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CONDUCT AND ANALYSIS OF WELL TESTS FOR DETERMINATION OF GAS RESERVOIR PARAMETERS

by

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Presented at the

AGA SYMPOSIUM ON ANALYTICAL TECHNIQUES AND APPLICATIONS FOR NATURAL GAS RESERVOIRS

Stanford University

February 15, 1979

From: "Analytical Techniques and Applications for Natural Gas Reservoirs" American Gas Assoc. / Stanford University Joint Symposium Febuary 16-1[illegible] 1979 pp. 47 - 79

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INTRODUCTION

In today's energy market the value of natural gas is many times what it was just a few years ago. The ability to analyze current performance from individual wells and to forecast future productivity from both wells and reservoirs is required now to a greater extent. A great deal of the information needed to effectively plan and operate a gas field can be determined from properly designed well tests. Although the number of parameters that can be measured in a gas well are relatively few, namely, pressures, flow rates, and time, the amount of information that may be developed by careful planning and analysis is significant.

The purpose of this paper is to review the procedures and analyses that are employed in basic well testing to determine fundamental reservoir parameters used in operating the well or field. The parameters that will be discussed are:

Well Flow Rate

Well tests have long been used to determine the rate a gas well will produce against a given pipeline "back pressure". This information is needed to determine the economics of the drilling operations and field development plans as well as to design producing, gathering system and processing plant facilities. It is also required in the negotiation of gas sales contracts. In addition, some type of gas well pressure test is often used by governmental regulatory bodies to set maximum permissible gas flow rates.

Reserves

The size of the reserves as well as the well rates control the economics of the investments that may be made on a gas reservoir.

Reservoir Pressure

Transient reservoir pressure testing is used to determine static reservoir pressure, effective reservoir permeability, the extent of formation damage, proximity to barriers, and changes in fluid and rock properties. Static reservoir pressure is a most important factor in both the determination of recoverable gas reserves and analysis of well deliverability tests.

Since this subject is adequately covered elsewhere in this symposium, it will not be covered here.

TYPES OF GAS WELL DELIVERABILITY TESTS

Well Rate Determination (Deliverability Testing)

Several types of gas well tests commonly fall under the general heading of deliverability testing. All of the following except the first are routinely performed in gas field operations today.

Open Flow Testing. This was the original deliverability test for gas wells and involved producing at maximum rate long enough to stabilize the production rate. The gas production was often flared. To the authors' knowledge, this type of testing is not carried out today.

Conventional Stabilized Back Pressure Tests. This is the original multi-rate back pressure test which was developed in the late 1920's.[1,2] It consists of producing a well at several stabilized rates in succession and measuring either the well head pressure or the bottom hole pressure at each rate. The analysis of this test is described in a later section.

Isochronal Back Pressure Test. Isochronal tests were developed in the 1950's by Cullender.[3] They generally require less time to complete because each flow rate in the sequence is of a fixed duration and does not need to be stabilized. A shut-in period of sufficient length for the reservoir to reach static pressure separates each flow period.

Modified Isochronal Back Pressure Tests. This testing technique differs from the isochronal technique in that it shortens the testing time even further by limiting both the time for each flow rate and the shut-in periods between each flow rate. Therefore, neither the flow rates nor the build-up pressures need to stabilize.

Single Point Pressure Test. This type of test is similar to the conventional stabilized back pressure test except that only one rate is tested. This procedure is used primarily to update an existing multi-point test.

WELL DELIVERABILITY TESTING

Basic Concepts

The basic concept in well deliverability testing is that a plot of log P^2 vs. log rate in a gas well is a straight line as shown in Figure 1. This was first reported by Rawlins.[2]

He showed that if a test involving three or four rates was taken and appropriate pressures measured, then by the construction of a graph, such as Figure 1, it is possible to determine the production rate at any given operating pressure. The ordinate is actually the log of the difference between the square of the static reservoir pressure, p_r, and the square of the bottom hole flowing pressure, p_{wf}. Note that the term absolute open flow (AOF) has been defined as the maximum rate the well could produce if the bottom hole flowing pressure were equal to 0 psia. This is obviously a fictitiously high deliverability rate since the flow does not have any well bore or surface facility restrictions, but the term is recognized throughout the gas industry, and maximum permissible rates are often set by regulatory agencies in terms of a percentage of the AOF.

$$q_{sc} = C \ (p_r^{\ 2} - p_{wf}^{\ 2})^n \qquad (1)$$

Equation 1 is the empirical representation[2] of the line shown on Figure 1. By accepted convention and usage the slope of this curve is $\frac{1}{n}$ and is a function of reservoir rock properties and the flow regime in the immediate vicinity of the well bore. When n is equal to 1 the flow obeys

$$q/A = - \frac{k}{\mu} \frac{dp}{dx} \qquad (2)$$

Darcy's law, Equation 2. When n is equal to .5 the flow is fully turbulent and does not obey Darcy's law. Where n is less than 1, Equation 3 can be used. This equation, reported by Forchheimer[4], accounts for the inertial forces which become

$$- \frac{dp}{dx} = \frac{\mu}{k} q/A + \beta\rho \ (q/A)^2 \qquad (3)$$

important in high rate gas flow.

The basic assumptions in well deliverability testing using this procedure are:

1. isothermal conditions of flow
2. no gravity effects
3. single phase flow
4. constant gas properties
5. homogeneous and isotropic rock properties
6. permeability independent of pressure

For most gas well testing situations assumptions 1, 2, and 3 are met. The assumption of constant gas properties can be avoided by expressing Equations 2 and 3 in terms of "real gas potential".[5,6] However, the simpler method will be used here. In most situations assumption 5 is rarely met. Permeability is usually not independent of pressure but the importance of the variation is usually minor. Although this list of assumptions might appear to limit the usefulness of deliverability testing, in practice this has not been the case.

Design of a Conventional Back Pressure Test

The conventional back pressure test will be described in detail as it is the basis for all modern methods for back pressure testing. The newer types of tests which are in use in many places because of their time saving advantages are fundamentally the same and will be discussed in later sections.

The time to conduct a test is after the well has been completed and stimulated and is ready for full scale production. This initial test is usually required by regulatory agencies before a maximum production rate can be assigned and production can actually begin. The initial test is usually a multi-point test. Later single-point tests may be performed on a scheduled basis to determine if well or reservoir conditions have changed since the previous test was conducted. These later tests are useful in determining such things as liquid dropout in the well bore, detrimental effect of water production with the gas, perforation or formation damage, plugging in the tubing, etc.

The selection of the type of test to be performed is usually determined by consideration of several parameters. However, the most important consideration should be the time required for the pressure to stabilize at a given flow rate. For shorter stabilization times, the conventional test may yield adequate results in the shortest period of time since there is no build-up period between the flow periods. However, for longer stabilization times, one of the iso-chronal procedures is usually preferred.

