_{sc} T_f - V_i T_{sc} \overline{P}/P_{sc} T_f z_{\overline{P}} \qquad (22)$$

where

$G_p$ = cumulative gas production (M SCF)

and $V_i$ = initial reservoir volume (cu ft).

$V_i$ will be assumed constant in this study.

Equation 22 indicates that for a volumetric (isolated) gas reservoir the graph of the cumulative gas production ($G_p$) versus the ratio $\overline{P}/z_{\overline{P}}$ is a straight line of negative slope $V_i T_{sc}/P_{sc} T_f$ and may be extrapolated to 12.5 psia to find the initial gas-in-place.

## Summary of Past Performance Analysis Procedure

The following is the step-by-step procedure to be followed in analyzing the past performance of any well in the DTU field:

(1) Determination of porosity and formation thickness.

 (A) Determine $\phi$ from geophysical logs.

 (B) If no geophysical logs are available, interpolate $\overline{\phi}$ value from adjacent well values.

(2) Determination of gas saturation:

 (A) Determine $\overline{S}_g$ from available core analysis data.

(B) If no core data are available, try geophysical log interpretation techniques.

(C) If not successful, use value obtained from Welge and Bruce's correlation between $k_g$ and $S_g$.

(3) Determination of radius of drainage:

(A) Determine drainage boundaries and $r_e$ from a consideration of well positions and relative $Q_{gs}$.

(B) If there are not enough data available, use $\overline{r}_e$ (1430 ft).

(4) Determination of initial gas-in-place:

(A) Determine reliable $P_i$ for well.

(B) Calculate $G_{wi}$ on a volumetric basis.

(5) Determination of effective permeability-to-gas:

(A) Determine $k_g$ from build-up test data.

(B) Confirm or improve previously determined $k_g$ value using stabilized drawdown data and equation 16.

(C) (a) Determine $\overline{P}$ for well drainage system from material balance principles and non-ideal gas law.

(b) Check previously determined $k_g$ value using stabilized drawdown data and equation 5.

(6) Confirmation of initial gas-in-place from material balance:

(A) (a) Determine $\overline{P}$ using stabilized drawdown data and equation 19. This calculation cannot be done for the same time period as was used in (5) (C) (a).

(b) Determine $G_{wi}$ from a $\overline{P}/z_{\overline{P}}$ vs $G_p$ plot or from equation 22.

(7) Adjustment of Parameters:

If the two $G_{wi}$ values are not the same, certain parameters may have to be adjusted. The adjustment depends on the relative reliability of the different parameters. For example, if the least reliable parameter seems to be the $\overline{\phi}$ value, then the $\overline{\phi}$ value has to be adjusted. Generally, it is believed that the $\overline{\phi}$ or $S_g$ parameter is the easiest to adjust since any change in $r_e$ implies a change in the $r_e$'s of the adjacent wells and this may be difficult to manipulate.

(8) Determination of extra energy:

If the points on the $\overline{P}/z_{\overline{P}}$ vs $G_p$ plot do not form a straight line, it may indicate the presence of extra energy (e.g. invading water front) and the $G_{wi}$ cannot be calculated from material balance principles unless the amount of invading water is known. In this case water levels in wells will have to be recorded carefully.

In general, however, the presence of extra energy is not expected in the DTU field due to the low effective permeability to water, the relatively high viscosity of water and the small pressure potential gradient available. Thus, most of the material balance calculations may be used for improving $k_g$ and $G_{wi}$ values.

## Past Performance Analysis of Well No. 38

The analysis procedure as recommended in the summary will be followed:

(1) Determination of Porosity and Formation Thickness.

(A) From Density Log:

Producing Interval = 2410' - 2780'

$\bar{\rho}_b$ = 2.42 gm/cc

$\bar{\phi}$ = 13.5%

h = 370'

(2) Determination of Gas Saturation.

(A) No core data available.

(B) Geophysical Log Interpretation not possible.

(C) From Welge and Bruce's correlation:

$\bar{S}_g$ = 40%

(3) Determination of Radius of Drainage.

(A) Drainage boundaries cannot be determined due to unknown stabilized production rates of neighboring producers (see Figure 1).

(B) Assume

$r_e = 1430$ ft

(4) Determination of Initial Gas-in-place.

(A) From Table 1:

$P_i = 448.4$ psia

$$G_{wi} = \pi r_e^2 \, h \, \phi \, S_g \, T_{sc} \, P_i \, / \, Z_{P_i} \, T_f \, P_{sc} \quad (3)$$

$\therefore G_{wi} = 4.54 \times 10^9$ SCF.

(5) Determination of Effective Permeability-to-gas.

(A) No build-up test data are available.

(B) Flow data after approximately 300 days of production (see Figure 8, time (A) ):

$Q_{gs} = 650$ M SCF/day

$P_{tf} = 145$ psig

$= 157$ psia

From equation 17:

$P_{wf} = 175$ psia.

From equation 16 ($n = 1.0$):

$k_g = 0.85$ md.

Since $k_g \neq 0.5$ md, the $t_s$ used (300 days) is too long. A $t_s$ of 210 days (time (B) ), can be used to improve the accuracy.

$Q_{gs} = 700$ M SCF/day,

$P_{tf} = 153$ psig,

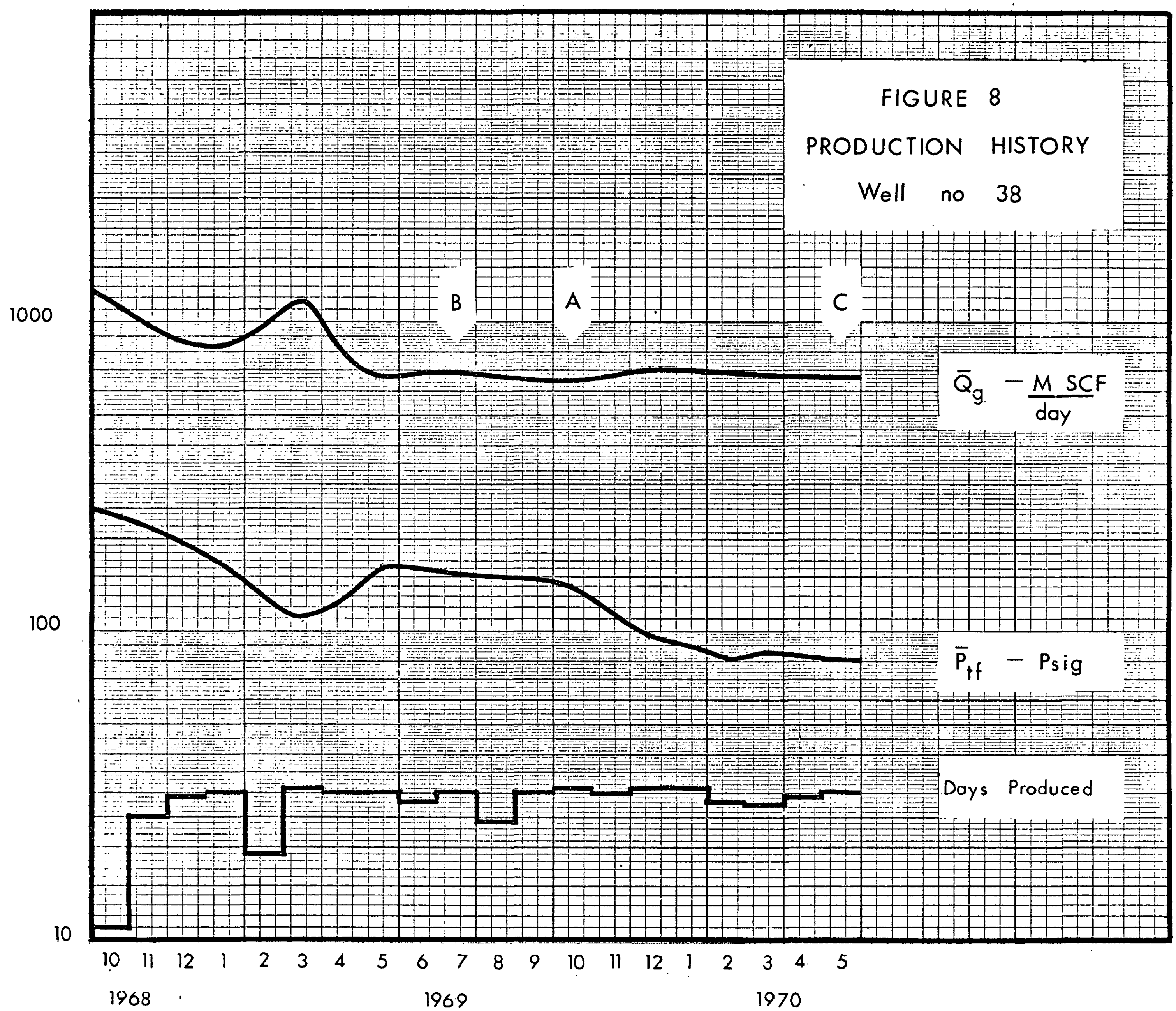

FIGURE 8
PRODUCTION HISTORY
Well no 38
B
A
C
$\bar{Q}_g$ — M SCF / day
$\bar{P}_{tf}$ — Psig
Days Produced
1000
100
10
10 11 12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5
1968
1969
1970

$P_{wf} = 183$ psia

and $k_g = 0.93$ md.

Thus, the $t_s$ used is still too long. Unfortunately $t_s$ cannot be shortened further since the flow rate varies too much in the earlier production period.

(C) (a) It is possible to calculate $\overline{P}$ at any time if $G_p$ is known and assuming $G_{wi}$ is correct. Calculation of $\overline{P}$ at time (A):