Stabilization is theoretically the time at which the radius of investigation or the pressure wave caused by initiation of flow at the wellbore reaches the outer boundary of the flow system. There are several published theoretical estimates of this time period. All these estimates have shown that time for stabilization is directly related to the formation porosity, gas viscosity, drainage radius, and inversely related to the formation permeability and static reservoir pressure. The reader is referred to references 7 and 8 for a more complete description of this calculational procedure.

Practically speaking, stabilization can be defined in terms of the rate of pressure change with time during the flow period. For example, the Texas Railroad Commission has indicated that a pressure change of 0.1 psia/15 minutes is a practical measure of stabilization.[7] In many cases this is a good rule. However, this can lead to poor results in low permeability reservoirs, and for this reason theoretical stabilization time should be evaluated before the test is undertaken.

The equipment required to conduct a back pressure test depends to some extent on the anticipated capacity of the well and the composition of gas that is expected to be produced. Figure 2 is a schematic diagram of the basic equipment set-up for testing gas wells. The flow meters and down hole pressure measuring devices are critical portions of the apparatus. The flow meters must be located between the separator and any valves or chokes to assure that they each measure flow of single phases. The gas from the separator is normally flared. In some cases, with sweet gas, it need not be. A very dry gas would eliminate the need for a separator and stock tank for liquids.

The down hole pressure can be measured in a number of ways. The illustrated method is to measure the well head pressure with a dead-weight guage and to calculate the bottom hole pressure from the equations[8,9,10] for flow in the tubing. These techniques are usually not as accurate as directly measuring the bottom hole pressure with either bottom hole recording or surface-reading pressure gauges. The gas flow rates are usually measured with orifice meters and liquid flow rates are usually measured with turbine meters. In the special case of a sweet dry gas flow may be metered with a flow prover connected to the well head.

Conduct of the Test. The first step in a back pressure test is to condition the well by flowing it for a sufficient time to clean out liquids from the bottom and stabilize the temperature to eliminate hydrates. A multi-point test usually consists of four flow rates beginning with the minimum rate required to unload liquids and prevent hydrates. Other flow rates should be spread out over the entire range of operating conditions anticipated for the operation of the well. Usually information on what these rates should be is available during either the initial testing or cleaning out of the well. If no information exists on the possible range, it is possible to calculate a theoretical AOF from equation 1 setting p_{wf} equal to zero and assuming Darcy flow. Based upon this calculated AOF value and the anticipated permissible flow rate, it is then possible to set the upper rate about 10 to 15 percent higher for the maximum flow rate of the test. As illustrated in Figure 3, the first and succeeding flow periods extend until the measured temperature and pressure have stabilized. When well head conditions have stabilized, the rate is increased to the next rate in the series up to or somewhat above the planned production rate.

The basic data which are gathered are the bottom hole and/or well head pressures, gas flow rates, liquid flow rates, and gas surface temperatures. The final step in the well test is to shut the well in and allow the pressure to build up. In this case the pressure is recorded as a function of time for analysis by transient pressure analysis techniques discussed elsewhere.[11,12,13,18]

Analyzing the test. First the flow rates and bottom hole pressures are computed from the raw data acquired during the test. The data used in the figures shown in this paper were taken from Example No. 4 of Reference 7. For calculation of the terms the reader is referred to this publication. The bottom hole pressures are expressed in psia; the flow rate of the combined well stream in MMSCFD is computed from the measured gas and liquid flow rates and a knowledge of the PVT relation-ships for the two phases. Next the AOF plot in Figure 1 is constructed by plotting the well stream flow rate on the abscissa and the square of the static bottom hole pressure minus the square of the flowing bottom hole pressure on the ordinate. The AOF then can be read from the straight line drawn through the points and at the point on the line corresponding to a bottom hole pressure of 0 psia. The slope $\frac{1}{n}$ can also be evaluated.

This graph can now be used for predicting the bottom hole pressure in the well at any flow rate. The information can be converted to a somewhat more useful form for the design of surface facilities by calculating[10] the well head pressure corresponding to the bottom hole pressure for various tubing sizes as shown in Figure 4. The low rate portions of the curves may not be possible to achieve if the gas is very wet or if hydrate formation is a problem. The corresponding pressure vs. flow rate curves for the surface equipment may be calculated and drawn as shown on the same figure to arrive at design and operating characteristics for different combinations of well and surface facilities.

As mentioned before, it may be necessary to calculate bottom hole flowing pressures from surface measurements if the bottom hole measurements are difficult or very expensive to make. Even though the surface pressure measurements are usually made from accurate dead weight testers, the calculated bottom hole pressures have significant uncertainty if the condition of the tubing is not well known, if there is a significant liquid retrograde condensation at well bore conditions, or if the gas is quite dense.

The results thus measured and calculated will hold for well flow rates within the tested range as long as the reservoir pressure remains above the dew point and as long as the mechanical condition of the well does not change. The test is usually updated every six months to a year with a single point test. This test is the same as the multi-point test except that only one rate is used. Since n is essentially a function of the flow regime, it is normally assumed to be constant so that the slope of the AOF line is known but the intercept C is not. The single point test therefore establishes a new line on the chart in Figure 1 which is parallel to the original line.

The effective permeability-thickness (kh) near the well bore can also be determined from this testing under certain conditions. Equation 4 shows the expression[6] for the calculation of permeability thickness from the constant C in Equation 1. It assumes laminar flow (Darcy's law) and no skin factor.

$$C = kh/1.417 \times 10^6 \mu ZT \{\ln(0.472\ r_e/r_w) + s\} \tag{4}$$

This equation is valid when n equals 1, i.e., for Darcy flow. Therefore, in theory if we knew the PVT properties of the gas and had information on the effective drainage radius, we could calculate kh. However, n is usually not 1 and therefore this relationship generally does not hold.

For the example shown in Figure 1 the value of n is 0.894 and the value of C is 11.1×10^{-6}. Thus for this example the flow can be considered nearly to obey Darcy's law and an approximation to the kh product can be calculated from Equation 4. In this test the well was on a 120 acre development pattern with a hole size equal to 7 inches. Other information from the example are used to calculate μ, Z and T at bottom hole conditions. The calculation of kh, for s equal to 0, from Equation 4 is shown below.

$$kh\ (\text{md-ft}) = 1.417 \times 10^6\ C\mu ZT\ \ln\ (0.472\ r_e/r_w)$$

$$kh = (1.417 \times 10^6)(11.1 \times 10^{-6})(0.017)(0.89)(676)(6.74)$$

$$= \quad 1094\ \text{md ft}$$

In general, a better approach to this problem is to use Equation 3 which takes into account inertial and turbulent forces and allows the calculation of reservoir properties when Equation 4 cannot be used.

When Equation 3 is integrated in radial coordinates, a practical expression, Equation 5, results[14,15] for evaluating the parameters k and β.

$$p_r^2 - p_{wf}^2 = a\, q_{sc} + b\, q^2_{sc} \tag{5}$$

Equations 6 and 7 give analytical expressions relating the constants a and b to the gas properties and the formation parameters of height, permeability, skin, and turbulence factor.

$$a = 1.417 \times 10^6 \frac{\mu ZT}{kh} \{\ln (0.472\, r_e/r_w) + s\} \tag{6}$$

$$b = \frac{3.161 \times 10^{-6}\ \beta ZT}{h^2}\ G\ (\frac{1}{r_w} - \frac{1}{r_e}) \tag{7}$$

Wattenbarger[13] derived a more rigorous form of Equation 6 which accounts for the dependence of viscosity on pressure. a and b are very simply obtained[16] by plotting the difference in squares of pressures divided by the flow rate, $\Delta p^2/q$, vs. flow rate as in Figure 5. This procedure linearizes Equation 5 by dividing both sides by q_{sc}. The use of later single point tests assumes a constant β but allows the kh to vary. Equations 6 and 7 give the following results for the above example: kh = 1261 md ft and $\beta = 1.8 \times 10^7$ ft^{-1} if s = 0 and h = 10 ft. This value of β is quite low[14] for rock of 126 md.

The fact that the kh values calculated with each of these techniques are very close to the same value is to be expected since the flow condition is very close to Darcy flow. However, you will note that the kh value for the Darcy flow condition is lower than that calculated utilizing Forchheimer equation. This will always be the case since the analysis using Darcy flow will interpret inertial forces as an additional skin factor and permeability thickness ratios calculated under these conditions will tend to be lower than actual values.

<u>Isochronal Tests</u>

As mentioned earlier, conventional back pressure tests may suffer from the need for excessive time to stabilize flow rates in low permeability reservoirs. Isochronal testing is a means of reducing the length of tests in highly productive reservoirs and a means of obtaining meaningful test results in reservoirs where stabilization may not be possible in a practical period of time.

Figure 6 shows the pressure and flow rate characteristics of an isochronal test. All flow rates but the last are held for equal periods of time, not necessarily sufficient to stabilize the rates. The last flow period is extended until it stabilizes. The shut-in periods, however, are long enough to allow the pressure to build up to initial shut-in pressure between each flow period. The length of the flow periods should consider both the time for any well bore storage effects which are introduced due to the shut-in periods to cease and the time necessary for the radius of investigation to get beyond any damage zone. These items are covered in detail in Reference 6. Usually two to three hours are sufficient to meet both these criteria in a wide majority of isochronal tests.

The reason that stabilization is not required is best explained by consideration of the mathematics of transient pressure analysis for Darcy Law flow. The radius of investigation was discussed earlier in connection with the time to achieve pressure stabilization in conventional testing. It can also be described as the point furthest from the well that has experienced a measurable pressure drop as a result of flow from the well bore. It has been shown that the radius of investigation is independent of the rate and hence depends only upon the time of flow and the fluid and rock properties. Hence, for equal flow periods, the volume of reservoir having had an appreciable pressure drop is the same and therefore the test investigates the same volume of reservoir rock for all rates.

The test procedures and evaluation procedures are identical to those for the conventional test methods with one exception. That is, the slope of the straight line on the AOF plot is determined from the first three data points and the location of the line is determined from the last data point (see Figure 8). The flow periods are usually a matter of a few hours each. If stabilization time is too long, it is possible to estimate a value of C from Equation 4 if permeability-thickness and drainage radius can be estimated from pressure buildup analyses and well spacing.

<u>Modified Isochronal Tests</u>

In tighter formations the isochronal testing procedure may still require too much time. The modified Isochronal method makes it possible to carry out deliverability tests in a relatively short period of time for formations of any permeability. As can be seen from Figure 8 the flow periods and the shut-in periods in this procedure are all equal. Therefore, the some-times lengthy periods required for pressure buildup between flow rates are reduced. The theoretical basis for the validity of this technique is similar to that for the isochronal testing.

Whereas the conventional and the isochronal testing procedures use the stabilized bottom hole pressure as a basis for the difference in pressure squared plotted on the ordinate of the AOF graph, the modified isochronal technique requires that the shut-in bottom hole pressure value be replaced with the last reading of the pressure during the shut-in time. Except for this modification in the procedure, the analysis technique as well as the equipment and testing procedures are the same as those for the isochronal tests. The final flow rate may be continued until the pressure stabilizes and the technique described above for the isochronal method can be used to locate the straight line on the AOF plot.

CALCULATING RECOVERABLE GAS VOLUMES

Recoverable gas volumes or gas reserves together with gas deliverability versus pressure are both required for forecasting gas deliverability. Recoverable gas volume is usually estimated by use of one of the following methods.

Volumetric Calculations

This method consists of utilizing well logs, core data and other geologic information to directly calculate reservoir volume and hydrocarbon saturations. Reservoir fluid volumes are determined from PVT relationships either by direct measurement from reservoir fluid samples or from existing correlations. Recovery factors are usually determined from correlations or by analogy from similar reservoirs at a later stage of depletion.

The volumetric method is probably the most widely used procedure in use today. It is particularly useful in the early producing life of the reservoir when the reservoir producing mechanism is unknown or where information required for other techniques is sparse.

Material Balance Calculations

This method utilizes the real gas law, material balance relationships and production history to determine total original gas volume and recoverable gas volume. It is perhaps the second most common procedure in use today. To illustrate this method we make use of the following relationships.[19] First, consider the following material balance in a fixed volume gas reservoir which originally contained n_i moles of gas, now contains n_f moles of gas and produced n_p moles of gas.

$$n_p = n_i - n_f \tag{8}$$

Secondly, consider a reservoir volume balance on the original volume occupied by gas. This volume can be expressed as

$$V_f = V_i - W_e + W_p \tag{9}$$

where V represents volume, W_e is volume of water encroached into the reservoir and W_p is volume of water produced, all at reservoir conditions.

The third relationship required is the real gas law as shown in Equation 9.

$$pV = ZnRT \tag{10}$$

If these relationships are properly combined the following equation for the gas produced between the initial and final conditions can be developed.

$$\frac{p_{sc} G_p}{T_{sc}} = \frac{p_i \, V_i}{Z_i T} - \frac{p_f (V_i - W_e + W_p)}{Z_f T} \tag{11}$$

The subscripts sc refer to standard conditions and G_p is volume of gas produced at standard conditions. For volumetric reservoirs water encroachment is zero and water production is negligible. For fixed values of p_{sc} and T_{sc} and noting that V_i, T, and Z_i are constant for a volumetric reservoir Equation 11 can be rewritten in the following form

$$G_p = c - m \left(\frac{p_f}{Z_f}\right) \tag{12}$$

Where b and m are given by the following

$$c = \frac{p_i \, V_i \, T_{sc}}{Z_i \, p_{sc} \, T} \tag{13}$$

and

$$m = \frac{V_i \, T_{sc}}{p_{sc} \, T} \tag{14}$$

Thus, a plot of produced gas vs. p/Z at static reservoir conditions yields a straight line which if extrapolated to the abandoment pressure of the reservoir yields the recoverable gas volume as shown in Figure 9. A further extrapolation to p/Z equals zero yields the original volume of gas in place. However, this is only true for constant volume reservoirs. For reservoirs with appreciable water encroachment[20] or supernormal pressures[21] this procedure can yield erronous results as shown in Figure 9.