$(G_p)_A = 278{,}660$ M SCF

$G_{wi} = 4.54 \times 10^9$ SCF (assumed)

$(G_R)_A = G_{wi} - (G_p)_A$

$= 4.261 \times 10^9$ SCF.

According to the non-ideal gas law,

$$(\overline{P})_A = \frac{(G_R)_A \, z_{\overline{P}} \, T_f \, P_{sc}}{\pi r_e^2 h \, \phi \, S_g \, T_{sc}} \qquad (23)$$

$= 420$ psia.

(b) From equation 5.

$(k_g)_A = 0.89$ md.

The different $k_g$ values calculated are almost identical, indicating that the theory is very much applicable and that it can be used with confidence. The good agreement between the values are really remarkable considering all the assumptions that are being used.

A $k_g$ value of 0.89 md will be used in the further calculations.

(6) <u>Confirmation of Initial Gas-in-place from Material Balance</u>.

(A) Calculation done for time (C).

(a) $(G_p)_C = 420,000$ M SCF

$(Q_{gs})_C = 670$ M SCF/day

From equation 17:

$$(P_{wf})_C = 92.5 + \frac{0.01875 \times 0.66 \times 2600 \times 250}{96 \times 540}$$

$= 108.0$ psia.

From equation 19:

$(\overline{P})_C = 402$ psia.

(b) Re-arranging equation 22:

$$G_{wi} = (G_p)_C + V_i \; T_{sc} \; (\overline{P})_C / P_{sc} \; T_f \; z_{(\overline{P})}$$

$= 4.46 \times 10^9$ SCF.

Therefore error in initial $G_{wi}$ assumption:

$$e = \frac{(4.54 - 4.46) \times 100}{4.46}$$

$= 1.8\%$.

If necessary, steps (5) (C) through (6) can be repeated using the new value of $G_{wi}$ to improve the accuracy of $k_g$ and

$G_{wi}$. This calculation was done without affecting the value of $k_g$ (0.89 md to the second decimal). Thus a $k_g$ value of 0.89 md can be used with confidence.

(7) Adjustment of Parameters.