Transient Pressure Analysis

Under certain conditions single well transient pressure tests can yield a minimum value of total reservoir volume. This method is covered elsewhere[18] and will not be reviewed here.

Reservoir Simulation Studies

After production has proceeded to the point where a representative reservoir production history has been established, solution of detailed reservoir performance equations can yield reasonably accurate values for recoverable gas volumes and original gas-in-place. This procedure of reservoir simulation calibrates the detailed coefficients of the complex equations to match the actual performance history and extrapolates given operating conditions to calculate the required values. This method can take into account most variables involved in the makeup of the reservoir, reservoir fluid and producing mechanism.

FORECASTING DELIVERABILITY

The final topic to be covered in this paper is the forecasing of gas deliverability from a reservoir. This information is essential to plan investments, to design facilities, to plan development programs, to write sales contracts and for acquiring bank loans. The desired information for these is well rate and reservoir rate vs. time for the optional plans under consideration.

The deliverability tests provide the rate vs. pressure information for individual wells in a developed field. Reserve estimates are usually based upon volumetric calculations early in the life of the reservoir while p/Z extrapolations or other methods are most often used in later stages of depletion.

Planning can often be done on basis of both the deliverability and p/Z extrapolation curves by construction of a total field rate versus time forecast for a particular development plan. If there is insufficient production history to establish a trend for the p/Z vs. cumulative production plot shown in Figure 9, an interpolation can be made between the initial p/Z point and the volumetrically estimated gas in place. Then the recoverable gas at an assumed abandonment pressure may be estimated. This plot provides a measure of reservoir pressure versus cumulative recovery which, together with the individual well deliverability plots, can be used to construct a total field rate curve versus time for a given development plan.

In practice volumetrically determined reserves will be optimistic for most fixed volume reservoirs. For water-drive reservoirs this estimate may be pessimistic particularly with respect to maintaining total field deliverability rates. However, unless the reservoir type and producing mechanism are known more accurately in advance by analogy with other reservoirs in later stages of development this procedure can be used to provide a reasonable approach to development planning.

CONCLUSIONS

This paper has described and reviewed a number of basic methods used to measure both individual gas well performance and total reservoir reserve values. The most commonly used deliverability test in use today is probably the modified Isochronal technique while the most common reserves estimating procedures are volumetric and material balance techniques involving p/Z versus cumulative production extrapolations. The results of these tests are used to satisfy regulatory body requirements for well performance control and for developing forecasts of gas deliverability rates for optional investment plans.

NOMENCLATURE

Symbol	Nomenclature	Units
A	Area	ft^2
a	Constant in Eqs. 5 and 6	psi^2/MMSCFD
B	Formation volume factor	res vol/std vol
b	Constant in Eqs. 5 and 7	
C	Constant in Eqs. 1 and 4	
c	Constant in Eqs. 12 and 13	
G	Gas volume, gas gravity	MMSCF
h	Formation thickness	ft.
k	Permeability	md.
m	Constant in Eqs. 12 and 14	
n	Gas quantity, exponent	moles
p	Pressure	psia
q	Volumetric flow rate	ft^3/day
R	Gas law constant = 10.732	psi ft^3/lb mole ^oR
r	Radius	ft.
s	Skin	-
T	Temperature	^oR
V	Volume	ft^3
W	Water Volume	res ft^3
Z	Compressibility factor	-
β	Turbulence factor	ft^{-1}
μ	Viscosity	cp

Subscript

e	reservoir boundary, encroached
f	fluid, final
i	initial
p	produced
r	reservoir
s	static
sc	standard conditions
w	well, water
wf	flowing bottom hole
ws	well shut-in

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GAS WELL DELIVERABILITY PLOT OF CONVENTIONAL BACK PRESSURE TEST

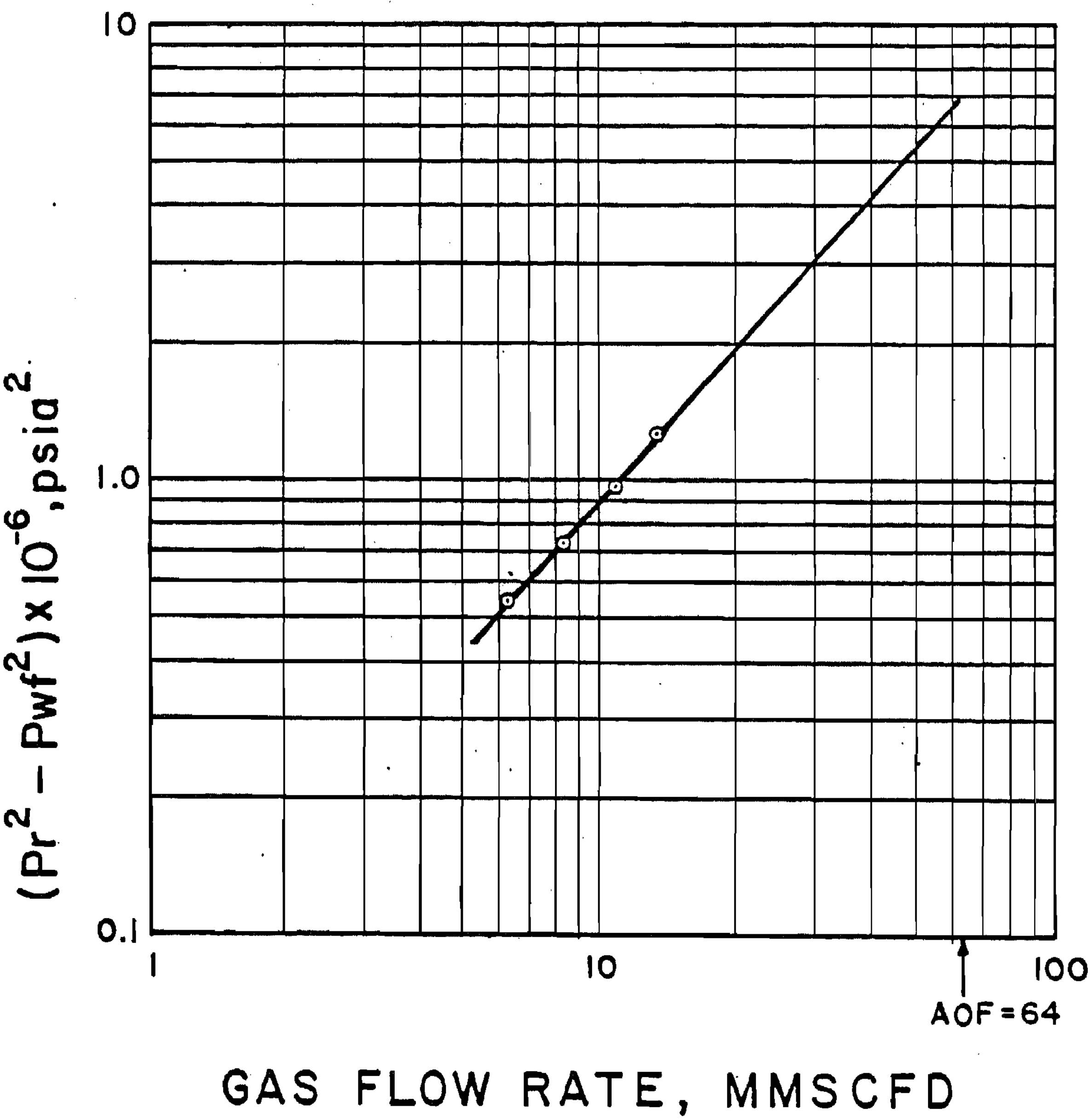

Figure 1

SCHEMATIC DIAGRAM OF SURFACE FACILITIES FOR GAS WELL TESTING

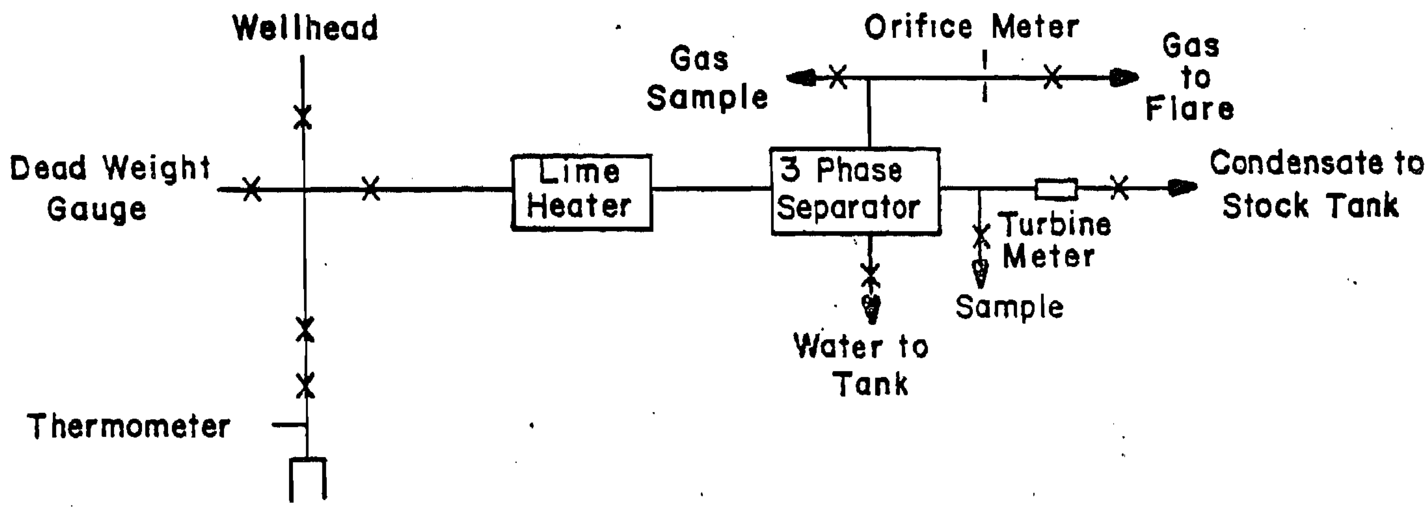