It was found that the volumetric $G_{wi}$ was 1.8% higher than the material balance $G_{wi}$. The volumetric calculation can be corrected by using a porosity value of 1.8% lower, i.e. $\phi$ = 13.25% instead of 13.5%.

(8) Determination of Extra Energy.

No further stabilized flow data are available to check previous calculations or to indicate the presence of extra energy.

## PERFORMANCE PREDICTION

An attempt will be made to obtain a correlation between gas production rates, backpressure and fractional recovery. This statement requires further clarification: It is known that there are compressors in the gathering system which attempts to maintain a high upstream pressure. The compressing rate of the compressor essentially determines the backpressure or upstream pressure which is applied to the producing formation. The downhole backpressure in turn controls the gas production rate. If the line (pipe) pressure, upstream of the compressor, decreases due to an increase in gas consumption, the compressing rate of the compressor is increased, the backpressure on the formation decreases and the gas production rate increases. This process is known as "floating on the (gas) line." Over a period, average reservoir pressure will decrease due to depletion and production rates for the same backpressure will consequently decline until a point is reached where the production rate at a given backpressure is uneconomical, i.e., it is not economically worthwhile to compress the gas and the well or field should be abandoned.

The problem is to predict the fractional recovery of initial gas-in-place when this point will be reached.

This study is not concerned with obtaining a specific "cut-off" point for the Dragon Trail Unit wells, but rather with obtaining a general "recovery formula" in terms of production rate, backpressure and fractional recovery. Fractional recovery then can be solved for application values of backpressure and production rates.

## Derivation of Recovery Formula

It is required that the recovery formula should define the total or fractional recovery as a function of stabilized flow rate and backpressure applied to the formation.

The material balance formula (equation 22) can be re-arranged in the following manner:

$$\bar{P} = P_i \, Z_{\bar{P}} / Z_{P_i} - G_P \, Z_{\bar{P}} \, T_f \, P_{sc} / V_i \, T_{sc} \qquad (24)$$

Equation 19 is another form of the modified Darcy flow equation with $\bar{P}$ on the lefthand side of the equality sign. Equation 24 and 19 can therefore be equalized and solved for $G_p$:

$$G_p = \left( - \left( \frac{Q_{gs} \, \mu_g \, T_f \, Z_{\bar{P}} \, \mathrm{Ln} \, (0.472 \, r_e / r_w)}{0.000703 \, h \, k_g} + P_{wf}^2 \right)^{\frac{1}{2}} + \frac{P_i \, Z_{\bar{P}}}{Z_{Pi}} \right) V_i \, T_{sc} / Z_{\bar{P}} \, P_{sc} \, T_f \qquad (25)$$

$$= P_i \, V_i \, T_{sc} / Z_{Pi} \, P_{sc} \, T_f - \bar{P} \, V_i \, T_{sc} / Z_{\bar{P}} \, P_{sc} \, T_f \qquad (26)$$

Equation 25 defines the total recovery partially in terms of $Q_{gs}$ and $P_{wf}$. The fractional recovery can be found by dividing equation 25 by $G_{wi}$:

$$\text{Fractional Recovery} = \frac{G_p}{G_{wi}}$$

$$= \left( - \left( \frac{Q_{gs} \mu_g T_f Z_{\bar{P}} \ln (0.472 r_e/r_w)}{0.000703 h k_g} + P_{wf}^2 \right)^{\frac{1}{2}} \right) \frac{Z_{Pi}}{P_i Z_{\bar{P}}} + 1 \qquad (27)$$

Inasmuch as a knowledge of $Z_{\bar{P}}$ is required before $\bar{P}$ is known, an approximate Z value can be used in the first calculation. The error in the DTU field will not be too large since Z only varies between 0.94 and 1.00. If necessary, the calculation can be repeated using a calculated $Z_{\bar{P}}$ value.

## Application of the Recovery Formula

The fractional recovery at the economic limit will be calculated for well 38, assuming the following conditions:

(1) $P_{wf}$ will stay constant at 50 psia.

(2) Maintenance cost is estimated at $120.00 per month per well.

(3) The contract price for gas is 20¢/M SCF.

Calculations for well No. 38:

(Economic limit in this calculation is defined as the "break-even point".)

Maintenance cost per day: $4.00

Required $Q_{gs}$ for breaking even:

$Q_{gs} \doteq 20$ M SCF/day

From equation 27:

$G_p/G_{wi} = 0.82$ or 82%

<u>Simplification of Recovery Formula</u>

Equation 27 can be simplified by substituting average values for the average drainage system in the DTU field. The average values used were the following:

$r_e$ = 1430 ft,

$r_w$ = 0.25 ft,

$\mu_g$ = 0.0122,

$T_f$ = 540° R,

$P_i$ = 448 psia,

$Z_{\bar{P}}$ = 0.98

and $Z_{P_i}$ = 0.94.

Equation 27 reduces to:

$$G_p/G_{wi} = 1 - 0.00214 \left(75{,}000 \frac{Q_{gs}}{hk_g} + P_{wf}^2\right)^{\frac{1}{2}}$$

where $Q_{gs}$ = stabilized production rate (M SCF/day),

$h$ = formation thickness (ft),

$k_g$ = effective permeability to gas (md)

and $P_{wf}$ = backpressure on formation (psia)

Equation 28 can be further reduced by the following assumptions:

$h$ = 370 ft

and $k_g$ = 0.8 md.

Therefore,

$$G_p/G_{wi} = 1 - 0.00214\ (253\ Q_{gs} + P_{wf}^{2})^{\frac{1}{2}} \qquad (29)$$

Equation 29 satisfies the requirements of a recovery formula that can be applied in the DTU field.

## CONCLUSIONS AND RECOMMENDATIONS

A careful evaluation of the past performance section will indicate that $k_g$ and $G_{wi}$ values obtained by following the suggested procedure, are very satisfactory.

The most important conclusion that can be drawn from this study is that average pressures obtained from approximately stabilized flow data are accurate enough for material balance calculations. Thus, long unprofitable shut-in periods to obtain average pressures are not necessary at all in this reservoir.

Calculations can further be improved by the following procedures:

(1) A better $r_e$ value can be obtained by a consideration of well positions and relative stabilized production rates.

(2) In this study, the data analyzed were not specially prepared or intended for drawdown analysis. (Flow data were usually averaged for monthly periods.) Reliability can further be improved by doing a special "drawdown test" consisting of (a) trying to keep the production rate (or backpressure) constant for at least half the stabilization time, (b) carefully recording $Q_{gs}$ and $P_{tf}$ for the duration of the test and (c) accurately determining $G_p$ at the end of the test.

The derived recovery and other formulae should be very useful in the solution of future economical problems, especially if the installation of further compressors (to boost the total production rate) is considered.

# APPENDIX I

## Diffusivity Equation for Compressible Fluids.

The diffusivity equation for a slightly compressible fluid is a linear differential equation describing the pressure distribution in a fluid-flow system in terms of space and time. The equation states:

$$\frac{\partial^2 P}{\partial r^2} + \frac{1}{r}\frac{\partial P}{\partial r} = \frac{\phi\, u\, c_t}{k}\ \frac{\partial P}{\partial t}$$

The derivation of the diffusivity equation is adequately described in the literature(25) and will not be repeated here. However, it may be worthwhile to review the assumptions which were made in the derivation:

1) Fluid flow is radial.

2) Fluid flow is horizontal.

3) Thickness of the producing formation is constant in space and time.

4) Porosity of producing formation is constant in space.

5) Fluid saturations in the flow system are constant in space and time.

6) The fluid flow is single-phase.

7) Fluid flow is viscous (laminar).

8) Absolute permeability is constant in space and time.

9) Viscosity of the flowing fluid is constant in space and time.

10) The total fluid compressibility is small.

11) The change of pressure with radial distance $\left|\frac{\partial P}{\partial r}\right|$ is small.