Figure 2

FLOW RATES AND BOTTOM HOLE PRESSURES- CONVENTIONAL BACK PRESSURE TEST

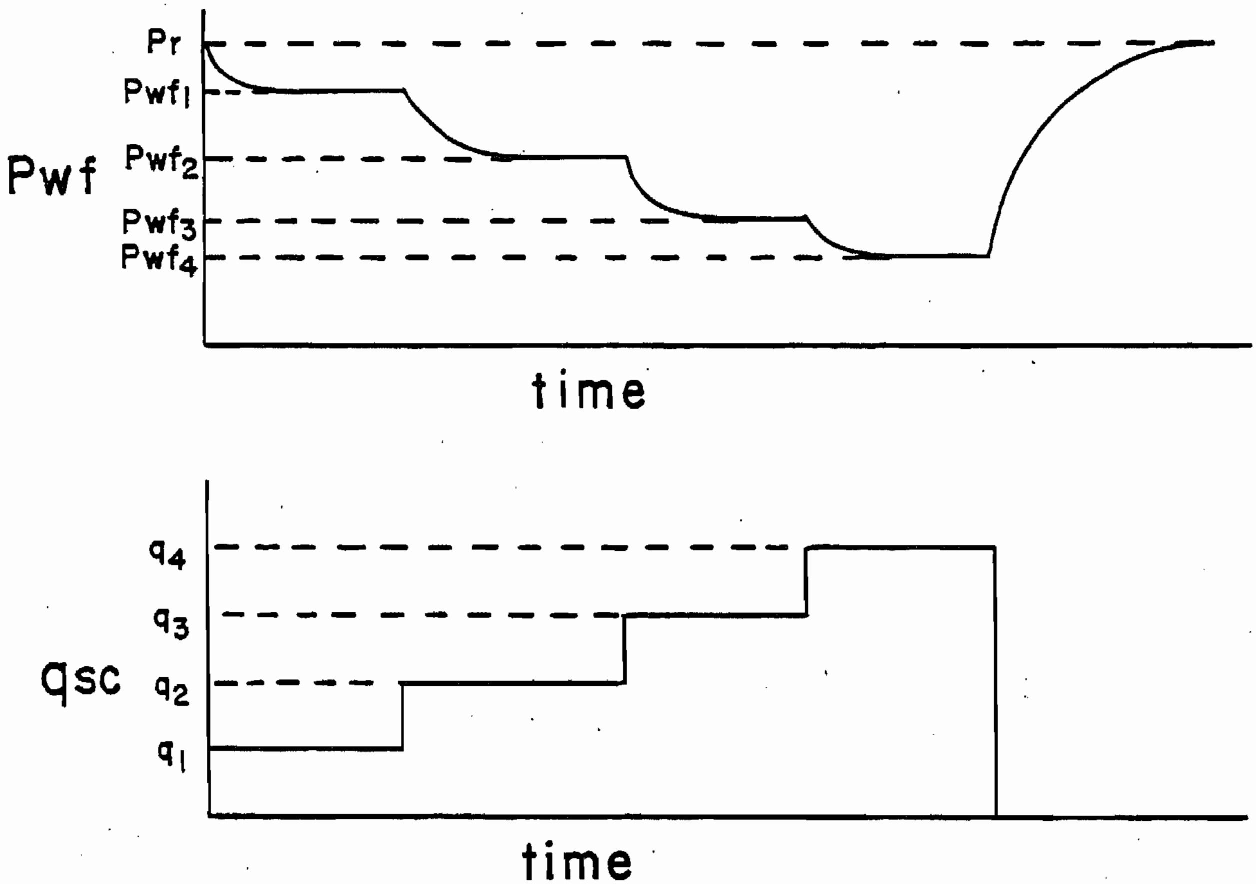

Figure 3

CALCULATED FLOW RATES AT WELLHEAD PRESSURE CONDITIONS

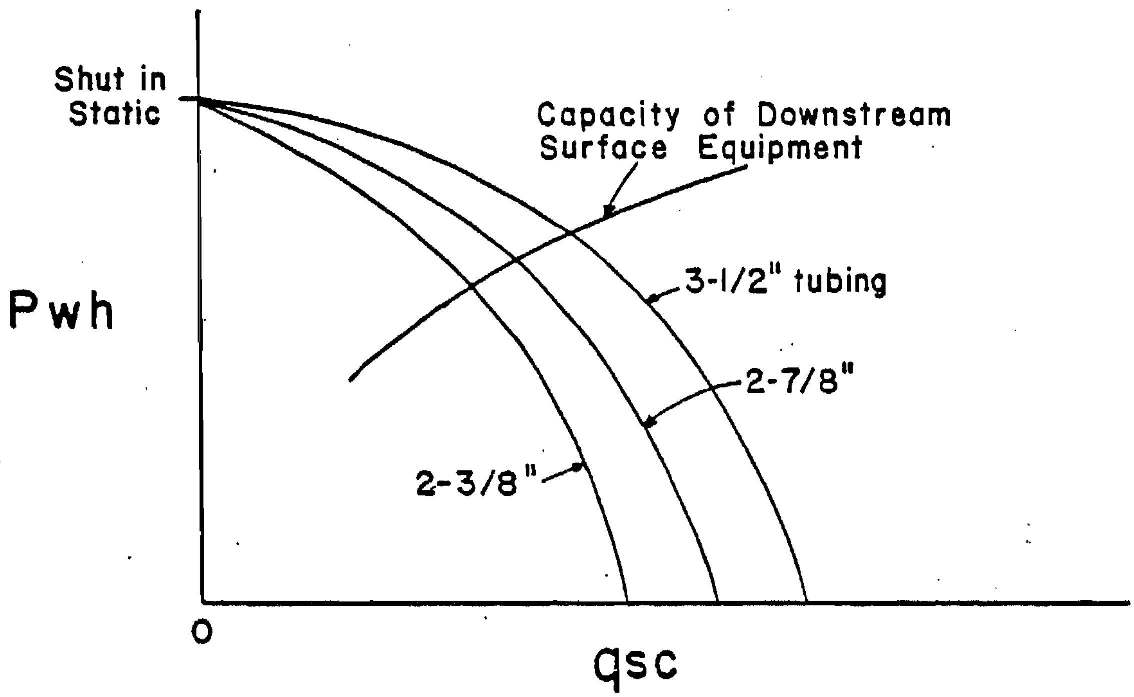

Figure 4

FORCHHEIMER PLOT OF GAS WELL DELIVERABILITY DATA

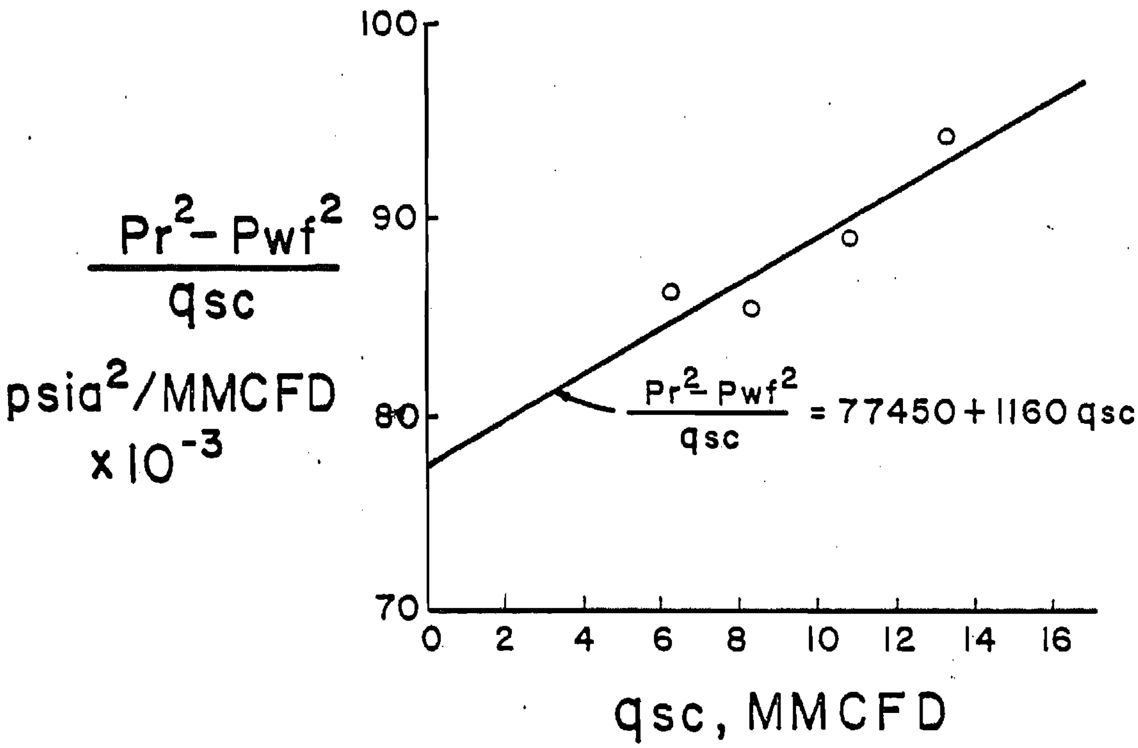

Figure 5

FLOW RATES AND BOTTOM HOLE PRESSURES-ISOCHRONAL BACK-PRESSURE TEST

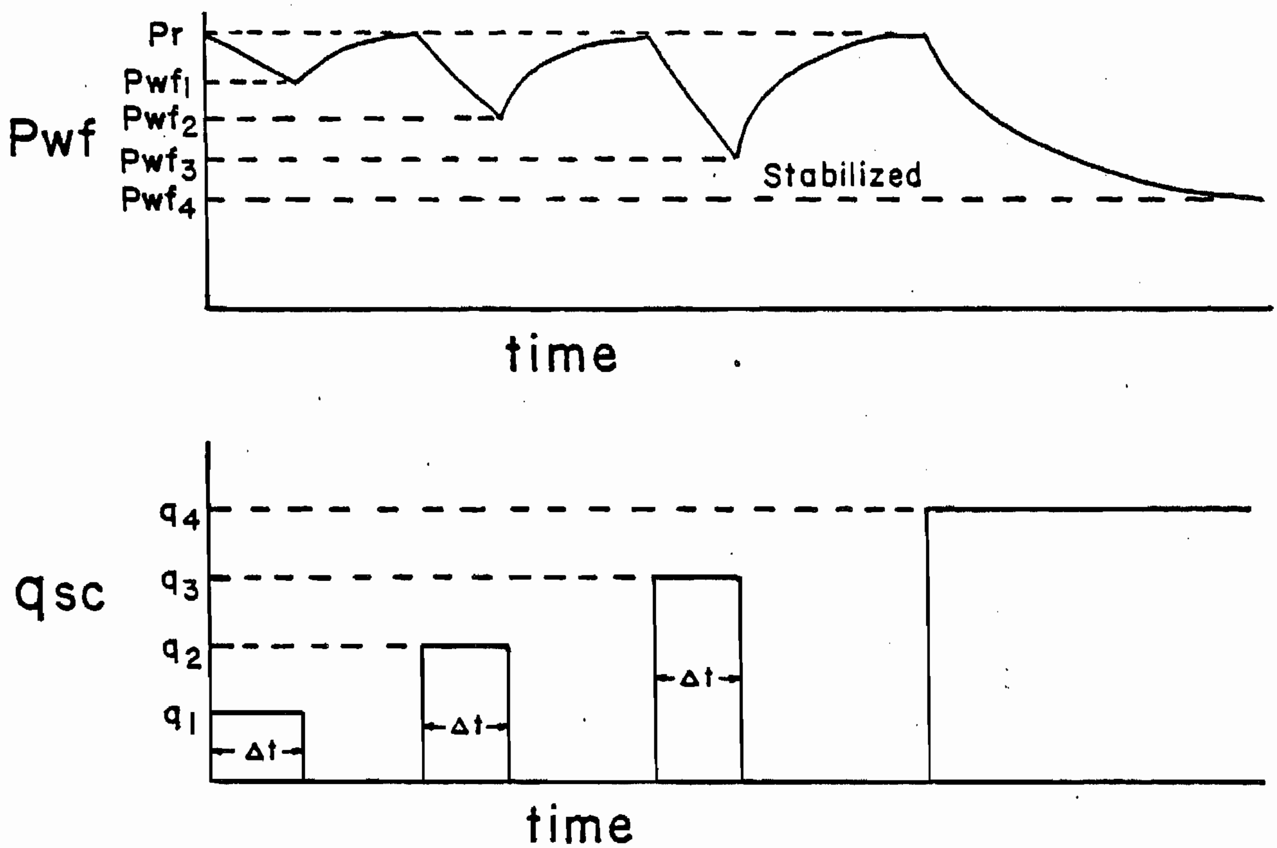

Figure 6

GAS WELL DELIVERABILITY PLOT OF ISOCHRONAL OR MODIFIED ISOCHRONAL TEST