## NOMENCLATURE

### SYMBOLS IN ALPHABETICAL ORDER

English Symbols

| | |
|---|---|
| $A$ | area |
| $B$ | formation volume factor |
| $B_g$ | gas formation volume factor |
| $c$ | compressibility |
| $c_f$ | formation (rock) compressibility |
| $c_g$ | gas compressibility |
| $c_w$ | water compressibility |
| $c_t$ | total compressibility |
| $D$ | depth |
| $e_u$ | error due to using unsteady flow data |
| $G$ | total initial gas-in-place in reservoir |
| $G_p$ | cumulative gas produced |
| $G_{wi}$ | initial gas-in-place of well drainage system |
| $h$ | net pay thickness |
| $k$ | absolute permeability |
| $k_g$ | effective permeability to gas |
| Ln | natural logarithm, base e |
| log | common logarithm, base 10 |
| $M$ | molecular weight |
| $n$ | slope of the backpressure curve |
| $N$ | number of producing wells |

| | |
|---|---|
| $P$ | Pressure |
| $P_D$ | dimensionless pressure |
| $P_e$ | external boundary pressure |
| $P_i$ | initial static reservoir pressure |
| $P_{sc}$ | pressure, standard conditions |
| $P_{tf}$ | tubing pressure, flowing |
| $P_w$ | bottom-hole pressure shut-in |
| $P_{wf}$ | bottom-hole pressure, flowing |
| $\overline{P}$ | average pressure |
| $q$ | production rate (downhole) |
| $Q$ | production rate (surface) |
| $Q_g$ | gas production rate |
| $Q_{gs}$ | stabilized gas production rate |
| $r$ | radial distance or radius |
| $r_e$ | external boundary radius |
| $r_w$ | well radius |
| $R$ | resistivity |
| $S$ | saturation |
| $S_g$ | gas saturation |
| $S_w$ | water saturation |
| $t$ | time |
| $\Delta t$ | shut-in time |
| $t_D$ | dimensionless time |
| $T$ | temperature |
| $T_f$ | formation temperature |

| | |
|---|---|
| V | volume |
| z | gas deviation factor (compressibility factor, $z = pV/nRT$) |

Greek Symbols.

| | | |
|---|---|---|
| $\Delta$ | delta | difference ($\Delta x = x_2 - x_1$ or $x_1 - x_2$) |
| $\mu$ | mu | viscosity |
| $\mu_g$ | mu | gas viscosity |
| $\rho$ | rho | density |
| $\phi$ | phi | porosity |

Subscripts.

(Subscripts can be combined, e.g. $Q_{gs}$ = stabilized gas production rate.)

| | |
|---|---|
| b | bulk (used with volume only) |
| D | dimensionless quantity |
| e | external boundary conditions |
| f | formation (rock) |
| g | gas |
| gr | grain |
| h | head |
| i | initial value or conditions |
| L | liquid |
| p | evaluated at that pressure |
| p | cumulative produced |

| | |
|---|---|
| $r_e$ | at external boundary radius |
| r | remaining |
| s | stabilized |
| sc | standard conditions |
| t | time or unaffected (used with resistivity) |
| t | total |
| tf | tubing, flowing (used with pressure only) |
| w | well conditions |
| wf | bottom-hole, flowing (used with pressure only) |

<u>Modifying Signs</u>.

| | |
|---|---|
| $\bar{x}$ | average x or mean x (x is any parameter) |
| $x'$ | approximate x (found by a particular method) |
| $x''$ | approximate x (found by another different method) |

## ABBREVIATIONS

| | |
|---|---|
| DTU | Dragon Trail Unit |
| ft | feet |
| gm | gram |
| cc | cubic centimeter |
| % | percent |
| sq | square |
| bbl | barrel |
| Cu | cubic |
| SCF | standard cubic feet |
| CONOCO | Continental Oil Company |
| i.e. | it is |
| M | thousand |
| ¢ | cent |

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