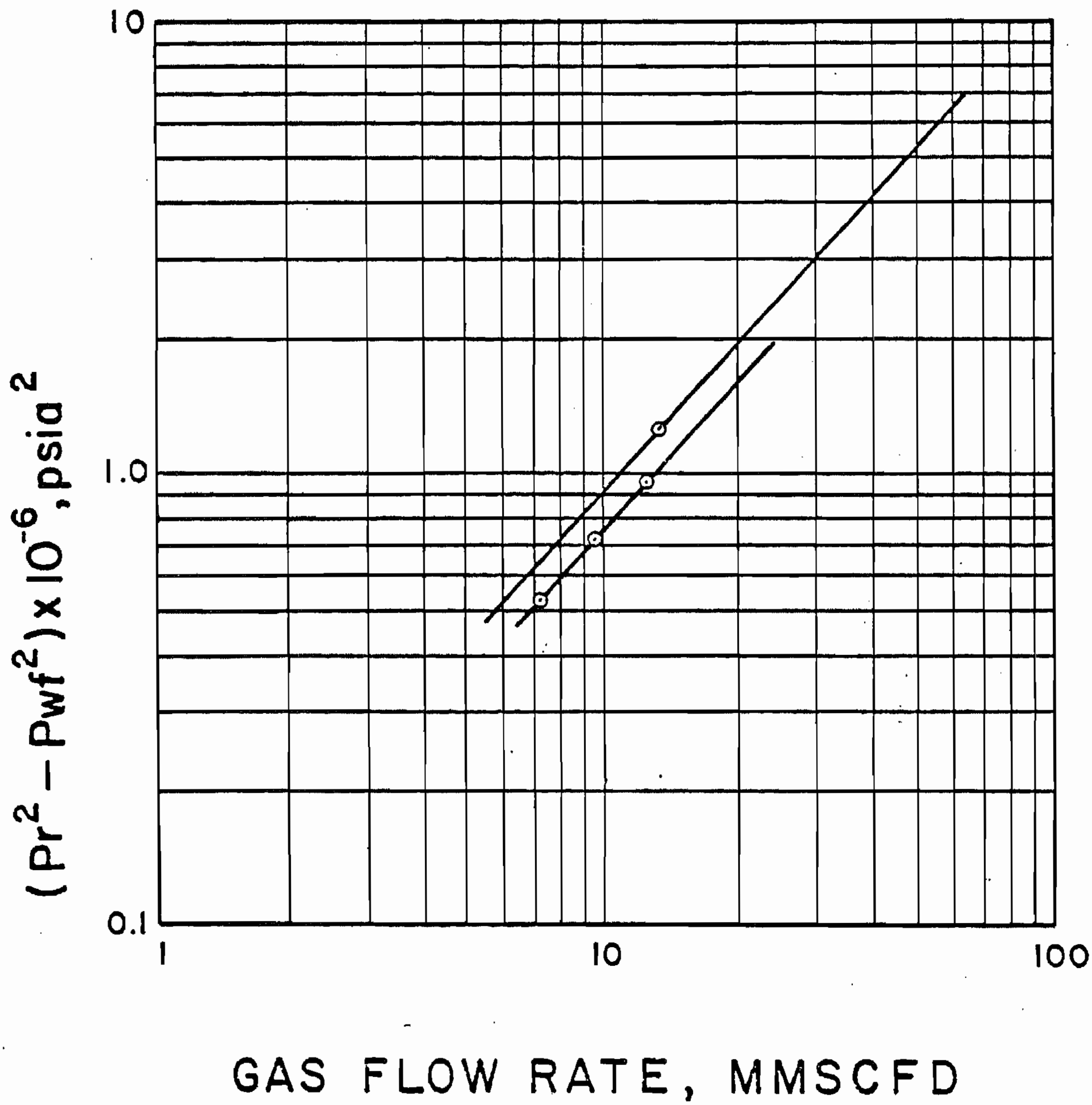

Figure 7

FLOW RATES AND BOTTOM HOLE PRESSURES - MODIFIED ISOCHRONAL BACK-PRESSURE TEST

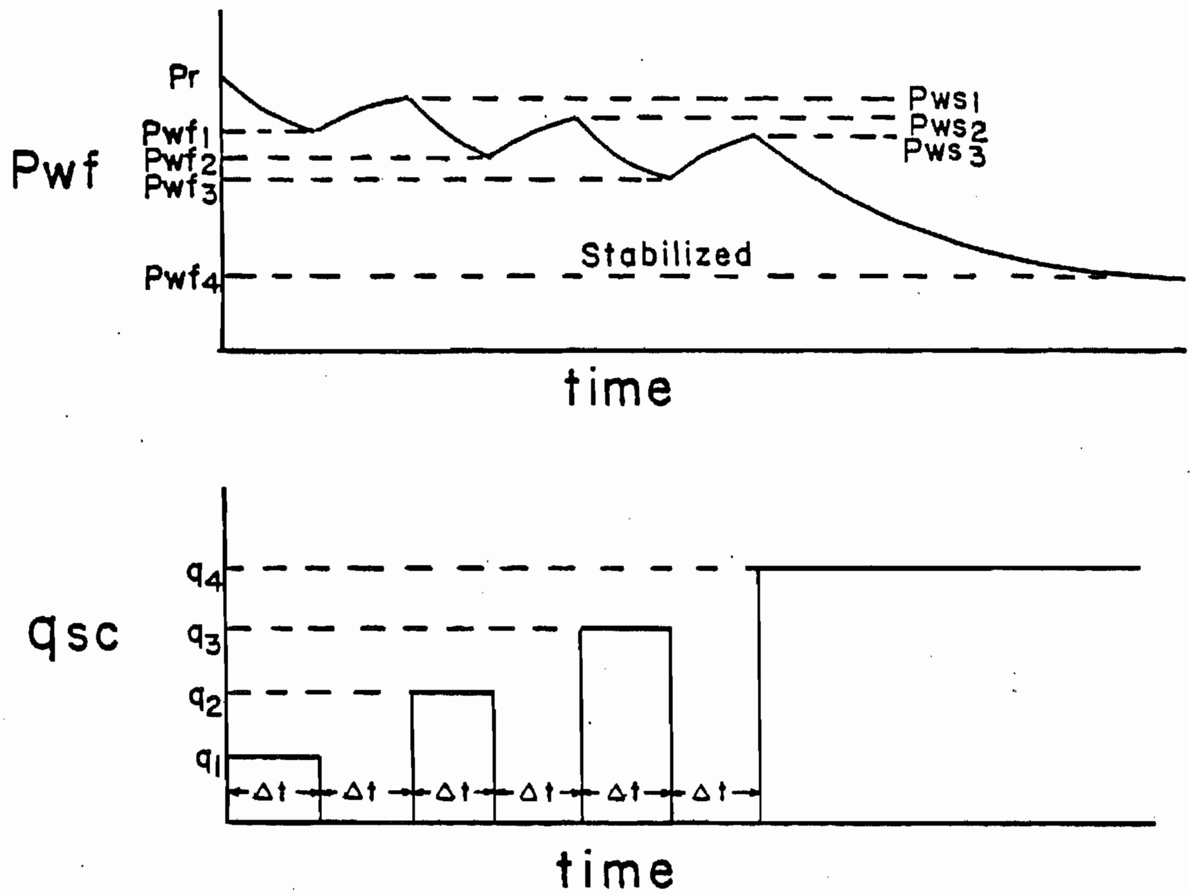

Figure 8

GAS RESERVES ESTIMATION PLOT

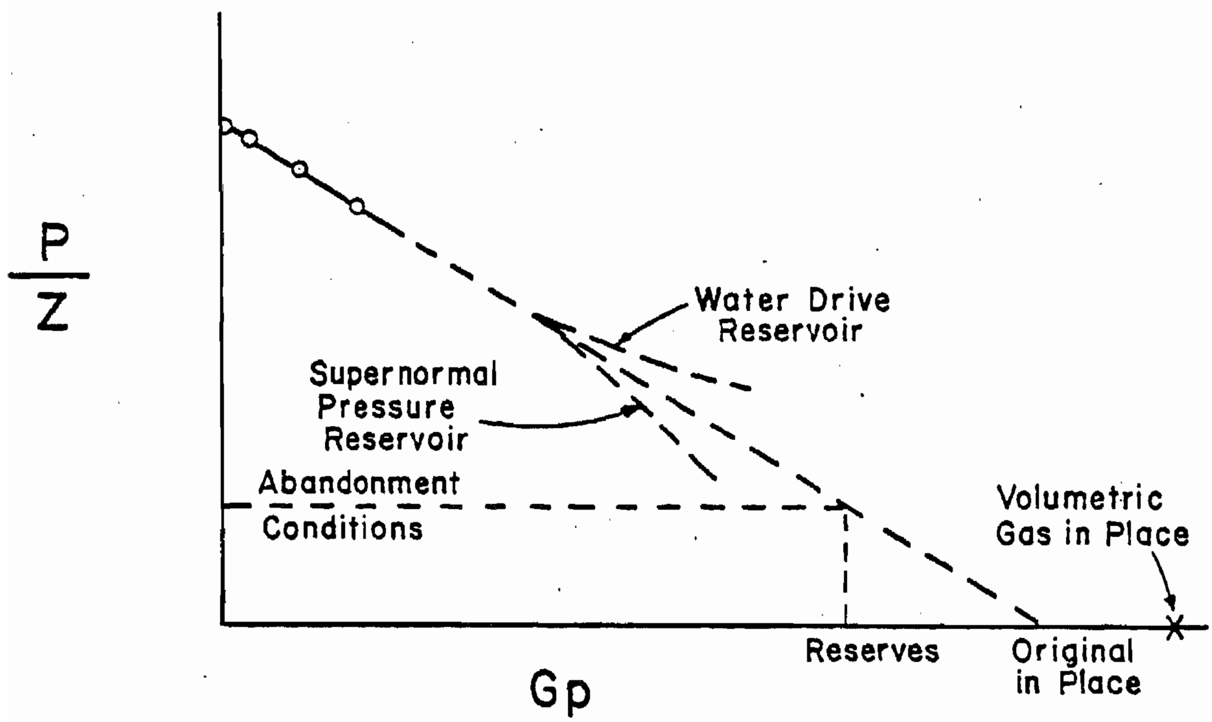

Figure 9